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Direct Testimony and Schedules
Christopher J. Shaw

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-20-____
Exhibit___(CJS-1)

Resource Prudence

November 6, 2020

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Shaw. I am the Manager, Regulatory Policy, for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company's affiliate, Northern States Power, a Wisconsin corporation (NSPW), provides electric service to customers in Wisconsin and Michigan. The Company and NSPW, together under the Interchange Agreement, own and operate the five-state integrated NSP System.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I began working at Xcel Energy in November 2015 as Principle Rate Analyst. Currently, I am a Regulatory Policy Manager in the NSPM Operating Company.

Prior to joining Xcel Energy, I worked for the Minnesota Department of Commerce and the Minnesota Attorney General's Office. My statement of qualifications is provided as Exhibit___(CJS-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I work with the Resource Planning team on the development of resource plans and acquisitions for the five-state integrated Upper Midwest Northern States Power Company system (NSP System), which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the prudence of the following resource additions, project cancellations, and retirement decisions that have been made by the Company since the Company's last North Dakota rate case:

- Retirement of Sherburne County Generating Station Units 1 and 2 (Sherco 1 and 2) in 2026 and 2023, respectively;
- Power Purchase Agreement for Mankato Energy Center Unit 2 (MEC II PPA);
- Cancelation of the Prairie Island Extended Power Uprate (EPU);
- Addition of 187 MW of Solar Projects (187 MW Solar Portfolio); and,
- Addition of Jeffers Wind and Community Wind North Projects.

Q. WHAT IS THE STANDARD FOR A RESOURCE SELECTION OR OTHER COST TO BE DEEMED "PRUDENT" IN NORTH DAKOTA?

A. My understanding is that North Dakota law only allows recovery in rates of money that is "honestly and prudently invested" by the utility. Under general utility ratemaking principles, a resource addition or other investment is prudent if the utility's action was reasonable when considering all relevant circumstances at the time the decision was made. This includes quantitative factors in the form of costs to customers as well as qualitative factors such as regulatory risk and reliability considerations.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO SHERCO 1 AND 2 IN THIS CASE?

A. The Company requests that the Commission find the Company's retirement dates for Sherco 1 and 2 prudent and allow the Company to adjust the remaining lives of the plant for depreciation purposes as further described by Company Witness Mr. Mark Moeller.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE MEC II PPA IN THIS CASE?

A. The Company requests that the Commission find the MEC II PPA prudent and allow recovery of the capacity costs of the contract in base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE PRAIRIE ISLAND EPU IN THIS CASE?

A. The Company requests that the Commission find that the Company's cancellation of the Prairie Island EPU project was prudent and allow recovery of the abandoned costs of the project.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE 187 MW SOLAR PORTFOLIO IN THIS CASE?

A. The Company requests that the Commission deem the Company's decision to enter into the PPAs for the 187 MW Solar Portfolio prudent and allow prospective recovery of the contract costs in the FCR.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO JEFFERS WIND AND COMMUNITY WIND NORTH IN THIS CASE?

A. The Company requests that the Commission find the Company's decision to acquire the Community Wind North and Jeffers Wind facilities to be prudent and allow the costs of the purchase of these repowered facilities to be recovered in base rates.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My Testimony is organized as follows:

- Section II presents a summary of the types of economic analysis discussed throughout my testimony;
- Section III presents the Company's decision to retire Sherco 1 & 2 earlier than anticipated, and the prudence of that decision;
- Section IV provides the historical background and prudence of the Company's addition of the MEC II PPA;
- Section V describes the Company's decision to undertake and subsequently cancel the Prairie Island EPU and the prudence of those decisions;
- Section VI describes the Company's addition of the 187 MW Solar Portfolio and the prudence of that investment;
- Section VII describes the Company's acquisition of the Jeffers Wind and Community Wind North projects and the prudence of these investments; and,
- Section VIII sets forth my conclusions and recommendations regarding the prudence of these various resource additions, retirements, and project cancellations.

II. SUMMARY OF TYPES OF ECONOMIC ANALYSIS

Q. WHAT TYPES OF ECONOMIC ANALYSIS ARE DISCUSSED IN YOUR TESTIMONY?

A. The Company uses three different types of economic analyses to evaluate the present value of revenue requirements (PVRR) impacts of resource additions and retirements, all of which are discussed at various points in my testimony:

(1) a pro forma modeling approach, (2) an analysis using the Strategist resource planning model (Strategist), and (3) an analysis using the EnCompass resource planning model (EnCompass).

Q. WHAT IS A PRO FORMA MODELING ANALYSIS?

A. A pro forma analysis is a simple way to isolate the anticipated costs or benefits of making changes to a specific resource without engaging in full system production cost and expansion plan modeling. This approach uses project cost and production information, along with the Company's financial assumptions, to evaluate the present value and annual cost implications of a proposed acquisition. In general, the pro forma model provides us a simpler view of the economic costs or benefits of a project, based on revenue requirements, than Strategist or EnCompass. We often use this modeling internally, as an initial indication of whether a project likely results in customer benefits, prior to or alongside conducting Strategist or EnCompass modeling. We also occasionally use a pro forma analysis to evaluate resource acquisitions when the analysis is more binary, as we did with the Mower County Wind Facility (Case No. PU-19-310).

Q. WHAT IS THE STRATEGIST RESOURCE PLANNING MODEL?

A. Strategist is a modeling program that the Company has used for years to simulate the operation of the NSP System and estimate the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. Until recently, the Company used this tool, which is still industry standard, for the majority of its resource planning efforts. Compared to the pro forma analysis, Strategist helps us evaluate proposed acquisitions in the broader context of the integrated NSP System and our most recent Integrated Resource Plan's Preferred Plan by fully evaluating the impacts of an action relative to our entire resource portfolio.

Q. WHAT IS THE ENCOMPASS MODELING TOOL?

A. Like Strategist, Encompass is a capacity expansion tool that allows the Company to optimize resource expansion plans based on a set of assumptions. One of the primary differences in the models is that Encompass evaluates resource needs and cost on a chronological hourly basis, which better accounts for hourly variations on our system. A full description of the EnCompass modeling tool is included in Schedule 2 to my Testimony. The Company has largely shifted to using the EnCompass tool rather than Strategist to perform capacity-expansion modeling.

Q. WHY DID THE COMPANY MOVE TO USING THE ENCOMPASS MODELING TOOL?

A. We shifted to using the EnCompass modeling tool for our most recent Integrated Resource Plan Supplement (filed on June 30, 2020 in Case No. PU-19-220) because EnCompass provides a more granular look at the costs and savings of certain actions than Strategist and allows us to capture variations in loads and resources on our system on a chronological hourly basis. As we add more variable resources to our system, it becomes increasingly important to ensure that we appropriately consider resource needs on an hourly basis.

III. SHERCO

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explain the basis for the Company's request that the Commission find the retirement dates for Sherco 1 and 2 prudent and allow the Company to adjust its depreciation rates accordingly.

A. Summary of Decision to Retire Sherco 1 and 2

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SHERBURNE COUNTY GENERATING FACILITY.

A. The Sherburne County Generating Station (Sherco) in Becker, Minnesota is the Company's largest power plant in the Midwest, with its three coal-fired units capable of providing a total of approximately 2,200 MW of electricity. Sherco 1 and 2, which were placed in service in 1976 and 1977, respectively, have a production capability of approximately 650 MW each for total capacity of 1,300 MW. Unit 3, which was placed in service in 1987 and is co-owned by the Company and the Southern Minnesota Municipal Power Agency, is not at issue in this rate case.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO SHERCO 1 AND 2 IN THIS RATE CASE?

A. The Company is asking the Commission to adjust the depreciation expense of Sherco 1 and 2 to match the Company's announced retirement dates for these units of 2026 and 2023, respectively. As I discuss further below, Company management made the decision to retire Sherco 1 and 2 in late 2015 based on a number of factors, and it is consistent with the approved remaining lives of the units in South Dakota (Sherco 1 and 2 remaining lives through 2022) and

Minnesota (Sherco 1 remaining life through 2026 and Sherco 2 remaining life through 2023). Consequently, the Company requires a similar adjustment to the remaining lives of these units in North Dakota.

Q. WHAT ARE THE CURRENT REMAINING LIVES OF SHERCO 1 AND 2 IN NORTH DAKOTA?

A. In North Dakota, the remaining lives for Sherco 1 and 2 were approved through 2034 as part of the Settlement Agreement in the Company's 2007 rate case (Case No. PU-07-776), approved by the Commission on December 31, 2008. This remaining life determination was based on a study completed by Advocacy Staff at the time that determined the average life span of all steam generating plants that had retired between 1900 and 2006 was 59 years. This remaining life analysis has not been changed since, causing a mismatch in the book life of Sherco 1 and 2 in North Dakota as compared to other NSPM jurisdictions.

Q. HAS THE COMPANY PERFORMED ANY FINANCIAL AND RESOURCE PLANNING ANALYSES REGARDING THE LIFE OF SHERCO 1 AND 2 SINCE 2008?

A. Yes. Since the settlement of the Company's 2007 rate case, we have repeatedly examined how best to manage the lifecycle of Sherco 1 and 2, beginning in our 2010 resource planning cycle with the Lifecycle Management Study for Sherco Units 1 and 2 (Sherco LCM Study). The Sherco LCM Study found no significant cost advantage between retrofitting Sherco 1 and 2 with pollution controls and retiring the units in 2019 and 2020, assuming a $21.50/ton price on carbon. The LCM Study noted that the cost and timing of environmental regulation and natural gas prices were key drivers of the results, so the Company decided at the time the most prudent course of action was to maintain the plants in operation while awaiting more clarity on potential regulation.

During our 2015 resource planning cycle, the Company continued our study of the lifecycle for Sherco 1 and 2, and ultimately we made the decision to retire the Units in 2023 and 2026, based on ongoing regulatory risks to the facility identified in the Sherco LCM Study and discussions with stakeholders and customers. At the time, the first federal regulations on carbon emissions from existing power plants had just been proposed, and the possibility of other environmental controls remained. Our analyses indicated that the early retirement plan produced virtually no additional costs compared to our 2010 Resource Plan baseline, but would generate $300 million in additional costs compared with our initially proposed 2015 Resource Plan. However, given the ongoing and increasing regulatory risks to the facility—which included the potential to install Selective Catalytic Reverters (SCRs) at a capital cost of $250 million per unit in 2015 dollars)—Company leadership made the decision to retire the Units and transition our generation fleet to flexible natural gas resources paired with significant investments in renewable generation.

We have continued to monitor this decision through additional analyses since 2015, many of which were conducted at the request of the Commission. These analyses have reinforced the prudence of the Company's decision to retire Sherco 1 and 2, as the economics of the decision have continued to improve over time, with gas and renewable prices remaining persistently low. In our most recent analysis, the Company found that retirement of Sherco 1 and 2 in 2026 and 2023, respectively, no longer caused incremental costs, and instead produced $13 million PVRR savings for customers compared to maintaining the plants in operation through 2034.

Q. WHAT HAS BEEN THE GENERAL TREND OF THE COMPANY'S ANALYSES OF ITS PLAN TO RETIRE SHERCO 1 AND 2?

A. The Sherco LCM study noted the potential for future environmental regulation to bring prohibitive costs and also the impact of gas prices on the economics of Sherco 1 and 2. By 2015, the Company's qualitative analysis of potential risks associated with maintaining the plants pointed clearly towards retirement within the planning period. Although the plan generated additional costs when compared to the Company's originally proposed 2015 resource plan, the Company concluded that the retirement plan appropriately balanced the risks and uncertainty while taking advantage of low-cost renewables to transition our fleet and position ourselves for the future. Since 2015, the cost to customers has steadily fallen to the point where we are now projecting savings, due to a continued fall in renewable energy costs and steadily low natural gas prices.

Q. WAS THE COMPANY'S DECISION TO RETIRE SHERCO 1 AND 2 PRUDENT AT THE TIME THE DECISION WAS MADE?

A. Yes. The Company made the decision to retire these resources based on the regulatory risks identified in the Sherco LCM Study and proposed federal carbon regulations. Further, at the time of the Company's decision to accelerate the retirement of these units, many of the Company's constituent communities and large and small customers were advocating a transition of the Company's fleet as quickly as possible. Given that the economic analysis at the time showed the retirement plan would produce minimal additional cost compared to the 2010 Resource Plan and that transitioning our fleet in this way provided significant regulatory hedge value, the Company made the prudent decision to stop investing in these nearly 40-year old facilities. The prudence of this decision has been further borne out by subsequent analyses that the Company has performed.

B. Sherco LCM Study

Q. LET'S DISCUSS THE STUDIES YOU REFERENCED IN MORE DETAIL. WHY DID THE COMPANY FIRST ANALYZE THE LIFECYCLE MANAGEMENT NEEDS OF SHERCO 1 AND 2?

A. During our 2010 resource planning cycle (Case No. PU-10-580), the Company determined that a comprehensive study that would examine the costs of continuing Sherco 1 and 2 operations and evaluate retrofit and retirement scenarios was necessary in light of the potential need to make substantial investments in pollution control equipment. At the time, environmental regulations regarding criteria pollutants were pointing to the potential need to invest in SCR technologies for the plants. Additionally, there was a reasonably high likelihood that carbon dioxide regulation was going to be enacted, which also affected the prudence of continuing to invest in the Units for a materially longer life. To perform the study, the Company completed extensive modeling, reviewed the status of current and potential environmental regulations, and engaged stakeholders to obtain inputs on the various options. This work resulted in the July 1, 2013, Sherco LCM Study, which is provided as Schedule 3 to my Testimony.

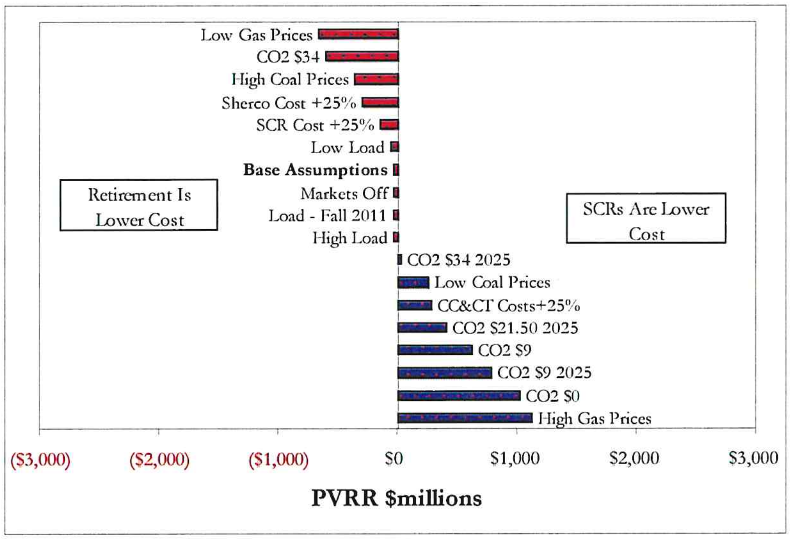
Q. WHAT WERE THE RESULTS OF THE SHERCO LCM STUDY?

A. The results indicated that low natural gas prices and a potential cost of carbon through regulation could materially affect the prudence of continuing to operate Sherco 1 and 2 with newly installed pollution controls versus retiring the units. Figure 1 below shows the results of the analysis, with a baseline assumption of

$21.50/ton cost of carbon dioxide. A zero cost of carbon dioxide sensitivity was also run and is identified in Figure 1 below.

Figure 1:

PVRR of Retirement of Sherco 1 and 2 in 2019 and 2020



Q. WHAT DOES FIGURE 1 DEMONSTRATE?

A. Figure 1 shows that there was little cost difference between retrofitting Sherco 1 and 2 with SCRs and retiring the units in 2019 and 2020 under the base assumptions. This meant that there was no significant cost advantage for either the early retirement or retrofit strategies when we assumed carbon would be priced at $21.50/ton. Figure 1 also illustrates which input assumption sensitivities favored which strategy and how much they change the PVRR results. Low natural gas prices, higher CO_2 prices, higher coal prices, or higher costs at Sherco favored retirement. Assumption sensitivities that favored the installation of SCRs and continued operation included higher natural gas prices, lower CO_2 costs or later implementation of CO_2 costs, low coal prices, or higher construction cost for new natural gas plants. The load sensitivities had little effect.

Q. WHAT CONCLUSIONS DID THE COMPANY DRAW FROM THE SHERCO LCM STUDY?

A. The Company concluded from the Sherco LCM Study that the most prudent course of action was to continue to operate Sherco 1 and 2 and await greater clarity and certainty around the development of environmental regulation and the resulting timing and costs. The study noted that the cost and timing of carbon regulation was a key driver of the results, but it was unknown at the time what if any regulation was forthcoming. The modelling also indicated that gas prices could also be a key driver of the results as lower gas prices would make the coal fired plant less economic. Additionally, the study noted considerable uncertainty around the need to further reduce NO_X emissions, noting that SCRs would only be required if Minnesota fell into nonattainment of the ozone or particulate matter NAAQS.

C. 2015 Resource Planning Cycle

Q. DID THE COMPANY PERFORM FURTHER ANALYSIS REGARDING THE LIFECYCLE OF SHERCO 1 AND 2?

A. Yes. Using the Sherco LCM Study as a starting point, the Company further analyzed potential lifecycle management options for Sherco 1 and 2 in its 2015 resource planning cycle (Case No. PU-15-019). This analysis was included with the Company's 2016-2030 Upper Midwest Resource Plan (2015 Resource Plan), filed with the Commission in early January 2015.

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO SHERCO IN THE 2015 RESOURCE PLAN?

A. The Company's original proposal (made in its January 5, 2015 filing in Case No. PU-15-019) in its 2015 Resource Plan called for operating Sherco 1 and 2 at reduced levels through 2030, while replacing the capacity and energy with a mix of new renewable and natural gas peaking resources (the Preferred Plan). The Preferred Plan noted that further NO_X reductions could be required during the planning period, but that this was dependent on pending litigation and future regulations. Thus, at the time, the Company concluded it could maintain operation of Sherco 1 and 2 without significant investment in SCRs, recognizing that this could change during the planning period. In the event future regulations or litigation required additional emission reductions, the Company stated that it would evaluate whether SCR installation, unit retirement, or another action would be in customers' best interest.

Q. DID THE COMPANY'S PLANS WITH REGARD TO SHERCO 1 AND 2 CHANGE AFTER THE 2015 RESOURCE PLAN WAS ORIGINALLY FILED?

A. Yes. During the course of the 2015 resource planning cycle, the Company refined its Preferred Plan. In an October 2, 2015 filing in Case No. PU-15-019, the Company proposed to retire Sherco 2 in 2023 and Sherco 1 in 2026, and to advance the addition of substantial renewable generation during the planning period, including 1,800 MW of wind, 1,400 MW of large solar generation, and 700 MW of small solar generation. The October 2, 2015 filing is attached as Schedule 4 to my Testimony.

Q. WHY DID THE COMPANY CHANGE ITS PLANS WITH REGARD TO SHERCO 1 AND 2?

A. Between the time of the initial development of the 2015 Resource Plan in January 2015 and the Company's update in October 2015, the Company engaged in extensive discussions with stakeholders and customers, and the U.S. EPA proposed the Clean Power Plan (CPP). While the full impact of the CPP was not known at the time, the proposed rule demonstrated how the potential for environmental regulations would continue to place pressure and cost risk on the operations of Sherco 1 and 2. Based on this regulatory risk and stakeholder input on the 2015 Resource Plan, the Company concluded that there were benefits to maximizing the availability of the Production Tax Credit through increasing purchases of renewable energy and replacing baseload generation during the 2016 - 2030 planning period. The Company also noted that an increasing number of its customers in its five-state service territory wanted cleaner energy, including large employers and cities seeking to meet sustainability goals.

Given these building pressures from regulators, stakeholders, and customers, Company leadership concluded that committing significant amounts of capital to Sherco 1 and 2 did not represent a prudent investment given a longer term view of the Company's energy future.

Q. WHAT ANALYSIS WAS PERFORMED TO SUPPORT THE OCTOBER 2015 REVISION TO THE 2015 RESOURCE PLAN?

A. The Company used the Strategist resource planning model to compare the Company's new plan to retire Sherco 1 and 2 early (2015 Updated Plan) with various scenarios that would continue operation of these units through the end of the planning period in 2030. This analysis was presented in a January 29, 2016 Supplement to the 2015 Resource Plan (2015 Resource Plan Supplement) filed in Case No. PU-15-019. The public version of this analysis is attached as Schedule 5 to my Testimony.[1] The results of this analysis are presented in Table 1 below.

Table 1

2015 Resource Plan Supplement Analysis

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant ?
2015 Updated Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
2015 Updated Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Original Preferred Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

Q. WHAT DOES TABLE 1 SHOW?

A. Table 1 shows that on a Present Value of Societal Costs (PVSC) basis (i.e., including the cost of carbon), the 2015 Updated Plan provided considerable savings as well a 58 percent reduction in CO_2 emissions from 2005 levels by 2030. On a PVRR basis, the 2015 Updated Plan was about the same cost as the

[1] The Company is providing the public (non-trade secret) version of this document for administrative ease. If the Commission requires the trade secret version, we will be happy to provide it in response to a discovery request.

Reference Case ($45,606 million versus $45,605 million), which would continue the operation of Sherco 1 and 2 through the planning period. Relative to the Preferred Plan that was proposed earlier in the initial 2015 Resource Plan, which assumed Sherco 1 and 2 would continue operation through 2030, the 2015 Updated Plan would generate approximately $300 million in additional costs to customers (system-wide) on a PVRR basis. The North Dakota plan produced some minor PVRR savings relative to the 2015 Updated Plan, but was more costly on a PVSC basis.

Q. WHAT IS THE "REFERENCE CASE" IN TABLE 1?

A. The Reference Case referred to in Table 1 represents a continuation of our 2010 Resource Plan, with expansions as necessary to meet minimum system needs, including continued operation of Sherco 1 and 2 through the end of the 2016 – 2030 planning period. We utilize the Reference Case as a baseline for our resource planning efforts as it represents a "business as usual" case against which to measure different scenarios.

Q. WHAT ACCOUNTS FOR THE COSTS AND SAVINGS OF THE DIFFERENT SCENARIOS IN TABLE 1?

A. The primary reason that the 2015 Updated Plan produces essentially no additional costs relative to the Reference Case is that the decision to retire Sherco 1 and 2 in the 2015 Updated Plan was paired with a large increase in very low-cost wind on the Company's system. The 2015 Updated Plan proposed to add 1,800 MW of wind, 1,400 MW of large solar, and 700 MW of small solar to the system by 2030, in contrast with the Reference Case, which proposed 400 MW of wind and 687 MW of total solar additions.

The primary reason that the 2015 Updated Plan produces approximately $300 million in additional costs relative to the original Preferred Plan is because in the 2015 Updated Plan investments in solar resources are moved earlier in the planning period to capitalize on favorable market pricing associated with the extension of the federal Investment Tax Credit (ITC). Additionally, the 2015 Updated Plan adds a combined cycle plant (CC) at the Sherco site to mitigate the capacity loss of retiring Sherco 1 and 2 and other plants in the mid-2020s period, thereby increasing the costs of that Plan relative to the original Preferred Plan.

Q. WHAT IS THE PVSC CALCULATION IN TABLE 1?

A. The Present Value of Societal Costs (PVSC) is the cost of a particular resource addition or plan when externality values are added. The calculation of PVSC is required by Minnesota regulation, and is calculated using the MPUC's regulatory cost of carbon dioxide and externality values for criteria pollutants. By contrast, the PVRR-based analysis excludes carbon costs and all externality values over the modeling period.

Q. HOW SHOULD THE COMMISSION TAKE INTO CONSIDERATION THE ANALYSIS PERFORMED ON A PVSC BASIS?

A. North Dakota law prohibits the consideration of proxy externality costs in the selection of resource additions absent a federal obligation to address particular pollutants. While no federal carbon regulation was in place at the time of the 2015 Resource Plan Supplement, PVSC calculations do provide a reasonable estimate of the impacts of *potential* future regulation. So while PVSC calculations cannot be used in North Dakota to justify the Company's action, they do provide a qualitative window into the decision making of our Company leadership at the time.

Q. IS THERE COMMISSION PRECEDENT FOR USING ENVIRONMENTAL EXTERNALITY VALUATIONS IN PRUDENCE DECISIONS IN NORTH DAKOTA?

A. Yes. In Case Nos. PU-06-481 and PU-06-482, the Commission upheld Otter Tail Power and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of the Big Stone II coal plant. In its August 27, 2008 Order in that case, the Commission found that "[w]hile the Commission is prohibited from considering quantitative environmental externality values, the Commission can consider the possibility of carbon regulation in a qualitative manner."

Therefore, while the Company cannot utilize PVSC calculations on a *quantitative* basis in North Dakota to justify the prudence of a decision to add or retire a resource, the Company and the Commission can consider these calculations in a *qualitative* manner as a general indication of the risk of future carbon regulation.

Q. THE CLEAN POWER PLAN HAS SINCE BEEN REPEALED. DOES THIS CHANGE THE COMPANY'S DECISION?

A. No. While it is true that there is currently no federal carbon price or cap in place due to the final repeal of the Clean Power Plan in 2019, this economic risk can be reintroduced with a new presidential administration, congressional majority, or via litigation. As indicated by the fact that our Resource Plans cover 15-year periods, utilities must plan resources on longer than 4-year time horizons. This is particularly true with regard to large baseload resources like Sherco.

Q. WHAT CONCLUSIONS DID THE COMPANY DRAW FROM ITS ANALYSIS IN THE 2015 RESOURCE PLAN SUPPLEMENT?

A. Due to advantageous market prices, we were able to offset the costs of retiring Sherco 1 and 2 by installing 1,800 MW of low-cost wind earlier in the plan, which mitigates the initial system costs of the accelerated Sherco retirements. On a PVSC basis, this was the least cost option, reflecting the regulatory hedge value of closing the Sherco units, and it was only modestly more expensive than the Reference Case (i.e., business as usual) on a PVRR basis. In light of this, the Company's decision to retire Sherco 1 and 2 was prudent at the time it was presented in the 2015 Resource Plan Supplement.

Q. CAN RETIRING SHERCO 1 AND 2 BE DONE WHILE MAINTAINING SYSTEM RELIABILITY?

A. Yes. There are some risks associated with these retirements, but they are manageable. Sherco 1 and 2 represent over 30 percent of the Company's baseload generating capacity. As the Company makes the transition away from large coal-fired baseload resources, maintaining the reliability of the system is critical. The Company's operational analyses at the time of the 2015 Resource Plan Supplement demonstrated that the most cost-effective way to mitigate the reliability risks associated with retiring Sherco 1 and 2 would be to build a CC at the existing Sherco site. Locating the new CC at the existing Sherco site would allow it to utilize the existing infrastructure, interconnection rights, water allocations and treatment facilities, and local labor pool.

Q. DID THE MINNESOTA COMMISSION TAKE ANY ACTION ON THE 2015 RESOURCE PLAN AS UPDATED BY THE COMPANY?

A. Yes. In a June 11, 2017 order, the MPUC approved the 2015 Updated Plan which included the retirement of Sherco 1 and 2 in 2026 and 2023, respectively, as well as the addition of 1,800 MW of wind, 2,100 MW of large and small solar, and a CC at Sherco. The MPUC further determined that there would likely be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.

Q. IN WHAT PROCEEDING DID THE MINNESOTA COMMISSION APPROVE REMAINING LIVES FOR SHERCO 1 AND 2 CONSISTENT WITH THE 2015 RESOURCE PLAN?

A. The Company adjusted depreciation rates in Minnesota consistent with the 2015 Updated Plan in MPUC Docket No. E,G002/D-15-46 which reflected retirement dates of 2026 for Sherco 1 and 2023 for Sherco 2.

Q. DID THE NORTH DAKOTA COMMISSION TAKE ANY ACTION ON THE 2015 RESOURCE PLAN?

A. No. The Company files its Resource Plans in North Dakota for informational purposes in accordance with the Settlement Agreement approved by the Commission in Case No. PU-07-776. The Commission held an informal hearing on the Company's 2015 Resource Plan on February 11, 2015. Following the Company's filing of the 2015 Resource Plan Supplement described above, Commission staff provided written comments on the 2015 Updated Plan, dated June 3, 2016. Commission staff argued that it was premature to retire Sherco 1 and 2 in 2026 and 2023, respectively, because the implementation of the Clean Power Plan was not certain, nor was the timing of

SCR requirements. Staff further noted that as part of a request for recovery of stranded Sherco costs or replacement generation, the staff would likely argue that the equipment is no longer used and useful and therefore any remaining stranded investment is not recoverable from customers.

Q. DID THE SOUTH DAKOTA COMMISSION TAKE ANY ACTION ON THE 2015 RESOURCE PLAN?

A. No. The Company is not required to file or seek approval for its Resource Plans in South Dakota.

Q. IN WHAT PROCEEDING DID THE SOUTH DAKOTA COMMISSION APPROVE REMAINING LIVES FOR SHERCO 1 AND 2 THAT PLACE RETIREMENT OF BOTH OF THESE UNITS IN 2023?

A. The South Dakota Commission most recently approved a 2022 end of life for Sherco 1 and 2 in Docket EL 14-058.

Q. GIVEN THE THEN-EXISTING CIRCUMSTANCES, WAS THE COMPANY'S 2015 DECISION TO RETIRE SHERCO 1 AND 2 IN 2026 AND 2023 REASONABLE AT THE TIME THE DECISION WAS MADE?

A. Yes. Given that the costs of the 2015 Updated Plan were essentially the same as the Reference Case on a PVRR basis and generated considerable savings on a PVSC basis, it was reasonable for the Company to move forward with a plan that will reduce carbon emissions by nearly 60 percent by 2030 and would comply with the then-proposed Clean Power Plan. Additionally, through technical workshops and informal discussions during the 2015 resource planning cycle, the Company heard from various stakeholders and large and small customers in Minnesota about the need to transition the Company's generation fleet as quickly as possible. Given the environmental regulatory risks and the input of many of our stakeholders, the Company's 2015 Updated Plan provided a cost-effective path to a cleaner energy fleet, while preserving the reliable and safe service our customers expect.

D. Subsequent Analyses

Q. HAS THE COMPANY PERFORMED ADDITIONAL MODELING SINCE 2015 THAT SHEDS LIGHT ON THE DECISION TO RETIRE SHERCO 1 AND 2?

A. Yes. The Company continues to monitor and analyze our decision until we actually shut down the plant. At the request of the Commission, the Company has performed multiple additional analyses of our decision to retire Sherco 1 and 2, including:

(1) an analysis in 2017, as part of the Company's Resource Treatment Framework proceedings (Case No. PU-12-813), which found $323-577 million PVRR in additional costs over the base North Dakota scenario when isolating the costs of the Sherco retirements;

(2) a Strategist analysis in October 2019, in response to a Commission staff inquiry regarding our 2019 Resource Plan (Case No. PU-19-220), which found $17 million PVRR in additional costs relative to the same North Dakota base scenario; and

(3) an EnCompass analysis in August 2020, which found $13 million PVRR in savings generated by the Company's Sherco retirement plan.

Although, as discussed above, the Company's decision to retire Sherco 1 and 2 early was prudent when made in 2015, these subsequent analyses reinforce that decision.

Q. WHAT HAVE THESE SUBSEQUENT ANALYSES DEMONSTRATED ABOUT THE COMPANY'S DECISION TO RETIRE SHERCO 1 AND 2?

A. The analyses that the Company has performed since 2015 have confirmed that the Company's decision to retire Sherco 1 and 2 in 2023 and 2026 was prudent and will generate savings for our customers.

Q. PLEASE DESCRIBE THE ANALYSIS OF THE SHERCO RETIREMENTS THAT THE COMPANY PERFORMED IN 2017.

A. In response to a staff inquiry as part of the Company's Resource Treatment Framework proceedings (Case No. PU-12-813), the Company further analyzed the costs and benefits of the 2015 Updated Plan as compared to the North Dakota-approved retirement date of 2034. This analysis was intended to show the costs or savings associated with the Sherco retirements only, rather than comparing the 2015 Updated Plan in its entirety with other plans. Said differently, this analysis isolates only the economic impact of retiring Sherco 1 and 2 in 2026 and 2023 without the including the impact of the additions of wind energy or the Company's proposed Sherco CC plant. The results of this analysis are shown in Table 2 below.

Table 2

Sherco Isolated Analysis of 2015 Updated Plan

Scenario	PVSC BASE	PVSC Low Gas	PVSC Mkts On	PVSC Low Gas Mkts On	PVRR (Rate Impact)	PVRR Low Gas	PVRR Mkts On	PVRR Low Gas Mkts On	PVSC IRP Renewables	PVSC IRP Renewables MH Ext	PVRR Mkts On IRP Renewables MH Ext
Retire per 2015 Updated Plan	0	0	0	0	0	0	0	0	0	0	0
Extend to 2034	32	151	94	116	(521)	(323)	(577)	(337)	84	210	(362)

Q. WHAT DOES TABLE 2 SHOW?

A. Table 2 shows the cost difference between our plan to retire Sherco 1 and 2 and the option to extend the units to their currently-approved North Dakota retirement date of 2034. Table 2 shows that the retirement of Sherco 1 and 2 resulted in $323-577 million PVRR in additional costs over the base North Dakota scenario of Sherco 1 and 2 retiring in 2034. The range in the estimated costs in Table 2 is due to different assumptions on market conditions and the amount of renewables used for replacement energy. While early shutdown results in additional costs, it is important to note that these PVRR results do not include any costs associated with potential required environmental controls. Indeed, Table 2 shows that on a PVSC basis, our plan to retire Sherco 1 and 2 results in savings to customers in all sensitivities. As I discussed earlier, PVSC results can be used as a general indication of the hedge value of a decision against the potential for future environmental regulation. This analysis used the same assumptions as our 2015 Resource Plan.

Q. WHY DO THE COSTS OF RETIRING SHERCO 1 AND 2 EARLY APPEAR HIGHER IN THIS ANALYSIS THAN IN THE 2015 RESOURCE PLAN SUPPLEMENT DISCUSSED ABOVE?

A. The range of costs associated with retiring Sherco 1 and 2 in 2026 and 2023, respectively, is higher in Table 2 than in the 2015 Resource Plan Supplement discussed earlier because, at the request of Commission staff, this analysis isolated the impact of the Sherco 1 and 2 retirements, rather than comparing the 2015 Updated Plan with the Reference Case and the original Preferred Plan as a whole. As a result, the savings associated with our additional early investments in low-cost wind resources are not reflected in the PVRR results in Table 2.

Q. WHAT SHOULD THE COMMISSION TAKE AWAY FROM THIS ANALYSIS?

A. The accelerated shutdown of Sherco 1 and 2 was one element of our 2015 Resource Plan, which also included significant additions of renewables, operation of the nuclear fleet through current licenses, additions of natural gas generation, and energy efficiency measures. Isolating the decision to retire these units removes critical context from the decision and does not reflect how we actually operate our system. In the broader context, the decision to retire Sherco 1 and 2 was and remains prudent.

Q. PLEASE DESCRIBE THE OCTOBER 2019 ANALYSIS OF THE SHERCO RETIREMENTS.

A. In response to a Commission staff inquiry regarding our 2019 Resource Plan (Case No. PU-19-220), in October 2019 the Company used the Strategist modeling tool to analyze the impact of retiring Sherco 1 and 2 in 2026 and 2023, respectively, against a Base Case in which the Units would retire in 2034 along with several other assumptions requested by Commission staff. These assumptions included removing externality costs, renewable energy objectives, and Sherco CC ownership from the model, because Units 1 and 2 would not be retired until 2034 in this scenario and thus the Sherco CC would not be needed. The public version of the full list of assumptions for this analysis is listed in Schedule 6 to my Testimony.[2]

[2] The Company is providing the public (non-trade secret) version of this document for administrative ease. If the Commission requires the trade secret version, we will be happy to provide it in response to a discovery request.

Q. WHAT WERE THE RESULTS OF THIS OCTOBER 2019 ANALYSIS?

A. The analysis demonstrated that the retirement of Sherco 1 and 2, as planned by the Company, results in only $17 million PVRR additional costs to customers when compared to a base case of retirement in 2034, as currently approved in North Dakota. Importantly, in the low natural gas prices scenario, the Sherco retirement option shows savings of $60 million PVRR for customers. The results of this analysis are shown in Table 3 below. This shows a trend that, as time passed since 2015 and conditions around the economics of coal fired generation continued to evolve, the Company's decision to retire Sherco 1 and 2 in the 2015 was prescient.

Table 3

October 2019 Strategist Results

	5-1 Sherco 12 Early
Base	$36,541
Change	$36,558
Costs (Savings)	$17
Low Gas	**5-1 Sherco 12 Early**
Base	$35,342
Change	$35,282
Costs (Savings)	($60)

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THIS ANALYSIS?

A. This analysis demonstrates that the Company's decision to retire Sherco 1 and 2 continues to improve from a cost perspective as time passes and assumptions are updated to then-current market levels. Lower natural gas prices increase the benefits or reduce the costs of early Sherco 1 and 2 retirements. As with other analyses I described earlier, the PVRR analysis does not factor in the costs and risks associated with potential future environmental regulation.

Q. PLEASE DESCRIBE THE MOST RECENT ANALYSIS OF THE SHERCO 1 AND 2 RETIREMENTS THAT THE COMPANY PERFORMED.

A. At the request of Commission Staff, we used the new EnCompass modeling tool to conduct an additional analysis using the same base North Dakota assumptions that I described earlier. This analysis found that retirement of Sherco 1 and 2 in 2026 and 2023 would produce $13 million PVRR savings relative to the Base Case requested by the Commission staff. The results of this analysis are shown in Table 4 below.

Table 4

August 2020 EnCompass Results

	5-1 Sherco 1&2 Early
Base	$36,105
Change	$36,092
Costs (Savings)	($13)
Low Gas	**5-1 Sherco 1&2 Early**
Base	$35,288
Change	$35,111
Costs (Savings)	($176)

Q. WHAT ARE THE PRIMARY REASONS THAT THE EARLY SHERCO RETIREMENTS WENT FROM REPRESENTING ADDED COSTS IN THE 2015 PLANNING MODELS TO DELIVERING PVRR SAVINGS?

A. The general evolution of the utility industry has strengthened the main drivers of the LCM study results indicating an early retirement of Sherco 1 and 2 would be prudent. Persistently low natural gas prices coupled with cost-effective renewable energy has created a new dynamic with respect to coal economics. More specifically, low gas prices have effectively made gas powered generation a more cost effective capacity resource. And, low cost wind energy has created a more stable price hedge against gas price volatility than the fuel diversity provided by coal-fired generation.

This change was not driven by any legislative changes or environmental regulations—although those are still possible—but rather primarily by the consistently low price of natural gas, wind, and solar energy over this period. As I noted earlier, the Sherco LCM Study found that natural gas prices were a primary driver of the costs of retiring Sherco 1 and 2, and the "low gas" scenario through all of our modeling has generated the least costs or most savings for Sherco retirement. Thus, the market trends of low gas and renewable prices have caused the economics of our retirement decision to continue to improve, as coal generation (including Sherco 1 and 2) has become a marginal resource.

Q. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY SHERCO 1 AND 2 ARE MARGINAL RESOURCES IN THE COMPANY'S GENERATION PORTFOLIO.

A. Due to the Company's strong capacity position and the higher relative cost of running coal plants, Sherco 1 and 2 are now rarely called upon to run during the spring and fall off-peak seasons. Sherco 2 did not clear the 2019 Midcontinent

Independent System Operator (MISO) Planning Reserve Auction, thus the Company is not required to offer it into the MISO energy market. Sherco 1 and 2 are now offered with the default commit status of "economic" rather than "must run," resulting in a significant reduction in the number of hours run due to the unfavorable economics of coal-fired generation. Table 5 below shows that, over more than a year between 8/25/19 and 8/31/20, Sherco Unit 1 started a total of 12 times and Sherco Unit 2 started 6 times.

Table 5

Recent Operations at Sherco 1 and 2

Sherco Unit #	Date Range	Run Hours		Offline Hours		Total Hours	Starts by Type		
		Company Must Run	MISO Economic	Reserve Shutdown	Outage		MISO Economic	Company Must Run	Total
1	8/25/19-8/31/20	5846	781	1981	344	8952	4	8	12
2	8/25/19-8/31/20	5774	926	2248	4	8952	2	4	6

Q. HAS THE COMPANY PERFORMED OTHER MODELING ON THE OPERATION OF SHERCO 1 AND 2?

A. Yes. As part of our proposal to shift Sherco Unit 2 to seasonal dispatch, the Company completed PROMOD modeling showing that, in most shoulder-season months, offering Sherco 2 into the MISO market through "economic commitment" would result in uneconomic operation of the unit. In other words, based on the offers we are currently using, the variable cost of operating the facilities (fuel and variable O&M) would be more than the units would receive in revenue.

Q. WHAT IS THE PROMOD MODELING TOOL?

A. PROMOD, short for production modeling, is a dispatch model the Company uses to analyze the cost of operating our fleet by dispatching our system 8,760 hours a year. Specifically, PROMOD is a computer program that simulates the electric market on an hourly constrained-dispatch basis based on models containing generation unit locations and operating characteristics, transmission grid topology, and market system operations. The PROMOD software can calculate the future cost of producing electricity, market congestion, and energy losses based on these assumptions.

Q. WOULD SHERCO 1 AND 2 BE DISPATCHED JUST AS SPARINGLY IN A "MARKETS OFF" SCENARIO?

A. Yes. The high cost of running Sherco 1 and 2 has moved this resource down our stack. Thus, even if the Company were just dispatching its own resources on a least cost basis in the absence of a market, Sherco 1 and 2 would still rarely be used.

Q. DID THE COMPANY UPDATE ITS ASSUMPTIONS FOR THE COST OF REPLACEMENT ENERGY IN THE MOST RECENT ANALYSIS?

A. Yes. Consistent with past practice, we incorporated the then most current *2019 Annual Technology Baseline* (ATB) data from the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) in the EnCompass model. The

NREL data represents the most currently available, reputable, forecasting for new technology costs.[3]

Using the NREL study, our resource planning assumptions for wind and solar resources resulted in slightly lower assumed costs than we used in our initial analysis while storage has higher costs. We also adjusted capacity factor estimates for both wind and solar resources to be more reflective of regional production trends. This resulted in lower assumed generic wind capacity factors and higher assumed generic solar capacity factors. Finally, in order to account for continuing transmission constraints in MISO West, we increased the assumed interconnection costs associated with generic renewables to $500/kW from $400/kW previously for wind and $200/kW for solar from $140/kW. By adding in this material cost increases for resource due to transmission needs, we are transparently including the "hidden" costs of transmission build out in our resource planning assumptions.

On the whole, these updated assumptions result in more PVRR savings for our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, because the cost of replacement energy (primarily gas, wind, and solar) continues to fall from where it was when we initially analyzed these retirement dates in the 2015 Resource Plan.

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[3] The NREL ATB data is available at: https://atb.nrel.gov/electricity/archives.html.

Q. YOU MENTIONED THAT A RESOURCE DECISION SHOULD BE DEEMED PRUDENT BASED ON WHETHER IT WAS REASONABLE AT THE TIME THE DECISION WAS MADE, SO WHY DOES IT MATTER THAT THE COST ESTIMATES FOR THE SHERCO RETIREMENTS HAVE IMPROVED SINCE 2015?

A. It is true that the prudence of a resource decision is measured at the time the decision was made, and the Commission should make its prudence determination for the Company's Sherco retirements based on that decision. However, in the case of a resource *retirement* rather than a resource *addition*, the Company has the time, and therefore ability, to continue to monitor its decision to determine if a different course is appropriate. Shutting down resources that have provided baseload electricity to our customers for 40 years is a major decision that will have implications for decades to come. As a result, even after we made the decision to retire Sherco 1 and 2 in the 2015 Resource Plan Supplement, we have continued to evaluate the impacts of this course of action on our customers to ensure that it remains the most prudent path.

In this Rate Case, we are only asking the Commission to adjust the remaining lives of these units to match our current plans. Should our plans change, the remaining lives can be adjusted again in the future, or they could keep running while fully depreciated. However, as I stated earlier, our further analysis of the plan to retire Sherco 1 and 2 early has demonstrated that Company leadership made the correct choice to do so in the 2015 Resource Plan Supplement.

E. Summary

Q. WAS THE COMPANY'S DECISION TO RETIRE SHERCO 1 AND 2 IN 2026 AND 2023, RESPECTIVELY, PRUDENT AT THE TIME THE DECISION WAS MADE?

A. Yes. After significant study and stakeholder input, the Company made the decision in 2015 not to further invest in nearly 40-year old coal generating units and instead shift to more flexible natural gas resources paired with significant investments in renewable generation. The Company had already performed the Sherco LCM study, which noted the potential for future environmental regulation to bring prohibitive costs and also the impact of gas prices on the economics of Sherco 1 and 2. At the time, the Company elected to keep the plants in place. By 2015, the Company's qualitative analysis of potential risks associated with maintaining the plants pointed clearly towards retirement within the planning period. On a quantitative basis, the plan to retire Sherco 1 and 2 in 2026 and 2023 produced virtually no additional costs when compared with our 2010 Resource Plan. Although the retirement plan did generate additional costs when compared to the Company's originally proposed 2015 Preferred Plan, the Company concluded that the retirement plan appropriately balanced the costs and future risks and uncertainty while taking advantage of low cost renewables to transition our fleet and properly position ourselves for the future. Since the time that decision was made, the Company has continued to evaluate the decision to retire the units in 2023 and 2026, and the cost to customers has fallen further, due to a continued fall in renewable energy costs and steadily low natural gas prices, reinforcing the prudence of this decision.

Q. WHAT DOES THE COMPANY REQUEST IN THIS RATE CASE WITH REGARD TO SHERCO 1 AND 2?

A. The Company is requesting that the Commission adjust the remaining lives of Sherco 1 and 2 to reflect their retirement in 2026 and 2023, respectively.

IV. MANKATO ENERGY CENTER II PPA

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explain the basis for the Company's request to recover the capacity and energy costs associated with the Power Purchase Agreement (PPA) for the energy and capacity from the new CC turbine at the Mankato Energy Center (MEC II). The Company requests that the Commission find the MEC II PPA prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the FCR.

A. Mankato Energy Center Background

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE MANKATO ENERGY CENTER FACILITY.

A. The Mankato Energy Center located in Mankato, Minnesota is a 760 MW 2x1 CC natural gas facility. Unit 1 (MEC I) is a 375 MW CC that was completed in 2006 by Calpine Corporation as a 1x1 CC with the intent to expand with a second unit. The capacity and energy of MEC I has been under contract with the Company since 2006 and is scheduled to expire in 2026. In June 2019, the facility was expanded with the addition of a second combustion turbine, transforming the facility to a 2x1 CC and adding approximately 345 MW of capacity (MEC II). MEC II is located on the same site and is incorporated into the existing footprint of the MEC I unit. The capacity and energy of MEC II is committed to the Company under a 20-year PPA which commenced in June 2019.

Q. WHAT IS THE OWNERSHIP HISTORY OF MEC II?

A. Before starting construction of the MEC II expansion, Calpine Corporation sold the MEC I facility and MEC II expansion rights to Southern Power in late 2016. In late 2018, the Company executed agreements with Southern Power to acquire the entire MEC facility, including the MEC II expansion that was then under construction. The Company filed an Advance Determination of Prudence (ADP) for this purchase in December 2018 in Case No. PU-18-403. During the pendency of that ADP, Southern Power completed the MEC II expansion on time and placed MEC II in-service on June 4, 2019. In late 2019, the Company withdrew its ADP application because the Company planned to instead acquire MEC I and II through a non-regulated affiliate. This purchase closed in January 2020. Since then, the Company's non-regulated affiliate has sold the facility to Southwest Generation. The sale to Southwest Generation closed on July 21, 2020. Notwithstanding this complex ownership history, the Company remains under contract to purchase the capacity and output of MEC II under the MEC II PPA.

Q. WHAT IS THE COMPANY'S CONTRACTUAL ARRANGEMENT REGARDING MEC II?

A. On April 28, 2015, Mankato Energy Center, LLC (an affiliate of Calpine Corporation) and the Company entered into a 20-year PPA with a kW-month price for capacity and MWh price for energy. The proposed capacity and energy prices escalate annually after the first year of operation. The new MEC II CC was placed in service in 2019, so the PPA will run until 2039.

Q. WHAT ARE THE PRINCIPAL TERMS OF THE MEC II PPA?

A. The proposed capacity and energy prices escalate annually after the first year of operation, beginning at **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** and rising to **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**. The other terms in the PPA generally mirror the same terms in the MEC I PPA, which reduces the administrative burden associated with using two different payment calculations and billing processes for the two PPAs.

Q. HAS THE COMPANY SOUGHT COMMISSION APPROVAL OF THE MEC II PPA IN OTHER PROCEEDINGS?

A. Yes. The Company requested an ADP for the MEC II PPA in 2015 in Case No. PU-15-96.

Q. WHAT WAS THE OUTCOME OF THAT CASE?

A. At the Company's request, the Commission dismissed the Company's application without prejudice to allow the Company to raise the issue with the Commission again in the future.

Q. WHAT IS THE COMPANY REQUESTING THE COMMISSION DECIDE WITH RESPECT TO THE MEC II PPA IN THIS CASE?

A. The Company requests that the Commission find the MEC II PPA prudent and allow recovery of the capacity costs of the contract in base rates. The Company's decision to add the MEC II PPA was prudent because the forecast upon which the decision was made predicted a capacity need, and the MEC II PPA provided a low-cost, combined-cycle solution to fill that identified need.

The MEC II resource provides dispatchable, low cost energy to our system, which is particularly important as part of our overall replacement plan for the retirement of baseload resources such as Sherco 1 and 2.

B. Need for and Selection of MEC II PPA

Q. PLEASE SUMMARIZE THE CIRCUMSTANCES UNDER WHICH THE COMPANY CHOSE TO PURSUE THE MEC II PPA.

A. In our 2010 resource planning cycle (Case No. PU-10-580), the Company identified a need for up to 500 MW of incremental capacity by 2019 based on the Company's fall 2011 forecast (Fall 2011 Forecast), which updated the initial demand and energy forecast included in the 2010 Resource Plan. Specifically, the Fall 2011 Forecast identified a capacity need of approximately 150 MW beginning in 2017 growing up to approximately 500 MW in 2019/2020, and suggested a capacity need growing to 920 MW by 2024. Based on this identified need, the Company determined that it would be prudent to add capacity to its system.

Q. HOW DID THE COMPANY DETERMINE WHICH RESOURCES IT WOULD PURSUE TO MEET THE NEED IDENTIFIED IN THE FALL 2011 FORECAST?

A. To meet this need, the Company initiated a "Competitive Acquisition Process" in Minnesota (MPUC Docket No. E-002/CN-12-1240), commonly referred to as a "CAP/CON" Proceeding, in order to ensure an open and competitive bidding process for the needed capacity. This process is required of the Company pursuant to the Minnesota Commission's orders. As part of the CAP/CON Proceeding, the Company obtained approval from the Minnesota Commission for capacity additions to meet the identified need of up to 500 MW of capacity by 2019 consistent with our 2010 Resource Plan.

Q. DID THE COMPANY SUBSEQUENTLY UPDATE THE FALL 2011 FORECAST?

A. Yes. During the pendency of the CAP/CON, the Company developed several updated forecasts. Regularly updating our load forecasts is a normal part of our resource planning efforts. After developing the Fall 2011 Forecast, we updated our load forecast in the spring of 2012, in the fall of 2012, in the spring of 2013, in the fall of 2014, and in 2015.

Q. DID THE IDENTIFIED NEED CHANGE IN THE COMPANY'S UPDATES TO THE FALL 2011 FORECAST?

A. Yes. The Company's updated Spring 2013 forecast identified a slackening of need of 117 MW in 2017, 118 MW in 2018, and 123 MW in 2019. The September 2014 forecast suggested that the previously forecasted increasing need had changed to a flat capacity surplus through as late as 2023.

Q. WHAT WAS THE CAUSE OF THE VARIABILITY IN THE FORECASTS IN THIS PERIOD?

A. In the years following the recession of 2008, it was difficult to predict what kind of economic conditions would result due to the uncertainty of the strength and timing of the economic recovery across the region at that time.

Q. NOTWITHSTANDING THIS VOLATILITY, DID THE 2013 AND 2014 UPDATED FORECASTS IDENTIFY A NEED TO ADD CAPACITY TO THE COMPANY'S SYSTEM?

A. Yes. The updated forecasts continued to identify a significant capacity deficit beginning in 2024 that would require resource additions on the NSP System. As a result, while there was agreement among the various forecasts that Xcel Energy would have a capacity need during the resource planning period, the exact timing of that need differed slightly among the various forecasts.

Q. WHICH FORECAST WAS USED BY THE MPUC IN THE CAP/CON?

A. In its February 5, 2015 Order selecting the MEC II PPA for execution (among other resources), the MPUC found that it was appropriate to rely upon the Fall 2011 Forecast – which was used in the analysis in the Company's Application – than the updated forecasts that were completed after the need had been identified.

Q. WHY DID THE MPUC CHOOSE TO RELY ON THE FALL 2011 FORECAST WHEN THE COMPANY HAD SUBSEQUENTLY PROVIDED FIVE UPDATED FORECASTS DURING THE CAP/CON PROCEEDING?

A. The MPUC considered the subsequent forecasts provided by the Company as valid data points, but ultimately made a holistic decision that a conservative approach should be used to protect ratepayers from uncertainty. In order to ensure that adequate generating capacity was installed in a timely fashion, it was necessary to adopt an analysis and finalize the inputs in order to provide certainty and finality to the decision-making process. As the MPUC stated in its Order:

> Need assessments are necessarily approximate and even the most analytic utilities must plan for a range of outcomes. In this docket, the Department has evaluated the consequences of selecting various combinations of generators under multiple scenarios – including a scenario of lower-than-expected demand. In short, Xcel's latest demand forecast, though new, was still within the range of contingencies contemplated and evaluated by the Department.
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> ***
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> Finally, the [Minnesota] Commission's goal is not to forecast the precise level of need – a task rife with the potential for error – but to identify the resource mix that will best manage forecasting error. . .. Based on the state of the record regarding Xcel's latest need assessment, the Commission will decline to alter its finding of need on this basis.

Q. DOES THE COMPANY AGREE WITH THE MPUC'S USE OF THE FALL 2011 FORECAST IN DETERMINING THE COMPANY'S CAPACITY NEED FOR PURPOSES OF EVALUATING THE MEC II PROPOSAL?

A. Yes. Factors affecting need are continually changing. As a result, resource decisions must necessarily be made in the midst of flux and the decision whether or not to pursue a particular resource must be made based on the totality of all of the circumstances. To determine whether the Company's decision was reasonable, the basis must be the information available at the time the decision was made. While our forecasts following the Fall 2011 Forecast showed a slackening of demand, they continued to indicate that the NSP System could be in deficit between 2017 and 2024. Relatedly, we believed that the variability in the forecasts favored a conservative approach to meeting our needs. Further, it is appropriate to primarily rely upon one forecast in order to provide consistency through the many regulatory reviews of resource selections.

Q. DOES THIS REFLECT THE COMPANY'S GENERAL STRATEGY FOR DETERMINING NEED?

A. Yes. Our general course of action is to act conservatively in the face of uncertainty and make resource additions as a need is forecasted and have those additions be of a size and type to address the need in a way that also positions us well for the future. This approach is premised on the assumption that it is better for a utility to be long than short on capacity, since the utility has the obligation to serve all of its customers' needs under all reasonable circumstances and must have resources available to meet those needs. The benefits to this approach are that it provides the time needed to make resource decisions through the use of competitive processes to help bring down the cost of these resources. Additionally, it avoids exposing the Company – and ultimately customers – to the short-term capacity markets and the price uncertainty inherent with such markets.

Q. ARE THERE OTHER FACTORS THAT FAVOR A CONSERVATIVE APPROACH FOR ESTABLISHING A CAPACITY NEED IN THIS CASE?

A. Yes. The slackening of demand found in subsequent demand forecasts after the Fall 2011 Forecast should be weighed against other factors present at the time, including: (1) anticipated MISO-wide capacity retirements at the time; (2) the favorable cost environment at the time; (3) an uncertain environmental regulatory environment; and (4) low capacity surplus margins.

Q. PLEASE DESCRIBE THE IMPACT THAT MISO-WIDE CAPACITY RETIREMENTS HAD ON THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THE TIME.

A. At the time, our analyses indicated that the cost of generation development, in particular gas-fired generation, may become more expensive as demand for new gas-fired generation increased due to the decommissioning of several coal plants in the MISO footprint. The plant retirements were also expected to increase the costs of short-term capacity in MISO's voluntary short-term capacity markets, causing such capacity to become more valuable as resources are constrained.

Q. PLEASE DESCRIBE HOW THE COST ENVIRONMENT AT THE TIME IMPACTS THE PRUDENCE OF MAKING A RESOURCE ADDITION.

A. As I discuss further below, the MEC II PPA represented some of the lowest cost CC capacity and energy we had seen at the time. Locking in this low-cost resource allowed the company to hedge against any potential tightening of capacity in the MISO markets. As I noted above, MEC II was created by adding a new combustion turbine to an existing 1x1 CC configuration. This means that we are able to obtain the efficiency of a combined cycle plant at nearly the cost of a combustion turbine. I explain the benefits of this later in my Testimony.

Q. PLEASE DESCRIBE HOW AN UNCERTAIN ENVIRONMENTAL REGULATORY ENVIRONMENT SUPPORTED MAKING RESOURCE ADDITIONS AT THE TIME.

A. By securing the very attractive pricing for gas-fired combined cycle generation in the MEC II PPA, we were able to position the NSP System for an uncertain regulatory future with respect to greenhouse gas and other potential environmental requirements.

Q. PLEASE DESCRIBE HOW THE ANTICIPATED MARGIN OF SURPLUS CAPACITY AFFECTED THE PRUDENCE OF MAKING A RESOURCE ADDITION AT THE TIME.

A. Given the variability in our demand forecasts and the small margin that we had on our system at the time, it was prudent to move forward with capacity additions in case our forecasts were inaccurate, leaving the NSP System short on capacity.

Q. DID THE COMPANY END UP BEING SHORT ON CAPACITY IN THE 2017-2019 PERIOD?

A. No. But this does not change the fact that the determination of need was prudent at the time the determination was made. Ultimately, it makes the most sense to add a resource when a need is sufficiently certain that it would make sense to add capacity to the system, but far enough into the future to allow the time necessary for the lengthy project analysis, regulatory approval, and resource development processes.

Additionally, while it is possible to abandon a project in reaction to changing forecasts, that is not a step that should be taken lightly as it could require starting over if circumstances shift or the forecast rebounds unexpectedly. As I said earlier, the Company generally believes a conservative approach should be taken for resource planning to ensure that customers are not adversely affected by the Company being caught unexpectedly short on capacity due to factors such as rapid changes in demand, changes to reserve requirements, and increased outages in aging resources.

Q. HOW DID THE COMPANY DETERMINE WHICH OF THE RESOURCES IDENTIFIED THROUGH THE CAP/CON PROCESS WOULD BEST MEET THE FORECASTED NEED?

A. The Company conducted a Strategist analysis that modeled portfolios consisting of different combinations of the resource proposals submitted in the CAP/CON proceeding that ranged from 358 MW to 636 MW. These proposals included peaking and intermediate resources.

Q. WHAT POTENTIAL RESOURCE ADDITIONS DID THE COMPANY ANALYZE?

A. In addition to the MEC II 345 MW CC unit, the Company also analyzed:

- The Company's proposal for a single CT unit at its Black Dog plant in 2017, 2018, or 2019 and two CT units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019;
- Invenergy Thermal Development, LLC's proposal to add a single 179 MW natural gas CT at its existing Cannon Falls, Minnesota plant and two 179 MW CTs located at a new plant site near Hampton Corners, Minnesota, in 2017 or 2018;

- Geronimo Energy's proposal for distributed solar generation, with an aggregate capacity of up to 100 MW, to be placed in service by the end of 2016 to take advantage of the federal Investment Tax Credit;
- Great River Energy's proposal for a three-year purchase of either 100 MW or 200 MW of resource capacity credits only, with no energy or generation associated with the purchase; and
- A generic large natural gas CC unit.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ANALYSIS OF THESE POTENTIAL RESOURCES?

A. Based on our analysis, the Company determined that the Black Dog CT Unit 6 was the most cost-effective individual resource and should be added regardless of which other resources were added in combination with it. The most cost-effective portfolios identified by our analysis consisted of combinations that included Black Dog Unit 6 being deployed in conjunction with either the MEC II PPA or the Invenergy Cannon Falls CT project. The results of our analysis on a PVRR basis are shown in Table 6 below.

Table 6

PVSC v. PVRR of Portfolios

Resource Combination	2013-2050 PVSC ($millions)	2013-2050 PVRR with ND Assumptions ($millions)
MEC II PPA + Black Dog 6	$45,368	$39,180
Black Dog 6 + RRV 1&2	$45,404	$39,198
Cost/(Savings) of MEC II PPA + Black Dog 6	($36)	($18)

Q. WHY WAS THE MEC II PPA ULTIMATELY CHOSEN AS PART OF THE PORTFOLIO TO BE ADDED?

A. The Company examined the cost effectiveness of peaking and intermediate natural gas generation in the CAP/CON proceeding. Generally, CT capacity is cheaper to build but less efficient to operate. CC units, on the other hand, can be operated much more efficiently, but typically cost more to build. The MEC II PPA was ultimately selected because in addition to its higher efficiency relative to the CT options, its initial capital costs were comparable to the typically lower cost of constructing a CT. Said differently, due to the unique circumstances of MEC II being added to an existing facility, we were able to obtain a CC resource at nearly CT pricing.

Q. WHY ARE CTS TYPICALLY MORE EXPENSIVE TO OPERATE THAN CCS?

A. Combustion turbines are less efficient to operate, and, as a result, each unit of energy they produce is comparatively more expensive than other types of generation resources. Because of this, CTs typically operate around five percent of the hours of the year or less because they are less efficient and therefore have higher marginal dispatch costs than baseload or CC resources.

On the other hand, CC plants can be operated efficiently, making each unit of energy cheaper to produce than that of a CT. CC plants typically operate 30-50 percent or more of the time to serve energy needs because they are more efficient and therefore have lower marginal dispatch costs than a CT. But the tradeoff for the dispatch efficiency is that CC plants are generally more expensive to build on a per-kW of capacity basis.

Q. WHY ARE CC PLANTS MORE EFFICIENT THAN CT PLANTS?

A. Combined cycle power plants are more efficient than CT plants because CCs recover the heat rejected by the higher temperature gas turbine cycle to generate power through the steam turbine in the second, lower temperature cycle. CT's, on the other hand, produce energy through only a single, gas turbine cycle.

Q. ARE THERE OTHER BENEFITS OF A CC RESOURCE?

A. Yes. Compared to some other available types of generation, CC plants can quickly ramp and/or start up and shut down, which allows rapid response to load variations and helps maintain the stability of the electrical grid. Additionally, since they are typically operating much more frequently than a CT, CCs are an online resource that can provide significant quantities of cost-effective energy (given current expectations for natural gas prices) that can help fill the gaps left by future baseload coal and nuclear retirements.

Q. WHY WERE THE MEC II CONSTRUCTION COSTS SO LOW?

A. The construction costs of the MEC II CC project were more in line with the costs of a CT due to the ability to take advantage of the existing MEC I infrastructure, natural gas access, existing permitting, and interconnection with the transmission and distribution networks, among other factors. Because the MEC I facility was designed to accommodate an expansion, Calpine Corporation could add a CT to make it into a highly efficient, 2x1 CC facility at a relatively low cost. As a result, the overall economics of the MEC II PPA and the CT options were roughly equivalent.

Although not directly relevant to the comparison of MEC II to the other available resources at the time, the economic benefits of MEC II compared to the estimated costs of constructing a natural gas generation resource in the future have only increased. MEC II was financed at a time of historically low interest rates and took advantage of relatively low steel prices, both of which are significant components of the overall cost of a gas generation project. Interest rates have increased since the MEC II PPA was executed, and the cost of steel has significantly increased in the recent past due, in part, to 25 percent tariffs on foreign steel implemented by the United States. As a result, at least a few of the most significant costs of building a gas generation facility have measurably increased over the costs incurred in developing the MEC II facility.

Q. YOU MENTIONED THAT THE INVENERGY CT WAS LOWER COST COMPARED TO MEC II IN SOME OF THE SCENARIOS ANALYZED. WHY WAS THE MEC II PROJECT ULTIMATELY SELECTED OVER THE INVENERGY OPTION?

A. In general, resource selection must include weighing of factors other than cost. To help determine whether the MEC II or Invenergy projects should ultimately be selected, the Company negotiated PPAs with both entities. Based upon its review of the negotiated PPAs, it was determined that the MEC II PPA would best meet the Company's needs because it provides the greatest flexibility of any of the options due to it offering both peaking and intermediate power capability. It was further determined that MEC II would have the lowest operating cost and would be the overall least-cost choice under a variety of potential future scenarios.

Q. WAS IT ULTIMATELY THE PRUDENT CHOICE TO SELECT THE MEC II PPA OVER THE CT OPTIONS?

A. Yes. The MEC II PPA gives the Company the best of both worlds with more efficient and cheaper CC energy production at construction costs competitive with a CT. In light of this, and the potential for the retirement of baseload coal and nuclear plants (which CC generation is expected to replace) throughout the region in the near future, it was prudent to capture this efficient generation resource at bargain pricing while it remained available.

In its February 5, 2015 CAP/CON Order, the MPUC selected MEC II as one of the resources to meet Xcel Energy's capacity need and ordered the Company to execute the MEC II PPA, which called for an in-service date of no later than 2019.

Q. HOW DOES THE COMPANY RECONCILE THE MPUC'S DECISION TO APPROVE MEC II TO BE IN SERVICE BY 2019 WHEN THE 2014 UPDATED FORECAST INDICATED THAT A CAPACITY NEED WOULD NOT ARISE UNTIL APPROXIMATELY 2024?

A. Xcel Energy acknowledges that the updated forecasts submitted in Case No. PU-15-96 showed a modest capacity surplus until 2024. But the Fall 2011 Forecast, which was used in the Company's initial need analysis in both Minnesota and North Dakota, demonstrated a capacity shortfall beginning in 2019. As I discussed above, it was appropriate to rely upon the Fall 2011 Forecast both to determine need and for resource planning in order to ensure consistency throughout the regulatory proceedings.

In any event, all of the forecasts indicated a significant capacity deficit beginning in 2026. Thus, all of the forecasts identified a need to add capacity to Xcel Energy's system, with only modest variations in the timing.

Q. HOW DO CHANGING ESTIMATES OF DEMAND AND CAPACITY NEEDS AFFECT RESOURCE PLANNING?

A. This is a continual challenge for us and all utilities, but as I discussed above we generally favor a conservative approach. We could continually update our forecasts and then only act when the size and timing of a need is certain. This would require us to wait until very close in time for our need to develop to ensure we have the certainty that there is a need to be filled. While this course of action would postpone any investment until need is more certain, it could potentially significantly limit our options as to how to meet that need given the lack of time to develop proposals and probe the market for cost-effective resources. It would also leave us vulnerable to spot market pricing.

On the other end of the spectrum, we could identify our needs many years out and then work to meet that more uncertain need. The advantage of such an approach is that the Company is in a position to be flexible as to the timing of resource selection/construction, taking advantage of periods when costs are lower, the market is not constrained, and financing costs are possibly lower.

Ultimately, the most prudent course of action is somewhere between these two extremes. It makes the most sense to move forward when a need is sufficiently certain that it would make sense to add capacity to the system but far enough into the future to allow the time necessary for the lengthy project analysis, regulatory approval, and resource development processes.

Q. PLEASE ELABORATE ON THE DIFFICULTY OF MATCHING RESOURCE ADDITIONS TO CAPACITY NEEDS.

A. Perfectly synchronizing the availability of the lowest cost resource additions with the timing of system capacity needs is nearly impossible. Need must be evaluated and resources must be planned over a general timeframe rather than attempting to achieve a false and unattainable precision in both forecasting and resource planning. Once a future capacity need has been identified, it is important to evaluate the type, size, and timing criteria with reasonable flexibility to ensure that the best available resources are selected to meet that need rather than requiring a perfect solution. And specifically related to timing, the analysis should focus on the impact to customers over the life of the proposed agreements or resources rather than on the cost in any specific year.

Q. PLEASE PROVIDE AN EXAMPLE OF THE DIFFICULTY OF MATCHING CAPACITY ADDITIONS TO CAPACITY NEEDS.

A. One current example of the difficulty of forecasting capacity needs is the Community Solar Gardens/Solar*Rewards program. To the surprise of the Company, this program has been embraced by our Minnesota customers and now accounts for over 700 MW of generation, which equates to more than 350 MW of capacity. This program is paid for by Minnesota customers—North Dakota pays the locational marginal price for this energy, which is below the system average cost of fuel—so North Dakota receives essentially free capacity from this program while only paying market price for the energy. But even three years ago, it is unlikely anyone would have predicted that this program would generate 350 MW of capacity, furthering the Company's capacity surplus through 2025.

Q. WAS IT ULTIMATELY PRUDENT TO MOVE FORWARD WITH A RESOURCE ADDITION AT THE TIME THE MEC II PPA WAS SELECTED?

A. Yes. The Company's forecast showed a capacity need of up to 500 MW in 2019 when the resource selection process began. While later forecasts showed this capacity need would be delayed until after 2019, the Company still had a need and ultimately decided to take a conservative approach and lock in the additional capacity.

C. Prudence of the MEC II PPA

Q. PLEASE EXPLAIN WHY THE MEC II PPA IS PRUDENT.

A. Based upon the information available at the time, the Company's decision to enter into the MEC II PPA was prudent. The Company's forecast in the fall of 2011 showed a dispatchable capacity need developing in the 2017 to 2019 timeframe. The Company conducted a competitive acquisition process to select the best, least-cost resources available to fill the identified need. Due to the MEC II PPA CC's combination of greater efficiencies and generation availability than a CT resource, with a cost of construction that was competitive with the typically cheaper CT options, it was selected through the competitive acquisition process to fill the capacity need. Due to this singular opportunity to get a CC at CT pricing, it made sense to lock in this resource, despite a mismatch in the timing of our capacity need that developed during the acquisition process. Thus, at the time, the decision to enter into the MEC II PPA was prudent.

Q. HAS THE COMPANY ANALYZED THE ECONOMIC IMPACT OF THE MEC II PPA USING NORTH DAKOTA RESOURCE PLANNING ASSUMPTIONS?

A. Yes. In Case No. PU-15-96, the Company modeled the PVRR – which excludes externality costs – of the base case and compared it to the PVRR of adding the

MEC II PPA. This analysis demonstrated that the MEC II PPA resulted in a lower PVRR than the base case in all but the "Low Gas" scenario. In the "Base Case" scenario, which used the Fall 2011 Forecast and North Dakota resource planning assumptions, the addition of MEC II resulted in an $11 million dollar savings over the life of the PPA. The results of this analysis are shown in Table 7 below.

Table 7

Total System Cost With/Without MEC II PPA

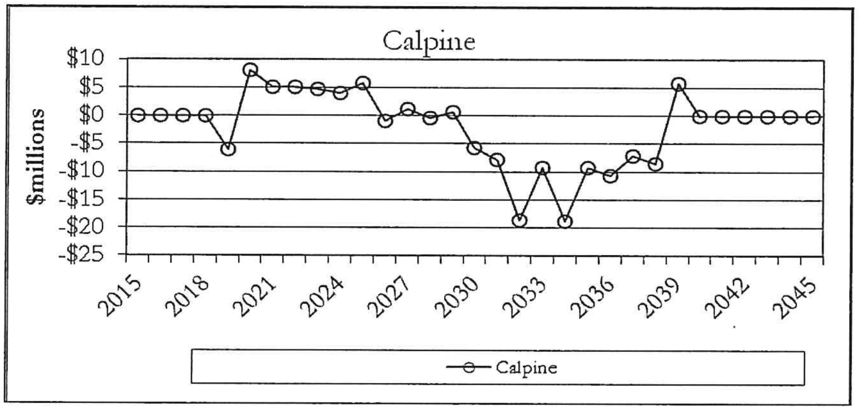
Changes in PVRR Cost ($millions)	**Base Case Using ND Assumptions**	**2012 Load Forecast**	**Low Gas**	**High Gas**	**Markets Off**	**MN Assumptions**
Base Case Using ND Assumptions	$44,949	**$49,279**	$41,260	$50,050	$45,957	$51,971
Base Case Using ND Assumptions with MEC II PPA	$44,937	**$49,257**	41,271	$50,010	$45,883	$51,944
Net Cost/(Savings)	($11)	($22)	$10	($40)	($74)	($27)

Q. HOW ARE THE MEC II PPA COSTS SPREAD OVER TIME?

A. Figure 2 below shows the year-over-year annual net costs or savings generated by the addition of MEC II (shown in the figure as Calpine), which results in the net $11 million PVRR savings identified in Table 7.

Figure 2

Annual Net System Costs (Savings) with MEC II PPA Compared to Base Case Using North Dakota Assumptions



Q. WHAT DOES FIGURE 2 DEMONSTRATE?

A. Figure 2 shows that while the MEC II PPA will add costs to the system initially when it goes into service, securing its value in 2015 was projected to lower system costs over the long term. In any event, adding this low cost resource to our system in 2019 would provide a reasonable hedge against future price fluctuations for combined cycle facilities.

Q. OTHER THAN THE COST SAVINGS DISCUSSED ABOVE, ARE THERE OTHER FACTORS THAT SUPPORT APPROVAL OF THE MEC II PPA FOR RECOVERY NOW RATHER THAN WAITING UNTIL A KNOWN CAPACITY NEED EXISTS?

A. Yes. Addition of the MEC II PPA provides much needed reliability and dispatchable energy as older generation resources are retired. From 2019-2030, the NSP System will experience significant reductions in energy resources due to resource retirements and power contracts expiring without extension or renewal. Several potential key changes include the following:

- 2023 - Blue Lake Units 1-4 cease operation (145 MW);

- 2023 – Sherco Unit 2 retires (648 MW);
- 2025 - Manitoba Hydro PPAs expire (850 MW);
- 2026 – Sherco Unit 1 retires (653 MW);
- 2026 - Cottage Grove combined-cycle PPA expires (236 MW);
- 2027 – MEC I combined-cycle PPA expires (291 MW);
- 2028 – Allen S. King Plant retires (483 MW); and
- 2030 – Sherco Unit 3 retires (511 MW).

Further, in the 2030-2035 timeframe, the Company faces the potential retirement of three baseload nuclear units. Altogether, this suggests that a significant proportion of our baseload generation may be retired within the next 5 to 15 years. These generating units have been the backbone of the NSP System for decades in some cases and have formed the foundation to provide reliable service to our customers. All of these retirements and contract expirations suggest that having additional advantageously-priced combined-cycle capacity is a reasonable choice for our system.

Even under the Company's updated forecasts, there will be a need for the capacity and energy from MEC II by 2026. Although the MEC II PPA began in 2019, the benefits of acquiring CC capacity at such a low cost outweigh the difference between MEC II's in-service date and the currently projected 2026 capacity deficit. It is very unlikely that any generation resource developed to be in service in 2026 would be able to match the cost advantages of the MEC II facility due to the significant increases in the cost of steel and interest rates, among other drivers of resource construction costs. As the analysis demonstrates below, the MEC II PPA will likely result in an overall cost reduction for North Dakota customers compared to building a similar facility in 2026.

Q. HAS THE COMPANY RECENTLY UPDATED THE FORECAST AND OTHER FACTORS USED IN ITS ANALYSIS OF THE MEC II PPA?

A. No. As I discussed earlier in my testimony, the prudence of the MEC II PPA should be evaluated based upon the information available at the time the decision was made by the Company. As a result, updated forecasting would not be appropriate for the prudence determination. This is in contrast with the Company's retirement decision for Sherco 1 and 2, which the Company has subsequently analyzed at the request of Commission staff. As I noted earlier, the decision to *retire* a resource is markedly different from the decision to *add* a resource, in that the Company has much more flexibility to reassess its retirement dates than to adjust construction timelines and contracts for resource additions. Thus, while it may be appropriate to examine updated modeling results in reviewing the prudence of the Company's ongoing decision to retire Sherco 1 and 2, it is not appropriate to take a 20/20 hindsight view of the Company's addition of the MEC II PPA.

Q. NOTWITHSTANDING WHETHER AN UPDATED FORECAST SHOULD BE USED TO DETERMINE PRUDENCE FOR THIS RESOURCE, HAS THERE BEEN A SIGNIFICANT CHANGE IN THE TIMING OF SYSTEM CAPACITY NEEDS IN RECENT FORECASTS?

A. No. Xcel Energy is still forecasting a capacity need in the mid-2020s timeframe. The modeling for the Mankato acquisition revealed a capacity need in 2026 across all of the scenarios evaluated. Load forecast and resource changes from previous years have been updated and shifted the need out slightly.

Q. HAS THE COMPANY PERFORMED ANY ADDITIONAL ANALYSIS THAT WOULD SPEAK TO THE PRUDENCE OF THE MEC II PPA?

A. I conducted one additional analysis to compare the cost of the annual fixed capacity costs associated with the MEC II PPA with both the levelized cost of a generic Greenfield CC and the MISO planning year 2020-2021 Cost of New Entry (CONE) price escalated at 1.5 percent annually for the period of the MEC II PPA (2019-2039). This is intended to provide a comparison point for the Commission to identify how the MEC II PPA compares against "new build" in the mid-2020s. It also provides a mechanism to match costs with the timing of the mid-2020s need so that the Commission may consider its strict "need plus least cost" resource planning paradigm.

Q. PLEASE EXPLAIN WHAT A GENERIC GREENFIELD CC IS AND HOW YOU ESTIMATED ITS COSTS.

A. A Greenfield CC represents a generically defined new Company owned combined cycle plant built on a site without any existing generation, gas or transmission infrastructure. The cost and performance data for this generic unit is based on consultants' estimates and internal company data. The costs used in this analysis represent the most recently updated generic greenfield CC costs that the Company used in modeling in its 2020 IRP Supplement.

The levelized fixed capacity costs included in this analysis represent all of the annual fixed charges associated with ownership including capital revenue requirements (depreciation, interest expense, taxes, etc.) and fixed operating & maintenance (O&M) costs. Fuel and variable O&M costs are not included as they are dependent on plant utilization/dispatch and therefore not fixed costs.

Q. WHAT IS THE MISO PLANNING YEAR 2020-2021 CONE PRICE AND HOW WAS IT DETERMINED?

A. The MISO planning year 2020-2021 cost of new entry (CONE) price for Local Resource Zone (LRZ) 1 is \$93,470/MW-year or approximately \$7.79/kW-month. MISO provides a detailed account of how the values are derived in its annual CONE filing letter to FERC. Below is an excerpt from the letter, which describes the methodology:

> In order to determine the appropriate CONE value for each of the LRZs, MISO relied upon the most recent EIA report on Capital Cost Estimates for Utility Scale Electricity Generation Plant (EIA Report). The EIA Report contains detailed specifications for a hypothetical advanced CT, including information regarding the differences in project costs for an advanced CT with a nominal capacity of 237 MW, based upon the state where the facility is constructed.
>
> MISO used a NPV analysis to determine an appropriate CONE value for hypothetical advanced CTs located in each of the LRZs. In accordance with Section 69A.8.a of the Tariff, MISO considered many factors in its calculation of the CONE value, including the following: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). MISO did not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services.[4]

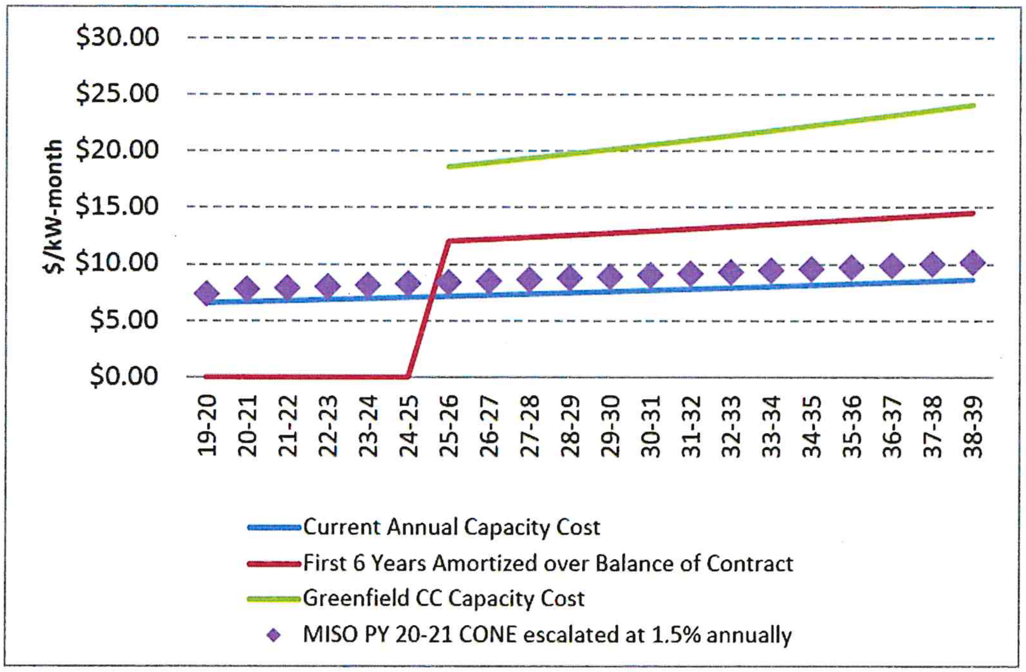
[4] This letter is available at: https://cdn.misoenergy.org/Final%20MISO%202017%20Annual%20CONE%20filing51321.pdf.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?

A. The results of this analysis are shown in Figure 3 below.

Figure 3

MEC II Capacity Cost Comparison



Q. WHAT DOES FIGURE 3 DEMONSTRATE?

A. Figure 3 shows that the total fixed capacity costs that the Company expects to pay for the MEC II PPA (the blue line) are lower than both the levelized Greenfield CC costs and the MISO planning year 2020-2021 CONE prices escalated at 1.5 percent annually. This demonstrates the cost benefits of the MEC II PPA over either the Company's (Greenfield CC cost) or MISO's (CONE price) cost projections for new resources beginning in 2025 when a new resource would come online in advance of a 2026 capacity need. Hence, the MEC II PPA is projected to be cheaper than adding either greenfield CC or, more importantly, MISO's definition of greenfield CT capacity costs in the future.

Q. WHY IS IT SIGNIFICANT THAT THE MEC II PPA COSTS ARE LOWER THAN MISO'S PLANNING YEAR 2020-21 CONE PRICE?

A. This is important because CTs typically represent the cheapest form of capacity available in the market, but in this case, the Company has procured a CC with capacity costs below that of a CT. As I discussed earlier, CC costs are typically higher than CT costs due to the greater costs of construction of a CC facility. But CCs offer much more system flexibility and security and are more efficient, and less costly, to run. Due to MEC II's lower construction and interconnection costs as a result of leveraging the existing MEC site and facilities, as well as the increased costs of developing new resources including the cost of steel and interest rates, the cost of the MEC II PPA is actually lower than MISO's projected cost for developing a new CT.

Q. YOUR ANALYSIS IN FIGURE 3 INCLUDES AN ADDITIONAL LINE LABELED "FIRST 6 YEARS AMORTIZED OVER BALANCE OF CONTRACT." PLEASE EXPLAIN WHAT THIS LINE SHOWS.

A. The First 6 Years Amortized Over Balance of Contract line demonstrates that even if the full capacity cost of the MEC II PPA is amortized over the 14-year period beginning when there is an identifiable need (2025) and ending at the expiration of the PPA (2039) instead of over the entire 20-year PPA term, the MEC II PPA is still a cheaper option to meet the capacity need in 2026 and beyond than the projected levelized cost of a Greenfield CC unit constructed by the end of 2025 to meet a 2026 capacity need. This further demonstrates the favorable pricing of the MEC II PPA. The amortization assumes the 20-year costs are only recovered in the last 14 years, so it is the same period.

The Greenfield CC capacity cost values were derived from modeling assumptions that were used in our 2019 Resource Plan (Case No. PU-19-220). These values represent the Company's best estimate of what it will cost to construct a brand new CC facility at a greenfield site. The capacity costs represent the full annual fixed costs associated with the ownership of a new CC plant and are inclusive of all fixed revenue requirement components.

Q. HOW DOES THIS ANALYSIS AFFECT THE PRUDENCE DETERMINATION?

A. The analysis demonstrates that it would be prudent to allow the MEC II PPA to be included in base rates even though the in-service date does not perfectly line up with the forecasted need. The MEC II PPA is favorably priced compared to the estimated cost of similar resources with an in-service date of 2025-2026. Moreover, even when the first six years of the MEC II PPA's capacity costs are amortized over the remaining years of the term of the PPA, MEC II is still cheaper than building a Greenfield CC to be in service in 2025 in advance of the 2026 capacity need. Thus, the MEC II PPA can be considered a least cost resource even if the timing of the payment for the resource and the capacity need are required to match up perfectly.

Q. IF THE COMMISSION DENIES RECOVERY OF THE MEC II PPA, HOW WILL THE RESOURCE BE ACCOUNTED FOR BY THE COMPANY?

A. Company Witness Mr. Greg Chamberlain discusses the history of the Resource Treatment Framework (RTF) filings that the Company has made before the Commission in his Testimony. This issue has yet to reach a resolution but the

Company requests the MEC II and other resource additions that are currently "stranded" in RTF limbo be addressed and resolved in this Rate Case. For the sake of fairness to our customers in other NSP jurisdictions, this issue should be resolved in a way that fairly allocates a share of the benefits and costs of the resources that serve each jurisdiction. In the event the Commission denies recovery of MEC II in this rate case, the Company will pursue a solution to this issue and other "stranded" assets under the RTF with the Commission and Commission Staff.

D. Summary

Q. PLEASE SUMMARIZE WHY THE ADDITION OF THE MEC II PPA TO THE COMPANY'S GENERATION RESOURCES WOULD BE PRUDENT.

A. The underlying merits of the MEC II PPA are clear: it is a low-cost, combined-cycle facility that was made available when the forecast upon which the original decision was based predicted a need for capacity. As a result, the addition of the MEC II PPA should be deemed prudent.

Even if the analysis takes into account more recent information, the MEC II PPA begins only a handful of years earlier than our most recent forecasts show a capacity deficit. The MEC II resource provides significant benefits by hedging against sudden variations in resource needs as well as providing low-cost, combined-cycle capacity and energy as we move into a rapidly changing energy future. As we move to reduce the baseload energy provided by Sherco 1 and 2, securing low-priced combined-cycle energy under the MEC II PPA helps to provide dispatchable, low-cost energy to the system as part of our overall replacement plan.

In sum, the benefits of the MEC II PPA outweigh the difference in timing between the in-service date and the currently forecasted capacity need. Due to the significant economic benefits that are unique to the MEC II project, it was prudent for the Company to take advantage of the low prices offered by the PPA rather than waiting until 2026 for a resource that will most likely be more costly to North Dakota customers in the long term.

V. PRAIRIE ISLAND EXTENDED POWER UPRATE

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY REGARDING THE PRAIRIE ISLAND EXTENDED POWER UPRATE.

A. The purpose of this section of my testimony is to provide information supporting the Company's decisions to first undertake, and then ultimately to cancel, the Prairie Island Extended Power Uprate (EPU). I will describe the Prairie Island nuclear facility, explain why the decision to initiate the EPU was prudent, and discuss why, in light of changed circumstances, it was prudent to ultimately cancel the EPU in the early stages of the regulatory approval process. Company witnesses Mark Moeller and Benjamin Halama discuss the accounting and rate impact of the Company's request.

A. Prairie Island Plant and Uprate Overview

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT.

A. Prairie Island is a nuclear power plant operated by the Company in Red Wing, Minnesota. The facility consists of two pressurized water reactors (PWR) with a total nameplate capacity of 1,100 MW.

The Federal Nuclear Regulatory Commission (NRC) issued the first 40-year operating licenses for Prairie Island Unit 1 on August 9, 1973 and for Unit 2 on October 29, 1974. The licenses were due to expire in August 2013 for Unit 1 and October 2014 for Unit 2. Beginning in 2008, the Company began the process of obtaining MPUC and NRC approvals to extend the life of the facility.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND EPU PROJECT.

A. In 2008, the Company began planning for a 164 MW uprate of the Prairie Island nuclear power plant that was expected to cost approximately $322 million and be implemented during the 2015 and 2016 scheduled refueling outages. The Prairie Island EPU Project included the installation of new turbines as well as optimizing water flow through the Measurement Uncertainty Recovery program (MUR).

Q. WAS THE PROPOSED PRAIRIE ISLAND EPU PRUDENT AT THE TIME THE COMPANY MADE THE DECISION TO PURSUE THE PROJECT?

A. Yes. Given the information at the time, the Prairie Island EPU would have provided the Company with an additional 164 MW of baseload generation that would have addressed a projected capacity need at the lowest cost compared to other available resources. At the time, the Company's economic analysis of the Prairie Island EPU Project indicated a potential for economic benefits to customers of approximately $519 million on a PVRR basis over the next best alternative for providing this additional capacity. Additionally, the Prairie Island EPU Project was seen as a cost-effective hedge against both higher natural gas prices and the potential for federal carbon legislation.

Q. WAS ANY REGULATORY APPROVAL NECESSARY FOR THE PRAIRIE ISLAND UPRATE?

A. Yes. To undertake an uprate, we needed to obtain:

- A Certificate of Need from the Minnesota Public Utility Commission (MPUC); and
- Operating license amendments from the Nuclear Regulatory Commission (NRC), allowing Prairie Island to operate the plant at a higher thermal level.

Q. DID THE COMPANY SEEK AN ADP FOR THE PRAIRIE ISLAND EPU?

A. Yes. On April 19, 2010, the Company filed an ADP application in Case No. PU-10-127 for two significant investments at Prairie Island: the Prairie Island EPU and the replacement of the steam generators for Unit 2 of the facility. The Company did not require an ADP to make these investments, but the ADP statute allows utilities to obtain the Commission's view of major projects prior to the utility making substantial commitments.

Q. WHAT WAS THE RESULT OF THE COMPANY'S ADP APPLICATION FOR THE PRAIRIE ISLAND EPU?

A. On October 23, 2012, the Company asked the Commission to postpone consideration of the ADP for the Prairie Island EPU in Case No. PU-10-127, due to a change in circumstances which I describe later in my Testimony. As a result, the Commission took no action on the Company's application for an ADP for the Prairie Island EPU.

Q. PLEASE DESCRIBE THE CERTIFICATE OF NEED PROCESSES FOR THE PRAIRIE ISLAND EPU.

A. The Company submitted a Certificate of Need application with the MPUC for the Prairie Island EPU on May 16, 2008 (Docket Nos. E002/CN-08-510 and E002/CN-08-509, respectively). The Certificate of Need was sought to increase the generating capacity of each of the two units at Prairie Island by an estimated 82 MW (164 MW total). The Company sought permission to acquire new fuel assemblies and improve the plant to convert steam into electric energy more efficiently.

Q. WHAT WAS THE OUTCOME OF THE PRAIRIE ISLAND EPU CERTIFICATE OF NEED PROCEEDING?

A. After a contested case hearing in front of an Administrative Law Judge (ALJ), the MPUC found that although the record included a variety of ways the 1,100 MW of generation from the plant could be replaced, none of the alternatives "approaches the cost-effectiveness of Xcel's proposal to extend the life of the" plant. The MPUC further concurred with the ALJ's conclusion that extending the life of the Prairie Island plant "should be expected to keep the cost of electricity lower than otherwise," and "that the uprate proposal was the most reasonable and prudent demonstrated on the record."

On December 18, 2009, the MPUC granted a Certificate of Need for the Prairie Island EPU. The uprate Certificate of Need contemplated implementation of a Unit 1 EPU during the 2014 scheduled outage, and implementation of the Unit 2 EPU during the 2015 scheduled outage.

Q. PLEASE DESCRIBE THE NRC LICENSE AMENDMENT PROCESS FOR THE PRAIRIE ISLAND EPU.

A. The Company sought uprate licenses from the NRC in two phases beginning shortly after receipt of the Minnesota Certificate of Need. First, the Company submitted a License Amendment Request (LAR) to the NRC to allow an 18 MW Measurement Uncertainty Recapture (MUR) Power Uprate for Prairie Island Units 1 and 2. This LAR was submitted on December 28, 2009, and approved in August 2010. The Company subsequently completed installation and necessary equipment upgrades for the MUR, and the 18 MW of additional capacity went into service in October 2010.

Second, the Company began preparations for an EPU LAR. Because an EPU LAR is a much more extensive, complex, and costly undertaking, the Company determined it was not feasible to submit one until after we obtained permission to continue operating Units 1 and 2 beyond 2013 and 2014. Additionally, NRC rules did not allow us to submit a LAR while our license renewal was pending. The Company initially anticipated that the NRC would issue the license renewal in late 2010 or early 2011, allowing the filing of an EPU LAR package for the Prairie Island EPU in mid-2011.

Q. WHAT HAPPENED NEXT?

A. As I discuss below, several circumstances changed while the NRC license amendment process was ongoing, ultimately causing the Company to reassess moving forward with the project.

B. Prairie Island Change of Circumstances

Q. WHAT INITIALLY DROVE THE COMPANY TO REEXAMINE THE PRUDENCE OF THE PRAIRIE ISLAND EPU?

A. The Company encountered several changes to the EPU Project and industry conditions over the course of 2011 and 2012 that, in combination, led the Company to reassess the prudence analysis for the Project, including: (1) a reduction in the project size; (2) a delay in the scheduled implementation of the EPU; (3) increased costs of completing the EPU; (4) increased regulatory scrutiny; (5) lower customer demand forecasts; and (6) lower natural gas prices.

Q. WHY WAS THE EPU PROJECT SIZE REDUCED?

A. Through the work undertaken to plan the EPU Project and information obtained during the competitive bidding process, the Company learned that one component of the planned EPU Project—installing a low pressure turbine—would not be cost effective. As a result, the Company decided to eliminate that component of the upgrade, which reduced the total project size to approximately 135 MW from 164 MW.

Q. WHY, AND BY HOW LONG, WAS THE EPU PROJECT SCHEDULE DELAYED?

A. Project implementation was delayed from 2014-2015 until the 2016-2017 refueling outages, or potentially an additional year, subject to receipt of timely NRC approvals.

Delayed implementation was due to several factors. The Company anticipated that it would receive NRC approval to extend the operating license for Prairie Island in late 2010 or early 2011, which would have facilitated filing the LAR package in early 2011. However, the Company did not receive that approval until June 2011, and NRC rules did not allow submission of an LAR while a license renewal was pending. Additionally, before an LAR can be reviewed it must be accepted by the NRC. However, in other LAR proceedings in 2011 and 2012 the NRC staff began requiring significantly more design detail before granting acceptance than had previously been the case. These requirements were a change from the historical practice of allowing design modifications in parallel with NRC review of the LAR. As a result, the Company would have required significant additional time and investment before receiving any feedback from the NRC.

Q. WHAT PROMPTED THE INCREASED REQUIREMENTS AND EXTENDED TIMING OF THE NRC'S LAR REVIEW PROCESS?

A. One of the main reasons for the increased complexity and timing of the LAR process was the Fukushima Daiichi incident. In March 2011 the Fukushima Daiichi nuclear power plant in Japan was devastated by an earthquake and tsunami. As a result, the NRC was in the process of comprehensively reviewing the impact of external events on the safe operations of nuclear power plants to determine if additional plant modifications or safety regulations were necessary. This review was occurring while the Company was preparing its LAR package. By the time the Company was reevaluating the PI EPU Project, it was our understanding that the NRC could have required 30-36 months to review LARs, compared to the historical 12-22 month processing period, due to the NRC diverting resources from LAR review to other higher-priority safety issues.

Q. HOW DID THE PRAIRIE ISLAND EPU COST ESTIMATES CHANGE FROM THE 2008 ANALYSIS?

A. The Company's analysis of the vendor bids from the request for proposals (RFP) indicated that the cost per kilowatt of completing the Prairie Island EPU would increase from $2,615 to $3,154, or 20 percent.

Q. WHAT CHANGED IN THE COMPANY'S LOAD FORECAST BETWEEN 2008 AND 2012?

A. The pace of projected load growth had slowed between 2008 and 2012. When the Company first analyzed the Prairie Island EPU Project in 2008, prior to the recession, growth forecasts indicated our demand and energy requirements would continue to grow at approximately 1 percent per year. When the Company reevaluated the Project in March 2012, annual energy growth rate forecasts were in the 0.7 to 0.5 percent range over the planning horizon. The impact of lower forecasted load growth lessened the need for the additional baseload generation at the time.

Q. HOW DID NATURAL GAS PRICES CHANGE IN THAT PERIOD?

A. Natural gas prices fell dramatically and were forecasted to remain relatively low. Development of shale gas had been ramping up and accounted for more than one-third of all U.S. natural gas production. The surge in production pushed gas prices down from $9.26/Mcf in 2008 to $3.54/Mcf in 2012, according to the EIA. One of the benefits of the Prairie Island EPU Project was to act as a hedge by reducing exposure to natural gas prices and future environmental regulations. The effect of lower gas prices mitigated the hedge value of the Prairie Island EPU Project.

Q. HOW DID THE COMPANY ANALYZE THE IMPACT OF THE FACTORS YOU LISTED ABOVE?

A. To assess the economic impact of the changed circumstances, the Company updated the analysis that it performed for the project in 2008. The most significant changes included delaying the expected in-service date from 2014-2015 to 2016-2017, reducing the customer demand forecasts, and lowering natural gas price forecasts.

Our modeling indicated that, even with the changes in circumstances discussed above, the Prairie Island EPU was still projected to provide a net benefit to customers across all of the scenarios modeled. Specifically, the Company calculated that the most probable estimate from the modeling at that time resulted in $50 million in PVRR savings. However, in a retrospective analysis, the overall benefits of the EPU when compared to the next best alternative had fallen from $433 million to $278 million when accounting for the implementation delay and reduction in size of the project. The results of this analysis are shown in Table 8 below.

Table 8

PVRR of Prairie Island EPU Due to Change in Timing and Size

Original Filing

	EPU	164 MW Coal PPA	Unconstrained
PVRR	$59,829	$60,298	$60,262
PVRR Delta		$468	$433

Changed Timing Only

	EPU	164 MW Coal PPA	Unconstrained
PVRR	$59,912	$60,248	$60,262
PVRR Delta		$336	$350

Changed Timing and Size

	EPU	136 MW Coal PPA[1]	Unconstrained
PVRR	$59,984	$60,205	$60,262
PVRR Delta		$221	$278

Q. WERE THERE ADDITIONAL CHANGED CIRCUMSTANCES AFTER THE MARCH 2012 ANALYSIS THAT LED THE COMPANY TO REASSESS THE PRUDENCE OF THE EPU PROJECT AGAIN?

A. Yes. When the spring 2012 Prairie Island Unit 2 refueling outage was extended approximately two months longer than planned, the Company began to look into the potential benefits of extending the time between scheduled refueling outages. After receiving MPUC approval for the uprate Certificate of Need in late 2009, the Company had applied for approval from the NRC to begin using new fuel and fuel assemblies prior to uprate project work. These new assemblies, in essence, made more fuel available so the plant could either support increased capacity as a result of an EPU or operate for longer periods between refueling outages. The Company began using some of the new fuel assemblies in Unit 1 in 2009 and Unit 2 in 2010.

In light of the changes in circumstances lowering the benefit of the EPU Project, the Company assessed the likely future refueling schedule if the EPU was cancelled. The analysis indicated that cancelling the EPU would allow the Company to extend the time between refueling outages. If the EPU was implemented, refueling outages would be required at 18-month cycles for each unit. Without the EPU, the installation of new fuel assemblies allowed the Company to extend outages by six months to 24-month cycles for each unit. This eliminated two refueling outages for each unit over the remaining life of the plant, at an estimated customer savings of $75 million on a PVRR basis.

Q. HOW WOULD THE CHANGES TO THE REFUELING SCHEDULE IMPACT THE PRAIRIE ISLAND EPU ANALYSIS?

A. The Company assessed the total benefits of the uprates by incorporating the revised fuel cycles into the modeling for the EPU that was conducted in March 2012. This analysis indicated that the total benefits of the uprates declined to $10 million PVRR, compared to the $50 million estimated in the Company's March analysis. The results of this analysis are shown in Table 9 below.

Table 9

PVRR Benefits of Prairie Island EPU

PVRR $millions	**March COC EPU 2016/17**	**Sept Update EPU 2016/17**	**Sept Update EPU 2017/18**	**Sept Updates Cost of Delay 2016/17 to 2017/18**
Base Assumptions	($79)	($3)	($38)	($35)
Low Gas	($19)	$55	$18	
Midpoint Rounded to Nearest $10M	**($50)**	**$30**	**($10)**	

Q. WERE THERE OTHER ISSUES THAT RAISED THE PROSPECT OF ABANDONING THE PRAIRIE ISLAND EPU PROJECT?

A. Yes. The uncertainty around the NRC processes at the time held out the possibility of additional project delay and the concomitant increase in costs. Timing delays could have added up to an additional $30 million in lost PVRR benefits of the projects. Additionally, the Project benefits would have been further reduced by lower natural gas prices or low load growth. As shown in Table 10 below, several of these scenarios resulted in an increase to the PVRR rather than a savings in the updated modeling.

Table 10

Sensitivity Analysis of Prairie Island EPU

PVRR DELTA S 2012-2050, 7.56%, $millions	March 2012 Change Of Circumstance			Sept 2012 Strategist Update		
	Base Case 2 No EPU LCM 2016	Case 2 EPU 2016-17	Case 3 EPU 2017-18	Base Case 2 No EPU LCM 2016	Case 2 EPU 2016-17	Case 3 EPU 2017-18
Base Case	BASE	($79)	($75)	BASE	($3)	($38)
EPU less 10MW	BASE	($29)	($24)	BASE	$43	$7
Low Gas -20%	BASE	($19)	($18)	BASE	$55	$18
Low Load 20th Percentile	BASE	($32)	($30)	BASE	$41	$6
Low Capital	BASE	($104)	($99)	BASE	($28)	($62)
High Gas +20%	BASE	($134)	($128)	BASE	($56)	($89)
High Load 80th Percentile	BASE	($108)	($104)	BASE	($30)	($66)
Late CO2 - 3 Source	BASE	($152)	($148)	BASE	($72)	($107)
High CO2 - $34/ton	BASE	($152)	($144)	BASE	($68)	($104)
Low CO2 - $9/ton	BASE	($90)	($85)	BASE	($10)	($47)
No Markets	BASE	($98)	($94)	BASE	($24)	($58)
High Externalities	BASE	($92)	($88)	BASE	($14)	($50)
Low Externalities	BASE	($81)	($77)	BASE	($5)	($40)

At the time, the only potential future change that would have increased the economic benefits of the Project was the potential for federal carbon legislation, although it was not a material driver at the time. While a hedge against such regulation is prudent, the project risk of the Prairie Island EPU outweighed this qualitative benefit, particularly in light of other alternatives.

C. Cancellation of the Prairie Island EPU Project

Q. WHEN AND HOW DID THE COMPANY ABANDON THE PRAIRIE ISLAND EPU PROJECT?

A. After the Company's March 2012 analysis raised questions about the economic benefits and ultimate prudence of the Prairie Island EPU Project, the Company ramped down and suspended the Project (which had yet to start construction) while the new information was presented to the MPUC in a Change in

Circumstances filing related to the Certificate of Need. Prior to the Hearing on that matter, the Company provided the MPUC with its updated 2012 analysis that took into account the potential savings from extending the time between scheduled refueling outages rather than implementing the EPU. The Company informed the MPUC that based upon the updated analysis, Xcel Energy concluded that the outstanding risks of delay and increased costs outweighed the small potential benefit and made further investment in the EPU Project imprudent.

In February 2013, the MPUC issued an order concurring with the Company's conclusions and terminating the Certificate of Need for the Prairie Island EPU prospectively.

Q. HOW MUCH IN ABANDONED PLANT COSTS IS THE COMPANY SEEKING TO RECOVER?

A. Company Witness Mr. Benjamin Halama discusses this in his Direct Testimony.

Q. WAS IT PRUDENT FOR THE COMPANY TO ABANDON THE PRAIRIE ISLAND EPU PROJECT?

A. Yes. The confluence of factors at the end of 2012 indicated that while economic benefits were still available for the Project, they were materially lower than first forecasted. Additionally, the inherent uncertainty with respect to gas prices, load growth, and carbon regulation argued that the slightly positive economic benefits of the Project could quickly become negative under multiple scenarios. In light of this, and the material change in need for the additional baseload capacity, it was prudent for the Company to abandon the Prairie Island EPU Project.

D. Summary

Q. PLEASE SUMMARIZE WHY THE PRAIRIE ISLAND EPU AND THE COMPANY'S SUBSEQUENT CANCELLATION OF IT WERE PRUDENT.

A. The history of the Prairie Island EPU indicates that both the decision to undertake the EPU and the decision to cancel the EPU were prudent based on the circumstances at the time. In 2008 when the Company first sought approval for the EPU, the Company's economic analysis indicated the potential for economic benefits to customers of approximately $519 million PVRR compared to the next most cost-effective alternative. Additionally, the project was properly viewed as a hedge against then-high natural gas prices. However, during the approval process for the Prairie Island EPU, circumstances changed considerably and changed the prudence calculus for the EPU. These changes to the prudence evaluation included: a reduction in the project size; a delay in the scheduled implementation of the EPU; increased costs of completing the EPU; increased regulatory scrutiny; lower customer demand forecasts; and lower natural gas prices. As a result, despite the investment that had already been made in obtaining approvals for the Prairie Island EPU, the Company concluded that the outstanding risks of delay and increased cost outweighed the small benefit that may have been obtained from pushing forward. Given this risk assessment, the Company concluded that any further investment in the Prairie Island EPU, beyond the investments incurred to date, would be imprudent.

VI. 187 MW SOLAR PORTFOLIO

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain the basis for the Company's request that the Commission (1) find the Company's decision to enter into the PPAs for the 187 MW Solar Portfolio prudent and (2) allow the Company to recover the PPA costs in the FCR.

A. Background

Q. WHAT PROJECTS ARE INCLUDED IN THE 187 MW SOLAR PORTFOLIO?

A. The three solar projects that together constituted the Company's proposed acquisition of 187 MW of solar generation for the NSP System are:

- Marshall Solar – a 62.25 MW project located near Marshall, Minnesota developed by NextEra;
- North Star Solar – a 100 MW project located near North Branch, Minnesota developed by Community Energy Resources; and
- MN Solar I – a 24.75 MW project located near Tracy, Minnesota to be developed by juwi Solar, Inc.

Q. PLEASE DESCRIBE THE MARSHALL SOLAR PROJECT.

A. The Marshall Solar project is a 62.25 MW solar energy generation facility on approximately 464 acres in an agricultural area east of Marshall, Minnesota in Lyon County. The project consists of 30° fixed tilt configuration, photovoltaic modules and interconnects at the existing Company Lyon County substation at 69 kV.

Q. WHAT WAS THE MARSHALL SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

A. The bulk of construction of the Marshall Solar project began in spring 2016, with engineering, procurement and some construction occurring in 2015. Marshall Solar became fully operational in January 2017.

Q. WHAT ARE THE TERMS OF THE MARSHALL SOLAR PPA?

A. The Marshall Solar PPA is for 25 years, and similar to wind-related PPAs, the pricing is designed on a pay for production basis. The purchase price of electric energy from Marshall Solar starts at **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. We calculate the levelized cost of energy over the term of the PPA to be **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.

Q. PLEASE DESCRIBE THE NORTH STAR SOLAR PROJECT.

A. North Star Solar is a 100 MW solar energy generation facility located on approximately 800 acres in an agricultural area southeast of North Branch, Minnesota in Chisago County. North Star Solar consists of single axis tracking panels. The project interconnects at 115 kV to the existing NSP Chisago County Substation.

Q. WHAT WAS THE NORTH STAR SOLAR PROJECT'S CONSTRUCTION SCHEDULE?

A. As with Marshall Solar, the construction schedule was designed so that the project would qualify for the 30 percent Federal ITC to offset project construction costs. Engineering, procurement and some construction occurred in 2015, with the bulk of construction of the North Star Solar project in 2016. North Star Solar became fully operational in December 2016.

Q. WHAT ARE THE TERMS OF THE NORTH STAR SOLAR PPA?

A. The purchase price of electric energy under the 25-year PPA with North Star Solar starts at **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. We calculate the levelized cost of energy over the term of the PPA to be **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.

Q. PLEASE DESCRIBE THE MN SOLAR I PROJECT.

A. MN Solar I was a proposed 24.75 MW project to be located near Tracy, Minnesota. Although approved by the MPUC in the 187 MW solar portfolio docket, MN Solar I exercised its rights to terminate its PPA in a notice provided to the Company on May 10, 2016 due to issues in obtaining an Interconnection Agreement.

Q. DOES THE TERMINATION OF THE MN SOLAR I PPA AFFECT THE ANALYSIS THE COMPANY PERFORMED IN EVALUATING THE 187 MW SOLAR PORTFOLIO?

A. Somewhat, but not significantly. The MN Solar I PPA comprised only 13 percent of the total 187 MW portfolio. The qualitative benefits such as fuel and environmental hedging are not affected by the termination of the MN Solar I PPA. The quantitative effect of MN Solar I PPA termination on ratepayers is also not very material.

Q. HAS THE COMMISSION ADDRESSED THE 187 MW SOLAR PORTFOLIO IN PRIOR PROCEEDINGS?

A. Yes. The Company requested an ADP for the 187 MW Solar Portfolio in 2014 in Case No. PU-14-810.

Q. WHAT WAS THE OUTCOME OF THAT CASE?

A. The Commission denied the Company's application and held that the Company may not recover costs associated with the 187 MW Solar Portfolio without specific approval from the Commission.

Q. IN LIGHT OF THE OUTCOME OF CASE NO. PU-14-810, HOW HAS THE COMPANY BEEN TREATING THE COSTS AND VOLUMES FOR THE 187 MW SOLAR PORTFOLIO?

A. Consistent with the Commission's Order in Case No. PU-14-810, which prohibited rate recovery for these projects until a future Commission order approving them, the Company has excluded both the costs and the volumes of the 187 MW Solar Portfolio from the calculation of system average cost of fuel in the FCR. This has resulted in the Company under-recovering the PPA costs in the FCR by approximately $2.1 million since the 187 MW Solar Portfolio projects were placed in service.

Q. WHAT ARE THE IMPACTS OF THIS RATE TREATMENT?

A. The PPAs for the 187 MW Solar Portfolio are mainly intended to provide energy for the NSP System and are, therefore, priced as energy only. However, the projects also provide over 90 MW of accredited capacity to the NSP System as well as Solar Renewable Energy Credits (S-RECs), which can be monetized for the benefit of customers. Consequently, failure to recover the costs of these resources results in our North Dakota customers obtaining the energy produced by these projects and the additional capacity and renewable benefits without paying their share of the costs.

Q. WHAT IS THE COMPANY REQUESTING THAT THE COMMISSION DO WITH RESPECT TO THE 187 MW SOLAR PORTFOLIO IN THIS CASE?

A. The Company requests that the Commission find the addition of the 187 MW Solar Portfolio to be prudent and allow the Company to recover the costs associated with the PPAs in the FCR.

B. Minnesota's Solar Energy Standard (SES)

Q. WHY DID THE COMPANY PROPOSE THE 187 MW SOLAR PORTFOLIO RESOURCE ADDITION?

A. The Company proposed acquiring the 187 MW Solar Portfolio primarily to comply with Minnesota's SES, Minn. Stat. § 216B.1691, Subd. 2f, which requires the Company to serve 1.5 percent of its retail customers with solar energy by the end of 2020, and established a 10 percent solar energy goal by 2030. This solar energy displaces fuel and energy that would have been purchased or produced in the absence of this new generation. As a fixed price source of clean energy, the solar energy provides a hedge against fuel prices and potential future regulation.

Q. WHAT LED THE COMPANY TO ISSUE ITS REQUEST FOR PROPOSALS (RFP) FOR SOLAR RESOURCES IN 2014?

A. The Company issued an RFP to help ensure there would be an adequate number of options to consider in the process of adding solar resources to the system to meet the Minnesota SES. Issuing the RFP in 2014 helped ensure that any projects selected could meet the December 31, 2016 expiration deadline for the 30 percent Federal Investment Tax Credit (ITC), which allowed the Company to capture more attractive pricing for the projects.

C. 187 MW Solar Portfolio Process

Q. PLEASE DESCRIBE THE COMPANY'S RFP.

A. The Company issued the Solar RFP on April 22, 2014, identifying eligible projects as those based on a photovoltaic solar resource with a nominal electrical output of at least five MW (ac), that offered to sell to the Company all energy, associated capacity, ancillary services, and RECs generated by the project.

Q. WHAT WAS THE RESPONSE TO THE RFP?

A. Developer response to the RFP was robust. There were 111 proposals totaling over 2,100 MW of solar photovoltaic generating capacity submitted by 36 developers. Individual projects ranged in size from 5 MW to 100 MW. Submissions included a number of ownership structures from independently owned and operated facilities to offers of partnerships with the Company.

Q. DID THE COMPANY CONSIDER ALTERNATIVE ENERGY SOURCES OTHER THAN SOLAR?

A. The RFP was designed to acquire solar energy as its purpose was to probe the market to obtain resources for compliance with Minnesota's SES. Consequently, the Company did not request proposals from other generation types. This is in contrast to the selection of the Aurora Solar project, which was acquired in a capacity acquisition process and was considered against other generation types to meet capacity needs in Case No. PU-15-95.

However, while the RFP was limited to solar proposals, it is important to note that the Company's modeling and the PVRR impacts under different sensitivities provided insights into how this solar generation compared to other types of resources. Our analysis compared the overall system costs with and without the addition of the solar portfolio. The solar additions provide value by avoiding the need for fossil fuel generation and market purchases, as well as by providing capacity. Since the solar additions drove only a small net increase in PVRR, the Company's analysis indicated that these resources were competitive with the resources in our existing generation portfolio. I discuss the economic analysis of the 187 MW Solar Portfolio further below.

Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

A. The Company's Resource Planning department led the evaluation team, logging all bids on a tracking spreadsheet and maintaining the bids in a locked room accessible only by the Company's Resource Planning group. Initial screening identified 15 projects, in aggregate totaling 630 MW of generation capacity, submitted by 11 companies, each with a levelized energy cost of $85/MWh or less. Copies of these proposals were then provided to our Transmission, Land and Siting, and Purchased Power staff for further evaluation.

A significant consideration for any project is its ability to interconnect with the transmission system. Therefore, our Transmission Access group performed a detailed multi-factor review of the status of each project's MISO interconnection request and potential transmission requirements. This review identified potential significant issues around transmission interconnection cost and curtailment risk for several of the projects. Based on this analysis, the Transmission Access group recommended that a number of these projects be eliminated from further consideration.

Q. WHY DID THE COMPANY CONCLUDE IN 2014 THAT IT SHOULD PURCHASE ENOUGH SOLAR ENERGY THROUGH PPAS TO MEET THE SES RATHER THAN SPREAD ITS ACQUISITION OF SOLAR RESOURCES OVER TIME?

A. As I mentioned previously, the Federal ITC of 30 percent represented a significant incentive to developers that resulted in very attractive pricing for solar energy at that time. Although the ITC was subsequently extended, at the time, the incentive was scheduled to decrease significantly to 10 percent at the end of 2016, with future federal incentives increasingly uncertain. The Company felt the circumstances warranted making a substantial, near-term purchase in order to capitalize on the ITC.

Additionally, the Minnesota's REC banking rules for solar energy allowed us to accumulate tradable S-RECs before 2020. Marshall Solar and North Star Solar result in a significant bank of RECs that the Company can use to maintain compliance throughout the 2020s. The bank is projected to be large enough to support percentages of sales higher than 1.5 percent if necessary. Early compliance coupled with the S-REC banking standards provides the flexibility to make subsequent solar additions if it is in customers' best interest, while ensuring compliance with the SES at a reasonable cost.

D. Economic Analysis of the 187 MW Solar Portfolio

Q. HOW DID THE COMPANY EVALUATE THE 187 MW SOLAR PORTFOLIO?

A. The Company performed two evaluations of the 187 MW Solar Portfolio: a quantitative analysis and a qualitative analysis in the relevant MPUC proceeding and NDPSC proceeding (MPUC Docket No. E002/M-14-162 and NDPSC Case No. PU-14-810). Based on the outcome of these analyses, the Company determined that the acquisition of the 187 MW Solar Portfolio was a prudent resource acquisition to allow cost effective means to meet the Minnesota SES requirements while providing a source of clean energy that has key fuel and environmental hedging benefits. In addition, as noted above, while solar generation is primarily a source of clean energy, it also provides some additional capacity to the system that can be used to offset future capacity needs.

To perform the quantitative analyses, the Company used the Strategist resource planning model and present the results in PVRR terms. To assess the impact on customer costs, the Company simulated the operation of the NSP System with and without the addition of the 187 MW Solar Portfolio.

The Company also performed a more qualitative analysis to identify the non-economic benefits of the 187 MW Solar Portfolio to the NSP System. When the quantitative analysis and the qualitative analysis are taken together, the 187 MW Solar Portfolio will add a relatively minor net cost to the NSP System, but provide material qualitative benefits which demonstrate the prudence of these resource additions.

1. *Quantitative Analysis*

Q. WHAT WERE THE RESULTS OF THE QUANTITATIVE ANALYSIS OF THE 187 MW SOLAR PORTFOLIO?

A. The Company's 2014 analysis estimated that adding the 187 MW Solar Portfolio to the NSP System would increase energy costs by approximately $14 million over the 25-year term of the PPAs, without considering any CO_2 or externality costs. The Company also analyzed the impact of adding the 187 MW Solar Portfolio to the system under various sensitivities, including a scenario where natural gas prices stay below current market forecasts, a scenario where the system cannot make market purchases to meet increasing demand (Markets Off), and scenarios when capacity factors of the 187 MW Solar Portfolio are higher or lower than expected.

Table 11 below presents the results of these sensitivity tests. The table shows the cost to the system to operate without the 187 MW Solar Portfolio (the Reference Case), and also shows that operating the system with the 187 MW Solar Portfolio under the various sensitivities uniformly results in a relatively negligible net cost.

Table 11

Strategist PVRR Analysis of 187 MW Solar Portfolio

	Base	Low Gas	Markets Off	+2.5% Capacity Factor	-2.5% Capacity Factor
Base Case (No Solar)	$49,030	$46,192	$49,747	$49,030	$49,030
Full Portfolio	$49,044	$46,235	$49,742	$49,055	$49,036
Cost (Benefit)	$14	$43	($5)	$25	$6
% Increase / Decrease	0.029%	0.093%	-0.010%	0.051%	0.012%

The Markets Off case indicated a $5 million PVRR savings that reflects the impact of not having the availability/benefit of market energy purchases.

Q. FOR CONTEXT, WHAT IS THE IMPACT TO NORTH DAKOTA'S PORTION OF THE SYSTEM BASED ON TABLE 11, ABOVE?

A. Our North Dakota jurisdiction makes up about six percent of the overall NSP System. Consequently, to approximate the economic impacts to our North Dakota customers, we can take six percent of the anticipated PVRR costs of the 187 MW Solar Portfolio to achieve a rough contextual number. Making that calculation, we would expect costs to North Dakota on a PVRR basis of approximately $840,000 in the base case and approximately $2.58 million in the low gas scenario. I note that this is a rough approximation.

Q. HOW WILL THESE SOLAR PROJECTS BENEFIT NORTH DAKOTA CUSTOMERS?

A. The 187 MW Solar Portfolio was, at the time, a least cost way to meet the Minnesota SES while providing reasonably priced solar energy for North Dakota customers. Participating in the 187 MW portfolio provides North Dakota with the other benefits of participating in the large, integrated NSP System. Given the very modest cost impacts of the 187 MW solar portfolio, that participation benefits North Dakota customers overall.

Q. WHAT IS THE BASIS FOR THIS QUANTITATIVE ANALYSIS?

A. The Company's quantitative analysis was based on the cost of electricity displaced by the 187 MW Solar Portfolio as well as the accredited capacity value of this resource.

The NSP System is dispatched by MISO and solar production is generally dispatched ahead of other generation such as natural gas and coal-based generation. Consequently, the more solar energy produced, the less other fossil generation is operated and the less fossil fuel must be purchased. Therefore, when the energy from solar resources is produced, it displaces a similar amount of fuel that would have been acquired by the Company or other purchases of market energy. Our Base Case assumed a displacement of fuel that would have been purchased to generate approximately 370,000 MWh of fossil generation, accounting for the majority of differences in cost of system operation with and without the addition of the 187 MW Solar Portfolio.

The 187 MW Solar Portfolio started providing accredited capacity in June 2017. MISO has initially assigned a capacity accreditation of 50 percent for all solar resources. Future capacity accreditation values will be dependent upon actual production at each project. The solar projects are required to provide MISO with a minimum of 30 consecutive days of historical data during June, July, or August for the hours of 1500 – 1700 EST. For purposes of the economic evaluation, the Company assumed the projects will receive capacity accreditation for the 2018/2019 planning year but were able to participate in the 2017/2018 planning year auction one year earlier than expected.

Q. WHAT IS THE ESTIMATED RATE IMPACT ON THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. While the 187 MW Solar Portfolio represents the largest utility solar energy acquisition the Company has made, we estimate that the customer rate impacts will be minor, because the NSP System is so large in comparison. In fact, we expect that soon after initial operation, customers' overall bills will go from being slightly higher to gradually reducing to a net increase by 2025 of approximately 0.015¢ per kWh. The impact to average residential usage of 750 kWh per month would amount to about $0.13/month in 2020 dropping to $0.12/month by 2025.

As shown in Table 12 below, our Strategist dispatch simulation forecasts that for most years the rate impact of the 187 MW Solar Portfolio will be nearly offset by decreases in the Company's cost of purchasing fossil fuel and other energy.

Table 12

Customer Impacts of 187 MW Solar Portfolio Addition

	2015	2016	2017	2018	2019	2020
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh
Fuel Clause	0.000¢/kWh	0.008¢/kWh	0.054¢/kWh	0.055¢/kWh	0.055¢/kWh	0.056¢/kWh
Avoided Fuel & Purchased Power	0.000¢/kWh	-0.004¢/kWh	-0.034¢/kWh	-0.035¢/kWh	-0.035¢/kWh	-0.039¢/kWh
Net Rate Impact	**0.000¢/kWh**	**0.003¢/kWh**	**0.020¢/kWh**	**0.020¢/kWh**	**0.020¢/kWh**	**0.017¢/kWh**

	2021	2022	2023	2024	2025
Base Rates	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh	0.000¢/kWh
Fuel Clause	0.057¢/kWh	0.057¢/kWh	0.058¢/kWh	0.059¢/kWh	0.060¢/kWh
Avoided Fuel & Purchased Power	-0.042¢/kWh	-0.041¢/kWh	-0.043¢/kWh	-0.044¢/kWh	-0.044¢/kWh
Net Rate Impact	**0.014¢/kWh**	**0.016¢/kWh**	**0.015¢/kWh**	**0.015¢/kWh**	**0.015¢/kWh**

Q. ARE THERE OTHER QUANTITATIVE CONSIDERATIONS THAT THE COMMISSION SHOULD TAKE INTO ACCOUNT WHEN ANALYZING WHETHER TO ALLOW THE COMPANY TO RECOVER THE COSTS OF THE 187 MW SOLAR PORTFOLIO IN THE FCR?

A. Yes. As I noted above, the Company has already under-recovered approximately $2.1 million of the costs of the 187 MW Solar Portfolio since the projects were placed into service. This under-recovery has more than ameliorated the net anticipated increase in system costs (and costs to North Dakota customers) expected over the life of the 187 MW Solar Portfolio projects. Consequently, Commission approval to allow cost recovery of the 187 MW Portfolio on a prospective basis now should not increase costs for North

Dakota customers when viewed over the life of the projects. Therefore, it would be appropriate for the Commission to approve cost recovery for these projects today as the Company has already "bought down" the costs to North Dakota customers of the Company's compliance with the Minnesota SES through the 187 MW Solar Portfolio.

2. *Qualitative Analysis*

Q. WHAT QUALITATIVE BENEFITS DOES THE 187 MW SOLAR PORTFOLIO PROVIDE?

A. The addition of the 187 MW Solar Portfolio acts as a hedge against higher natural gas prices and future environmental regulations through the displacement of natural gas and coal-based generation. If the Company were not to acquire these resources, future levels of natural gas consumption and MISO market purchases would be higher, creating higher cost uncertainty for our customers.

Q. HOW DOES THE 187 MW SOLAR PORTFOLIO PROVIDE THESE QUALITATIVE BENEFITS?

A. As I mentioned, the 187 MW Solar Portfolio displaces the purchase of fossil fuel, including fuel for gas-fired generation, as well as market purchases and replaces these purchases with fixed price clean energy. Displacement of this generation by the 187 MW Solar Portfolio provides qualitative benefits to the NSP System and therefore to our customers.

Additionally, the displacement of variable cost fossil-based and market energy with a fixed price energy source provides a commodity hedge against volatile gas process and market risk. The fixed price certainty provides an additional qualitative benefit to our customers.

E. Summary

Q. ARE MARSHALL SOLAR AND NORTH STAR SOLAR PRUDENT, ECONOMICAL, AND EFFICIENT RESOURCES?

A. Yes. These projects were selected through a competitive RFP to provide the Company with low cost projects to meet Minnesota SES compliance. Our economic analysis of these resources bears this out. Additionally, acquisition of these resources will provide the NSP System with an additional source of clean energy that will displace other fuel and energy purchases. The 187 MW Solar Portfolio results in a relatively minor cost impact to NSP System customers, which, when balanced by qualitative benefits such as providing a natural gas price hedge, shows that acquisition of these resources is prudent.

Further, the Company's under-recovery of the project costs from their initial in-servicing has resulted in an amelioration of the costs to North Dakota customers of these projects. Therefore, it would be appropriate for the Commission to approve rate recovery on a going forward basis notwithstanding that these projects were selected for Compliance with the Minnesota SES.

Q. IF THE COMMISSION DENIES RECOVERY OF MARSHALL SOLAR AND NORTH STAR SOLAR, HOW WILL THE RESOURCES BE ACCOUNTED FOR BY THE COMPANY?

A. Company Witness Mr. Greg Chamberlain discusses the Resource Treatment Framework filings that the Company has made before the Commission in his Direct Testimony. As I noted earlier, this issue has not been resolved but the

Company requests that these solar resources and other resources in limbo due to the RTF proceeding be addressed and resolved in this Rate Case.

VII. REPOWERED WIND ACQUISITIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I explain the basis for the Company's request to recover the costs associated with acquiring, owning, and operating two repowered wind projects: (1) Jeffers Wind and (2) Community Wind North.

A. Background

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE JEFFERS WIND PROJECT.

A. Jeffers Wind is a 44 MW wind project located in Cottonwood County, Minnesota. The facility, initially established as a Community-Based Energy Development (C-BED) project, consists of twenty 2.5 MW Clipper C-96 wind turbines and achieved commercial operation on October 10, 2008. The Company entered into a PPA with Jeffers Wind 20, LLC on July 31, 2006, with a term of 20 years.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMMUNITY WIND NORTH PROJECT.

A. Community Wind North consists of two 13.2 MW wind projects located in Lincoln County, Minnesota. The facilities, originally established as C-BED projects, consist of twelve 2.5 MW Clipper C-96 wind turbines and achieved commercial operation in May 2012. The Company entered into two PPAs with Community Wind North on May 28, 2010. The terms of the PPAs are 20 years.

Although the C-BED statute was repealed in 2016 by the Minnesota Legislature, the PPAs with Jeffers Wind and Community Wind North were negotiated and approved during the time period when C-BED projects were given a statutory priority in Minnesota, and Minnesota public utilities were authorized to provide C-BED projects with favorable pricing compared to non-C-BED projects.

Q. WHEN WERE THE PROJECTS REPOWERED?

A. In 2016, the then-owner of both Jeffers Wind and Community Wind North informed the Company that it was undertaking a substantial project to refurbish both facilities, in order to ensure successful operation for the duration of the PPAs and beyond, and to re-qualify for Production Tax Credits (PTCs). In light of this, the Company entered into an agreement to purchase these projects. As part of the refurbishing, which was completed in 2020, the Owner installed smaller, more efficient 2.2 MW Vestas wind turbines and Automated Generation Control (AGC) technology, allowing the facilities to become dispatchable resources.

Q. WHEN DID THE COMPANY ACQUIRE THE PROJECTS?

A. In connection with these refurbishment projects, the Company negotiated amendments to the PPAs to reduce the cost of energy purchased under the agreements. In the course of these negotiations, the Company recognized we could further benefit customers by purchasing, owning, and operating the refurbished facilities. As a result, the Company negotiated and exercised an option to acquire both the Jeffers Wind and Community Wind North facilities. The MPUC (Docket No. E002/PA-18-777) found that these acquisitions were prudent and consistent with the public interest and approved the Company's acquisition of both facilities on December 3, 2019. The transaction is expected to close in November.

Q. DID THE COMPANY REQUEST ADVANCE DETERMINATIONS OF PRUDENCE IN NORTH DAKOTA FOR THE ACQUISITION OF THESE RESOURCES?

A. No. Pursuant to the Settlement Agreement in Case No. PU-07-776, the Company is required to seek an ADP for any resource addition that is 50 MW or greater. Because both Jeffers Wind and Community Wind North are under 50 MW and they were not acquired as part of a portfolio like the 187 MW Solar Portfolio I described earlier, the Company did not seek ADPs for these acquisitions.

Q. NOTWITHSTANDING THE FACT THAT THE COMPANY DID NOT SEEK ADPS, DO THE SAME PRUDENCE PRINCIPLES APPLY IN THIS RATE CASE?

A. Yes. As I stated above, my understanding is the Company must demonstrate that the resource additions were prudent at the time the decision was made to add the resources in order for the costs to be recoverable in base rates.

Q. WHAT IS THE STATUS OF THE ORIGINAL PPAS FOR JEFFERS WIND AND COMMUNITY WIND NORTH?

A. The PPAs will be cancelled when the Company acquires the projects.

Q. IS THE COMPANY CURRENTLY RECOVERING ANY COSTS ASSOCIATED WITH THE JEFFERS WIND OR COMMUNITY WIND NORTH PROJECTS?

A. Pursuant to the Settlement Agreement approved by the Commission on March 9, 2016 in Case No. PU-12-813, the Company agreed to not recover the costs and volumes of 15 specified C-BED wind projects, including Community Wind North and Jeffers Wind, in its calculation of the FCR. Rather, we are currently recovering the system average cost of fuel for the production of these projects. However, pursuant to the Settlement Agreement approved by the Commission on February 26, 2014 in Case No. PU-12-813 (2014 Settlement), the Company includes the expenses associated with the original PPAs in its calculation of weather-normalized earnings, for purposes of determining earnings sharing with North Dakota customers.

Q. PLEASE ELABORATE.

A. In the 2014 Settlement, the Company and Commission Staff agreed to set up an earnings sharing mechanism whereby the Company would annually refund a portion of its earnings that exceeded the Company's authorized return on equity (ROE) for that particular year. Under the 2014 Settlement, the costs of any PPAs that are excluded from the calculation of the FCR, including C-BED projects like Jeffers Wind and Community Wind North, would be accounted for in the Company's calculation of its weather-normalized earnings for this revenue sharing mechanism. Thus, the Company's weather-normalized earnings do account for the costs of the Jeffers Wind and Community Wind North PPAs when those costs are incurred.

Q. WHAT IS THE COMPANY REQUESTING FROM THE COMMISSION WITH RESPECT TO JEFFERS WIND AND COMMUNITY WIND NORTH IN THIS CASE?

A. The Company requests that the Commission find the Company's decision to acquire the repowered Jeffers Wind and Community Wind North facilities to be prudent and to allow recovery of the costs and energy of these projects in base rates.

B. Prudence of the Jeffers Wind Acquisition

Q. PLEASE PROVIDE A SUMMARY OF THE PRUDENCE OF THE JEFFERS WIND ACQUISITION.

A. The Company's purchase of the Jeffers Wind project provides system cost savings to our customers over the life of the repowered facility in comparison to the terms of the original PPA, with market price replacement energy after the PPA expires. Additionally, the purchase of the refurbished facility enables the Company to continue to improve environmental performance in a cost-effective manner in furtherance of the Company's goal of achieving an 80 percent reduction in carbon emissions by 2030. Ultimately, the Company's purchase of Jeffers Wind reduces costs for all of our customers.

Q. HOW WERE THE ECONOMIC IMPACTS OF THE JEFFERS WIND ACQUISITION EVALUATED?

A. Consistent with the analysis the Company performed in another recent acquisition of a repowered wind facility for which an ADP was recently granted by the Commission (Mower County Wind, Case No. PU-19-310), the Company performed two economic analyses to evaluate the PVRR impacts of the acquisition of the Jeffers Wind project: (1) a pro forma analysis, and (2) a traditional analysis using the Strategist resource planning tool. For reference, the PPA price of the Jeffers Wind project is **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]** and the levelized cost of energy after purchasing the project is **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.

Q. WHEN DID THE COMPANY PERFORM ITS ANALYSIS OF THE POTENTIAL ACQUISITION OF THE JEFFERS WIND FACILITY?

A. The modeling of the acquisition of Jeffers Wind was completed in 2018, when the Company was considering acquiring the facility.

Q. HAS THE COMPANY PERFORMED AN UPDATED ANALYSIS OF THE JEFFERS WIND ACQUISITION FOR THIS RATE CASE?

A. No. As I discussed above, this would be inappropriate because the prudence of the decision is measured by the information at hand when the Company made the decision to acquire the facility. That said, we have performed an analysis consistent with North Dakota evaluation standards for resource acquisitions and consistent with the information we would normally file in an ADP proceeding.

Q. IS THE PRO FORMA ANALYSIS AN APPROPRIATE TOOL FOR EVALUATING THESE PROJECTS?

A. Yes. The pro forma analysis is appropriate for evaluating our purchase of projects already under contract under a PPA because they produce zero marginal cost or "must take" energy that is generally predictable from year to year and not subject to fluctuations driven by the dispatch of different resources on our system. With known production levels, we can then simply compare the costs of one option (PPA with market replacement) to the costs of another (resource acquisition). While adding incremental wind energy would have larger impacts on the system and potentially impact the dispatch of other resources, here we are assuming the same levels of wind in both cases which allows us to simply focus on the cost deltas.

Q. HOW WAS THE PRO FORMA ANALYSIS USED TO EVALUATE THE JEFFERS WIND ACQUISITION?

A. The pro forma analysis compares the cost of acquiring the repowered Jeffers Wind facility with the costs of the original PPA through its current term, and a market price for the replacement energy after the expiration of the original PPAs.

Q. WHY IS IT APPROPRIATE FOR THE COMPANY TO MEASURE THE COST IMPACT OF THESE PROJECTS AGAINST THE ACTUAL PPA COSTS WHEN THE COMPANY WAS ONLY RECOVERING SYSTEM AVERAGE COST OF FUEL FOR THESE PROJECTS?

A. The fact that the Company is adjusting its earnings to account for the Jeffers Wind PPA, notwithstanding the fact that the PPA has been cancelled, demonstrates the appropriateness of using the original PPA as the point of comparison against ownership of the resource. As discussed below, ownership of this resource generates savings for customers on a system-wide basis, and will generate further savings if the Company is no longer factoring this project into its annual calculation of earnings for the purposes of earnings sharing with North Dakota customers.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S PRO FORMA ANALYSIS OF ACQUIRING THE JEFFERS WIND FACILITY?

A. The results of our pro forma analysis show that the acquisition of the Jeffers Wind facility results in net savings for our customers when compared with the original PPAs plus market price replacement energy through 2044, the expected life of the project. Table 13, below, shows the PVRR savings for the facility.

Table 13

Pro Forma PVRR Analysis of Jeffers Wind Acquisition

PVRR PPA + Mkt Replacement	$82.8
PVRR Ownership	$65.1
Cost (Savings)	($17.6)

Q. WHAT DOES TABLE 13 SHOW?

A. Table 13 demonstrates that the proposed repower and acquisition of Jeffers Wind provides $17.6 million PVRR savings when compared with the original PPAs.

Q. DOES THE COMPANY'S ANALYSIS ASSUME THAT THE PPAS WILL BE REPLACED BY MARKET PURCHASES OF ENERGY?

A. Yes. Consistent with the Commission's assessment of a different purchase of a repowered facility, the Mower County wind facility (Case No. PU-19-310), our analysis assumed the Jeffers Wind PPA would expire in 2028 pursuant to the terms of the original PPA. After the PPA expires, the energy is assumed to be replaced by market purchases in the MISO market. Under the acquisition scenario, the repowered wind resources are assumed to operate for 25 years from the date of repowering.

Q. HOW DID THE COMPANY DETERMINE THE FORECASTED MARKET PRICE OF ENERGY USED IN THE ANALYSIS?

A. The market price forecast is the same assumption used in the modeling for our most recent IRP Supplement, the public version of which is attached to my

Testimony as Schedule 7.[5] The company uses a simple average of long-term on-peak and off-peak implied heat rate forecasts provided by Wood Mackenzie, S&P Global and IHS Markit for the MISO Minnesota Hub. The implied heat rates, denominated in MMBtu/MWh, are then multiplied by the Company's long-term natural gas price forecast to convert the implied heat rate values into energy prices.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE PROPOSED ACQUISITION OF THE JEFFERS WIND FACILITY?

A. To perform the Strategist analysis, the Company simulated the operation of the NSP System through 2057, comparing the acquisition of the Jeffers Wind Facility to the continuation of the existing PPA.

Q. WHAT ASSUMPTIONS WERE USED WHEN MODELING THESE ACQUISITIONS?

A. The full list of Strategist assumptions used in our modeling is attached as Schedule 8. All of our analyses assumed the addition of the 1,850 MW of wind generation approved by the Commission pursuant to settlement agreements in Case Nos. PU-17-120 and PU-17-372, and the Dakota Range III wind resource which was later approved by the Commission in Case No. PU-18-430.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S STRATEGIST ANALYSIS OF THE JEFFERS WIND ACQUISITION?

A. The Company's Strategist analysis found that the acquisition of the Jeffers Wind facility generates PVRR savings for our customers similar to the savings found

[5] The Company is providing the public (non-trade secret) version of this document for administrative ease. If the Commission requires the trade secret version, we will be happy to provide it in response to a discovery request.

in our pro forma analysis. Table 14 below shows the PVRR savings generated by the acquisition of Jeffers Wind.

Table 14

Strategist PVRR Analysis of Jeffers Wind Acquisition

Scenario	PVRR	Delta
Base	44,903.4	-
Own Jeffers - 20 years	44,901.3	(2.2)
Own Jeffers - 25 years	44,894.8	(8.7)
Own Jeffers - 30 years	44,890.5	(12.9)

Q. WHAT DOES TABLE 14 SHOW?

A. Table 14 shows that the proposed repower and acquisition of Jeffers Wind provides $8.7 million PVRR savings when compared with the original PPAs under the expected 25 year life of the repowered project. Table 14 also shows savings under a 20 and 30 year assumed life.

Q. WHY DOES THE STRATEGIST MODEL ESTIMATE MORE CUSTOMERS SAVINGS THAN THE PRO FORMA MODEL?

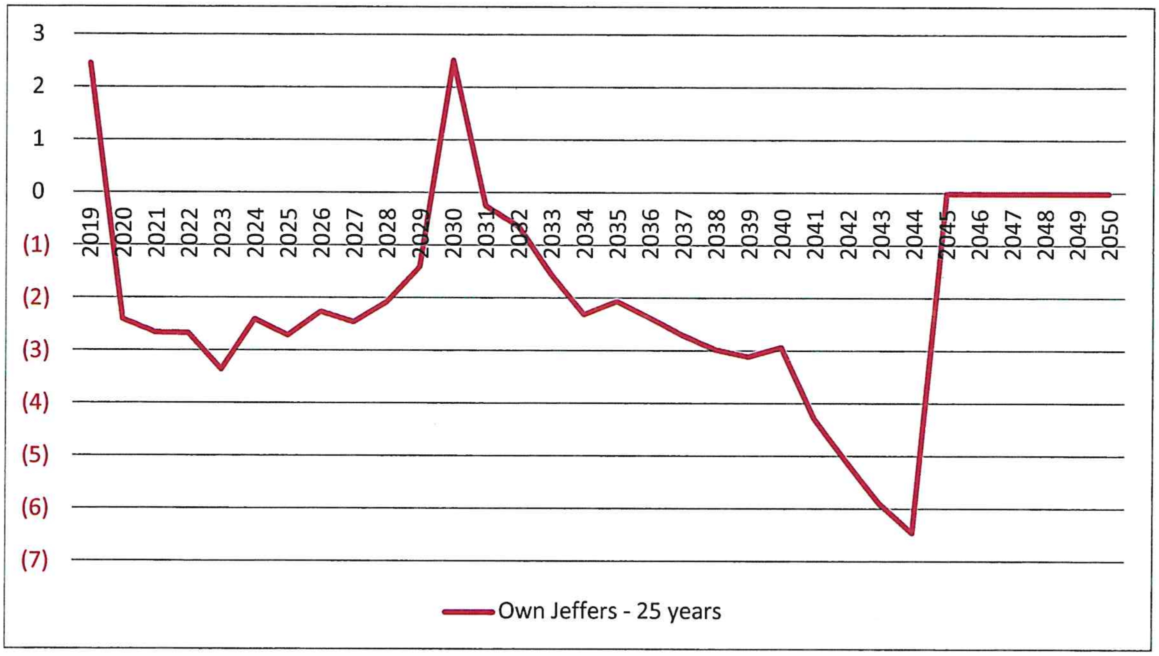
A. Unlike the pro forma model, the Strategist analysis captures the capacity value of the Jeffers Wind project beyond the term of the PPA, resulting in additional benefits to customers that are reflected in the PVRR savings. Ultimately, however, the results of the pro forma and Strategist analyses are similar because with a relatively simple analysis such as this one, the pro forma approach is a reasonable proxy for a full Strategist analysis.

Q. DID THE COMPANY MODEL THE ANNUAL COSTS AND SAVINGS OF THE ACQUISITION?

A. Yes. Figure 4 below shows the annual cost impacts of the acquisition beginning in 2020, the first full year of the repowered project. Savings in the near-term are strong for the acquisition, but costs rise after the expiration of the PTC.

Figure 4

Annual Costs/Savings Deltas – Jeffers Wind Acquisition



Q. DOES FIGURE 4 ASSUME MARKET PURCHASES AND SALES?

A. Yes. The PVRR savings shown in Figure 2 assumes we are able to take advantage of the MISO energy market to make energy purchases and sales. Consistent with the analysis performed for our most recent wind acquisitions, we included a limit on the maximum amount of market sales based on historical data. Due to this limit on market sales, a significant amount of the incremental wind generation is "dumped" and does not receive any value.

Q. PLEASE ELABORATE.

A. While we have used the same limit on market sales in the past, this assumption is likely overly conservative. At the time we performed this modeling, MISO expected the Zone 1 export limit to increase by approximately 2,500 MWs for the 2019-2020 planning year due to additional transmission lines going into service. Consequently, we expected less dump energy than we included in the modeling, which will result in more benefits than shown in Figure 4. We will continue to evaluate changes to the limit on market transactions in future filings. As the Company will take advantage of MISO energy market transactions when in the interest of our customers, we believe modeling the availability of the MISO energy market is an appropriate indicator of the likely impacts to customers of the wind resource addition. I would also note that we have included wind integration costs and coal cycling costs as shown in Schedule 8.

Q. WHAT IS THE LEVELIZED COST OF ENERGY FOR THE JEFFERS WIND PROJECT?

A. The levelized cost of energy (LCOE) of the Jeffers Wind project is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** By contrast, the contract price of the original PPA was **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**.

Q. WHAT DOES THIS DEMONSTRATE REGARDING THE COMPANY'S DECISION TO ACQUIRE THE PROJECT?

A. The low LCOE of this repowered project indicates that the Company's decision to acquire it was prudent. While the original PPA was executed pursuant to the policy priorities in place at the time, our decision to acquire the repowered resource is a prudent way to mitigate the costs of these policy choices from a decade ago. This is consistent with the Commission's recent approval of an ADP for the Mower County Wind Facility in Case No. PU-19-310, in which the Company acquired a repowered wind facility that was previously under a PPA executed by the Company as required by the MPUC in the Company's 2000 Resource Plan docket (MPUC Docket No. E002/RP-00-787). It is also consistent with the Commission's approval of a settlement agreement allowing the Company to buy out certain biomass contracts in Case No. PU-17-270. In general, this indicates that the Commission recognizes it is prudent to encourage outcomes with net savings to customers, regardless of the resource.

Q. OVERALL, WHAT DID THE COMPANY'S ANALYSIS OF THE JEFFERS WIND ACQUISITION DEMONSTRATE?

A. Our analysis of the transaction found that the purchase of this repowered facility was reasonable and prudent because it would provide savings to our customers when compared with the then-existing PPA pricing, and would mitigate the impact of the high costs in the original PPA.

C. Prudence of the Community Wind North Acquisitions

Q. PLEASE PROVIDE A SUMMARY OF THE PRUDENCE OF THE COMMUNITY WIND NORTH ACQUISITIONS.

A. The Company's purchase of the Community Wind North facilities offers system cost savings to our customers over the lives of the repowered facilities in comparison to the terms of the original PPAs, assuming market price replacement energy after the PPAs expire. Additionally, the purchase of the facilities furthers the Company's goal of achieving an 80 percent reduction in carbon emissions by 2030.

Q. HOW WERE THE ECONOMIC IMPACTS OF THE COMMUNITY WIND NORTH ACQUISITIONS EVALUATED?

A. As with Jeffers Wind and the recently-approved Mower County wind facility (Case No. PU-19-310), the Company performed (1) a pro forma analysis and (2) a traditional analysis using Strategist. For reference, the current PPA price is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** and the levelized cost of energy from purchasing the facility is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**.

Q. WHEN DID THE COMPANY PERFORM ITS ANALYSIS OF THE POTENTIAL ACQUISITION OF THE COMMUNITY WIND NORTH FACILITIES?

A. The modeling of the acquisition of Community Wind North was completed in 2018, when the Company was considering acquiring the facilities. As I discussed above, the Company has not performed any updated analyses because the prudence of the decision is measured by the information at hand when the Company made the decision to acquire the facilities. That said, we have performed an analysis consistent with North Dakota evaluation standards for resource acquisitions and consistent with the information we would normally file in an ADP proceeding.

Q. HOW WAS THE PRO FORMA ANALYSIS USED TO EVALUATE THE COMMUNITY WIND NORTH ACQUISITIONS?

A. The pro forma analysis compares the cost of acquiring the repowered Community Wind North facilities with the costs of the original PPA through its current term, with a market price for the replacement energy after the expiration of the original PPAs. As I discussed earlier regarding Jeffers Wind, it is appropriate to measure the cost impact of these projects against the PPA costs because the Company is currently adjusting its earnings to account for the PPAs, notwithstanding the fact that they have been cancelled.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S PRO FORMA ANALYSIS OF ACQUIRING THE COMMUNITY WIND NORTH FACILITIES?

A. The results of our analysis show that the acquisition of the Community Wind North facilities results in net savings for our customers when compared with the original PPAs plus market price replacement energy through 2044, the expected life of the repowered projects. Table 15 shows the combined PVRR savings for the Community Wind North facilities.

Table 15

Pro Forma PVRR Analysis of Community Wind North Acquisition

PVRR PPA + Mkt Replacement	$69.7
PVRR Ownership	$65.3
Cost (Savings)	($4.4)

Q. WHAT DOES TABLE 15 SHOW?

A. Table 15 demonstrates that the proposed repower and acquisition of Community Wind North generates $4.4 million PVRR savings in comparison to the then-existing PPAs.

Q. DOES THE COMPANY'S ANALYSIS ASSUME THAT THE PPAS WILL BE REPLACED BY MARKET PURCHASES OF ENERGY?

A. Yes. As I discussed earlier, consistent with the Commission's assessment of the Mower County wind facility in Case No. PU-19-310, our analysis assumed the

Community Wind North PPAs would expire in 2031, which were the terms of the PPAs at that time. After the PPAs expire, the energy is assumed to be replaced by market purchases in the MISO market. Under the acquisition scenario, the repowered wind resources are assumed to operate for 25 years.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE PROPOSED ACQUISITION OF THE COMMUNITY WIND NORTH FACILITIES?

A. To perform the Strategist analysis, the Company simulated the operation of the NSP System through 2057, with and without acquisition of the Community Wind North facilities. As I discussed earlier, our analyses assumed the addition of the 1,850 MW of wind generation approved by the Commission pursuant to settlement agreements in Case Nos. PU-17-120 and PU-17-372, and the Dakota Range III wind resource which was later approved by the Commission in Case No. PU-18-430. The full list of Strategist assumptions used in our modeling is attached as Schedule 8.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S STRATEGIST ANALYSIS OF THE COMMUNITY WIND NORTH ACQUISITION?

A. The Strategist analysis found that the acquisition of the Community Wind North Facility generates a slight increase in PVRR of $900k under the expected 25 year life of the project. While the net PVRR cost increase under a 20-year assumed life, under a 30-year life, cost savings are realized. These results are similar to the savings found in our pro forma analysis. Table 16 below shows the PVRR savings generated by the acquisition of Community Wind North.

Table 16

Strategist PVRR Analysis of Community Wind North Acquisition

Scenario	PVRR	Delta
Base	44,903.4	-
Own CWN - 20 years	44,907.7	4.3
Own CWN - 25 years	44,904.3	0.9
Own CWN - 30 years	44,902.4	(1.0)

Q. WHAT DOES TABLE 16 SHOW?

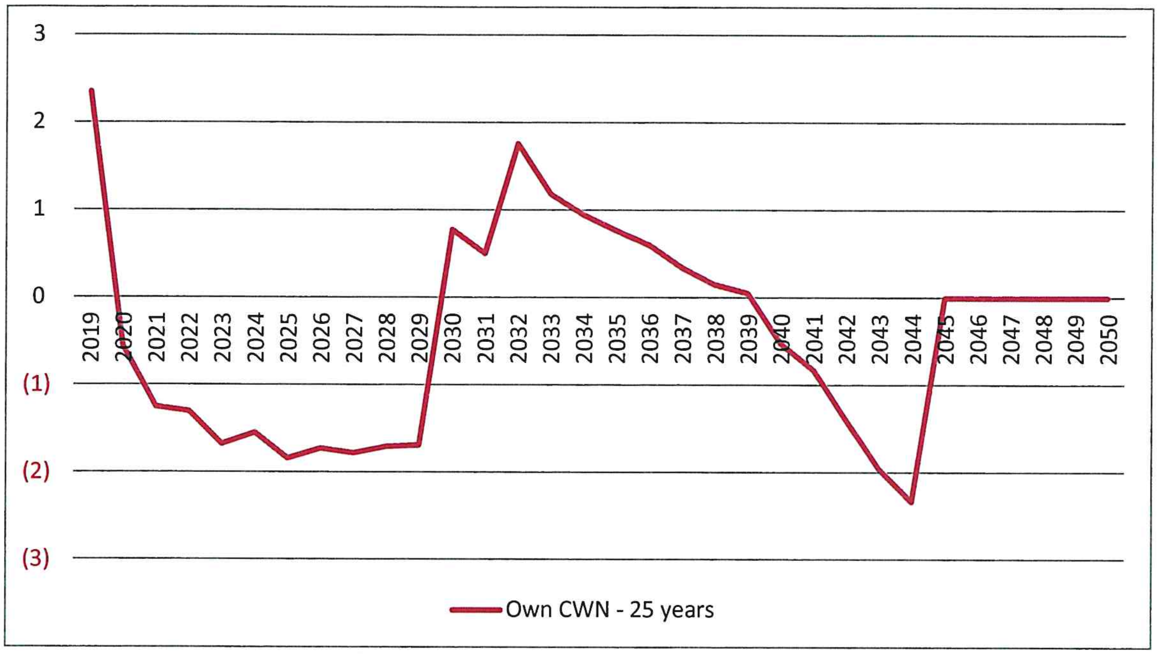
A. Table 16 shows that the proposed repower and acquisition of Community Wind North results in a net PVRR increase of $900k when compared with the original PPAs.

Q. DID THE COMPANY MODEL THE ANNUAL COSTS AND SAVINGS OF THE ACQUISITIONS?

A. Yes. Figure 5 below shows the annual cost impacts of the acquisitions beginning in 2020, the first full year of the repowered projects. Savings in the near-term are strong for the acquisition, but costs rise after the expiration of the PTC.

Figure 5

Annual Costs/Savings Deltas – Community Wind North Acquisition



Q. DOES FIGURE 5 ASSUME MARKET PURCHASES AND SALES?

A. Yes. As with the Jeffers Wind analysis I discussed previously, the PVRR savings shown in Figure 5 assumes we are able to take advantage of the MISO energy market to make energy purchases and sales, and we included a limit on the maximum amount of market sales based on historical data. Due to this limit on market sales, a significant amount of the incremental wind generation is "dumped" and does not receive any value.

Q. WHY DID THE STRATEGIST ANALYSIS RESULT IN AN INCREASE IN COST FOR THE COMMUNITY WIND NORTH PROJECT?

A. The increase in cost in less the $1 million on a system wide basis. Therefore, the Strategist analysis, like the proforma analysis, essential results in benefits and cost that are approximately equal. Compared to Jeffers, CWN has a higher existing PPA price and a longer existing contract, so that the benefits of the capacity of the repowered project occur earlier in the Strategist analysis for Jeffers. In addition, as noted above, the market sales limit results in generation that is "dumped" in the Strategist model and therefore does not receive value. In reality, transmission may be available to sell the dumped energy into the market and credit revenues back to customers.

Q. WHAT IS THE LEVELIZED COST OF ENERGY OF THE COMMUNITY WIND NORTH PROJECT?

A. The LCOE of the Community Wind North project is **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. By contrast, the contract price of the original PPAs was **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. As I discussed earlier with regard to Jeffers Wind, this reduced LCOE indicates that the Company's decision to acquire the repowered project was a prudent way to mitigate the costs of policy choices made a decade ago.

Q. OVERALL, WHAT DID THE COMPANY'S ANALYSIS OF THE ACQUISITION OF COMMUNITY WIND NORTH DEMONSTRATE?

A. As with Jeffers Wind, our analysis found that the purchase of these repowered facilities was reasonable and prudent because it would provide savings to our customers when compared with the then-existing PPA pricing, and would mitigate the impact of the high costs in the original PPAs.

D. Summary

Q. PLEASE SUMMARIZE WHY THE COMPANY'S ACQUISITION OF COMMUNITY WIND NORTH AND JEFFERS WIND WAS PRUDENT.

A. The Company's acquisition of these facilities was prudent because it provides savings to our customers when compared to the existing PPAs and leaves the Company with newly repowered wind facilities whose useful lives stretch well beyond the original terms of the PPAs. As a result, the Company requests that the Commission find these acquisitions to be prudent and allow for recovery of the acquisition costs in base rates.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE COMPANY'S DECISION TO ADJUST THE RETIREMENT DATES FOR SHERCO 1 AND 2 TO 2026 AND 2023, RESPECTIVELY.

A. The Company's decision to adjust the retirement dates for Sherco 1 and 2 was prudent because the Company determined that the ongoing and increasing regulatory risks to the facility made it imprudent to further invest in these nearly 40-year old units. Although the early retirement plan generated additional costs when compared to the Company's originally proposed 2015 Resource Plan, it was prudent for the Company to conclude that the early retirement plan appropriately balanced the risks and uncertainty while taking advantage of low-cost renewables to transition our fleet and position ourselves for the future. Since 2015, additional analyses requested by Commission staff have further borne out the prudence of the Company's decision to retire the units.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE MEC II PPA.

A. The Company's addition of the MEC II PPA was prudent because the forecast upon which the decision was based predicted a capacity need, and the MEC II PPA provided combined-cycle capacity at combustion turbine pricing to fill the identified need. Even though the Company's capacity need shifted during the acquisition process, it was still prudent for the Company to move forward with acquiring this combined-cycle capacity resource, particularly given the anticipated high costs of adding a Greenfield CC in the mid-2020s timeframe.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE COMPANY'S DECISION TO CANCEL THE PRAIRIE ISLAND EPU.

A. The Company's decisions to first undertake, and to later cancel the Prairie Island EPU were both prudent based on the Company's economic analysis and the circumstances at the time of each decision. When it was first proposed, the Company estimated the Prairie Island EPU would save our customers more than $500 million compared to the next best alternative for providing this capacity, in addition to providing a hedge against then-high natural gas prices and potential carbon regulation. However, major changes to the circumstances surrounding the EPU changed the prudence calculus, including a reduction in the project size, delays in implementation, increased costs, and lower customer demand. Following this change in circumstances, it was prudent for the Company to conclude that additional risks of delay and increased costs outweighed the reduced benefit from moving forward.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE 187 MW SOLAR PORTFOLIO PPAS.

A. The Company's addition of the Marshall Solar and North Star Solar PPAs—the two remaining PPAs in the original 187 MW Solar Portfolio—was prudent because these resources were selected through a competitive RFP to provide the Company with low cost solar projects to meet Minnesota's Solar Energy Standard, and they provided a relatively low-cost hedge against fuel prices.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE JEFFERS WIND ACQUISITION.

A. The Company's purchase of the Jeffers Wind project was prudent because our economic analysis found that the acquisition would generate system cost savings for our customers, as compared to both (1) the original PPA plus market energy replacement when it expires, or (2) continuing the terms of the original PPA. Additionally, acquiring the Jeffers Wind project furthers the Company's long-term goal of achieving an 80 percent reduction in carbon emissions by 2030.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE COMMUNITY WIND NORTH ACQUISITION.

A. The Company's purchase of the Community Wind North facilities was prudent because the Company's economic analysis found that it generated savings when compared with continuation of the existing PPAs through their original term with market replacement energy. Our economic analysis of the acquisition in comparison to continuing the original PPAs found a slight increase in PVRR, but given the benefits that Community Wind North provides in furthering our long-term goal of achieving an 80 percent reduction in carbon emissions by 2030, the Company's acquisition of Community Wind North was prudent.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-20-___

AFFIDAVIT OF
Christopher J. Shaw

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Christopher J. Shaw

Subscribed and sworn to before me, this 20 day of October, 2020.

Notary Public
My Commission Expires: January 31, 2025

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

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EXPERIENCE

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Manager, Regulatory Policy 8/18-Present
Principal Rate Analyst 11/15-8/18
Developed strategy, coordinated subject matter expert analysis and prepared filings for the 2019 Upper Midwest Integrated Resource Plan (IRP), the 2016 IRP filing, Resource Treatment Framework (RTF), and resource acquisitions. Represented the Company at hearings on the IRP and other resource related proceedings.

Minnesota Department of Commerce-Division of Energy Resources
Public Utilities Rates Analyst 8/06-6/12 & 6/13-11/15
Developed and supported the recommendations of the Department of Commerce in proceedings before the Minnesota Public Utilities Commission. Performed analysis of utility regulatory filings. Appeared as an expert witness in numerous contested cases. Analyzed proposed legislation and prepared reports for the Minnesota Legislature.

Minnesota Office of the Attorney General-Anti-Trust and Utilities Division
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Advocated for residential and small business energy consumers on behalf of the Attorney General, including advocacy in Xcel Energy's 2012 rate case.

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Mixed Integer Programming (MIP) in EnCompass

EnCompass utilizes mixed integer programming to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems.

Economic Dispatch

The economic dispatch problem seeks to minimize total production costs given a commitment schedule of which units are online and offline in every interval (usually one hour). EnCompass formulates this as a linear problem by using a piecewise-linear representation of unit heat and emission rates, and either a zonal or DC (linearized) powerflow model for transmission. Constraints applied for the economic dispatch include load and ancillary service requirements, transmission limits, fuel limits, environmental limits, storage limits and efficiencies, capacity factor (energy) limits, ramp rates, and resource capacity limits for energy and ancillary services.

Linear programming is a fast, robust, and well-established process that will always return an optimal solution if the problem is feasible (i.e., the constraints are not conflicting). EnCompass uses "soft" constraints for load balance, ancillary services, and certain transmission limits by allowing the limits to be violated subject to input penalties (unserved load and curtailment penalties). In this way, the problem will always be feasible, and any limit violations are reported. In most cases, there is only a single optimal solution. However, if there are multiple units with identical costs, the selection of which units to dispatch is arbitrary. EnCompass will always produce the exact same solution for the same scenario. If a unit that was not dispatched is removed from the scenario, the structure of the problem changes, and a different dispatch of identical units could occur if a different route were taken to find an optimal solution.

When EnCompass is run using the "No Commitment" option, the minimum capacities of resources that are not must-run are relaxed, so that there is no unit commitment problem to solve. In this mode, any startup and no-load costs are converted to linear $/MWh costs using the input Expected Runtime (or if not set, the Minimum Uptime), and are added to a unit's energy and ancillary service costs. This option is the fastest way in which to run EnCompass.

Unit Commitment

The unit commitment problem extends the economic dispatch problem by allowing the selection of which units are online and offline in every interval, given a set of units with fixed commission and retirement dates. This selection uses integer, or whole-number, variables together with the continuous variables from the economic dispatch problem, which is why the methodology is referred to as a "mixed" integer program.

The unit commitment constraints that EnCompass applies includes minimum uptime, minimum downtime, maximum daily and weekly starts, and profiles for which intervals are allowed for unit starts and shutdowns. Fuel requirements and direct costs can be applied to starts and shutdowns, with the option to vary startup requirements based on cold, warm, and hot input definitions. Operating constraints can be applied across a group of units to model load pocket and voltage support requirements, as well as dependencies and other restrictions.

When EnCompass is run using the "Partial Commitment" option, all of the unit commitment costs and constraints are applied, but the number of units committed in any interval is allowed to be a continuous variable between 0 and 1. For example, if the optimal solution included a value of 0.3 for the number of units committed, this would incur 30% of the cost of a start and only allow the unit to dispatch up to 30% of its capacity. The unit would still have to be at least 30% committed for the minimum uptime, and once it goes below that cannot increase until the minimum downtime has passed. The Partial Commitment option turns the unit commitment problem into a linear problem, which makes it faster to solve than the "Full Commitment" option and provides more detail and constraints than the "No Commitment" option.

Capacity Expansion

The capacity expansion problem extends the unit commitment and economic dispatch problem by allowing the selection of new resources, transmission upgrades, and economic retirements. This selection uses also uses integer variables that represent the number of resource additions and retirements in each year. The economic carrying charge is used to represent capital costs for new projects, which increases at the rate of construction escalation and provides the same present value of annual revenue requirements over the book life.

Instead of firm reserve margin constraints, EnCompass uses capacity demand curves to incent meeting reserve margin targets. These can represent "high cliffs" where the penalty for falling short of the target reserve margin is very high ($10,000/kW-year) and then goes to 0 once the reserve margin is met; or they can be downward-sloping curves like those used in PJM, New York and New England for capacity markets.

Each project can have constraints on the maximum additions (incremental) per year, and the minimum and maximum active (cumulative) projects each year. Project Constraints can be used to set these constraints over a group of projects, which can include exclusivity and dependencies.

EnCompass includes a "Partial" optimization option which will allow the number of additions to be a continuous variable. For example, if the optimal solution included a value of 0.3 for the number of additions, this would incur 30% of the capital costs and only consider 30% of the capacity added. Over the operating life of the project, the number of active projects would be at least 30%. If the unit commitment option is "No Commitment" or "Partial Commitment" (which are the typical settings for capacity expansion), Partial project option turns the capacity expansion problem into a linear problem, which makes it faster to solve than the "Full" option. There is also a "Rounded" option which will automatically round up all additions and retirement to the next whole number, but this is typically only used for market-based capacity expansion over large regions. Finally, even with the "Full" option, individual projects can consider partial additions after an input year, which improves the overall runtime.

The MIP Process

If either the unit commitment or capacity expansion options are set to "Full", EnCompass will solve the problem using mixed integer programming. Unlike linear programming, it is not always feasible to find the global optimal solution to a mixed integer problem since the process requires evaluating numerous potential integer solutions. Instead, the problem is considered to be solved when the costs of the best integer solution found is within an input tolerance of the cost of the best remaining partial solution (known as the best bound). The tolerance is measured as the percent difference between the best solution and best bound, and in EnCompass the MIP Stop Basis is input as basis points (1/100th of 1%).

The MIP process first determines the best partial solution using linear programming, as if the option had been set to "Partial". The cost of this solution then becomes the initial best bound, since rounding partial variables up or down will only increase the costs from there. Then, the MIP will create and evaluate several subproblems to find integer solutions and eliminate other possibilities. When a better solution is found, this reduces the best solution cost; when a path is eliminated, this increases the best bound cost. The process continues until the gap between these two costs is within the input tolerance.

Consider a simple example of a one-year capacity expansion problem with three potential projects (P1, P2, and P3) where each project has a maximum of 1. The first step is to solve the partial problem, and assume it provides these results:

- Node 0: Cost = $15.5 million, P1 = 0.3, P2 = 0.8, P3 = 0

The best bound is now $15.5 million, and the MIP will now start to evaluate the subproblems by branching on the partial solutions. For example, two subproblems will be created, one with the constraint P1 = 0 and the other with the constraint P1 = 1. These subproblems are then solved using linear programming, and assume these results:

- Node 1: Cost = $16.1 million, P1 = 0, P2 = 1, P3 = 0
- Node 2: Cost = $15.8 million, P1 = 1, P2 = 0.4, P3 = 0.1

Note that the project results for Node 1 are now all integers, and we have our first feasible solution. Node 2 still has partial projects, so the best bound now increases to $15.8 million. The gap between the best solution and best bound is 1.9%. If the MIP Stop Basis was set to 200, the process will stop and return Node 1 as the best solution. Assume that the MIP Stop Basis is lower, and the process will now branch on Node 2 by setting P2 = 0 and P2 = 1:

- Node 3: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0.3
- Node 4: Cost = $16.2 million, P1 = 1, P2 = 1, P3 = 0

Node 4 is a feasible integer solution, but has a higher cost than Node 1, so the process does not do anything else with Node 4 (that "branch has been pruned"). Node 3 is a partial solution, so the best bound increases to $15.9 million, leaving a gap of 1.3% with the best solution (Node 1). Assume that the MIP Stop Basis is less than 120, so the process will now branch on Node 3 by setting P3 = 0 and P3 = 1:

- Node 5: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0
- Node 6: Cost = $16.3 million, P1 = 1, P2 = 0, P3 = 1

The process is now left with only integer solutions, so the best bound and best solution are both $15.9 million, the gap is 0%, and Node 5 is the optimal solution.

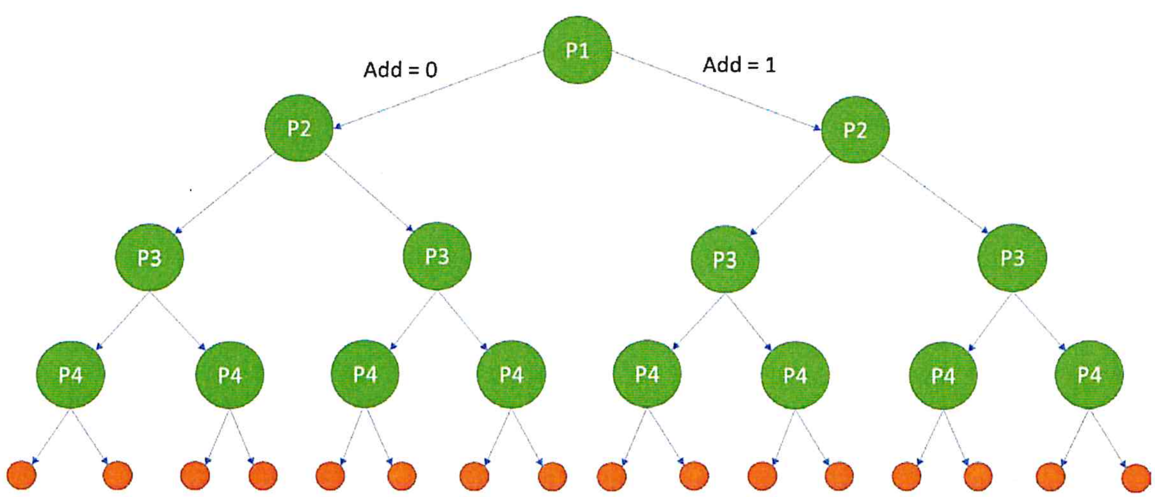
Objective Functions and the Unified Solution

Models like Strategist and EGEAS use dynamic programming to enumerate all feasible nodes. Each node is run through a non-linear probabilistic sub-module to determine production costs, which are added to the capital costs to determine the selected objective function value. The objective function is then ranked across all those nodes to determine the optimal plan. In this simple problem, there were 2 x 2 x 2

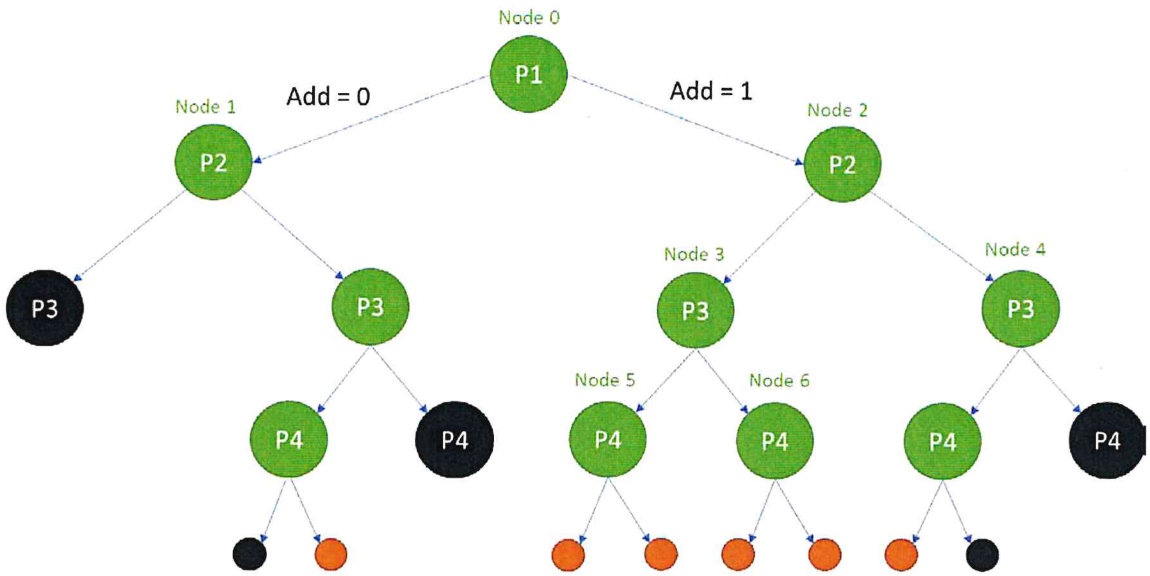
= 8 nodes to evaluate with dynamic programming, and 7 nodes with mixed integer programming. In a typical multi-year expansion problem, there are usually thousands of integer variables that can take values larger than 1. This makes the number of nodes to evaluate with a dynamic program skyrocket and requires additional constraints to be imposed to bring that number down. With mixed integer programming, the number of nodes is manageable since only those nodes that show promise are evaluated and used to look for other nodes.

With dynamic programming, the objective function can be distorted between the production cost sub-module and the capacity expansion decision. For example, if the objective function is to minimize total utility costs plus emission externalities, the ranking of nodes may pick up externality costs from the production cost sub-module, even if that was not included in the commitment and dispatch objective function. With mixed integer programming, there is no decoupling of capacity expansion, unit commitment, and economic dispatch, so all three of these decisions work together to minimize the single selected objective function. As an example, given the objective function of minimizing total utility costs plus emission externalities, a low-cost alternative might be to displace a MWh from a higher emitting resource, such as a coal-fired unit, with a MWh from a lower emitting unit such as either renewable or gas-fired generation. Depending on the design of the model, a dynamic programming algorithm might recognize one, both or neither of these options and possibly not produce the most economical alternative. Conversely, a mixed integer model that co-optimizes production cost and capacity expansion will evaluate all options for minimizing the objective function.

To illustrate this further, assume a fourth potential project, P4, is considered. The dynamic programming approach builds a decision tree, with a branch for every project decision (add 0 or 1). The result is 16 feasible solutions, shown in the figure below as orange leaves on the tree, each of which must be evaluated with the production cost sub-module:



Because the mixed integer process uses a unified solution, it knows the change in costs as the tree is being built and can prune branches that will always produce higher-cost feasible solutions. In the figure below, those pruned branches are shown in black, and the nodes from the example above are identified:



Another key advantage is that in the MIP process, each node can be evaluated using the solution to the prior node as a starting point, greatly reducing the processing time required to evaluate new nodes. The non-linear production cost sub-module of the dynamic program cannot "learn" as it goes, and each feasible solution must be evaluated from scratch.

To minimize the size of the problem that must be solved, EnCompass does not include the variables, constraints, and costs of any decisions which are fixed. This means that if the selections of one project in a capacity expansion optimization is "frozen" and the case is run again, the objective function values will be lower since the capital and fixed operating costs of that frozen project are not included. Since the convergence threshold is a percentage of the objective function, that gap becomes tighter, and a different overall plan with a slightly lower cost may be chosen.

The structure of the problem can also impact the selection of which variables are branched and the path that is used to find solutions. For example, removing limits that are never binding or resources and projects that are never utilized does not change the underlying economics, but it does make the problem smaller, which could lead to different approaches and different solutions that are both within the convergence tolerance. For capacity expansion problems where the MIP Stop Basis is set to a low value like 50 (0.5%), multiple solutions that are within that threshold should be considered to have comparable costs over the multi-year optimization period.

Xpress Optimization Suite

EnCompass uses the Xpress Optimization Suite from FICO to solve the linear and mixed integer problems described above. The branch-and-bound process can be sped up considerably by making better choices on which variables to branch on, and by performing heuristic searches for additional nodes. Xpress uses these techniques and others to provide the best possible performance for solving mixed integer problems.

One of the key techniques to reduce runtime for large problems is parallelism. This allows multiple "leaf" nodes to be solved simultaneously, based on the number of available computing cores and memory. As a result, the solution path may be different when solving using one set of computing resources versus another. This could produce two different solutions that are both feasible and within the input gap threshold.

Xcel Energy

Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2

Minnesota Public Utilities Commission Docket Number E002/RP-13-368

July 1, 2013

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 1, 2013

—Via Electronic Filing—

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101

Re: SHERBURNE COUNTY (SHERCO) GENERATING STATION UNITS 1 AND 2
LIFE CYCLE MANAGEMENT STUDY
DOCKET NO. E002/RP-13-368

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Life Cycle Management Study for the Sherburne County Generating Station Units 1 and 2 as required by paragraph 4 of the Minnesota Public Utilities Commission's November 30, 2012 ORDER in the Company's most recent Resource Plan (Docket No. E002/RP-10-825).

We have electronically filed this document with the Commission and copies have been served on the parties on the attached service lists. The study can be accessed by searching for Docket No. E002/RP-13-368 at the following website: https://www.edockets.state.mn.us/EFiling/home.jsp.

Please contact me at james.r.alders@xcelenergy.com or (612) 330-6732 if you have any questions regarding this filing.

Sincerely,

/s/

JAMES R. ALDERS
STRATEGY CONSULTANT
REGULATORY AFFAIRS

Enclosures
c: Service Lists

CERTIFICATE OF SERVICE

I, Ketti R. Lindberg, hereby certify that I have this day served copies of the foregoing document or a summary thereof on the attached list of persons.

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

xx via electronic filing

- **Docket No. E002/RP-10-825**
- **Minnesota Environmental Quality Board**
- **Stakeholders and Other Interested Parties**

(Regarding Filing in Docket No. E002/RP-13-368)

Dated this 1st day of July 2013

/s/

____
Ketti R. Lindberg

2010 NSPM Resource Plan Docket No. E002/RP-10-825 Service List - Page 1 of 3

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2010 NSPM Resource Plan Docket No. E002/RP-10-825 Service List - Page 2 of 3

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2010 NSPM Resource Plan   Docket No. E002/RP-10-825   Service List - Page 3 of 3

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Life Cycle Management Study for Sherburne County (Sherco) Generating Station Units 1 and 2

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Chapter 1. Executive Summary

The Sherburne County (Sherco) generating facility in Becker, Minnesota is the Company's largest power plant in the Midwest, with its three units capable of providing a total of 2,400 MW of electricity. Units 1 and 2 have a production capability of 750 MW each for total capacity of 1,500 MW and provide approximately 20% of the electricity used by our Minnesota customers each year. As a baseload facility, Sherco is available 24 hours a day, seven days a week, giving it a critical role in meeting our customers' energy needs. Sherco's size, age, role in our generation fleet, and existing pollution control investments differentiate it from other coal-fired power plants in Minnesota that have been retired or are scheduled to be retired in the next few years.

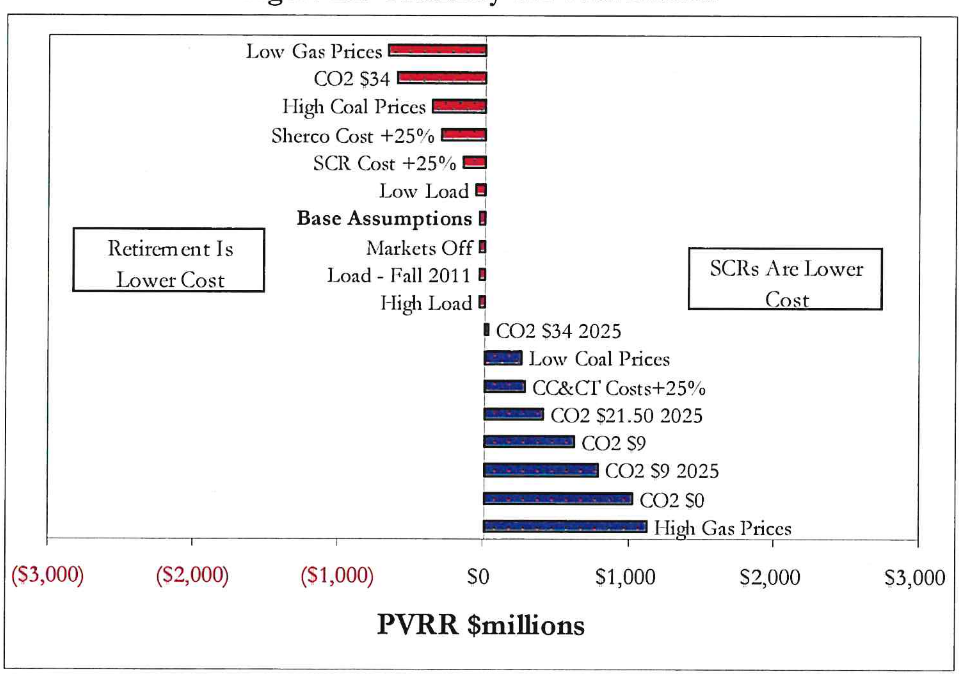
In our 2010 Resource Plan filing, the Company noted that Sherco 1 and 2 are over thirty years old and that we had begun the process of investigating how best to manage the units for the future. In its November 30, 2012 Resource Plan Order, the Commission directed the Company to prepare a study that examines the cost of continuing to operate Sherco 1 and 2 and evaluates retrofit and retirement scenarios. To ensure that the Commission has a comprehensive view of the risks and benefits of the various options for Sherco 1 and 2, the Company has completed extensive modeling, thoroughly reviewed the status of environmental regulation, and engaged stakeholders of various backgrounds and perspectives.

The Company used the Strategist resource planning model to evaluate the cost of retrofitting the units with additional pollution control equipment or retiring Sherco 1 and 2. The retrofit scenarios evaluate the installation of Selective Catalytic Reduction (SCR) pollution control equipment, while the retirement scenarios evaluate replacing Sherco 1 and 2 with new natural gas generation, renewable energy, and conservation or a combination of those options. With the assistance of consulting engineers, the Company conducted an extensive review of the capital investments and operations and maintenance expenses necessary to keep the plant running efficiently and reliably. We have carefully evaluated the costs of replacement generation, including estimating the cost of supplying natural gas to a replacement combustion turbine or combined cycle unit and upgrading or adding transmission capacity to deliver energy from new generation resources.

The scenarios were tested under a wide range of assumptions about the future to understand the sensitivity of the analysis to changes in input assumptions. These sensitivities include suggestions from our stakeholders that help further test the results. The modeling results show that when the anticipated direct costs to operate Sherco 1 and 2 (including SCRs) are compared to the alternatives, continued operation of Sherco 1 and 2 is clearly the most cost-effective option. Only a significantly lower forecast of natural gas prices or a much higher forecast of coal prices calls that conclusion into question.

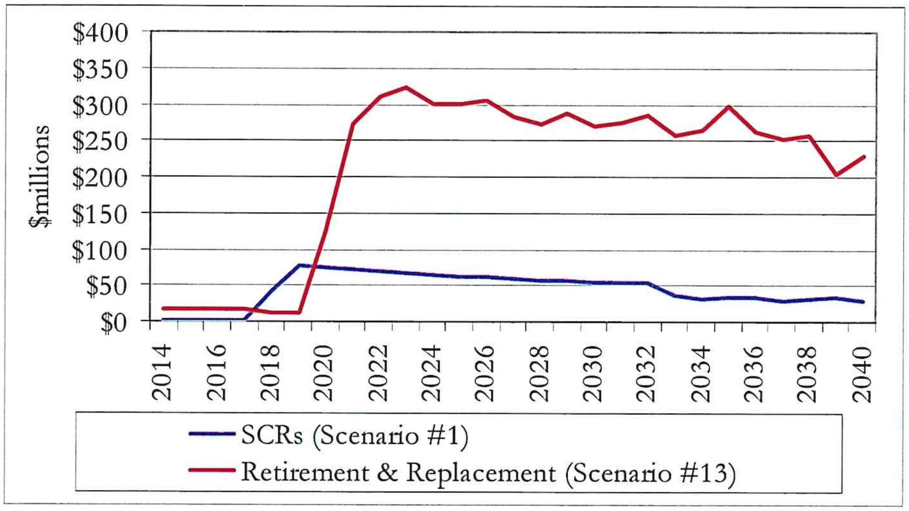
When the Commission's carbon proxy cost values are applied, however, there is very little cost difference over the long term between continued operation and some of the replacement scenarios. Thus, the timing and cost of carbon regulation is a key factor in determining the relative costs of retrofit and retirement scenarios. Figure 1.1 compares the present value of revenue requirements (PVRR) of retirement of Sherco 1 and 2 in 2019 and 2020 to the alternative of retrofitting the units with SCRs and continuing operations until 2040. As the chart shows, under the base assumptions, including a carbon dioxide (CO_2) cost of \$21.50/ton, the cost difference between installing SCRs and retiring the units is negligible. This implies that there is no significant cost advantage of either the retirement or the retrofit strategies with carbon priced at \$21.50/ton. The chart also illustrates which input assumption sensitivities favor which strategy and how much they change the PVRR results. Low gas prices, higher CO_2 prices, higher coal prices, or higher costs at Sherco favor retirement. Assumption sensitivities that favor the installation of SCRs and continued operation include higher natural gas prices, lower CO_2 costs or later implementation of CO_2 costs, low coal prices, or higher construction cost for new natural gas plants. The load sensitivities have little effect.

Figure 1.1: Summary of PVRR Results



Another method of evaluating the scenarios is to estimate the annual costs to customers. Figure 1.2 shows the projected annual costs to customers of early installation of SCRs and early retirement of Sherco 1 and 2. The chart is based on the \$0/ton CO_2 sensitivity simulations to align with current regulatory conditions and the expectation that there will not be carbon regulation in effect by 2017. The chart illustrates that installation of SCRs on both units would results in a total annual cost of almost \$75 million and the cost of retirement and replacement could exceed \$300 million.

Figure 1.2: Annual Cost Impacts of SCRs and Retirement Strategies



As previously mentioned, the cost and timing of carbon regulation is a key driver of the results. Yet it is unknown what kind of carbon policy will ultimately be adopted and how that that policy will affect existing coal-fired power plants like Sherco 1 and 2. Similarly, there is considerable uncertainty around the need to further reduce NO_X emissions. Units 1 and 2 are well-positioned to comply with current environmental regulations and do not need SCRs at this time. However, SCRs might be required if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014 or falls into nonattainment for particulate matter. Additionally, the Company could be required to install SCRs under the Regional Haze Rule or "reasonably attributable visibility impairment" (RAVI) visibility regulations, which is currently subject to litigation between the Environmental Protection Agency and environmental advocates. While the timing is uncertain, we anticipate that SCRs may be required late this decade or sometime the following decade.

This uncertainty is particularly relevant because it is these regulatory factors that drive when a decision on the future of Sherco 1 and 2 needs to be made and the cost-effectiveness of the various scenarios. The Company has not identified factors that suggest action should be taken immediately. As shown in the charts above, advancing installation of SCRs or beginning the process of replacing Sherco 1 and 2 will have a significant impact on customer rates. Each SCR is estimated to cost approximately $170 million in 2012 dollars. The cost to replace both Sherco units with combined cycle natural gas plants, for example, is estimated at $1.7 billion.

The Company believes the most prudent course of action at this time is to continue to operate Sherco 1 and 2 as we await greater clarity and certainty around the development of environmental regulation and the resulting timing and costs. This strategy aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of more complete information. To ensure timely action when additional information becomes available, we recommend the Commission establish firm triggers for reevaluation and future decision-making. Specifically, we recommend the Commission require reanalysis when: 1) air quality regulations establish a need for SCRs, or 2) a carbon regulation framework takes shape. Should an SCR requirement emerge prior to development of carbon regulation, the Company will reevaluate the cost-effectiveness of installing SCRs and recovering the cost over a shorter period to preserve the option to retire the units earlier than 2040 in the event of eventual carbon regulation.

Chapter 2. Introduction

The Company develops integrated resource plans to identify the expected demand for electricity over a 15-year period and propose options for reliably meeting the projected need. The decisions made in resource plan proceedings directly affect what generation resources are planned and when they are constructed. The decisions also impact the amount of conservation and demand-side resources targeted in the Company's Conservation Improvement Program (CIP).

As part of the Company's 2011-2025 Integrated Resource Plan, the Company agreed to complete a Life Cycle Management Study for Sherco Units 1 and 2. The Commission's Resource Plan Order requires the Company, by July 1, 2013, to:

> …submit a Sherco Life Cycle Management Study that examines the feasibility and cost-effectiveness of continuing to operate, retrofitting, or retiring Sherburne County (Sherco) Generating Station Units 1 and 2. Procedurally, interested parties shall have the opportunity to intervene, conduct discovery, and comment.[1]

The Commission's Order also outlined minimum required study components, including:

- Specific cost estimates of controls and other required investments.
- An analysis of how a temporary or permanent outage at either Sherco 1 or 2 would affect system reliability.
- A base case that includes Commission-adopted carbon dioxide (CO_2) costs and externality values.
- A base case that accounts for all likely federal Environmental Protection Agency (EPA) regulations.
- Analysis of scenarios that include the following:
  - A range of updated externality values based on those used by Commission and federal government for regulatory impact analysis.
  - A wide range of fuel prices.
  - Least-cost scenarios to reduce greenhouse gasses relative to 2005 levels by at least 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050.
  - Least-cost plans for replacing 50 and 75 percent of the capacity of Sherco 1 and 2 through a combination of conservation and capacity powered by renewable sources of energy.

[1] Docket No. E002/RP-10-825, ORDER ESTABLISHING PROCEDURAL SCHEDULES AND FILING REQUIREMENTS (November 30, 2012).

This study addresses all components of the Commission's Order and provides additional information in response to input from interested parties that advised the Company on the study. Through the stakeholder engagement process, we aimed to:

- Develop modeling scenarios, modeling assumptions, and study contents that reflected stakeholders' interests and perspectives;
- Maintain transparency of the modeling process and proactively address stakeholder concerns and requests for information;
- Develop shared understanding of modeling results; and
- Lay the groundwork for successful continuation of stakeholder engagement following study submission.

We appreciate the thoughtful and constructive input provided by the stakeholders, and believe their involvement resulted in a comprehensive and objective study. The following organizations participated in the stakeholder process:

- Minnesota Department of Commerce, Division of Energy Resources
- Minnesota Department of Natural Resources
- Minnesota Pollution Control Agency
- North Dakota Public Service Commission (Staff)
- South Dakota Public Service Commission (Staff)
- City of Becker, Minnesota
- Liberty Paper Inc.
- Minnesota Chamber of Commerce
- Xcel Large Industrials
- Center for Energy and the Environment
- Fresh Energy
- Izaak Walton League, Midwest Office
- Minnesota Center for Environmental Advocacy
- Sierra Club

This study helps inform our next Resource Plan, which is scheduled to be filed February 1, 2014. It is in the context of the next Resource Plan, and not this study, that the size, type, and timing of future resources will be decided. In this study, we provide the information needed to evaluate the benefits and risks of the various options for Sherco 1 and 2.

Chapter 3. Background

A. NSP Generation Portfolio

The NSP Electric System serves over 1.6 million electric customers in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. Together, NSP's generating plants have a net maximum capacity of over 8,300 MW.[2] Our generating facilities use a variety of fuel sources including coal, natural gas, nuclear fuel, water (hydro), oil, and refuse; we also have facilities that generate electricity from the wind and sun. We strive to operate our plants safely and responsibly and have a national reputation for operational excellence and environmental stewardship. Figure 3.1 shows the NSP System fuel mix as a percent of total energy generated and purchased in 2012. Figure 3.2 shows the fuel mix as a percent of 2012 accredited capacity.

Figure 3.1: NSP System Energy Mix, 2012[3]

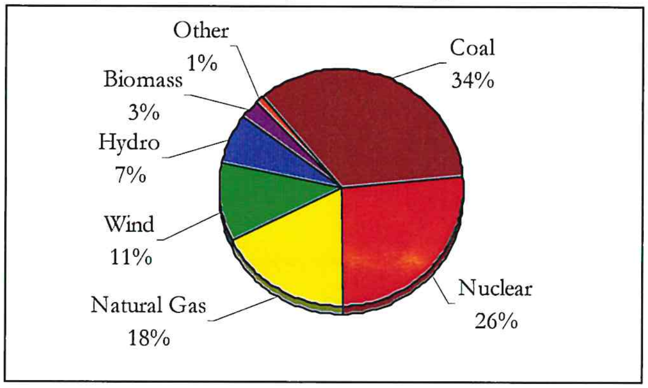
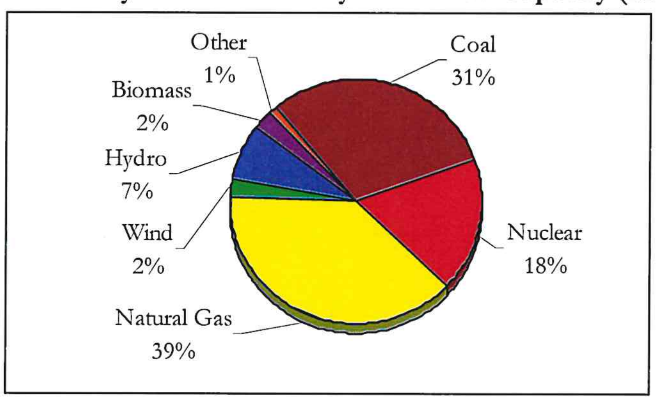


Figure 3.2: NSP System Fuel Mix by Accredited Capacity (MW), 2012[4]



[2] The Net Maximum Capacity (NMC) is defined as the unit's Gross Maximum Capacity less any capacity (MW) that is used for that unit's station service or auxiliary load.
[3] 2012 actual generation reflects unavailability of Sherco Unit 3 for all of 2012.
[4] Unforced capacity or UCAP includes an adjustment for recent forced outage factors. This figure includes capacity for Sherco 3 to be more representative of typical NSP system.

Our generation portfolio has evolved over time as a result of state and federal energy policies and regulations and Company-driven efforts to improve efficiencies and environmental performance. For example, to comply with the Minnesota Renewable Energy Standard, we have added over 1,200 MW of renewable energy to the NSP System since 2006, including wind, hydro, biomass, and solar resources. We have nearly 1,900 MW of commercial wind capacity on the NSP System through purchased power contracts and owned assets. We also have approximately 10 MW_{DC} of solar generation on our system from a combination of distributed generation sites and the 2 MW solar installation in Slayton, Minnesota. The expansion of our renewable energy portfolio helped us lower carbon emissions by 22% over the 2005 to 2012 period.

Through the Metropolitan Emissions Reduction Project (MERP), the Company made extensive voluntary efforts to reduce air emissions from three Twin Cities coal-powered generating plants, while increasing the amount of electricity they produce. MERP projects included adding state-of-the-art emissions controls to the coal-fired Allen S. King plant in Oak Park Heights, Minnesota; replacing the coal-fired High Bridge plant built in 1923 near downtown St. Paul with a natural gas-fired combined-cycle plant; and repowering the coal-fired Riverside plant running since 1911 in northeast Minneapolis with natural gas-fired combined-cycle units. As a result of these efforts, the nitrogen oxide (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) emissions from those three plants were reduced by 90% or more and carbon dioxide (CO_2) emissions were reduced by 40%.[5]

We are also making significant investments in our nuclear facilities to keep them operating safely and reliably for the next 20 years. Xcel Energy owns and operates three nuclear units in Minnesota: one unit at Monticello and two units at Prairie Island in Welch. These plants have provided safe, efficient, and clean energy to our customers since the 1970s. We proposed and the Commission approved extending the life of these plants and increasing power output at our Monticello nuclear plant.

We expect our generation portfolio to continue to evolve as some of our older plants are refurbished or retired and we add new generation to the system. Based on our current Resource Planning estimates, we expect to retire the older, coal-fired units at our Black Dog generation facility (Units 3 and 4) by spring 2015 and the peaking units at Key City in Mankato and at Granite City near St. Cloud in 2018, for total retirements of approximately 370 MW of fossil-fuel fired production capacity.

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[5] http://www.xcelenergy.com/About_Us/Energy_News/News_Archive/Xcel_Energy_completes_Twin_Cities_Metro_Emissions_Reduction_Project.

The Commission's March 5, 2012 Order in Docket No. E002/RP-10-825 determined that the record demonstrates a need for an additional 150 MW by 2017, increasing up to 500 MW by 2019. The Company is engaged in a competitive resource acquisition process to meet the identified need.[6] We are also currently evaluating bids for additional wind resources to begin construction this year. The Company will pursue additional solar resources in order to comply with the solar energy standard passed by the 2013 Legislature, requiring 1.5 percent of retail sales to come from solar energy by 2020.[7]

[6] Docket No. E002/CN-12-1240.
[7] Minn. Stat. §216B.1691, subd. 2f.

Chapter 4. Sherco Units 1 and 2

The Sherco generating plant is the Company's largest plant in the Midwest, located 45 miles northwest of the Twin Cities in Becker, Minnesota. It is a three-unit, coal-fired power plant capable of providing enough power to serve more than two million typical homes. Units 1 and 2 have a production capability of 750 MW each for total capacity of 1,500 MW.[8] As a baseload facility, Sherco is available 24 hours a day, seven days a week, giving it a critical role in meeting our customers' energy needs.

Sherco 1 and 2 were built in the 1970s to meet the growing demand for electricity and to reduce the use of older, less efficient plants. The plant was constructed on a 4,500-acre site to accommodate future expansion. A third unit was built in 1983-1987, which at the time marked the largest construction project ever in the state of Minnesota. Sherco Unit 3 is co-owned by Xcel Energy (59%) and Southern Minnesota Municipal Power Agency (41%).

A. Existing and Pending Pollution Control Equipment

The development of environmental regulation coincided with the development of Sherco Units 1 and 2. These units became operational in 1976 and 1977 to meet the growing demand for electricity and to reduce the use of older, less efficient plants. Sherco 1 and 2 were specifically designed to be well-controlled units in order to minimize their impact on the environment. For example, wet scrubbers control PM and SO_2 emissions. State-of-the-art cooling water intake structures limit the impacts on aquatic organisms and closed cycle cooling limits the impacts of heated water discharge from the power plant. Land resources were protected by the design and construction of engineered ash ponds to ensure safe handling of ash generated from the units.

The environmental controls for Sherco 1 and 2 have continued to be enhanced as new technology and environmental regulations have developed. For example, new particulate emission controls were installed in the late 1990s. Wet electrostatic precipitators (WESPs) were added to the scrubbers to further remove PM, especially fine particles. To lower emissions of NO_X several projects have been completed, including:

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[8] The net dependable production capacity is 681MW for Unit 1and 682 MW for Unit 2.

- Low NO_X burners (LNBs) with separated and closed coupled overfire air (OFA) on Unit 2 in 1995;
- Replacement of furnace dampers and associated controls to help optimize combustion on Unit 2 in 2006; and
- LNB with separated and closed coupled OFA on Unit 1 in 2007.

The air emissions control devices are being upgraded from the original scrubber design to incorporate new sparger tubes, which increases the SO_2 removal capacity of the systems, and new electrodes and higher frequency power supplies are being installed on the WESPs to improve PM removal. With completion of the sorbent injection system for mercury (Hg) control in 2014, Sherco Units 1 and 2 will have control devices in place for PM, SO_2 and Hg that will reduce emissions to levels consistent with Best Available Control Technology (BACT) or BACT-equivalent technology for retrofit units. Below we discuss the existing pollution control equipment by pollutant and historical and forecasted emissions performance. Table 4.1 summarizes the existing pollution control equipment and equipment currently being installed.

Table 4.1: Existing and Pending Pollution Control Equipment

Effluent	Control Equipment Description	Existing	In Progress
PM	Wet Particulate Scrubber	X	
	Wet Electrostatic Precipitator (WESP)	X	
	High Frequency Power Supplies and Upgraded Electrodes on WESP		2012-14
NO_X	Low NOx Burners	X	
	Over Fire Air	X	
	Combustion Optimization Systems	X	
SO_2	Wet Flue Gas Desulfurization (WFGD)/ Wet Particulate Scrubber	X	
	Sparger Tubes in Scrubber/WESP modules		2012-14
Hg	Activated Carbon Injection		2014
Ash	Fly Ash Disposal Ponds	X	
	Bottom Ash Disposal Ponds	X	
Water	Water Recycling	X	
	Advanced Screen Technology	X	
	Closed Cycle Cooling	X	

1. *Particulate Matter (PM)*

Sherco 1 and 2 were originally equipped with venturi scrubber modules – a type of wet scrubber – for control of particulate matter. The venturi scrubber modules have been retrofit with wet electrostatic precipitators (WESP) to increase the removal capacity of the control devices. A WESP collects negatively-charged particles on positively-charged surfaces, which are flushed with water to remove the particulates. At Sherco 1 and 2, the WESP is installed downstream of an existing wet flue gas desulfurization (WFGD) system, where the flue gas is already saturated, thus minimizing the amount of added water. The Company is currently installing new high frequency power supplies on each module to allow significantly higher electrical voltage and current to each WESP field, which results in reduced particulate emissions. In addition, an upgrade of the electrodes is being completed, which will increase the overall electrode coverage and improve performance. This work will be completed by the end of 2014.

2. *Nitrogen Oxides (NO_X)*

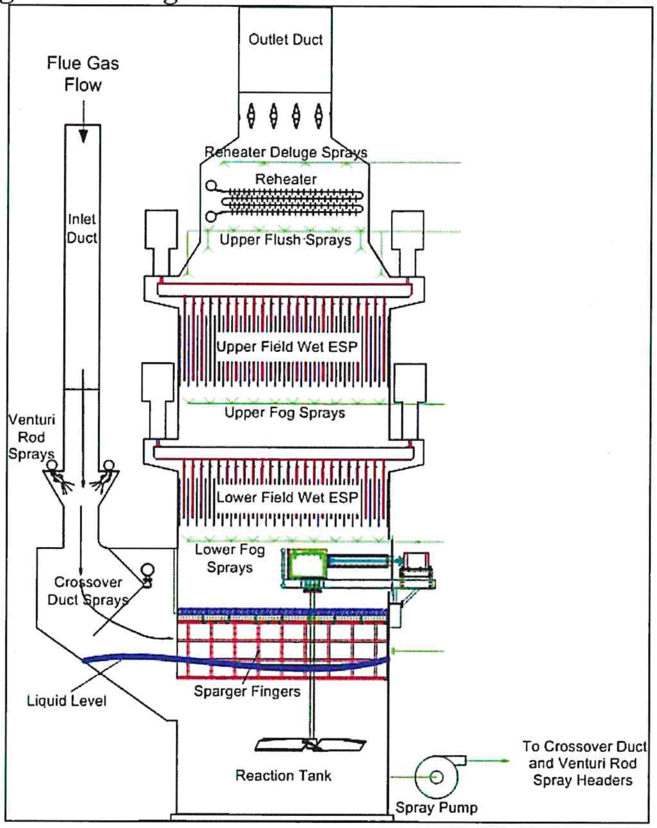
Sherco 1 and 2 currently utilize low NO_X burners (LNB), separated and close coupled overfire air (OFA) systems, and combustion optimization systems to reduce NO_X emissions. These systems were installed on Sherco Units 1 and 2 as part of our efforts to reduce NO_X emissions at the facility for several federal programs.

LNB control the formation and emission of NO_X through staged combustion. LNB control and balance the fuel and airflow to each burner, and control the amount and position of secondary air in the burner zone. The OFA systems work by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and further reducing NO_X emissions. To further reduce NO_X emissions and to optimize combustion, "burner balancing" is used to properly balance the amounts of coal and air that enter the furnace. This entails monitoring and adjusting burners in real time, so that the fuel-to-air ratio is equalized across the boiler.

3. *Sulfur Dioxide (SO_2)*

Both units currently use WFGD systems to control SO_2. The WFGD systems historically achieved 75% removal. The Company is currently in the process of retrofitting the current venturi scrubber/WESP modules with sparger tubes to further increase SO_2 removal from these units. These sparger tubes are being installed within the existing modules so that the incoming flue gas is channeled through the sparger tubes, forcing the flue gas to bubble through the slurry in the reaction tank. This increased contact time of the flue gas with the slurry results in greater levels of SO_2 removal. Figure 4.1 is a diagram of a scrubber module with sparger tubes.

Figure 4.1: Diagram of 1 of 12 Scrubber Modules Per Unit



4. *Mercury (Hg)*

In 2009, the Company submitted its plan to install mercury controls in accordance with the Minnesota Mercury Emission Control Act of 2006. This plan has two parts: 1) continue to study and test new mercury control technologies, while monitoring the development of potential federal environmental regulations; and 2) install a sorbent injection system at Sherco 1 and 2 by no later than December 31, 2014, if no other mercury control technologies are determined to be more advantageous, considering mercury control and cost. We have completed full-scale testing of mercury control technology on Units 1 and 2 to validate that the sorbent injection system, using activated carbon as the sorbent, will effectively remove mercury from Units 1 and 2. We are continuing to evaluate alternate control technologies, but, absent the identification of a superior alternative in the immediate future, we plan to complete the installation of the sorbent injection system by December 31, 2014.

5. Ash

The Sherco Plant uses a variety of methods to manage its coal ash. Fly ash from Units 1 and 2 is transported to lined ponds designed and permitted for permanent disposal. The ponds are lined with clay and/or High Density Polyethylene (HDPE) membranes and are operated under permits issued by the state. New ponds are constructed as the old ponds are filled to capacity. When filled, the disposal ponds are capped with a Linear Low Polyethylene (LLPE) membrane and dewatered. This provides for permanent disposal in what is essentially a dry disposal facility after dewatering is complete. Post closure requirements include an engineered cap and vegetation, long-term maintenance, and ongoing groundwater monitoring until such time as the ponds are fully dewatered.

Bottom ash collected from Sherco Units 1 and 2 is hydraulically transported to a clay-lined pond that temporarily stores the ash. The ash is periodically removed by mechanical dredging. Most of the bottom ash is beneficially used onsite as construction material. A small percentage that is not reused is disposed of in the Unit 1 and 2 ponds.

The U.S. Environmental Protection Agency (EPA) inspected the Sherco ponds in fall 2009 and awarded the facility its highest possible rating for design and structural integrity.

6. Water

The Sherco Plant uses water from three different sources: Mississippi River, groundwater, and storm water. The plant generates numerous different wastewater streams and about 90% is treated, stored, and reused onsite within various plant processes. The only plant process water that is discharged to the Mississippi River is from the cooling tower.

The closed-cycle cooling system withdraws water from the Mississippi River and continuously recirculates that water through the condensers and cooling system in a process that reuses the water six or seven times before eventual discharge. The condenser cooling water is treated with sodium hypochlorite and sodium bromide to control the microbiological growth in the system and sulfuric acid is added for pH control and to reduce scaling. As the cooling water passes over the cooling towers several times, some is lost through evaporation, which requires the addition of make-up water from the river to maintain water levels in the system. This continuous evaporation of water in the system, coupled with the constant replenishment from the river, eventually concentrates total dissolved and suspended solids to levels six to 10 times that of the source water. To maintain water quality in the cooling towers and condensers, some water from the cooling towers is continuously bled from the system (referred to as blow-down) to a holding pond to be treated before being discharged to the river. The holding pond is designed for at least a 24-hour residence time to reduce total residual chlorine in the discharged water.

Process wastewater is also generated at Sherco by sluicing ash to the scrubber solids ponds and from various other plant service water systems. As discussed above, fly ash from Units 1 and 2 is hydraulically transported to the scrubber solids pond. The water is then returned to the plant for reuse. Bottom ash from Units 1 and 2 is similarly sluiced to the bottom ash pond. Excess bottom ash transport water is decanted to the recycle basin for reuse. The system of plant drains also discharges to the recycle basin where it is collected for reuse. All water used to manage ash is recycled for use in the plant's industrial processes. Under normal operating conditions there is no discharge of process wastewater from the site, other than cooling tower blow-down.

B. Emissions Performance

Our investments in pollution control equipment on Sherco 1 and 2 have resulted in substantial quantifiable emissions reductions. Figure 4.2 shows the long-term emissions trends for PM, NO_X, and SO_2. The projected emissions reflect these units achieving the emission rate limits included in our Administrative Order with the Minnesota Pollution Control Agency (MPCA) beginning January 1, 2015. These limits are less than or equal to 0.12 pounds SO_2 per million British Thermal Unit (lb/mmBTU) and less than or equal to 0.15 lb NOx/mmBTU.

Figure 4.2: Sherco 1 and 2 Emissions Trend, 2005-2020 (PM, NO_X, and SO_2)

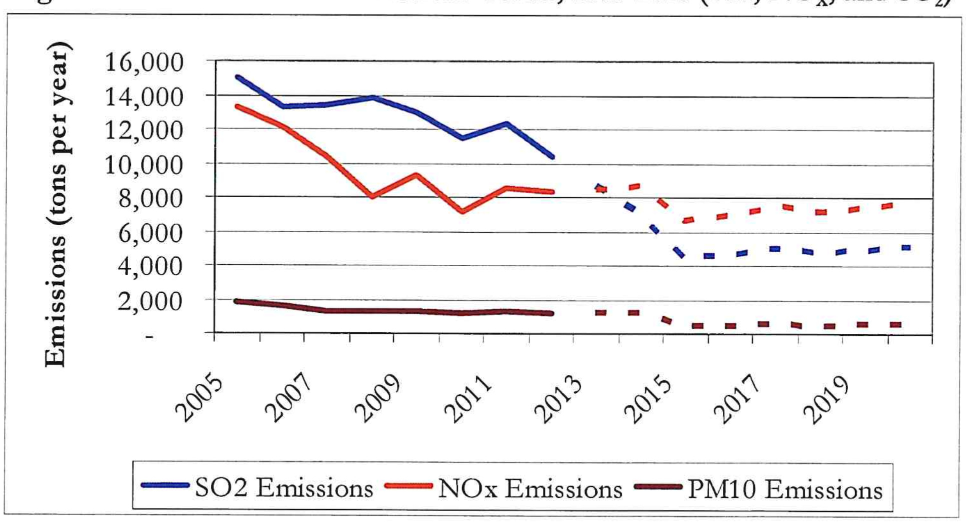
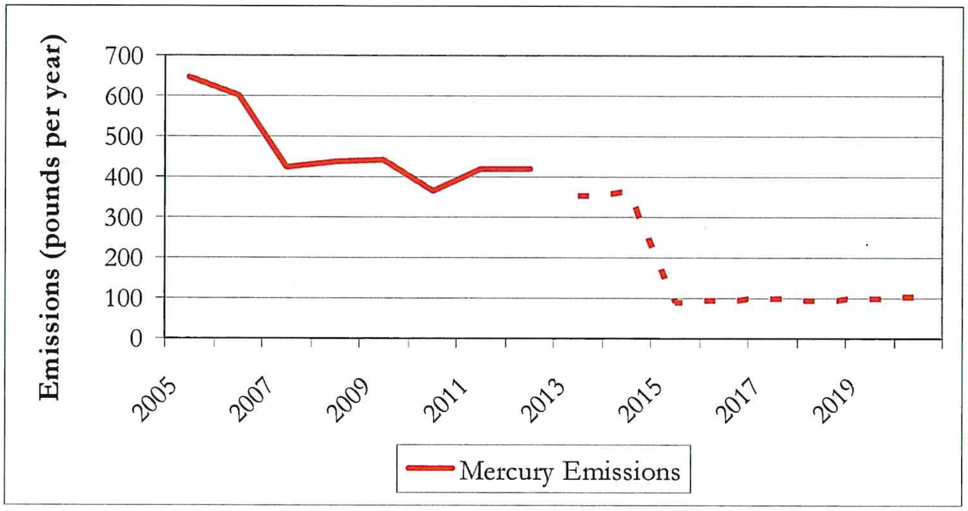


Figure 4.3 shows the long-range trend for mercury emissions. The projected mercury emissions reflect these units achieving an emission rate of less than 1.0 pound of mercury per terra BTU beginning in 2015.

Figure 4.3: Sherco 1 and 2 Emissions Trend, 2005-2020 (Mercury)



Chapter 5. Environmental Regulation

Sherco Units 1 and 2 are subject to numerous environmental rules and regulations designed to protect human health and the environment. The EPA regulates multiple activities to protect air, water and land resources. For example, the EPA implements air quality programs to reduce air emissions from many types of sources to the levels needed to meet health-based air quality standards. Through periodic reviews, EPA has made these standards significantly more stringent over time in response to studies on the health effects of various air pollutants.

Sherco Units 1 and 2 are well prepared to comply with existing and developing air, water and land regulations, including EPA's Mercury and Air Toxics Standards (MATS). There are two regulatory areas that could require additional pollution control equipment beyond what is currently installed or being installed, including:

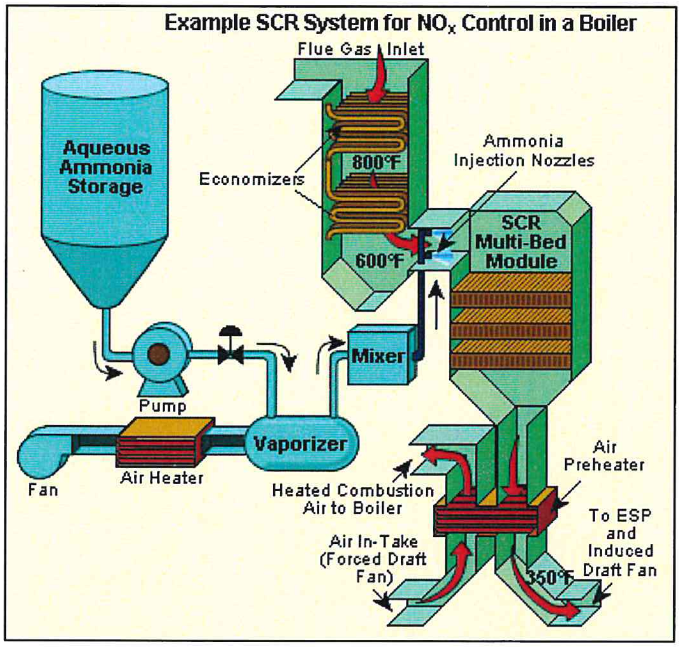
- National Ambient Air Quality Standards (NAAQS) for ozone or PM; and
- Regional Haze Rule or "reasonably attributable visibility impairment" (RAVI) visibility regulations, which focus on emissions of SO_2, NO_X and PM.

We briefly discuss these developments below, as well as uncertainties surrounding the future direction of carbon regulation. Appendix A provides a complete discussion of the known and anticipated environmental rules and regulations and how they may impact operation of Sherco 1 and 2.

A. Potential Future Investments Required for Environmental Compliance

Sherco Units 1 and 2, with their upgraded particulate matter controls and the scrubber upgrades that will be completed by 2015, are expected to have emission performance for PM and SO_2 equivalent to current BACT for retrofit units. The combustion controls, low NO_X burners and overfire air controls put on the units several years ago have substantially reduced NO_X emissions. As a result, the only additional control equipment that could reasonably be anticipated to be required for the units is the addition of Selective Catalytic Reduction (SCR) technology, which would further reduce NO_X emissions. In SCR systems, vaporized ammonia injected into the flue gas stream acts as a reducing agent, achieving NOx emission reductions when passed over a catalyst. The NO_X and ammonia react to form nitrogen and water vapor. Figure 5.1 is a diagram of an SCR system.

Figure 5.1: Diagram of Example SCR System



Further NO_X emission reductions might be required if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014, or falls into nonattainment for particulate matter. Once EPA adopts or revises a NAAQS, states are required to monitor their air quality to determine whether the ambient air in any areas of the state fail to meet the NAAQS. States analyze their air monitoring data and submit to EPA their designations of parts of the state as in attainment or nonattainment of the NAAQS. EPA then reviews the state's proposal and determines the final area designations. Typically, this process is completed two years after a NAAQS revision.

If any areas within Minnesota were to be classified as being in nonattainment, the Minnesota Pollution Control Agency (MPCA) would have to develop a State Implementation Plan (SIP) to bring the area back to attainment. When developing the SIP, the MPCA would need to address point source emissions inside of the nonattainment area, which could include Sherco 1 and 2, as well as mobile source emissions and other sources.

EPA is working to revise the ozone NAAQS and is expected to propose a new standard in 2013 with expectations that it will be finalized in 2014. According to the ozone NAAQS implementation schedule shown in Appendix A, further NO_X reductions might be required in the early to mid 2020s, if Minnesota is designated as being in nonattainment for ozone.

Similarly, on January 15, 2013, EPA finalized NAAQS for both coarse and fine particulate matter. EPA is expected to designate non-compliant locations by December 2014. We believe Minnesota will remain in attainment for $PM_{2.5}$ based on the latest revisions to the NAAQS described above. However, according to the MPCA's 2013 Report to the Legislature,[9] despite overall improvements in air quality, Minnesota is at some risk of exceeding the federal standards for both ozone and $PM_{2.5}$. If installation of SCRs were to be found necessary to address any future nonattainment of the particle NAAQS, the compliance date would be in the mid-2020s.

The visibility programs focus on reducing emissions of PM, SO_2 and NO_X as pollutants that can result in visibility impairment in national parks and wilderness areas. Based on the current level of controls for PM and the upgraded controls for SO_2 at Sherco 1 and 2, it is not expected that any further reductions would be required due to continued implementation of visibility programs. However, should further NO_X reductions be required at some point in the future, SCR systems on one or both units could be installed. The time when additional controls may be required for Sherco Units 1 and 2 for visibility regulation purposes is difficult to assess due to ongoing litigation. Based on our analysis, the range of time within which SCR systems might be required would be 2018-25. Further discussion is included in Appendix A.

As discussed later in the study, our model assumes early implementation of SCR systems in 2018 and 2019, and later implementation in 2024 and 2025 to address the range of potential timelines for additional pollution control. The addition of an SCR system on one of the units would take approximately four years to receive the necessary regulatory approvals and install and test the system for operation. Due to the scheduling of major overhauls for the units, addition of an SCR on the second unit is expected to take five years.

Additionally, in the event that one or both of the units is repowered or replaced with natural gas capacity, the new natural gas-fired unit would be required to complete a full permitting and regulatory approval process, install BACT, and comply with existing and developing air, water and land regulations.

B. Carbon Dioxide Regulation

The most significant environmental policy affecting the future of coal-fired power plants (including Sherco Units 1 and 2) is also the most uncertain. Today, it is

[9] The electronic version is available on the MPCA web site at *www.pca.state.mn.us/yhizb6a*.

unknown what kind of greenhouse gas (GHG) policy will ultimately be adopted or how that that policy will affect existing coal-fired power plants like Sherco 1 and 2. For example, a strict stack-by-stack approach could reduce future operation of the units, while a more flexible portfolio-based approach could potentially allow operations to continue at Sherco 1 and 2 with emissions reductions achieved through other means.

The EPA has already started regulating carbon dioxide (CO_2) under the CAA, but there is also the possibility of a broader federal legislative policy that could establish GHG reduction targets. In addition, state legislatures and other policy makers are considering their own GHG proposals. Consequently, at this time, the impact of CO_2 regulation on future operation of Sherco Units 1 and 2 is unclear. As discussed below, the Commission requires utilities to incorporate a carbon proxy cost in resource planning analyses to recognize the eventual likelihood of some form of carbon regulation. The Company uses the Commission-approved carbon proxy cost range in this study.

1. Background

CO_2 is a greenhouse gas that traps the sun's energy in the atmosphere, resulting in an overall warming of the Earth's climate. CO_2 is an inevitable consequence of the combustion of fossil fuels, and, as such, the concentration of CO_2 and other GHGs in the atmosphere has increased as global use of fossil fuels as an energy source has grown. To address climate change, many policymakers have sought to reduce CO_2 emissions through various legislative policy proposals. Over the last several years, some policymakers have turned to EPA regulation under the CAA as the primary vehicle to reduce emissions of CO_2.

During the first four years of the Obama administration, Congress attempted to pass comprehensive climate and GHG legislation. Although the U.S. House of Representatives passed a nationwide cap and trade program proposal (H.R. 2454) in 2009 that would have required a 17% emissions reduction from 2005 levels by 2020 for utilities and other major emitters, the Senate did not follow and that proposal did not become law. After the elections of 2010 and 2012, Congress expressed stronger opposition to cap and trade and other climate legislation. As a result, national climate legislation remains unlikely in the near term.

Nevertheless, President Obama continues to express interest in moving toward more sustainable forms of energy to address climate change. During his second inaugural speech on January 21, 2013, President Obama stated, "We, the people, still believe that our obligations as Americans are not just to ourselves, but to all posterity. We will respond to the threat of climate change, knowing that the failure to do so would betray our children and future generations."

Some political groups are advocating a direct federal tax on the carbon content of fossil fuels (*i.e.* coal, oil and natural gas) as a means to reduce carbon emissions while generating tax revenue. Other carbon reduction policies could include a clean energy standard, which would be similar to a renewable standard but would also include (in addition to renewable energy) other clean and low-carbon sources, such as natural gas, nuclear power and "clean coal" technology with carbon sequestration. Market-based proposals such as cap-and-trade programs remain a possibility, but are considered unlikely in the short term.

2. *GHG Regulation under the CAA*

EPA has already begun regulating GHG through the CAA. In 2009, in response to the U.S. Supreme Court's decision in *Massachusetts v. EPA*[10] the EPA issued its "endangerment finding" that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. The EPA also promulgated permit requirements for GHGs for large new and modified stationary sources, such as power plants. In December 2010, the EPA announced a settlement with several states and environmental groups to begin preparing regulations of emissions from both new and existing steam EGUs, such as coal-fired power plants, under Section 111 of the CAA. The EPA has proposed regulations for new sources and is developing regulations for existing sources.

Although several businesses and business organizations have challenged EPA's regulations, on June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit upheld EPA's determination that GHGs can be regulated under the Clean Air Act.[11] As a result of this decision, EPA's development of GHG regulation will likely continue.

a. New Source Review

Starting January 1, 2011, EPA began regulating GHGs under the New Source Review (NSR) Program of the CAA. EPA now requires a review of GHG emissions for air permits issued to new power plants that are major sources, or to existing power plants that undertake major modifications. This review, known as the BACT review, is required before the plant can receive an air permit. EPA requires BACT review on all

[10] 549 U.S. 497 (2007).
[11] *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012).

new plants emitting at least 100,000 tons per year of CO_2 emissions and modified facilities increasing their CO_2 emissions by at least 75,000 tons per year.[12] The GHG BACT review is a process that involves identifying a set of options for reducing GHG emissions, analyzing those options, then choosing the best available option based on energy, environmental and economic reasons.

b. New Source Performance Standard

In April 2012, EPA proposed a New Source Performance Standard (NSPS) under section 111(b) of the CAA for new power plants.[13] This NSPS would require all new coal- or gas-fired generating plants (excluding peaking plants) to meet a CO_2 emission rate achievable today only by natural gas combined cycle plants. This proposed GHG NSPS acts as a ban on new coal-fired plants unless they utilize carbon capture and sequestration to capture half or more of their emissions. Today, carbon capture and sequestration is not a commercially available technology. In its proposal, EPA recognizes this fact and, as a result, the proposal would allow construction of a coal-fired plant without carbon capture provided the owner or operator commits to installing capture and sequestration technology within ten years. Despite this provision, it is unlikely that any coal plant developer would risk the substantial capital required to build a coal plant on the assumption that capture and sequestration technology would develop over the next decade. If adopted as proposed, the rule would not allow additional coal to be considered in the future following any decision to retire an existing coal facility. The proposed rule is currently being challenged. As a result, the timing of its finalization and its final requirements are not known. On June 25, 2013, the Obama administration announced plans to re-propose this rule by September, 30, 2013. The timing of the final rule and its final requirements are not known.

c. Existing Power Plants

In its 2010 settlement with the environmental community, EPA also committed to regulate CO_2 emissions from existing power plants. The EPA originally stated that it would propose GHG rules for existing power plants under Section 111(d) of the CAA and finalize these rules in 2012. The Obama Administration announced on June 25, 2013 its plan to issue a proposed rule for existing power plants by June 1, 2014, with a final standard by June 1, 2015. The proposal is expected to include a requirement that State Implementation Plans (SIP) be submitted to EPA by June 30,

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[12] *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule*, 75 *Fed. Reg.* 31514 (June 3, 2010).
[13] *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, 77 *Fed. Reg.* 22392 (April 13, 2012).

2016. Compliance deadlines would likely be within three to five years of EPA's adoption of the new existing power plant standard or a state's SIP that implements the standard. The Administration encourages working directly with the states to build upon current efforts, provide flexibility, and take advantage of a wide variety of energy sources and technologies. Given Congress' likely opposition to climate legislation, EPA's Section 111(d) program is likely to be one of the principle vehicles for the Obama Administration's efforts to address climate change.

Section 111(d) of the CAA grants EPA authority to establish "guidelines" for reductions of certain emissions from existing sources like power plants. It is not certain how EPA will develop its guidelines. For example, in light of the lack of a commercially viable capture and sequestration technology, EPA may establish emission limits for specific types of power plants (*i.e.* stack-by-stack) based on achievable efficiency improvements. Regardless, once the stack-by-stack standards are established, the options for state implementation of the guidelines are broad. Unlike other sections of the CAA (which set mandatory, stack-by-stack targets), Section 111(d) contemplates significant state flexibility in meeting these guidelines and allows states to develop their own plans for compliance. Xcel Energy believes that Section 111(d) allows states to develop alternative plans that incorporate renewable portfolio standards, demand-side management, emission reduction programs such as MERP, and other clean energy programs. We also believe that is imperative for EPA to recognize in its proposal clean energy initiatives already underway. Our customers have paid for these initiatives and if they are not considered in the "baseline assumptions," then customers will have to pay for additional reductions that do not reflect those already achieved.

Other advocacy groups have proposed alternative proposals for Section 111(d) regulations. The National Resources Defense Council (NRDC) has provided a proposal that would cut existing power plant emissions 26% by 2020 from 2005 levels.[14] The proposal would require emissions limits for each state that would need to be met in 2020. NRDC contemplates that states could comply through the use of a credit trading program similar to a cap and trade program. Based on the technology available today, a state could not meet the emission limits solely by making changes to its coal-fired plants; it would have to make significant reductions by some combination of switching to natural gas-fired generation and adding more renewable energy and energy efficiency.

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[14] www.NRDC.org/policy.

3. *Strategies to Reduce Carbon Emissions*

Because the policies for CO_2 regulation are not established, we do not know whether utilities will have the flexibility to make system-wide carbon reductions based on the most cost-effective strategies, or whether reductions will have to be made via a stack-by-stack approach. Under a stack-by-stack approach, Sherco Units 1 and 2 may be able to slightly reduce carbon emissions through heat rate and other efficiency improvements. While carbon capture and sequestration technology may be available in the future for coal-fired power plants, the geologic formations near Sherco do not allow for sequestration of CO_2, making it likely unviable for Sherco 1 and 2.

Xcel Energy advocates for a systematic approach based on the clean energy programs discussed above. This approach results in more significant emission reductions at far lower cost and could include emissions reduction strategies like making efficiency improvements at fossil fuel-fired plants; adding more renewable energy to the system; and increasing customer demand side management programs. Utilities can also retire coal-fired (or inefficient gas-fired) power plants and replace them with more efficient natural gas combined cycle plants or a combination of natural gas and renewables. Combined cycle plants have a CO_2 emission rate that is approximately half of that of typical pulverized coal plants. If the applicable carbon policy will allow the use of clean energy programs, such as renewable portfolio standards and demand-side management, Sherco Units 1 and 2 may be largely unaffected by a carbon policy, as Xcel Energy pursues emissions reductions through other strategies.

4. *Carbon Proxy Cost*

To address carbon policy uncertainty when making future resource decisions, Minn. Stat. § 216H.06 requires the Commission to establish an estimate of the likely range of costs of future carbon dioxide regulation on electricity generation, and update the estimates annually following informal proceedings. The carbon proxy cost is intended as a planning tool to estimate how future regulation of CO_2 emissions will affect the cost of generating electricity. The Commission's November 2, 2012 Order in Docket No. E999/CI-07-1199 maintained the estimate of the range of likely costs of CO_2 regulation at between \$9 and \$34/ton of CO_2 for 2012 and 2013. Utilities must apply the range of CO_2 values in their resource planning as of 2017.

Chapter 6. Strategist Modeling Inputs and Assumptions

A. Overview

The Strategist planning model simulates the operation of the NSP System under different future scenarios and tests the model results under a range of input assumptions. Strategist is used in resource planning to estimate the cost of various resource expansion plans, to evaluate specific capacity alternatives, and to measure the potential risks of new environmental legislation and other policy scenarios. Each model run produces total system cost and emissions results, which are analyzed across the various scenarios. In this analysis, Strategist is used to evaluate the cost of retrofitting Sherco 1 and 2 with new pollution control equipment to reduce NO_X emissions and the alternative of retiring the units and replacing with combinations of new natural gas generation, renewable energy, and conservation.

The Strategist analysis is organized into three parts:

- Reference Case Assumptions
- Scenarios and Sensitivities
- Model Output

The Reference Case is the starting point from which the various life cycle management strategies are built. The Reference Case contains the cost and performance inputs for all of our generation resources, load growth projections, fuel cost forecasts, and expected cost to construct new generation resources. The Reference Case assumes that Sherco 1 and 2 continue current operations through 2040 without the addition of new environmental controls beyond what is already in progress. Structuring the Reference Case this way allows for clear comparison of each scenario's incremental cost and impact to customer rates. The Reference Case includes our estimate of the necessary costs to continue reliable operations of the unit, including operation and maintenance expenses, and capital investments. It also incorporates known policy commitments, such as the Renewable Energy Standard and energy conservation goals.[15] Per the Commission's Order, a CO_2 cost of $21.50/ton is included in the Reference Case starting in 2017.[16] We ran an alternative Reference Case without the CO_2 cost to satisfy the North Dakota Public Utilities

[15] Minn. Stat. §216B.1691 sets the renewable energy objectives of achieving 25% of retail sales by 2016 and 30% by 2020. Minn. Stat. §216B.2401 establishes a goal of achieving annual savings of 1.5% of retail sales. The Reference Case assumes savings of 1.5% of sales through 2015 and 1.4% thereafter to reflect an expected decline in achievable savings.

[16] Docket No. E999/CI-07-1199. Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs. November 2, 2012.

Commission's request. To the Reference Case, we add pollution control scenarios and retirement scenarios.

Scenarios establish the high level options for the future of Sherco 1 and 2, specifically whether one or both units continue to operate and if retired, what resources replace them. For this analysis, the scenarios address:

- Timing of additional pollution control equipment at one or both of the units;
- Timing of retirement for one or both of the units; and
- Replacement options that will maintain system reliability.

To model the cost of NO_X pollution control equipment, we add to the Reference Case the capital investment needed to install the equipment and ongoing costs to operate and maintain it. With the installation of SCRs, we make the assumption that the units will continue to operate until 2040. In retirement scenarios, the Sherco units are decommissioned either in 2019 and 2020, before their current fully depreciated dates, or in 2024 and 2025, and replaced with a variety of different generation alternatives. Strategist tracks fuel consumption, plant emissions, and calculates total annual system costs. Annual costs are discounted to derive a single present value of revenue requirements (PVRR) for each scenario.

We conduct sensitivity analysis to test the impact of important input assumptions on the PVRR results. The sensitivity analysis changes a single input variable at a time and estimates different PVRR values for each scenario. We conducted sensitivity tests for load, fuel prices, CO_2 costs, and equipment costs. In total, we ran 23 different scenarios and 26 sensitivities or 598 Strategist simulations for this analysis. These are summarized in Appendix B.

As required by the Commission's Resource Plan Order,[17] the Company also analyzed sensitivities that include a wide range of fuel prices and meet the 15% by 2015 and 30% by 2025 GHG goals established by the Minnesota Legislature. Achievement of the 80% by 2050 GHG goal is unaffected by our Sherco LCM strategy as both units will likely be retired by 2050 regardless. The Company also included as sensitivities the full range of CO_2 and criteria pollutant externality values developed by the Commission. The Company also provides cost estimate impacts from federal CO_2 externality values and for non-carbon air pollutants, values derived from a National Research Council study. Similar to the externality values established by the Minnesota Commission, the cost of CO_2 has the largest impact on our analysis and the costs applied to the other effluents are much less significant.

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[17] Docket No. E002/RP-10-825. Order Establishing Procedural Schedule and Filing Requirements. November 30, 2012.

At the request of Environmental Intervenors, the Commission also asked us to investigate the use of externality values in the development of Regulatory Impact Assessments associated with EPA rulemaking and incorporate them if possible. We investigated the use of externality values in several of the most recent EPA rulemaking dockets and found no values that could be applied to emissions in the same way the Commission's environmental values are applied. We then asked Environmental Intervenors for their thoughts on a source of externality values we should consider and were referenced to a report from the National Research Council. While the NRC study is only one of a broad range of externality investigations in the literature, we used it to test the sensitivity of our analysis to its externality values. Appendix C provides a more in-depth discussion of the results of sensitivity testing, the difficulties we encountered as we reviewed EPA Regulatory Impact Assessments, as well as the limitations of the application of the NRC study.

The results of the simulations are summarized in Strategist Output spreadsheets. These spreadsheets provide several key results, such as total system energy mix, air emissions, fuel consumption, and total annual costs. The spreadsheets also contain detailed information on each individual generation resource in the Strategist model. The total system costs are reported as the net present value of revenue requirements or "PVRR." This value is the sum of all operating, depreciation, return on rate base, and tax costs discounted back to 2013 using the Company's most recently authorized weighted after tax cost of capital.

Rate impacts are also derived from the Strategist output simulation results. This rate impact is calculated by dividing the difference between the annual revenue requirements for the specific sensitivity, minus the same for the Reference Case, divided by annual forecasted sales. The Strategist model tracks fuel as a separate component, allowing the rate impact to be provided in terms of both rate base and fuel clause components.

B. Reference Case Assumptions

As noted above, the Reference Case is the foundation on which the other scenarios and sensitivities are built. Below we discuss the main assumptions of the Reference Case. Additional details on the modeling inputs used in the Reference Case are provided in Appendix D.

1. *Load Forecast*

The Company used the load forecast developed in spring 2013. This forecast is planned to be the basis for our Resource Plan filing in 2014. From 2013 to 2040, the average growth rate for total energy is 0.60%, and the average growth rate for peak demand is 0.74%. The load forecast incorporates a conservation target of 1.5% of sales from 2013-2016 and 1.4% of sales thereafter. We assume load management of 985 MW in 2013 increasing to 1,045 MW in 2019, for a long term average 1,039 MW. The analysis includes sensitivities on the growth rate of energy and demand, as well as a sensitivity using the forecast from our most recent Resource Plan.

2. *Natural Gas and Market Energy Prices*

We updated the price of natural gas and market energy in March 2013. The near term prices are based on published NYMEX prices. In the longer term, the prices are a simple average of forecasts from three independent forecasting firms. The natural gas prices listed below are for the Ventura distribution hub. Each natural gas generating unit in the Strategist model will include a small delivery charge from Ventura to the plant site. The Strategist model includes a simulation of energy purchases from the MISO market. In each hour of the simulation the model has the option to purchase energy from the MISO market if it is economically efficient to do so. Hourly purchases are limited by a 1,000 MW energy import maximum. Strategist is restricted from selling energy into the MISO market to ensure that new plants are not constructed based on the speculative assumption that their energy could be sold into the market at a profit.

Table 6.1: MISO Market Prices[18] and Natural Gas Forecasts

	On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)		On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)		On ($/MWh)	Off ($/MWh)	Ventura Gas ($/MMBtu)
2013	$34.54	$21.08	$3.87	**2026**	$63.88	$40.82	$7.27	**2039**	$83.18	$57.06	$9.64
2014	$35.03	$20.52	$4.15	**2027**	$64.77	$41.44	$7.44	**2040**	$84.78	$58.15	$9.82
2015	$37.27	$22.74	$4.28	**2028**	$65.92	$42.30	$7.60	**2041**	$86.40	$59.27	$10.01
2016	$39.59	$25.58	$4.41	**2029**	$68.05	$45.00	$7.82	**2042**	$88.06	$60.40	$10.20
2017	$43.17	$27.88	$4.62	**2030**	$69.85	$46.67	$8.01	**2043**	$89.74	$61.56	$10.40
2018	$47.62	$31.46	$4.96	**2031**	$71.11	$47.41	$8.16	**2044**	$91.46	$62.74	$10.60
2019	$51.56	$34.40	$5.33	**2032**	$72.79	$49.19	$8.33	**2045**	$93.21	$63.94	$10.80
2020	$52.54	$33.52	$5.67	**2033**	$73.81	$50.34	$8.53	**2046**	$95.00	$65.16	$11.01
2021	$55.15	$35.17	$5.93	**2034**	$75.51	$51.38	$8.72	**2047**	$96.82	$66.41	$11.22
2022	$56.85	$36.53	$6.19	**2035**	$77.10	$52.89	$8.93	**2048**	$98.67	$67.68	$11.44
2023	$58.79	$37.36	$6.61	**2036**	$78.58	$53.90	$9.10	**2049**	$100.56	$68.98	$11.66
2024	$60.18	$38.51	$6.83	**2037**	$80.09	$54.93	$9.28	**2050**	$102.49	$70.30	$11.88
2025	$62.76	$39.86	$7.06	**2038**	$81.62	$55.99	$9.45				

3. *Coal Prices*

Coal price forecasts are developed using two major inputs: current contract information combined with long range estimates of future commodity costs and

[18] The MISO market prices are based on the NSP.NSP commercial pricing node.

delivery charges. Typically, coal is purchased by contract for a one to five year term; these actual contract prices are combined with forecasts from Wood Mackenzie, JD Energy, and John T. Boyd Company. To the basic commodity costs we add estimates of transportation charges, SO_2 costs, freeze control, and dust suppressant, as required. The analysis assumes a coal price of $2.25/mmBtu in 2013 escalating at an average of 2.15% per year.

4. CO_2 Emissions

The Reference Case includes a cost of $21.50/ton of CO_2 emitted by fossil fuel generation beginning in 2017 and escalating at 2.3% per year. This is the midpoint of the Commission-approved range of $9 to $34/ton. The endpoints of this range will be run as sensitivities. To facilitate the requests of the North Dakota Commission staff, we also conduct all scenarios and sensitivities without any costs applied to CO_2 emissions.

5. Costs at Sherco

The Reference Case assumes that Sherco 1 and 2 will continue to operate until 2040 without installation of any new pollution control equipment. It includes our estimate of the necessary costs to continue reliable operations of the units, including O&M expenses and capital investments. The primary operations assumptions are summarized below.

- Maximum Capacity[19] – Unit 1: 681 MW, Unit 2: 682 MW
- Average Heat Rate – Unit 1: 10.3 mmBtu/MWh. Unit 2: 10.5 mmBtu/MWh
- Average Maintenance Requirement – 2.6 weeks/year
- Average Forced Outage Rate – 4%
- Emission Rates (lbs/MWh)[20]
  - Unit 1 – CO_2: 2260, SO_2: 1.07, NO_X: 1.60
  - Unit 2 – CO_2: 2210, SO_2: 1.07, NO_X: 1.61
- Fuel – $2.25/mmBtu in 2013 escalating at an average of 2.15%
- Variable O&M - $1.06/MWh in 2015 escalating at 2.39% (includes activated carbon for mercury control)
- Fixed O&M - $21 million/year for each unit ($42 million total) escalating at 2.45%
- Ongoing Capital 2013-2040 – Unit 1: $648 million, Unit 2: $616 million

[19] This is the maximum capacity net of plant usage and is based on recent capacity testing.
[20] These emission rates are based on expected rates in 2014 after the sparger tube project in the wet scrubbers is complete.

- Decommissioning[21] - $1.5 million/year for each unit.
  - 2013-2040 total decommission accrual – Unit 1: $41.5 million, Unit 2: $41.5 million

The forecasted cost to cover regular operations and maintenance of Units 1 and 2 is comprised of labor, materials, consumables, chemicals, and other items directly used by each unit, as well as an allocation of resources utilized by all of the units at the plant. The forecasted cost of regular O&M increases significantly in 2015 due to the use of activated carbon to control mercury emissions on Units 1 and 2.

The capital investment required to meet currently applicable environmental regulations are included in the Reference Case forecast for Units 1 and 2. This includes the following projects to be completed in the 2013-2015 timeframe:

- FGD Scrubber Sparger Modifications,
- WESP Power Supply Replacement,
- WESP Electrode Replacement,
- Activated Carbon Injection Mercury Control, and
- Boiler Combustion Optimization Controls Replacement.

Throughout the life of these two units, capital investments have been and will continue to be made to retain the reliability, production performance, and environmental performance of the units. Units 1 and 2 each have approximately 25,000 discrete components. Each year a portion of components that cannot economically or practically be repaired are replaced or rebuilt as a capital investment.

Many of the major components on both units are original to the plant. Inspection and testing results for this equipment indicate that the majority will last for many more years before a capital investment is needed, but some will require capital investments in foreseeable future. In any event, these projects will undergo environmental regulation applicability review before they are completed.

6. *Long-Term Expansion Plan*

To develop the long term expansion plan, most units were modeled as retiring at their currently scheduled book life.[22] Retirements include the 500 MW King coal plant in

[21] In Strategist, decommissioning costs are incurred as yearly expenses during the operating life of the plant and accumulated until the end of life when they are needed.

[22] Blue Lake 1-4, Key City, and Granite City are small peaking facilities. These plants are currently at the end of their book depreciation lives. However, the Company plans to operate these units for a few more years.

2036 and our nuclear facilities in 2031 through 2035. This creates a substantial capacity deficit in future years. Strategist was allowed to pick from natural gas, coal, and nuclear capacity alternatives. Renewable alternatives were not included as optimization alternatives. Instead, specific levels of wind and solar were hard-coded into the model to reflect the need to meet RES requirements. The least cost plan that resulted from the Reference Case simulation was almost entirely natural gas. The expansion plan included continuation of our Solar*Rewards program and sufficient wind additions to meet our 30% by 2020 renewable energy standard. Table 6.2 summarizes the total retirements and additions that are included in the Reference Case. Figures 6.1 and 6.2 illustrate the timing of the resource additions and retirements.

Table 6.2: Resource Additions and Retirements

	Retirements	Replacements
Nuclear	1,610MW	0MW
Coal	2,075MW	0MW
Natural Gas	3,166MW	11,617MW
Oil	304MW	0MW
Renewables*	1,284MW	495MW
Other	102MW	0MW
Total	8,541MW	12,112MW

* Wind capacity credit is 12.9%

beyond the end of their book lives. These extensions were discussed in the Company's 2011-2025 Resource Plan. Sherco 3 was also assumed to operate through the end of the study period.

Figure 6.1: Resource Retirements

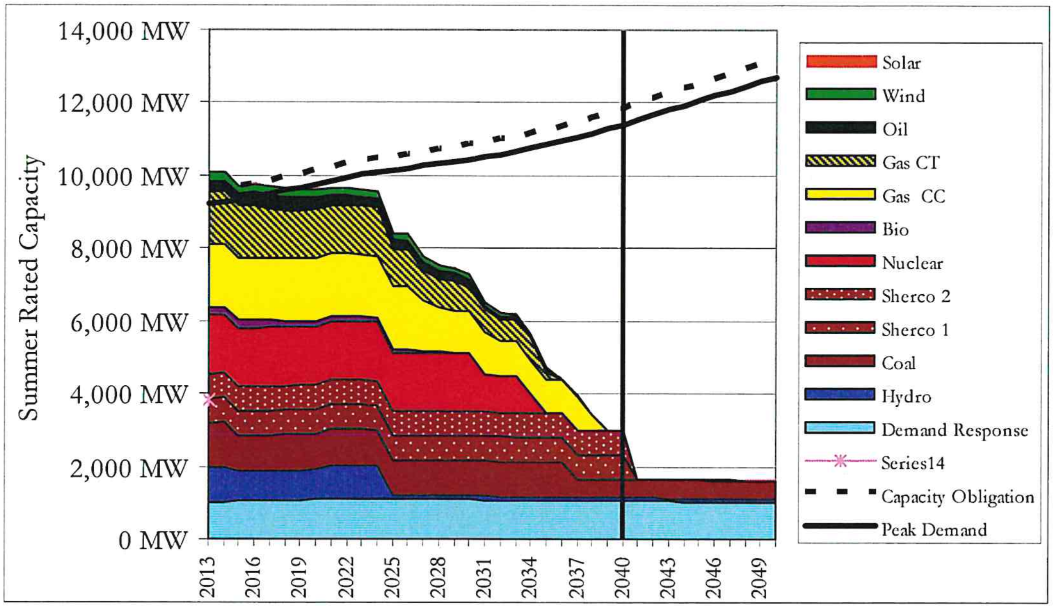


Figure 6.2: Resource Additions

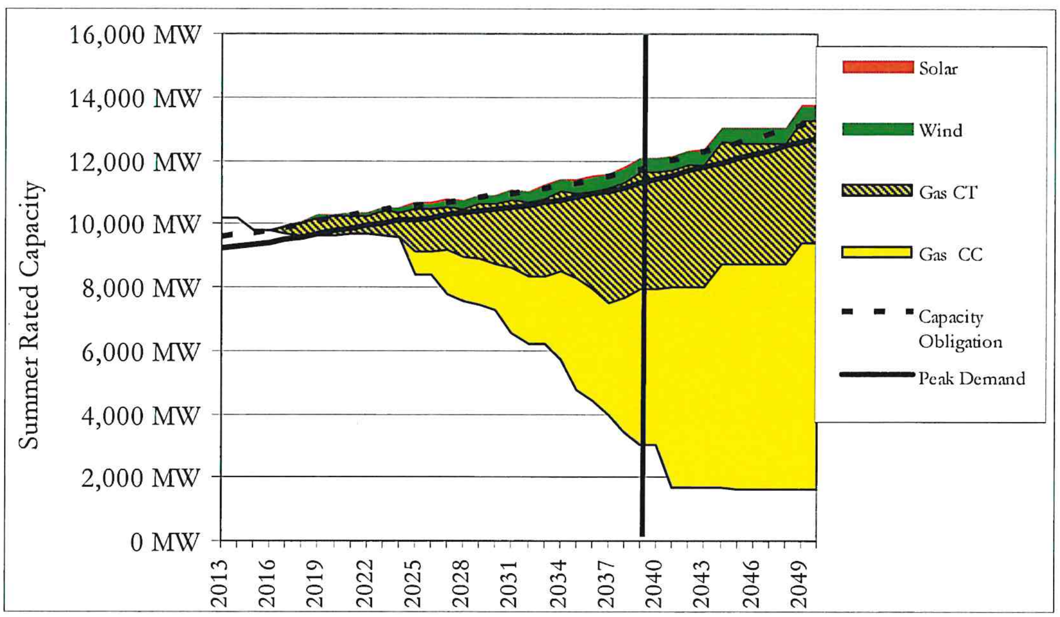
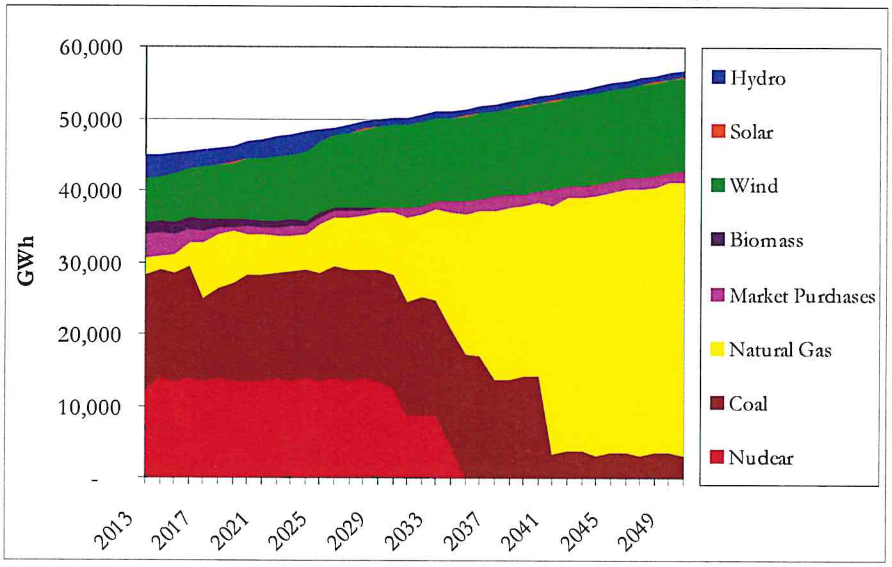


Figure 6.3 shows the Company's projected energy mix based on the Reference Case that was optimized in Strategist. This optimization was based on current cost assessment for various technologies and is for illustrative purposes only since many factors can influence our future fuel mix. As shown, the Reference Case retirements and additions change the characteristics of our energy portfolio, with most of the

future energy coming from natural gas resources with renewables maintaining a level of approximately 30%.

Figure 6.3: 2013-2050 NSP Total System Energy Mix



Chapter 7. Strategist Modeling Results

A. Overview

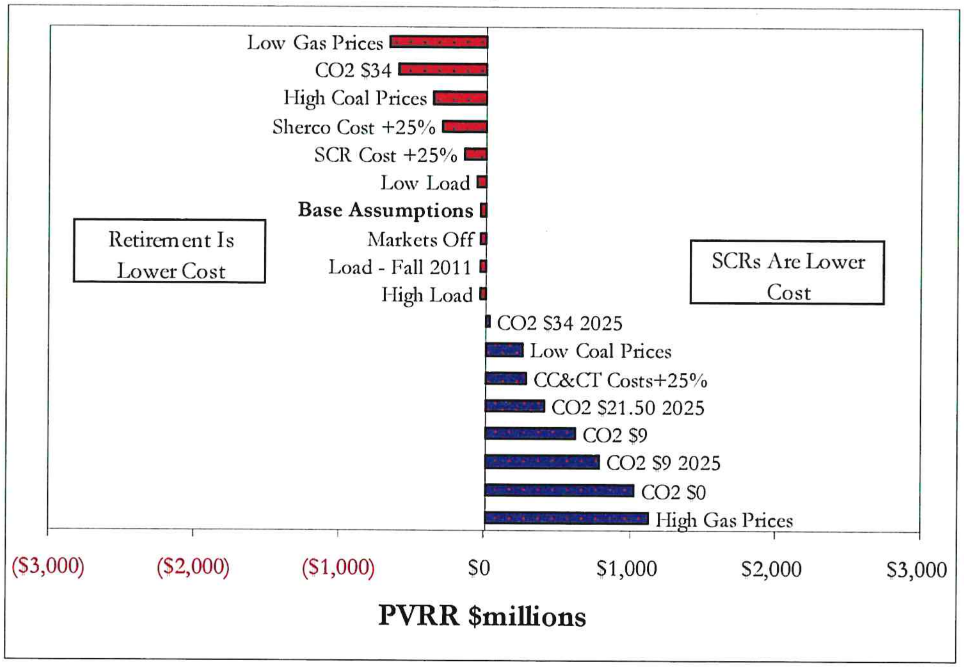
The Company ran a total of 598 simulations to evaluate the cost-effectiveness and emissions profile of various futures for Sherco Units 1 and 2. At a high level, the scenarios compare the relative costs of installing SCRs and continuing to operate one or both units with retirement of one or both units, given a number of assumptions about the future. Sensitivities are used to test the results against changes in assumptions.

The modeling results show that whether retirement or retrofitting is lower cost over the long term largely depends on the assumed price of carbon regulation. Figure 7.1 illustrates the relative PVRR impacts of retirement of Sherco 1 and 2 in 2019 and 2020 to the alternative of retrofitting the units with SCRs and continuing operations until 2040. The chart shows that under base assumptions (including \$21.50/ton CO_2 costs) the difference in total PVRR between the retirement and the SCR scenarios is negligible at only \$38 million PVRR. The chart also illustrates which input assumption sensitivities favor which strategy and how much they change the PVRR results. For example, the analysis shows that:

- Lower natural gas prices, higher CO_2 costs, higher coal prices, and higher-than-expected costs at the Sherco plant all favor retirement of the units.
- Higher natural gas prices, lower CO_2 costs or later implementation of CO_2 costs, low coal prices, and higher construction cost for new natural gas plants all favor installation of SCRs.
- Load sensitivities and the availability of market energy from MISO have little impact on the results.

PVRR results for all scenarios and sensitivities are provided in Appendix E, along with annual details for the 23 base assumption scenarios.

Figure 7.1: Summary of PVRR Results



Our analysis did not attempt to assign probabilities to the various futures. It simply evaluated the impacts should certain assumptions hold true. As discussed previously, there is significant uncertainty around key assumptions, particularly if and when SCRs would be required for continued operation, and how and when potential carbon regulation would affect Sherco 1 and 2's ability to continue to operate. Thus, while the modeling is useful to illustrate the potential costs and benefits of various scenarios and decision paths, the results must be interpreted in the context of this uncertainty. This is particularly true given the significant incremental costs associated with both retrofit and retirement scenarios.

The Company believes the most prudent option is to leave options open until there is greater certainty on the development of environmental regulations. At the same time, we recommend that clear and firm triggers be established that require reevaluation of the alternatives and provide an opportunity for a future Commission decision on the future of Sherco 1 and 2.

B. Retrofit Scenarios

As noted earlier, the only additional emission control equipment that could reasonably be anticipated to be required for Sherco 1 and 2 is the addition of Selective Catalytic Reduction (SCR) technology. If this equipment is required in the future, it will entail significant capital investments and a commensurate increase in customer rates.

However, continued operation would help maintain a diverse fuel mix on our system and mitigate exposure to fluctuations in the natural gas market.

We modeled several scenarios in Strategist that added SCRs to one or both units at Sherco. The scenarios were developed by adding estimates of the capital cost to construct the SCRs and the associated operating costs to the Reference Case. Comparison of the Strategist output for the SCR scenarios to the Reference Case provides an estimate of the incremental cost of the SCRs over the Reference Case, where Sherco continues to operate without additional emission controls.

The cost estimates for the SCRs were originally developed as part of Multi-pollutant Control Study for Sherco 1 and 2 completed by an engineering consulting firm in 2011 and then updated by the same firm in 2013 for use in this study. The costs were entered into Strategist as either capital investments or as annual operating expenses. We did not include any operational impacts from the SCRs on maximum capacity or heat rate because the cost estimates for the project include the installation of new induced draft (ID) fans, which will offset the operational impacts normally associated with SCRs.

The key SCR inputs used in Scenarios 1 and 2 include:

- SCR NO_X Reduction – 67% from baseline emissions;
- SCR Construction Cost Estimate
  - Early (2018/2019) – Unit 1: $190 million, Unit 2: $193 million
  - Late (2024/2025) – Unit 1: $218 million, Unit 2: $222 million;
- SCR Ongoing Capital Costs – Approximately $2 million/year escalating at inflation;
- SCR Variable O&M - $0.27/MWh escalating at 2.39%; and
- SCR Fixed O&M - $146,000/year escalating at 2.45%.

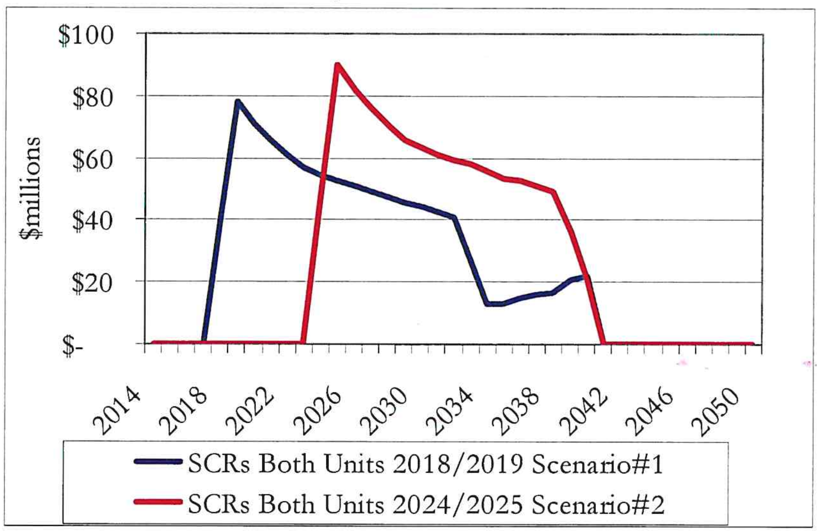
The cost impact of the SCRs are significant; if installed on both units the incremental PVRR cost is an estimated $391 million for the early installation date of 2018/2019 and $282 million for the later dates of 2024/2025. The lower cost for later installation is simply a result of discounting future costs. The costs of SCRs primarily come from the capital investments necessary to install and maintain the equipment. However, there is an additional variable O&M cost associated with chemicals necessary to remove the NO_X from the flue gas stream. The following table segregates the PVRR results for the SCR projects into four subcategories. These results are in comparison to the Reference Case, where Sherco 1 and 2 continue to operate until 2040 without the installation of any new pollution control equipment.

Table 7.1: PVRR Impacts of SCRs Relative to Reference Case

	SCRs Both Units 2018/2019 Scenario#1	SCRs Both Units 2024/2025 Scenario#2
Incremental PVRR from Reference Case	$391million	$282million
PVRR Impact By Cost Category		
Capital Revenue Reqirements	$380million	$275million
Fixed O&M and Other Annual Fixed Costs	$3million	$2million
Fuel and Other Variable Cost	$38million	$23million
Emission Costs	-$29million	-$17million
Total	$391million	$282million

In addition to PVRR impacts, it is also instructive to analyze the annual results that are produced in Strategist. This analysis will help gauge the relative rate impacts of each strategy and the timing of costs that will be borne by our customers. For the SCR alternative, the annual cost impacts begin at approximately $75 to $90 million. These costs gradually decline as the equipment is depreciated and the net book value falls.

Figure 7.2: Annual Costs Impacts for SCRs Relative to Reference Case



Most of the sensitivity tests (load, fuel prices, CO_2 costs) had little to no impact on the cost of the SCRs relative to the Reference Case, as the installation of SCRs on Sherco 1 and 2 will not significantly impact the operation of our system. For example, because Unit 1 and 2 continue to operate until 2040 in both the Reference Case and the SCR scenario, the forecasted amount of coal usage is the same in both scenarios.

As a result, when different coal prices are tested in the model, there is no change in the cost of the SCR scenario relative to the Reference Case.

The sensitivities that impact the SCR scenarios are: 1) the SCR costs assumptions, and 2) the assumed book depreciation life of the SCR equipment. As expected, the SCR +25% cost sensitivity raises the total PVRR of the scenario – that is, it increases rates. In contrast, the total PVRR is lower under the assumption of faster depreciation. Our baseline assumption for the book lives of the SCRs was 15 years. However, continued operation of the Sherco units for 15 years after the installation of the SCRs could put the Company and our customers at risk for extra costs from federal carbon legislation. To test the possibility that the cost of the SCRs could be recovered over a shorter period, allowing the plant to be retired earlier in the event of significant carbon costs, we ran sensitivities with 10 and five-year book depreciation for the SCRs. The total PVRR costs under the assumption of accelerated depreciation were lower than under the base assumption of 15 years. Although the annual book depreciation expense was higher, the shorter financing term resulted in significant savings. This is similar to a comparison of a 30-year versus a 15-year mortgage. With a longer mortgage, the monthly payments are likely to be lower, but the total interest costs will be higher. The following charts illustrate the annual impacts of the depreciation sensitivities and the total PVRR impacts of all the sensitivities ran on the SCR scenarios.

Figure 7.3: Annual Cost Impacts of SCR Book Depreciation Assumptions

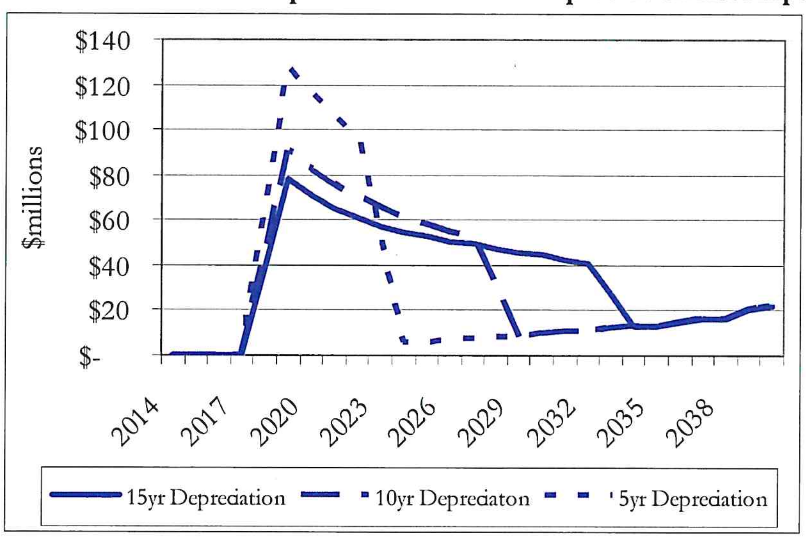
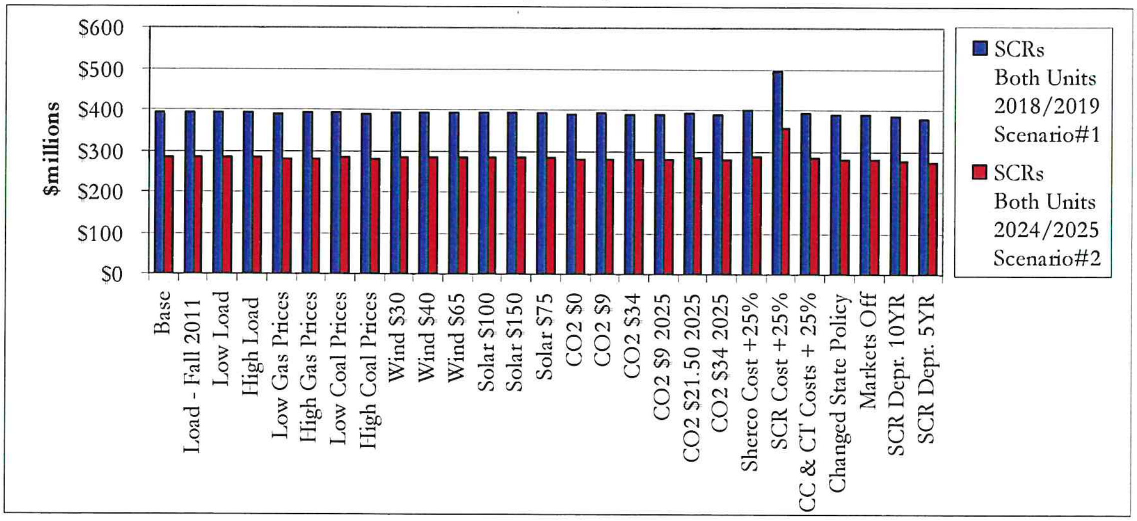


Figure 7.4: Sensitivity Analysis for SCR Scenarios



The installation of SCRs at both units at Sherco is estimated to cost almost $400 million. When depreciated over 15 years and spread across the entire five state region that the Company serves, the incremental impact on rates is 0.23¢ /kWh or less than 2%. The impact on various customer classes depend on the amount of fixed charges and proportion of baseload resource costs allocated to each class. Table 7.2 summarizes the impact of the SCRs on rates.

Table 7.2: Rate Impacts of 2018/2019 SCRs – Scenario 1

		Scenario 1 Rate Impact $ per kWh						
	Customer Class	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Scenario 1 Install SCRs Sherco 1 & 2 2018/2019	Residential	$0.0015	$0.0026	$0.0023	$0.0021	$0.0020	$0.0019	$0.0018
	C&I Non Demand	$0.0016	$0.0026	$0.0024	$0.0022	$0.0020	$0.0019	$0.0018
	C&I Demand	$0.0013	$0.0022	$0.0020	$0.0018	$0.0017	$0.0016	$0.0015
	Lighting	$0.0010	$0.0017	$0.0015	$0.0014	$0.0013	$0.0012	$0.0012
	All Classes	$0.0014	$0.0023	$0.0021	$0.0019	$0.0018	$0.0017	$0.0016

In summary, the installation of SCRs results in a cost increase for our customers, primarily due to invested capital that will flow to customers through increases in base rates. However, this is a relatively low risk strategy for complying with future environmental regulations. The primary risk is uncertainty associated with construction costs for the SCRs. Faster depreciation of the SCRs will increase near-term rate impacts, but would also provide the option of retiring the units earlier if significant federal carbon legislation is passed.

C. Retirement and Replacement Scenarios

Retirement of Units 1 and 2 is a potential alternative to adding SCRs. This strategy also results in a significant increase in customer rates, as well as increased exposure to natural gas prices, which have historically been more volatile than coal prices. However, if a tax were imposed on all CO_2 emissions at or near the $21.50/ton rate that we included in our model, the net cost of retirement and replacement would be similar to the cost of installing SCRs.

To model retirement scenarios in Strategist, the retirement date for Sherco 1 and 2 was changed from 2040 to 2019/2020 for the early retirement case or 2024/2025 for the later retirement case. The capital budget for Sherco was modified to reflect a shorter operating life with fewer investments needed to maintain the facility. The capital depreciation schedule was changed to match the modeled retirement date and the recovery of decommissioning costs was adjusted such that sufficient funds are available upon retirement to remove and remediate the site.

The resources that replace the retired Sherco units were selected in two ways. First, Strategist was allowed to select from coal, nuclear, natural gas combined cycle, natural gas peaking, wind, solar, and market energy resources in order to find the lowest cost bundle of resources that could replace Sherco 1 and 2. Using this approach, Strategist selected natural gas combined cycle units as the least cost resources to replace the retiring units. These units replaced the firm capacity needed for system reliability and provided most of the daily energy that had been produced at Sherco. Through its hourly dispatch simulation, Strategist also relied on higher operating hours at other existing units and some market purchases to make up the remaining portion of the daily energy needs. The scenarios that used Strategist to optimize the replacement resources were numbered 13 and 18.

Second, we hard-coded several different replacement alternatives in order to evaluate the cost and benefits of each alternative. By specifying particular replacement resources, we can investigate the performance of options other than the least cost alternatives selected by Strategist. The following sections provide a description of the various replacement scenarios and the input assumptions used in each.

1. *Natural Gas Combined Cycle (Scenarios 14 and 19)*

In these scenarios Sherco 1 and 2 are replaced with two natural gas combined cycle units. The current design of large combined cycle units achieve a maximum summer capacity of 707 MW, which is close to the per unit maximum for Sherco 1 and 2. The key natural gas combined cycle inputs used in Scenarios 14 and 19 include:

- Maximum Winter Capacity – 817 MW each;
- Maximum Summer Capacity – 707 MW each;
- Capital Costs – $692 million each;
- Natural Gas Pipeline Costs – $200 for two units;
- Ongoing Capital Costs – $3.4 million/year escalating at inflation;
- Fixed O&M – $7 million/year each escalating at 2.45%; and
- Variable O&M – $1.05/MWh each escalating at 2.39%.

Individual combined cycle plants comprised of two F class combustion turbines, two heat recovery steam generators (HRSGs), and one steam turbine (known collectively as a 2X1 CC) have been identified as near match replacements for the Sherco units. Pricing and performance information was developed based on siting the 2X1 CCs either at the Sherco site or at a new "greenfield" site. The Sherco site offers existing infrastructure for water supply and transmission interconnection, as well as land, but would need a new gas supply. As water supply is available at the current Sherco site, the 2X1 CC design and performance is based on utilization of wet cooling towers. For the greenfield options, the design, performance, and cost have been based on utilization of dry or air-cooled technology (ACC).

The 2X1 CC options are based on either General Electric (GE) 7FA Series 5 or Siemens SGT6-5000F5 combustion turbines. The two GE 7FA Version 5 or Siemens SGT6-5000F5 combustion turbines are similar to the design for a peaker. The plant has a single steam turbine generator and is designed to operate on natural gas fuel using dry, low NO_X combustion and SCR for further NO_X emissions reduction.

The natural gas fuel supply required for either the 2X1 CC plants or the combustion turbine peaker plants is anticipated to be from existing interstate pipelines in the NSP service territory. We have discussed availability and potential for service with several suppliers, including Northern Natural Gas, Alliance Pipeline, WBI, and Viking. Based on these discussions, we assumed supply from the Alliance pipeline, as it appears to have the capacity to serve the large new loads and have the potential for firm service. In order to provide service to the vicinity of Sherco, a new 88-mile line from Alliance would be required. The preliminary cost estimate is approximately $200 million. This cost has been included in the capital estimates for the 2X1 CCs located at Sherco.

2. *Natural Gas Peaking Units + Wind Resources (Scenarios 15 and 20)*

These scenarios replaced the firm capacity from Sherco 1 and 2 needed for reliability with natural gas peaking units with the majority of the energy normally generated by Sherco replaced with additional wind generation. Specifically, the replacement bundle consisted of 3,000 MW of wind and five peaking units with a summer rating of 192 MW each. The amount of wind was selected such that approximately 100% of the energy produced by Sherco is replaced by renewable energy. This represents an large increase in the amount of wind energy on the NSP System. Currently, we have approximately 1,800 MW installed, which is equivalent to about 14% of our total energy mix, and to comply with the Minnesota Renewable Energy Standard we must achieve a wind penetration level of 25% of retail sales by 2020. The additional 3,000 MW to replace the energy from Sherco with wind would bring the total wind penetration on our system to 44%. To accommodate this additional wind generation, the model included $700 million for new transmission infrastructure to deliver the power from high wind areas to our load centers. The baseline assumption for wind pricing is based on our current estimate of the cost of wind turbines without the benefit of the federal production tax credit, which is set to expire at the end of 2013. The key natural gas combustion turbine inputs used in Scenarios 15 and 20 include:

- Maximum Winter Capacity – 226 MW;
- Maximum Summer Capacity – 192 MW;
- Capital Costs – $136 million each escalating at inflation;
- Fuel Supply and/or Transmission Costs – $40 million each escalating at inflation;
- Ongoing Capital Costs – $1.3 million/year each escalating at inflation;
- Fixed O&M – $668,000/year each escalating at 2.45%; and
- Variable O&M – $1.40/MWh escalating at 2.39%.

The key wind generation inputs include:

- Purchase Costs – $44/MWh (2014) escalating at inflation ($53/MWh levelized);
- Wind Integration Costs – $1.13 escalating with the price of natural gas; and
- Transmission – $700 million capital investment to support 3,000 MW of wind escalating at inflation.

The combustion turbine facility is estimated on the basis of a greenfield plant located near a major interstate gas pipeline and a 345 kV transmission line to minimize the cost impacts of interconnection costs. On that basis, it has been assumed for this study that the plants would be adjacent to the Alliance pipeline, with one plant located near Franklin, Minnesota and one near Fargo, North Dakota. The simple cycle or peaker plants assumed for this study are comprised of three F class combustion turbines.

3. *Natural Gas Peaking Units + Wind Resources +Solar (Scenarios 16 and 21)*

We modified the preceding scenario to include solar electricity as part of the replacement bundle for Sherco. Specifically, this scenario has three natural gas peaking units, 2,200 MW of wind, and 1,200 MW of solar. The amount of transmission investment necessary to support the delivery of wind power was decreased proportionally to the lower level of wind and no additional transmission was added for the solar, as it is expected that the solar resources can be constructed at or near load centers. Under this scenario wind penetration reaches 38% and solar reaches 5%. The key inputs include:

- Natural Gas Combustion Turbine – Same as scenarios 15 and 20
- Wind – Same as scenarios 15 and 20
  - Transmission – $550 million capital investment to support 2,200MW of wind escalating at inflation
- Solar
  - Purchase Costs – $105/MWh (2014) escalating at inflation ($125/MWh levelized)
  - No Solar Integration Costs
  - No Additional Costs for Transmission Infrastructure.

4. *Natural Gas Peaking Units + Wind Resources +Solar + DSM (Scenarios 17 and 22)*

Our final hard-coded replacement bundle added DSM to the wind and solar replacement energy. The Company has conducted extensive energy conservation programs in our service territory, which suggests the opportunities for additional savings are diminishing. Our Reference Case assumptions include the 1.5% DSM goal for 2014-2016 and 1.4% for the remaining years. This enhanced DSM scenario raises the DSM achievements to 1.6%, which is an increase equivalent to 55 MW and 295 GWh annually. Specifically, these scenarios include three natural gas peaking units, 2,000 MW of wind, 1,100 MW of solar, and DSM equal to 1.6% of sales. The key inputs include:

- Natural Gas Combustion Turbine – Same as scenarios 16 and 21;
- Wind – Same as scenarios 16 and 21
  - Transmission – $500 million capital investment to support 2,000 MW of wind escalating at inflation;
- Solar – Same as scenarios 16 and 21; and
- DSM – $264 million spent over five years to achieve an incremental 55 MW and 295 GWh.

5. *Summary*

Under the base assumptions used in Strategist, including \$21.50/ton CO_2 costs, the PVRR impact of retirement and replacement with natural gas combined cycle units is similar to the PVRR impact of the installation of SCRs. Note that the optimized replacement scenario also selected the combined cycle alternatives, giving it an identical PVRR impact.

Table 7.3: PVRR Impacts of Retirement Scenario Relative to Reference Case

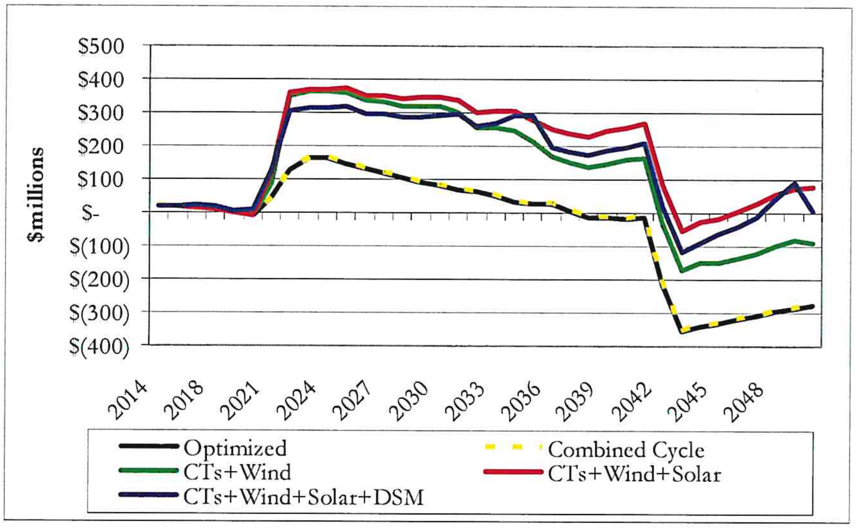
	Retire Both Units 2019/2020 Optimized Replacement Scenario#13	Retire Both Units 2019/2020 CC Replacement Scenario#14	Retire Both Units 2019/2020 CT + Wind Replacement Scenario#15	Retire Both Units 2019/2020 CT + Wind + Solar Replacement Scenario#16	Retire Both Units 2019/2020 CT + Wind + Solar + DSM Replacement Scenario#17
Incremental PVRR from Reference Case	\$354 million	\$354 million	\$1,789 million	\$2,154 million	\$1,849 million
PVRR Impact By Cost Category					
Capital Revenue Reqirements	\$789 million	\$789 million	\$728 million	\$229 million	\$175 million
Fixed O&M and Other Annual Fixed Costs	(\$295million)	(\$295million)	(\$375million)	(\$400million)	(\$398million)
Fuel and Other Variable Cost	\$1,087 million	\$1,087 million	\$3,051 million	\$4,020 million	\$3,609 million
Wind Integration Costs	\$0 million	\$0 million	\$430 million	\$317 million	\$287 million
DSM Expenses	\$0 million	\$0 million	\$0 million	\$0 million	\$146 million
Emission Costs	(\$1,228million)	(\$1,228million)	(\$2,044million)	(\$2,011million)	(\$1,970million)
Total	\$354 million	\$354 million	\$1,789 million	\$2,154 million	\$1,849 million

Table 7.3 illustrates the large impact the CO_2 assumption has on the PVRR results. For the combined cycle scenario, there is a \$1.2 billion CO_2 benefit associated with retirement of Sherco. That benefit more than offsets the \$1.1 billion cost increase from higher levels of natural gas generation.

The addition of wind and solar to the replacement scenarios adds significant costs to the replacement of Units 1 and 2. At \$53/MWh levelized plus transmission costs, the wind resources are not cost-effective alternatives. This reflects the role of the federal production tax credit (PTC) in the economics of wind. Later in this section we show the results of a sensitivity test where the price of wind is lowered to a level that reflects the benefit of the PTC; under those assumptions, wind is much more cost-effective. The addition of solar resources at a price of \$125/MWh levelized is also not cost-effective, even though the solar additions eliminated the need for two natural gas combustion turbines. The addition of DSM does create a net decrease in PVRR. The PVRR results, however, do not reflect some incremental cost that will be paid by participants in those programs, suggesting the total societal cost of the DSM programs is higher. Also, because DSM simultaneously reduces costs and sales, the net impact on rates may be positive or negative. The result of a later retirement and replacement of Sherco in the 2024/2025 timeframe had very similar PVRR results, but the total PVRR values were lower due to discounting the costs over more years.

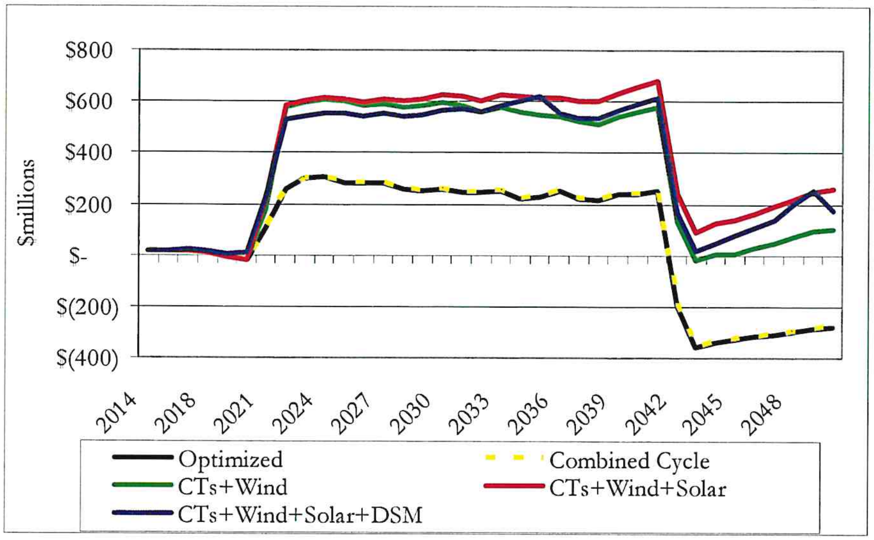
The annual cost impacts for the retirement scenarios show significant cost increases at the time of retirement that gradually decline over time. When considering a CO_2 cost of $21.50/ton, replacement with natural gas combined cycle units has a first year impact of $160 million. After 2040 the retirement scenarios shows significant cost savings. This is because in the Reference Case Sherco 1 and 2 retire in 2040 and must be replaced by new generation. But in the retirement scenarios, this replacement capacity was constructed earlier at lower cost and then significantly depreciated by 2040, thus lowering its cost even further.

Figure 7.5: Annual Costs for Retirement Relative to Reference Case – CO_2 $21.50/ton



As noted previously, under the base assumptions there is a large benefit from the reduction of CO_2 emissions associated with retirement of Sherco 1 and 2. Figure 7.6 also shows the annual cost impacts from the retirement scenarios but under the assumption of $0/ton CO_2 (sensitivity N). Without the cost on carbon, the first-year cost impact of replacing Sherco with natural gas combined cycles is $320 million.

Figure 7.6: Annual Costs for SCRs Relative to Reference Case – CO_2 \$0/ton



Retirement of Sherco 1 and 2 would fundamentally change the NSP System with respect to energy mix and annual emissions. As a result, the sensitivity tests that involve fuel and emissions costs show variability associated with the retirement scenarios. Also, the sensitivities associated with the cost of wind that, with the assumption of \$21.50/ton CO_2, wind is cost-effective at the \$30/MWh levelized price (including the cost for transmission infrastructure). A review of all the input assumption sensitivities run in Strategist is provided in Appendix B. The following graph and table show the relative costs of the replacement alternatives under a range of sensitivities. In the table, negative values indicate that retirement is lower cost than the Reference Case.

Figure 7.7: Sensitivity Analysis for Retirement Scenarios

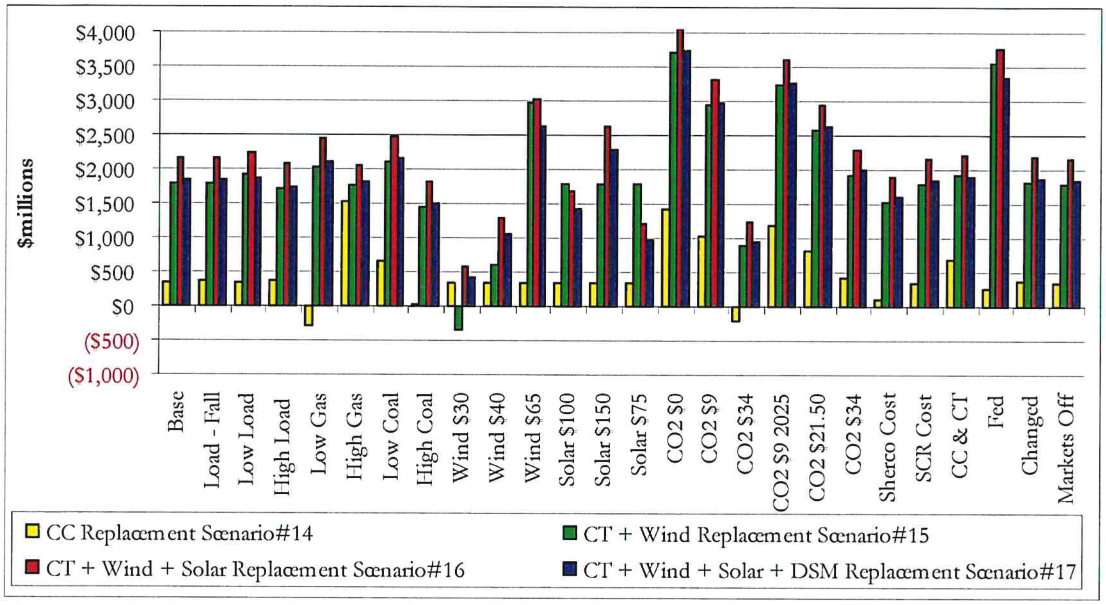


Table 7.4: Sensitivity Analysis for Retirement Scenarios

PVRR Impacts Relative to the Reference Case $millions	Optimized Replacement Scenario #13	CC Replacement Scenario #14	CT + Wind Replacement Scenario #15	CT + Wind + Solar Replacement Scenario #16	CT + Wind + Solar + DSM Replacement Scenario #17
Base	$354	$354	$1,789	$2,154	$1,849
Load - Fall 2011	$363	$363	$1,789	$2,156	$1,851
Low Load	$339	$339	$1,916	$2,250	$1,876
High Load	$363	$363	$1,703	$2,090	$1,724
Low Gas Prices	($278)	($278)	$2,032	$2,444	$2,100
High Gas Prices	$1,524	$1,524	$1,768	$2,056	$1,804
Low Coal Prices	$648	$648	$2,115	$2,469	$2,161
High Coal Prices	$29	$29	$1,437	$1,811	$1,509
Wind $30	$354	$354	($343)	$581	$424
Wind $40	$354	$354	$602	$1,278	$1,055
Wind $65	$354	$354	$2,963	$3,020	$2,633
Solar $100	$354	$354	$1,789	$1,676	$1,412
Solar $150	$354	$354	$1,789	$2,632	$2,285
Solar $75	$354	$354	$1,789	$1,198	$976
CO2 $0	$1,425	$1,425	$3,723	$4,082	$3,732
CO2 $9	$1,017	$1,017	$2,942	$3,304	$2,973
CO2 $34	($211)	($211)	$884	$1,236	$951
CO2 $9 2025	$1,175	$1,175	$3,239	$3,602	$3,264
CO2 $21.50 2025	$806	$806	$2,572	$2,941	$2,620
CO2 $34 2025	$417	$417	$1,925	$2,293	$1,988
Sherco Cost +25%	$101	$101	$1,536	$1,901	$1,596
SCR Cost +25%	$354	$354	$1,789	$2,154	$1,849
CC & CT Costs + 25%	$672	$672	$1,911	$2,198	$1,893
Fed Externalities	$273	$273	$3,561	$3,774	$3,346
Changed State Policy	$358	$358	$1,818	$2,172	$1,867
Markets Off	$354	$354	$1,789	$2,154	$1,849
SCR Depr. 10YR	$354	$354	$1,789	$2,154	$1,849
SCR Depr. 5YR	$0	$0	$0	$0	$0

We evaluated the rate impacts of the retirement scenarios under the assumption of \$0/ton CO_2. At this time, there is no firm proposal to implement a direct tax on CO_2 that would be similar to the \$21.50/ton planning value that is used in the Strategist base assumptions. The following table shows that the natural gas combined cycle replacement option is expected to increase rates by over 1¢/kWh by 2024. This would be an approximate 8% increase in rates, both a base rate increase due to plant investment and increased fuel charges.

Table 7.5: Rate Impacts of Retirement Scenarios

		Scenario 13 Rate Impact $ per kWh						
	Customer Class	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Scenario 13 Replace Sherco 1 & 2 with Natural Gas Combined Cycle	Residential	$0.0025	$0.0070	$0.0103	$0.0113	$0.0116	$0.0115	$0.0105
	C&I Non Demand	$0.0025	$0.0071	$0.0103	$0.0113	$0.0116	$0.0115	$0.0105
	C&I Demand	$0.0021	$0.0058	$0.0082	$0.0088	$0.0090	$0.0091	$0.0083
	Lighting	$0.0016	$0.0042	$0.0057	$0.0058	$0.0059	$0.0060	$0.0054
	All Classes	$0.0022	$0.0061	$0.0089	$0.0096	$0.0098	$0.0098	$0.0089

Overall, the cost-effectiveness of the retirement scenarios is heavily dependent upon the CO_2 pricing assumption used and the price of the replacement technology. The natural gas replacement scenario appears to be cost-effective under the assumption of $21.50/ton CO_2 and lower-than-forecasted natural gas prices. Similarly, the renewable energy replacement alternatives might be cost-effective with CO_2 pricing and low cost for wind and solar. Under the assumption of $0/ton CO_2 costs and current pricing of natural gas and renewables, retirement is expected to be much higher cost than the SCR scenarios.

D. Combined Scenarios

We also evaluated scenarios where an SCR was installed at one unit with the other unit retired and replaced with the various alternatives discussed in the previous section. As is to be expected, the Strategist results for the combined scenarios are approximately halfway between the full SCR and the full retirement scenarios. For the combination scenarios Unit 1 was retired and Unit 2 was retrofitted with an SCR, but Unit 1 and Unit 2 could have been interchanged without significantly impacting the results. The cost and performance assumptions used were the same as listed in the preceding sections.

The PVRR results for the combination scenario indicate that if Unit 1 is replaced by a combined cycle unit, the incremental costs are similar to the full retirement or the full SCR scenarios under base assumptions. However, if the other more costly replacement alternatives are utilized, the incremental cost estimates fall somewhere between the full SCR and the full retirement strategies.

Table 7.6: PVRR Impacts of Combination Scenarios Relative to Reference Case

	Retire Unit 1 2019 Optimized Replacement Unit 2 SCR 2019 Scenario#3	Retire Unit 1 2019 CC Replacement Unit 2 SCR 2019 Scenario#4	Retire Unit 1 2019 CT+Wind Replacement Unit 2 SCR 2019 Scenario#5	Retire Unit 1 2019 CT+Wind +Solar Replacement Unit 2 SCR 2019 Scenario#6	Retire Unit 1 2019 CT+Wind +Solar+DSM Replacement Unit 2 SCR 2019 Scenario#7
Incremental PVRR from Reference Case	$467 million	$467 million	$897 million	$1,231 million	$959 million
PVRR Impact By Cost Category					
Capital Revenue Requirements	$682 million	$682 million	$582 million	$313 million	$259 million
Fixed O&M and Other Annual Fixed Costs	($150million)	($150million)	($200million)	($219million)	($217million)
Fuel and Other Variable Cost	$573 million	$573 million	$1,334 million	$2,036 million	$1,651 million
Wind Integration Costs	$0 million	$0 million	$178 million	$157 million	$127 million
DSM Expenses	$0 million	$0 million	$0 million	$0 million	$146 million
Emission Costs	($637million)	($637million)	($998million)	($1,055million)	($1,008million)
Total	$467 million	$467 million	$897 million	$1,231 million	$959 million

The annual cost impacts show that the combination scenario could mitigate the cost impacts to customers in comparison to the full retirement case. However, the annual cost impacts still reach almost $400 million when no cost is assigned to CO_2.

Figure 7.8: Annual Costs for Combination Scenario Relative to Reference Case CO2 $21.50/ton

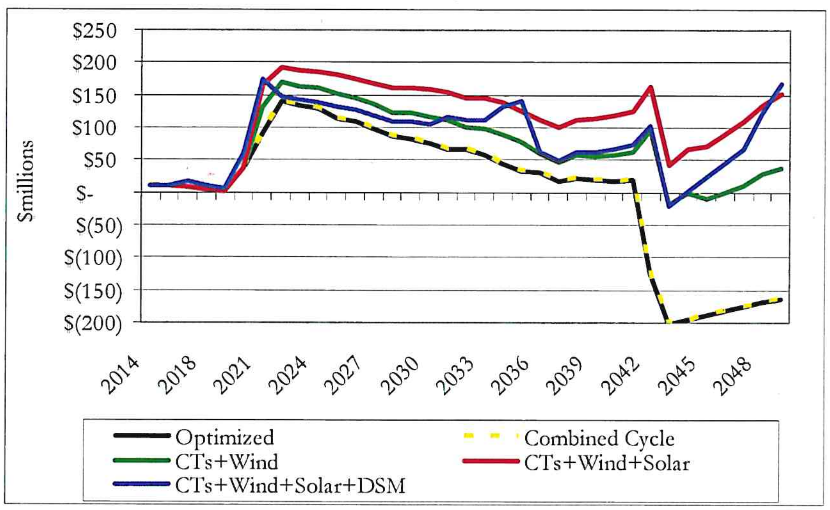
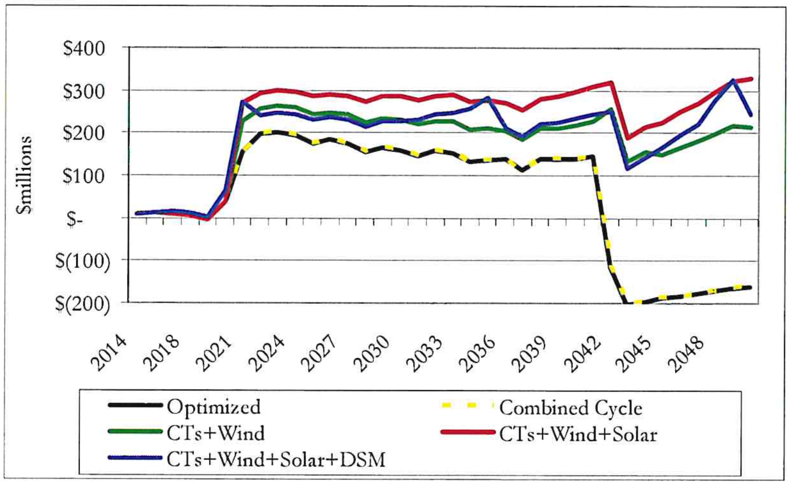


Figure 7.9: Annual Costs for Combination Scenario Relative to Reference Case CO2 $0/ton



The sensitivity analysis performed on the combination scenario shows that by diversifying the strategies used in Sherco 1 and 2's life cycle management, we could potentially limit our exposure to any one risk factor. For example, in comparison to the full retirement scenario, the impact of the high gas scenario is mitigated by the combination scenario. Conversely, the impact of the high coal price scenario is higher.

Figure 7-10: Sensitivity Analysis for Combination Scenario

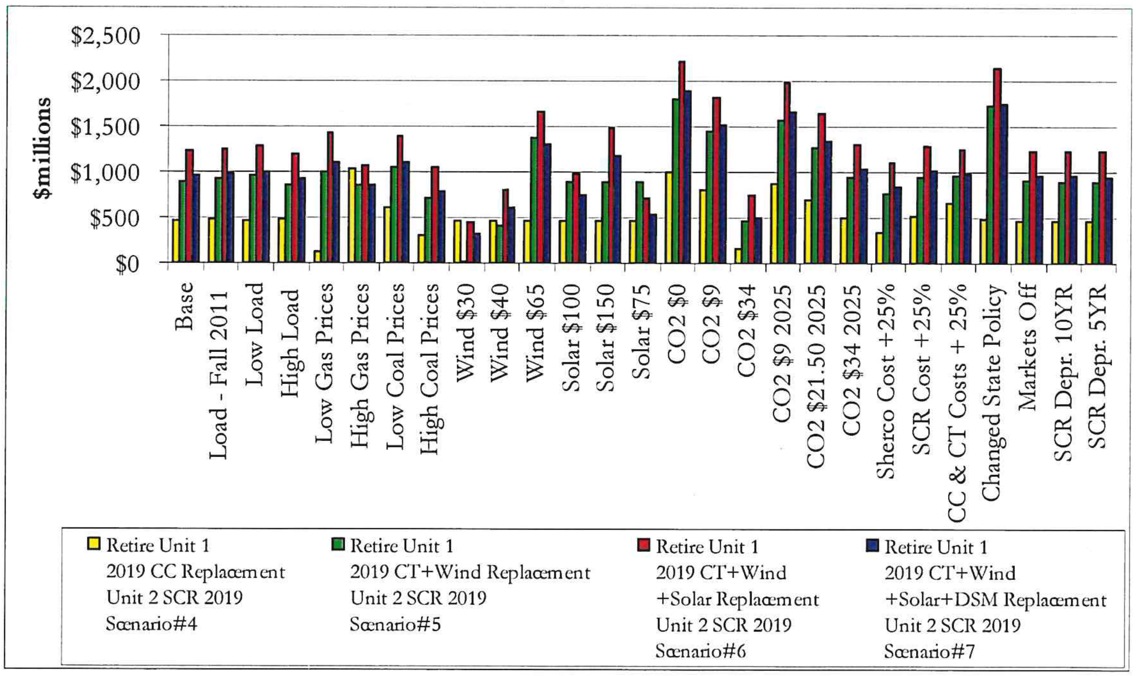


Table 7.7: Sensitivity Analysis for Combination Scenarios

PVRR Impacts Relative to the Reference Case $millions	Retire Unit 1 2019 Optimized Replacement Unit 2 SCR 2019 Scenario#3	Retire Unit 1 2019 CC Replacement Unit 2 SCR 2019 Scenario#4	Retire Unit 1 2019 CT+Wind Replacement Unit 2 SCR 2019 Scenario#5	Retire Unit 1 2019 CT+Wind +Solar Replacement Unit 2 SCR 2019 Scenario#6	Retire Unit 1 2019 CT+Wind +Solar+DSM Replacement Unit 2 SCR 2019 Scenario#7
Base	$467	$467	$897	$1,231	$959
Load - Fall 2011	$475	$475	$921	$1,248	$978
Low Load	$456	$456	$958	$1,283	$1,002
High Load	$474	$474	$849	$1,194	$926
Low Gas Prices	$124	$124	$1,000	$1,424	$1,099
High Gas Prices	$1,034	$1,034	$858	$1,068	$862
Low Coal Prices	$610	$610	$1,052	$1,386	$1,110
High Coal Prices	$296	$296	$721	$1,054	$784
Wind $30	$467	$467	$14	$453	$329
Wind $40	$467	$467	$405	$798	$608
Wind $65	$467	$467	$1,384	$1,660	$1,306
Solar $100	$467	$467	$897	$974	$743
Solar $150	$467	$467	$897	$1,489	$1,175
Solar $75	$467	$467	$897	$717	$527
CO2 $0	$999	$999	$1,804	$2,220	$1,891
CO2 $9	$797	$797	$1,441	$1,822	$1,517
CO2 $34	$154	$154	$459	$745	$497
CO2 $9 2025	$878	$878	$1,578	$1,976	$1,663
CO2 $21.50 2025	$700	$700	$1,267	$1,640	$1,347
CO2 $34 2025	$503	$503	$955	$1,303	$1,029
Sherco Cost +25%	$342	$342	$771	$1,105	$833
SCR Cost +25%	$518	$518	$947	$1,282	$1,009
CC & CT Costs + 25%	$652	$652	$969	$1,251	$978
Changed State Policy	$306	$480	$1,729	$2,140	$1,748
Markets Off	$468	$468	$907	$1,235	$965
SCR Depr. 10YR	$464	$464	$894	$1,228	$956
SCR Depr. 5YR	$461	$461	$890	$1,225	$952

E. Scenario to meet 80% CO_2 Reduction by 2050

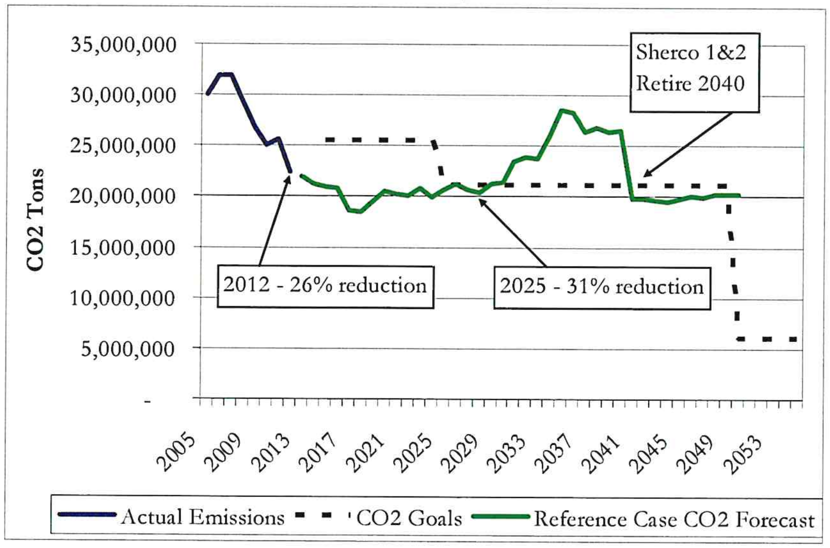
The Commission's November 30, 2013 Order in our 2011-2025 Resource Plan specified that our life cycle management study should include analysis of least cost scenarios that reduce greenhouse gas emissions by 80% by 2050, relative to 2005 levels. While we provide information on this scenario below, the strategy for life cycle management of Sherco does not impact our ability to achieve the 80% goal. In this study the latest retirement date for Sherco 1 and 2 is 2040. Thus, under all scenarios presented, the units will retired by 2050 and will not impact the achievement of the 80% goal.

Through conservation, renewable energy additions, and MERP, we have already reduced our CO_2 emissions by over 25% from 2005 levels. That puts us well ahead of the 2015 goal of a 15% reduction. Our Reference Case Strategist model, which includes continued operation of Sherco 1 and 2, forecasts that we will also meet the 2025 goal of a 30% reduction. In the 2030 to 2035 timeframe, the CO_2 emissions for the NSP system may increase significantly with the retirement of our Monticello and Prairie Island nuclear plants. These CO_2-free resources account for approximately 29% of our total system generation and replacement options will need to be carefully considered before their retirement dates arrive.

By 2050 all of NSP's current coal fleet will likely be retired. What resources comprise our energy portfolio and affect our ability to meet the 80% reduction goal will depend on how generation technologies evolve over the next several decades. Depending on cost, nuclear generation may contribute to achieving significant CO_2 reductions. Alternatively, renewable resources would likely supply a majority of energy on our system. While cost estimates over this timeframe are speculative, we have run various Strategist analyses around the 80% reduction scenario. One Strategist analysis indicated that approximately 13,000 MW of wind and 4,500 MW of solar energy would be needed to meet the 80% goal. Such a large proportion of intermittent resource would require significant energy storage capability. To meet the CO_2 goal Strategist also selected 5,000 MW worth of battery storage technology.

Regardless of the specific technologies chosen, achievement of an 80% CO_2 reduction will be challenging, requiring that approximately 85% of our energy come from renewable resources or other CO_2-free generation by 2050. However, given the long time horizon for this emissions reduction goal, Sherco 1 and 2 do not play a significant roll in reaching the target.

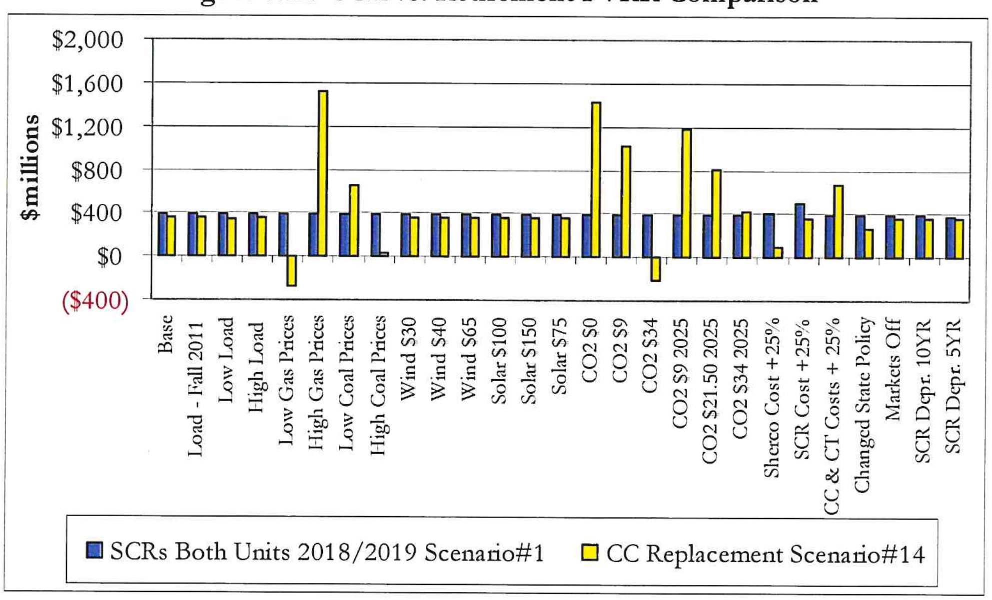
Figure 7.11: NSP Historic CO2 Emissions, CO_2 Goals, and Reference Case Projections



F. Summary

The Strategist analysis suggests that the installation of SCR equipment to comply with potential environmental regulations is costly, but that the alternative strategy of retirement is likely to have a much higher impact on customer rates and would only be cost-effective with a significant cost on CO_2 emissions. Figure 7.12 shows the difference in cost between SCR and retirement scenarios for a range of assumptions, including CO_2 costs and natural gas prices.

Figure 7.12: SCR vs. Retirement PVRR Comparison



We believe that a strategy that aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of additional information on the necessity for SCRs and impending cost on CO_2 is in the best interest of our customers. If federal or state regulations are adopted that require lower NO_X emissions at Sherco 1 and 2, then the Company will reevaluate whether the installation of SCRs or retirement is the preferred strategy. The analysis shows that faster depreciation of the SCRs increases near-term rate impacts, but provides the option of retiring the units earlier than 2040 if significant federal carbon legislation is adopted.

Chapter 8. Other Considerations

The analysis identifies least cost options under a range of sensitivities to help inform what decision alternatives result in the lowest cost for all customers. It is also appropriate, however, to recognize that there are impacts of retirement that the Strategist analysis does not capture.

A. Socioeconomic Impacts

The Sherco Plant is the primary economic driver of the city of Becker, which is a small community with a population of approximately 4,600 people. Sherco provides jobs for local residents, contributes to local tax revenue, and supports local schools and police and fire services. Sherco's operations also support regional jobs, including railroad and mining jobs. The steam from Sherco 1 and 2 is sold to Liberty Paper, also a major employer in Becker, for its operations. Thus, the decisions made on the future of Sherco 1 and 2 will directly and significantly impact Becker, Liberty Paper, and surrounding communities. The following analysis evaluates the potential impacts the loss of jobs and decline in tax revenue would have on the city of Becker, as well as the impacts of Sherco 1 and 2 retirement on Liberty Paper.

1. *Jobs*

The Sherco Plant employs a total of approximately 370 people, of which 300 are full-time employees and 70 are contractors. Of the total full-time employees, approximately 150 directly support Units 1 and 2. An additional 40 people are employed in management or support roles serving all three units. More than half of Sherco's employees live in Becker and the surrounding communities. Should Units 1 and 2 be shut down, it is possible that the majority and possibly all employees at Units 1 and 2 would be laid off. In the event that a natural-gas-fired plant is built on the former Sherco 1 and 2 site, some employees may be able to remain, but not all, as natural gas plants have lower staffing requirements. The loss of jobs at Sherco could have cascading effects throughout the local economy, as fewer dollars are spent at local restaurants, grocery stores, hotels, and other businesses.

In addition to local jobs, the Sherco Plant supports regional jobs in the mining and railroad industries. Sherco receives an average of three rail deliveries of coal per day. The coal is delivered from mines in Wyoming and Montana. The retirement of Sherco 1 and 2 would reduce the demand for coal, which would reduce the number of rail deliveries and amount of coal needed from the mine. This reduction could result in layoffs at the railroad and mining companies.

2. *Tax Base*

In 2013, property taxes related to the Sherco plant will total approximately $6.4 million, with $4.15 million paid to Sherburne County and $2.25 million paid to the city of Becker. The tax revenues from Sherco comprise approximately 75% of the city of Becker's budget, making it the primary source of revenue for the city. Absent this tax revenue, the city would have to significantly increase the tax rate, which would likely shift the tax base from industrial taxpayers to residential and commercial taxpayers. This increase in taxes could force local residents and businesses out of Becker, further reducing tax revenue. This is in addition to the expected departure of Sherco employees who must leave Becker in search of different employment. As more and more residents leave Becker the property values will likely decline and the tax base will be further reduced, thus creating a vicious circle that challenges the city's viability. Additionally, because schools are paid based on enrollment, a decline in enrollment would also reduce funding to local schools.

3. *Liberty Paper*

Retirement of Units 1 and 2 would also impact Liberty Paper. Liberty Paper is a private company that operates a paper mill adjacent to the Sherco facility and employs approximately 135 people. Built in 1994, the mill was sited there specifically for the steam supply from Units 1 and 2. If Units 1 and 2 are retired, Liberty Paper must produce an alternative source of steam or cease operations. While the option may exist to install a boiler in the mill, the cost would be significant and beyond what Liberty Paper anticipated when agreeing to locate in Becker. The company estimates that they would need three years advance notice to design, permit and install a boiler. If Liberty Paper is forced to close or relocate due to the economics of replacing the steam from Sherco 1 and 2, the impacts to the Becker community will be compounded.

B. System Reliability

The Commission's Order in our last Resource Plan required the life cycle management study to include an analysis of how a temporary or permanent outage at either Sherco 1 or 2 would affect system reliability. The Company hired a consultant to analyze the impact of a temporary or permanent outage at both Sherco 1 and 2, as well as determine if any new system reliability concerns arise from the new generation pattern. The consultant performed stability analysis using a 2022 shoulder season (off-peak) stability model that was developed using the MISO generator interconnection study model used for the August 2012 generator interconnection studies. The stability study evaluated both voltage and rotor angle conditions following the occurrence of both regional and local transmission disturbances. The stability analysis was performed for the following conditions, which were considered the most limiting:

- Sherco 1 and 2 out of service;
- Sherco 1, 2 and 3 out of service; and
- Sherco 1 and 2 and Monticello out of service.

The analysis did not identify any areas of concern regarding dynamic or voltage stability. All conditions were within the reliability requirements. The analysis did show a slightly worse voltage response for regional disturbances with the generating units out of service, but all were within the allowable limits.

The transmission studies performed only evaluated a few specific conditions on the transmission system. A more thorough analysis would necessitate studying additional conditions and would include stressing the transmission system for a larger range of conditions in which one would expect to see when operating the transmission system. This additional analysis would include studies at various power transfer levels across the transmission system, various load levels, and various generation dispatches. A more thorough analysis could identify additional issues that would need to be addressed.

It is also important to note that replacement generation would need to be in place prior to retirement of one or both units. This ensures adequate supply in the absence of Sherco 1 and 2, which would mitigate reliability issues.

Chapter 9. Conclusion

The Company completed an extensive analysis of the costs of continuing to operate Sherco 1 and 2, including retrofitting the units with SCRs to further reduce NO_X emissions. Those results were compared to a broad range of replacement alternatives using both a longer-term planning perspective traditionally used in resource planning as well as a shorter-term rate impact view. The Company also reviewed the emerging and potential future air quality regulations and assessed the current status of federal carbon regulation. The analysis shows that Sherco 1 and 2 can continue to provide cost-effective electricity to our customers well into the future. However, the relative cost-effectiveness of the retirement and retrofit scenarios depends on assumptions about the price and timing of carbon regulation and natural gas prices. Lower or no carbon costs and higher natural gas prices favor a retrofit decision, while higher carbon costs and lower natural gas prices favor retirement. Under the Reference Case assumptions, including a CO_2 cost of $21.50/ton, the cost difference between installing SCRs and retiring the units is negligible.

The Company believes the most prudent option is to continue to operate Sherco 1 and 2. Doing so leaves both continuing operation and replacement options open until there is greater clarity and certainty on the development of environmental regulations and the associated timing and cost. We have identified two key public policy decisions, either of which should trigger a reassessment. If and when air quality regulations require the addition of selective catalytic reduction, we intend to reexamine the alternatives before making the nearly $400 million investment in the plant. If and when policies are established that create significant costs associated with CO_2 emissions a reassessment is warranted as well. To help guide subsequent Resource Plan proceedings, we recommend these triggers be established that require reevaluation of the alternatives and provide an opportunity for a future Commission decision on the future of Sherco 1 and 2. Specifically, we recommend the Commission require reanalysis when: 1) air quality regulations establish a need for SCRs, or 2) a carbon regulation framework takes shape. This strategy aligns the timing of a decision on the future of Sherco 1 and 2 with the availability of more complete information, which reduces the risk of imposing significant and potentially unnecessary costs onto customers.

Appendix A
Assessment of Federal and State Environmental Regulations and Impacts on Sherco Units 1 and 2

I. AIR QUALITY REGULATION OF EMISSIONS OF CRITERIA AND HAZARDOUS AIR POLLUTANTS

The EPA and the Minnesota Pollution Control Agency (MPCA) have promulgated air quality regulations that reduce emissions of air pollutants in order to protect the health and welfare of the general public. These regulations reduce emissions from a wide variety of sources of air pollution, including coal-fired power plants. The following sections describe the major air quality rules and regulations that impact Sherco Units 1 and 2.

A. National Ambient Air Quality Standards

The Clean Air Act (CAA) requires EPA to set National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. There are two types of NAAQS: (1) primary standards that set limits to protect public health, including the health of sensitive populations, such as asthmatics, children, and the elderly; and (2) secondary standards that set limits to protect public welfare, including protection against damage to animals, crops, and buildings.[1] EPA has established NAAQS for: particulate matter, ozone, nitrogen oxides, sulfur dioxide, carbon monoxide, and lead. EPA is required to review the standards every five years and revise them as appropriate to protect public health and welfare. Pollutants regulated under a NAAQS are called "criteria" air pollutants.[2] The NAAQS program has been in place since the early 1970s.

Once EPA adopts or revises a NAAQS, states are required to monitor their air quality to determine whether the ambient air in any areas of the state fail to meet the NAAQS. This process identifies areas that will be designated as in attainment of the NAAQS or in nonattainment of the NAAQS. Typically, this process is completed two years after a NAAQS revision. States analyze their air monitoring data and submit to EPA their designations of parts of the state as in attainment or nonattainment of the NAAQS. EPA then reviews the state's proposal and determines the final area designations. A designation can also change when a state

[1] CAA, 42 U.S.C. sections 7408-7409.

[2] EPA has also started to refer to the NAAQS pollutants as "common" pollutants. "Criteria" refers to a detailed document that summarizes what is known about the effects of air pollutants, which is prepared before a NAAQS is established or revised.

finds that a nonattainment area attains the NAAQS and should be redesignated to attainment, or when a state finds that an attainment area does not meet a NAAQS and should be redesignated to nonattainment.

All areas of the country must comply with the NAAQS. Those areas that have monitored ambient air quality concentrations below the NAAQS are considered in compliance with the standard and are called Attainment Areas. Those areas that have monitored ambient air quality concentrations above the NAAQS are in violation of the standard and are called Nonattainment Areas. In either case, states are required to develop policies, rules and control requirements to ensure that all areas of the state meet the NAAQS. When monitoring data shows an area to be in Nonattainment, the state must develop a new State Implementation Plan (SIP) that includes emission reduction requirements needed to demonstrate that air quality would attain the NAAQS in the timelines required by the CAA. Such a nonattainment SIP would include requirements to implement stringent and potentially costly emissions controls to ensure future compliance with the NAAQS.[3]

In the event any areas within Minnesota were to be classified as Nonattainment, the MPCA would have to develop a SIP to address this situation. When developing the SIP, the MPCA would need to address at least the following issues:

- point source emissions inside of the nonattainment area,
- mobile source emissions inside of the nonattainment area,
- area and residential source emissions inside of the nonattainment area, and
- transport of air pollution across state boundaries.

The MPCA in their 2013 report to the Minnesota Legislature[4] stated:

> The majority of air pollutants of most concern today come from smaller wide-spread sources that are not regulated in the way power plants and factories are. These non-point sources include cars, trucks, construction equipment, residential wood burning, and residential garbage burning. The current regulatory structure will not help much with pollution from these sources.

This statement suggests that while further emissions reductions from larger point sources such as Sherco Units 1 and 2 are possible, the primary focus is likely to be on numerous small sources in order to achieve the needed emissions reductions to address the causes of nonattainment should it occur.

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[3] An area can be in attainment of the NAAQS for one or more pollutants, but be in nonattainment of the NAAQS for other pollutants, and, therefore, SIPs are tailored to address emissions on a pollutant-by-pollutant basis as needed to attain the NAAQS.

[4] *Air Quality in Minnesota: 2013 Report to the Legislature*, Summary, MPCA, January 2013.

The MPCA states that Minnesota has a good record in complying with NAAQS and that it is important for the health of Minnesotans and the Minnesota economy to continue meeting these standards. MPCA also points out the following challenge to maintaining NAAQS compliance:

> In 2011, nearly all areas of Minnesota were in compliance with the federal ambient air quality standards. In recent years, the EPA has strengthened or proposed to strengthen the federal ambient air quality standards .... As a result, despite overall improvements in air quality, Minnesota is at some risk for being out of compliance with federal standards for ozone and $PM_{2.5}$.[5]

A description of each NAAQS is provided below, along with a discussion of what pollution control equipment is currently in place on Sherco Units 1 and 2 to address each pollutant. As relevant to the specific NAAQS, there is also discussion of available control technologies, if any, that might be needed for Sherco Units 1 and 2 to comply with present and future NAAQS. The NAAQS are discussed in three groups: particulate matter NAAQS, ozone NAAQS and other NAAQS.

1. Coarse Particulate Matter (PM_{10}) and Fine Particulate Matter ($PM_{2.5}$)

On January 15, 2013, EPA finalized NAAQS for both coarse and fine particulate matter.[6] Fine particulate matter generally refers to particles less than or equal to 2.5 micrometers (μm) in diameter ($PM_{2.5}$). Coarse particulate matter concerns particles between 10 and 2.5 μm in diameter (PM_{10}). EPA lowered the primary (health-based) NAAQS for annual $PM_{2.5}$ from 15 to 12 $\mu g/m^3$, and retained the established 24-hour $PM_{2.5}$ standard, which was set at 35 $\mu g/m^3$ in 2006. EPA also retained the existing standards for PM_{10}.[7]

EPA established the following timeline for implementation of the new $PM_{2.5}$ NAAQS:

Action	Timeline
EPA finalizes revised particle NAAQS	2013
MPCA submits designation recommendations to EPA	2014
EPA designates areas as attainment, nonattainment or unclassifiable	2015
State Implementation Plans due to EPA	2018
Attainment Date (5-10 years after nonattainment designation)	2020-2025

5 *Id.* at 4.
6 *National Ambient Air Quality Standards for Particulate Matter; Final Rule*, 78 *Fed. Reg.* 3086 (Jan. 15, 2013).
7 EPA established the $PM_{2.5}$ NAAQS in 1997. In 2006, EPA lowered the daily $PM_{2.5}$ standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$.

In Minnesota, current monitored air concentrations are below both the 24-hour and the annual primary standard. EPA's current projection is that Minnesota will remain in attainment for the new annual standard for $PM_{2.5}$.[8] However, in 2010, two $PM_{2.5}$ monitors in St. Paul exceeded the daily standard. While fine particle levels have returned to compliant levels, the 2010 exceedances highlight the risk for future nonattainment with the fine particle NAAQS. EPA is expected to designate non-compliant locations by December 2014. We believe Minnesota will remain in attainment for $PM_{2.5}$ based on the latest revisions to the NAAQS described above.

Xcel Energy manages primary particulate matter emissions (particles directly released into the environment) from Sherco Units 1 and 2 with the particulate control devices in place on the units. Specifically, Sherco Units 1 and 2 are equipped with wet scrubbers and wet electrostatic precipitators (WESPs). We do not foresee a need to change the controls that remove particulate matter from the flue gas.

Xcel Energy manages secondary particulate matter emissions (particles created in the air by chemical reactions among other pollutants) from Sherco Units 1 and 2 with the wet scrubber systems for sulfur dioxide (SO_2) emissions and with combustion controls, low nitrogen oxides (NO_X) burners and separated overfire air (SOFA) for NO_X emissions. We believe the scrubber upgrades underway will result by 2015 in SO_2 emission levels that are consistent with recent BACT determinations for SO_2 control technology retrofits, which would be sufficient for fine particle controls as well as SO_2 control requirements of other CAA programs.

Installation of SCR on Sherco Units 1 and 2 could result in lower NO_X emissions, helping to lower secondary particulate matter formation. We do not anticipate having to install SCR for $PM_{2.5}$ purposes unless Minnesota becomes nonattainment for $PM_{2.5}$ in the future. Every five years, EPA reviews the scientific data on health effects and decides whether any revision to the particle NAAQS may be needed. It is not known what adjustments to the particle NAAQS, if any, EPA may make after its next review cycle, which will occur in the 2018-19 timeframe. If the NAAQS were to be made more stringent, and if part of Minnesota were to become nonattainment for the NAAQS, the MPCA would conduct a SIP planning process to assess Minnesota's air quality, evaluate emission reduction options, and impose appropriate emission reduction requirements. If installation of SCRs were to be found necessary to address any future nonattainment of the particle NAAQS, the compliance date would be in

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[8] EPA based its projections on 2009-2011 air quality data. For a map released by EPA when it adopted the more stringent annual standard in December 2012, *see* http://www.epa.gov/airquality/particlepollution/2012/20092011map. EPA also released a map showing its projections that all areas of the country will attain the new annual standard by 2020, except some counties in California.

the mid-2020s. It is also possible that Minnesota can avoid nonattainment for particulate matter, resulting in no requirement for additional NO_X controls.

2. *Ozone (O_3)*

Ozone (also called smog) is formed from the reaction of NO_X and volatile organic compounds (VOCs) in the presence of sunlight. As a result, ozone levels are highest in the summer months. In 2008, EPA finalized the current NAAQS for ozone, which is more stringent than the previous ozone NAAQS that was adopted in 1997.[9] The primary NAAQS for ozone consists of an eight-hour standard of 0.075 ppm. Attainment is determined by calculating the annual fourth highest daily maximum eight-hour concentration average over three years. Monitored data in Minnesota shows ozone concentrations at all monitoring sites are below the 8-hour NAAQS. EPA has designated all of Minnesota as in attainment of the 2008 ozone NAAQS.[10]

EPA is working to revise the ozone NAAQS and is expected to propose a new standard in 2013 with expectations that it will be finalized in 2014. We expect the regulatory process to address ozone nonattainment will develop on the following schedule:

Action	**Timeline**
EPA proposes new ozone NAAQS	2013
EPA finalizes new ozone NAAQS	2014
MPCA submits designation recommendations to EPA	2015
EPA designates areas as attainment, nonattainment or unclassifiable	2016
State Implementation Plans due to EPA	2018-2019
Attainment Date (5-10 years after nonattainment designation)	2021-2026

Depending upon the level of the new standard, portions of Minnesota may not be in attainment with the standard. For example, based on current monitoring data, all of Minnesota might be expected to attain an ozone standard of 0.70 ppm, but parts of Minnesota would likely not attain an ozone standard of 0.60 ppm. If part of Minnesota is designated nonattainment for ozone, MPCA would be required to develop a SIP to achieve further emissions reductions of compounds that contribute to ozone formation on the approximate timeline shown above. Such a SIP would

[9] *National Ambient Air Quality Standards for Ozone; Final Rule*, 73 *Fed. Reg.* 16436 (March 27, 2008).
[10] *Air Quality Designations for the 2008 Ozone National Ambient Air Quality Standards; Implementation of the 2008 National Ambient Air Quality Standards for Ozone: Nonattainment Area Classifications Approach, Attainment Deadlines and Revocation of the 1997 Ozone Standards for Transportation Conformity Purposes; Final Rules*, 77 *Fed. Reg.* 30088, 30129 (May 21, 2012).

consider reductions needed and possible from many different sources of ozone precursors, and might include Sherco Units 1 and 2.

If Minnesota becomes nonattainment for ozone, MPCA may well target, as part of its SIP, large point sources, like Sherco Units 1 and 2, for further emissions reductions of pollutants that contribute to ozone formation. Sherco Units 1 and 2 can further reduce NO_X emissions through the use of SCR technology. Sherco Units 1 and 2 have minimal VOC emissions and additional controls beyond good combustion practice for VOC control are unlikely. Therefore, if Minnesota does not demonstrate attainment for ozone, Sherco Units 1 and 2 might be required as part of a SIP completed in 2018-2019 to install SCRs for additional NO_X control. The SIP would establish a timeline to complete the installation and start to operate the SCRs by a date in the early to mid 2020s. It is also possible that Minnesota can avoid nonattainment for ozone, resulting in no requirement for additional NO_X controls.

3. *Other NAAQS Pollutants*

a. Nitrogen Dioxide (NO_2)

In 2010, EPA finalized a revised primary (health-based) NO_2 NAAQS. EPA retained the existing annual average NO_2 NAAQS, and set a new one-hour standard.[11] The one-hour NO_2 NAAQS has a primary (health-based) one-hour standard of 100 parts per billion (ppb). To meet this standard, the three year average of the annual 98th percentile daily maximum one-hour NO_2 concentration must not exceed 100 ppb. Currently, all Minnesota sites meet the annual and one-hour NO_2 NAAQS. EPA completed area designations in early 2012, finding no area in the country to be in nonattainment.[12] The MPCA reported that in 2011, monitors showed concentrations at levels less than half of the levels allowed by the NO_2 NAAQS.[13]

Because NO_2 concentrations near roads are usually higher than at other locations, the new NO_2 NAAQS changed the requirements for state ambient air monitoring networks. EPA recently established a phased schedule for states to amend their monitoring network plans to include near-road monitors, requiring them to be operational between 2014 and 2017. The MPCA will be required to site two near-road monitors, one operational in 2014 and one in 2015. EPA will review the roadside monitoring data after the monitors are deployed for three years. Following

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[11] *Primary National Ambient Air Quality Standards for Nitrogen Dioxide; Final Rule*, 75 *Fed. Reg.* 6474 (Feb. 9, 2010).
[12] *Air Quality Designations for the 2010 Primary Nitrogen Dioxide (NO_2) National Ambient Air Quality Standards*, 77 *Fed. Reg.* 9532, 9563 (Feb. 17, 2012).
[13] *Air Quality in Minnesota: 2013 Report to the Legislature*, at 4, MPCA, January 2013. Nitrogen oxide emissions from point sources declined 49% between 2000 and 2010. *Id.* at 3.

this review, EPA will re-evaluate its designations to determine if any areas do not attain the NO_2 NAAQS.

While current monitoring shows concentrations in Minnesota at 46 percent of the new NAAQS,[14] we anticipate that the near roadside monitors will show higher levels of NO_2 than previously monitored due to mobile source emissions. These higher NO_2 levels may lead to nonattainment with the NO_2 NAAQS. The regulatory process to address NO_2 nonattainment will develop approximately on the following schedule:

Action	Timeline
New NO_2 roadway monitoring begins	2014-2017
EPA issues Nonattainment Redesignations	2017-2018
State Implementation Plans due to EPA	2020
Attainment Date (5-10 years after date of nonattainment)	2022-2027

If Minnesota cannot attain the NO_2 standard, MPCA would have to develop a SIP to address the nonattainment. It is not clear what strategy MPCA would take in this situation, since roadway monitors would record emissions mostly from mobile sources. MPCA's 2013 report[15] shows a 49 percent reduction in point source NO_2 emissions from 2000 to 2010, indicating that point sources, including sources like Sherco Units 1 and 2, are not the primary contributors to any elevated concentrations at a near-road monitoring site. We believe that MPCA would be much more likely to target mobile sources for reductions before they target large point sources, like Sherco Units 1 and 2, for further NO_2 emissions reductions if nonattainment is based on results from a near-road monitor. As such, we do not view the NO_2 NAAQS as likely to result in a requirement for installation of SCRs on Sherco Units 1 and 2.

b. Sulfur Dioxide (SO_2)

EPA revised the primary SO_2 NAAQS in 2010.[16] The primary NAAQS for SO_2 is a one-hour standard with a value of 75 ppb. The primary standard is met if the 99th percentile value of one-hour daily maximum concentrations, averaged over a three-year period, is less than 75 ppb. SO_2 also has a secondary NAAQS, which is a three-hour standard with a value of 0.5 ppm. This standard is not to be exceeded more than once per year. Minnesota is currently in attainment with both of the SO_2

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[14] *Id.* at 4.
[15] *Id.* at 3.
[16] *Primary National Ambient Air Quality Standard for Sulfur Dioxide; Final Rule*, 75 *Fed. Reg.* 35520 (June 22, 2010).

NAAQS, with levels at 32% of the standard,[17] and we do not foresee that status changing in the near future. EPA proposed its designations for areas not attaining the SO_2 NAAQS in February 2013, and did not include any areas in Minnesota.[18]

Xcel Energy manages SO_2 emissions from Sherco Units 1 and 2 by using a wet scrubber system to remove SO_2 from the flue gas. Sherco Units 1 and 2 are Best Available Retrofit Technology (BART)-eligible units under the Regional Haze program (see section C). To satisfy our BART obligations, we entered into an Administrative Order to implement additional SO_2 control measures. We are proceeding with the addition of sparger modules to our existing wet scrubbers to further reduce SO_2 emissions from these units, and will complete this work by 2015. We believe these control changes will prove to have emissions equivalent to levels consistent with recent BACT determinations for SO_2 control technology retrofits.

c. Carbon Monoxide (CO)

EPA completed its review of the primary CO NAAQS and published its final determination to maintain the existing standards in 2011.[19] The primary NAAQS for CO has two parts: a one-hour standard and an eight-hour standard. The one-hour standard is 35 parts per million (ppm) while the eight-hour standard is 9 ppm. These standards are not to be exceeded more than once per year. Minnesota is currently in attainment with both of the CO NAAQS, meaning ambient air quality measurements are below the NAAQS. We do not foresee that status changing in the near future.[20]

The Company manages CO emissions from Sherco Units 1 and 2 by maintaining good combustion to minimize formation of CO. Specific pollution control equipment to manage CO emissions is unnecessary. The CO-specific controls available on the market today consist mainly of oxidation catalysts. We do not foresee a time where we would need to add specific CO controls to these units.

d. Lead

In 2008, EPA finalized a new NAAQS for lead that made the standard substantially more stringent.[21] The primary NAAQS for lead consists of a rolling, three-month

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[17] *Air Quality in Minnesota: 2013 Report to the Legislature*, at 4, MPCA, January 2013. Sulfur dioxide emissions from point sources declined 44% between 2000 and 2010. *Id.* at 3.

[18] *EPA Responses to State and Tribal 2010 Sulfur Dioxide Designation Recommendations: Notice of Availability and Public Comment Period*, 78 *Fed. Reg.* 11124 (Feb. 15, 2013).

[19] *Review of National Ambient Air Quality Standards for Carbon Monoxide*, 76 *Fed. Reg.* 54294 (Aug. 31, 2011).

[20] EPA decided that the CO NAAQS, which has remained at the same level since 1971, did not require revision.

[21] *National Ambient Air Quality Standards for Lead; Final Rule*, 73 *Fed. Reg.* 66964 (Nov. 12, 2008).

average which cannot exceed 0.15 micrograms per cubic meter ($\mu g/m^3$). With the exception of a monitoring site located near Gopher Resource Corporation in Eagan, MN, existing lead monitoring sites within Minnesota meet the lead NAAQS of 0.15 $\mu g/m^3$.[22] Between 2000 and 2010, point source lead emissions dropped by 71 percent in Minnesota. [23]

Xcel Energy manages lead emissions from Sherco Units 1 and 2 with the particulate control devices in place on the units. Specifically, Sherco Units 1 and 2 are equipped with wet scrubbers and WESPs. We do not foresee a time where we would need to change the particulate controls that remove lead from the flue gas. We also do not foresee any increases in lead emissions if emissions control technology is added to address any other pollutants (*i.e.*, SCR for control of NO_X).

4. *Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of NAAQS Implementation*

Sherco Units 1 and 2, with their upgraded particle controls and the scrubber upgrades that will be completed by 2015, are expected to have emission performance for particulate matter and SO_2 consistent with recent BACT determinations for control technology retrofits. The combustion controls, low NO_X burners, and overfire air controls put on the units several years ago have substantially reduced NO_X emissions. As a result, the only additional control equipment that could reasonably be anticipated to be required for the units is the addition of SCRs, which would reduce NO_X emissions further.

The revisions to all six NAAQS discussed above were finalized between 2008 and 2012 to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed on Sherco Units 1 and 2. The next timeframe where NO_X emission reductions might be required due to NAAQS nonattainment would be if Minnesota has areas that do not meet the ozone NAAQS as it may be revised in 2014, or goes into nonattainment for particulate matter at some point. According to the NAAQS implementation schedules shown above, further NO_X reductions might be required to be achieved in the early to mid 2020s, but only if Minnesota enters nonattainment.

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[22] As cited on page 28 of MPCA's "Annual Air Monitoring Network Plan for Minnesota – 2013"
[23] *Air Quality in Minnesota: 2013 Report to the Legislature*, at 3, MPCA, January 2013.

B. Clean Air Act Programs that Address Interstate Transport of Air Pollution

The prior section discussed recent and upcoming revisions to the NAAQS and their potential to result in nonattainment designations in Minnesota. If Minnesota were to fail to attain a NAAQS, the state would be required to develop a SIP that would include emission reduction requirements needed to demonstrate that air quality would attain the NAAQS in the timelines required by the CAA.

In addition, the CAA also provides that SIPs include provisions that prevent sources within the state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[24] EPA has been working to develop programs for the Eastern U.S. that would reduce interstate transport of pollutants that are precursors to two NAAQS pollutants: ozone and fine particles. NO_X is a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation. For the utility industry, the relevant programs are called the Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR).

Both CAIR and CSAPR were designed to be "cap and trade" programs that reduce overall emissions from Electric Generating Units (EGUs). This means that total emissions from EGUs in a state or region are limited (the cap), and that each ton of allowed emissions is represented by an emission allowance that can be transferred (the trade). A cap and trade program thus reduces total emissions to the capped amount, but allows EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on EPA's analysis of an upwind state's emissions impact on nonattainment areas in downwind states, CAIR and CSAPR imposed one or both of the following emission limitations: (1) summer season NO_X, emissions (to address ozone), and/or (2) annual NO_X and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of downwind concern has been fine particle nonattainment areas in downwind states, not ozone.

[24] CAA, 42 U.S.C. section 7410(a)(2)(D)(i)(I).

1. *Regulatory and Litigation History of CAIR*

The CAIR was adopted in 2005, and initially applied to Minnesota for fine particle precursors, requiring reductions in annual NO_X and SO_2 emissions in two stages, 2009 and 2015. The U.S. District Court for the District of Columbia Circuit (D.C. Circuit), however, issued an opinion in 2008 that found the CAIR to contradict the CAA in multiple respects. As a result, the D.C. Circuit reversed and vacated the CAIR.[25] The court later decided to allow the CAIR to be implemented pending EPA's adoption of a replacement program.[26] The CSAPR, described below, was EPA's attempt to adopt a new program to replace the CAIR.

The court's decision, however, found specific errors may have affected EPA's analysis of Minnesota's modeled impact on nonattainment areas in downwind states, and required EPA to respond to this concern. In 2009, EPA adopted a rule that administratively stayed the effectiveness of CAIR in Minnesota, pending further rulemaking in response to the court's remand of the overall CAIR rule.[27] As a result, CAIR is not effective in Minnesota.

2. *Regulatory and Litigation History of CSAPR*

EPA adopted CSAPR in 2011 as the program intended to replace CAIR. The CSAPR, similar to CAIR, would have applied to Minnesota for fine particle precursors, requiring reductions in annual NO_X and SO_2 emissions starting in 2012. On December 30, 2011, however, the D.C. Circuit stayed the effectiveness of CSAPR and instructed the EPA to continue administering CAIR pending the court's resolution of the appeals filed against the CSAPR.[28] On August 21, 2012, the D.C. Circuit issued an opinion finding the CSAPR to contradict the CAA, vacated it, and again instructed the EPA to continue administering the CAIR pending adoption of a valid replacement.[29] In January 2013, the D.C. Circuit denied all requests for rehearing.[30] On June 24, 2013, the U.S. Supreme Court decided to review the case. It

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[25] *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).
[26] *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) (on rehearing).
[27] *Administrative Stay of Clean Air Interstate Rule for Minnesota; Administrative Stay of Federal Implementation Plan to Reduce Interstate Transport of Fine Particulate Matter and Ozone for Minnesota*, 74 *Fed. Reg.* 56712 (Nov. 3, 2009).
[28] Order, Case No. 11-1302 (D.C. Cir. Dec. 30, 2011).
[29] *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7 (D.C. Cir. 2012). NSP-Minnesota appealed the CSAPR, seeking the allocation of additional emission allowances for NSP-Minnesota. NSP-Minnesota contended that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. NSP-Minnesota also requested that EPA reconsider and amend the CSAPR to address this issue. Because of the court's overall ruling on CSAPR, these issues have not been addressed.
[30] Orders, Case No. 11-1302 (D.C. Cir. Jan. 24, 2013).

is likely that the Court will decide the case by June 2014. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. If the Court reverses the D.C. Circuit's decision, the case will likely be remanded to the D.C. Circuit to consider issues that were raised in the litigation but not decided because the issues on which the D.C. Circuit ruled resolved the case. Therefore, it is not known what requirements may be imposed in the future.

3. Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of Interstate Transport Programs

Had the CSAPR requirements been applied to Minnesota, Xcel Energy could have met the overall emission limitations imposed on its Minnesota system and would not have needed to install any further controls on Sherco Units 1 and 2. As described above, the installation of combustion controls have resulted in substantial NO_X emission reductions and the scrubber upgrades in progress will achieve substantial SO_2 emission reductions.

If EPA continues to pursue a cap and trade program model, no particular technology is required at any particular time. If EPA shifts, however, to having states develop their own SIPs, then MPCA would evaluate and impose reduction requirements in a future state proceeding. A cap would likely be ratcheted down over time as EPA tightens NAAQS in future NAAQS reviews, but would only apply to Minnesota if Minnesota significantly contributes to downwind nonattainment areas. For SO_2, no additional controls would be required because the scrubber upgrades are expected to result in emission levels consistent with recent BACT determinations for control technology retrofits. For NO_X, installation of SCR on one or both units might be needed, but only if cost-effective compared to: (1) purchasing allowances, or (2) other changes to NSPM's system operations to meet an overall annual emission cap.

The time when additional requirements under the interstate transport program may be imposed is particularly hard to assess. If the Court reverses the D.C. Circuit's decision, the case will likely be remanded to the D.C. Circuit to consider issues raised in the litigation that were not decided because the issues the D.C. Circuit ruled on resolved the case. In this scenario, the litigation would likely continue into 2015. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. It seems likely, however, that development and implementation of a new program could take several years.

C. Clean Air Act Programs that Address Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees, thus impairing visibility. In 1977, the CAA established a national goal of remedying any existing and preventing any future visibility impairment from man-made air pollution in specified "Class I" areas of the United States.[31] "Class I" areas are national parks and wilderness areas, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota.

EPA has taken a two-phased approach to implement this program. The first phase was implemented in the 1980s to address visibility impairment "reasonably attributable" to a specific source. This is called "reasonably attributable visibility impairment" or "RAVI." EPA adopted regulations for this program designed to address "plume blight," which is "smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or a small group of sources."[32] After detailed study, EPA made a finding in 1988 that there was no RAVI impairment in Voyageurs National Park.[33]

The second phase was designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 1999, EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment.[34] State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no man-made visibility impairment in Class I areas by 2064. State RHR SIPs focus on emissions of SO_2, NO_X and particulate matter. State SIPs will be revised approximately every ten years to continue to take incremental steps that achieve reasonable further progress toward reaching the 2064 national goal.

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31 CAA, 42 U.S.C. section 7491(a)(1).

32 *Visibility Protection for Federal Class I Areas*, 45 *Fed. Reg.* 80,084-85 (Dec. 2, 1980).

33 *Assessment of Visibility Impairments and Integral Vista Identification*, 53 *Fed. Reg.* 35956, 35958 (Sept. 15, 1988).

34 40 C.F.R. Sections 51.300 to 51.309 & App. Y. *See Regional Haze Regulations*; Final Rule, 64 *Fed. Reg.* 35714 (July 1, 1999). In 2005, EPA revised its guidelines for control technology determinations under the RHR. This revision followed a court case in which the court concluded, in part, that EPA's prior guidelines did not sufficiently recognize the statutory primacy the CAA gives the states in making control technology retrofit determinations for existing sources. *See American Corn Growers Ass'n v. EPA*, 291 F.3d 1, 6 (D.C. Cir. 2002).

1. *Implementation of the Regional Haze Program in Minnesota*

The MPCA began developing the Minnesota Regional Haze SIP after EPA issued its final BART Guidelines in 2005. In this initial round of Regional Haze SIP development, MPCA was required to identify sources subject to BART requirements and determine what constitutes BART for each source, in addition to the general RHR SIP requirements described above. BART applies to major emission sources in the state that were placed into operation between 1962 and 1977, if they are also found to reasonably contribute to visibility impairment in one or more Class I areas. A "BART Determination" is a case-by-case analysis that "take[s] into consideration the costs of compliance, the energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[35] The MPCA identified multiple units in the utility and taconite industries as "subject to BART." For Xcel Energy, the units found subject to BART were Sherco Units 1 and 2.

The MPCA initially determined that the emission restrictions under CAIR would be BART for EGUs. EPA allowed states to decide that the emission reductions to be achieved from EGUs through CAIR would be "better than BART" under the RHR, removing the need for a source-specific control technology determination. After the D.C. Circuit reversed CAIR in 2008 and EPA stayed the effect of CAIR in Minnesota in 2009, the MPCA made source-specific BART determinations for EGUs.

In December 2009, the MPCA approved the Regional Haze SIP for Minnesota, which included selection of the BART controls for Sherco Units 1 and 2. The MPCA concluded that SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs.[36] The MPCA's BART controls for Sherco Units 1 and 2 consist of combustion controls to reduce NO_X and scrubber upgrades to reduce SO_2. The combustion controls were installed on Sherco Units 1 and 2, and the scrubber upgrades are underway and scheduled to be installed by 2015. MPCA submitted this Regional Haze SIP to EPA for review and approval.

Following its adoption of CSAPR in 2011, EPA determined that the requirements of the CSAPR satisfy the requirements for an approvable "BART Alternative" under the RHR. This rule, as with the rule approving CAIR as BART before it, allows states

[35] CAA, 42 U.S.C. section 7491(g)(2).
[36] *Regional Haze State Implementation Plan*, at 899-906, MPCA (Dec. 2009).

subject to CSAPR to utilize compliance with CSAPR in lieu of source-specific BART emission limits for EGUs.[37]

In April 2012, the MPCA approved a supplement to its 2009 Regional Haze SIP, finding that the CSAPR meets BART for EGUs in Minnesota. The supplement also included an Administrative Order that established source-specific BART emission limits for Sherco Units 1 and 2 that reflected the MPCA's 2009 determination.[38] In June 2012, the EPA issued its final approval of the Minnesota SIP for EGUs.[39] This included approval of the source-specific emission limits for Sherco Units 1 and 2 as strengthening the SIP, but EPA avoided characterizing them as BART limits.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eight Circuit.[40] The court denied intervention in the case to NSP-Minnesota and other regulated parties who petitioned to intervene. It is not yet known how the U.S. Supreme Court's review of the CSAPR may impact the EPA's approval of the Minnesota SIP or the course of this litigation.[41]

Whatever the course of the litigation, MPCA is due to make its five-year progress report on implementation of the Regional Haze SIP in 2014. The MPCA will also be required to revise its SIP by 2018 to consider additional emission reductions that may be necessary to maintain reasonable further progress toward achievement of the national visibility goal by 2064. In this SIP revision, MPCA would be anticipated to consider whether additional control technology should be required for Sherco Units 1 and 2, as well as on multiple other sources of emissions in Minnesota.

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[37] *Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans*, 77 *Fed. Reg.* 33642 (June 7, 2012). EPA's conclusion was based on its findings that the CSAPR would result in greater overall reductions from locations not substantially different than would occur under source-specific BART. In addition, EPA's analysis indicated that visibility would not decline in any areas, and that greater overall improvements in visibility would be achieved. As a result, EPA found that CSAPR meets the requirements for a BART Alternative program under the RHR.

[38] *Regional Haze State Implementation Plan Supplement*, at 2-3 & App. 2, Administrative Order by Consent, Xcel Energy Sherburne County Generating Station, MPCA (April 2012).

[39] *Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze*, 77 *Fed. Reg.* 34801 (June 12, 2012).

[40] *National Parks Conservation Association (NPCA) et al v. US EPA*, Case Nos. 12-2910 and 12-3481 (8th Cir.).

[41] On June 25, 2013, the EPA filed an unopposed motion with the 8th Circuit to hold the Minnesota Regional Haze SIP litigation in abeyance until the Supreme Court decides the CSAPR case.

2. Implementation of the RAVI Program in Minnesota

The RAVI program was adopted in the 1980s as the first phase of EPA's visibility program, and was intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a Class I area. In 1985, EPA began adopting federal implementation plans (FIPs) for those states that had failed to submit SIPs to implement RAVI. EPA adopted a FIP for Minnesota that included general visibility requirements and long-term strategies, and determined that it was not necessary to revise the FIP for Minnesota to include BART requirements.[42] As part of its administration of the FIP, EPA contemplated that it would develop, review, and revise long-term strategies for Minnesota, starting in late 1987. After detailed study, EPA made a finding in 1988 that there was no RAVI impairment in Voyageurs National Park.[43]

In October 2009, the Department of the Interior certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA has said that it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.[44] It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy, and Sierra Club.[45] The lawsuit alleges that the EPA has failed to perform a nondiscretionary duty to determine BART for the Sherco Units 1 and 2 under the RAVI program. In initial filings in the case, EPA disputes the plaintiffs' claim. NSP-Minnesota sought leave to intervene in this case, but the Magistrate Judge denied

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[42] *State Implementation Plans for Visibility New Source Review and Monitoring Strategy*, 50 *Fed. Reg.* 28544, 28547 (July 12, 1985) (adopting visibility monitoring requirements for Minnesota); *State Implementation Plans for Visibility Long-Term Strategies, Integral Vistas, and Control Strategies*, 52 *Fed. Reg.* 45132, 45133-34 (Nov. 24, 1987) (adopting visibility long term strategy requirements for Minnesota and deferring decision on control strategies).
[43] *Assessment of Visibility Impairments and Integral Vista Identification*, 53 *Fed. Reg.* 35956, 35958 (Sept. 15, 1988) (after a detailed monitoring study, determining that BART and other control strategies did not need to be adopted in Minnesota).
[44] *Approval and Promulgation of Air Quality Implementation Plans; Minnesota; Regional Haze*, 77 *Fed. Reg.* 34801, 34806 (June 12, 2012).
[45] *NPCA v. US EPA*, Civil Case No. 12-3043 (D. Minn.).

intervention. NSP-Minnesota is now seeking review of that decision with the federal District Court Judge who is assigned to the case.

Xcel Energy vigorously disputes the contention that emissions from Sherco Units 1 and 2 are having a direct RAVI-type impact on the national parks. Sherco Units 1 and 2 were among numerous units found subject to BART under the regional haze program, which is meant to reduce haze that results from the combined emissions of a large number of sources over a broad regional geographic area. RAVI-type impacts are distinct from regional haze. Complex tracer studies and visibility impairment event back trajectory analyses are necessary to determine if any individual source in Minnesota, including multiple sources far closer to the national parks, might have this uncommon impact.

This section need not discuss multiple issues concerning the plaintiffs' contentions that will be disputed in any litigation or proceeding concerning the RAVI program. For purposes of developing scenarios for analysis, we describe below the timing of potential emission reduction requirements based on different potential outcomes of this dispute.

3. Assessment of Timing of Potential Future Emission Reduction Requirements as a Result of Visibility Programs

The visibility programs focus on reducing emissions of PM, SO_2 and NO_X as pollutants that can result in visibility impairment. Based on the current level of controls for PM and the upgraded controls for SO_2 at Sherco Units 1 and 2, it is not expected that any further reductions would be required due to implementation of visibility programs. For NO_X, SCR on one or both units might be required at some point to obtain some further emission reductions.

If the litigation on Regional Haze results in new revisions to the SIP, the currently selected controls for Sherco Units 1 and 2 might continue to be required, or the BART determination might be revised to include SCRs on one or both units. If the litigation on RAVI results in a new BART determination process for Sherco Units 1 and 2, the currently selected controls for Sherco Units 1 and 2 might continue to be required, or the BART determination might be revised to include SCRs on one or both units.

The time when additional controls may be required for Sherco Units 1 and 2 is particularly hard to assess. If the Court reverses the D.C. Circuit's decision on CSAPR, the case will likely be remanded to the D.C. Circuit to consider issues raised in the litigation that were not decided because the issues the D.C. Circuit ruled on resolved the case. In this scenario, the litigation would likely continue into 2015. If the Court affirms the D.C. Circuit's decision, it is not yet known how the EPA might approach a replacement rule. It seems likely, however, that development and implementation of a new program could take several years. It is also not known how the EPA might then approach a follow up strategy related to its decisions on regional haze. If CSAPR remains vacated, then the range of time within which SCRs might be required would be about 2018-20 at the earliest. The next interval where SCRs might be required would be about 2023-25.

The earliest time estimate might pertain if EPA: (1) commenced a RAVI proceeding in 2013-14, and determined a new BART for Sherco Units 1 and 2 without performing the required studies to first determine whether the units have a RAVI-type impact, or (2) evaluated the Minnesota Regional Haze SIP in 2014 following a Supreme Court decision that leaves CSAPR overruled, disapproved the MPCA's BART determination, and required SCRs. Sources are generally given up to five years to complete installation of controls after they are required, so if one or both units require SCRs, they would need to be installed and operating by 2018-19 at the earliest.

If SCRs were required as part of the 2018 revisions to the Minnesota Regional Haze SIP, the timeframe for installation and operation would be 2023-25, since the five-year timeline starts when EPA approves the SIP, which usually takes at least two years after the state submits a SIP. Further controls on emission units in the state would be considered as part of each succeeding revision to MPCA's Regional Haze SIP.

D. Electric Utility Hazardous Air Pollutant Regulations

In 2012, the EPA adopted its final rule establishing national emissions standards for hazardous air pollutants (NESHAP) and new source performance standards (NSPS) for coal- and oil-fired power plants. This rule was issued under the CAA and is most often referred to as the Mercury and Air Toxics Standards (MATS). Coal-fired power plants, including Sherco Units 1 and 2, must demonstrate compliance with the rule by April 16, 2015.

Under MATS coal-fired power plants need to meet numerical emission limits for a number of toxic air pollutants, including mercury, non-mercury metals, and acid gases. Plants will need to utilize a variety of control technologies, work practices, and compliance strategies to meet the emission limits.

Sherco Units 1 and 2 are presently equipped with wet scrubbers and WESPs for control of PM, SO_2 and acid gases. We are proceeding with power supply projects to the WESPs in order to improve their performance in terms of additional PM removal efficiency. In addition to these controls, Xcel Energy is in the process of adding sparger modules to the existing wet scrubbers to improve control of SO_2 and acid gases. Finally, the Company intends to install and operate mercury control technology by the end of 2014 to comply with Minnesota mercury reduction requirements (see section E). Once implemented, all of these technologies operating together will reduce emissions of the compounds regulated under MATS to levels well below the numerical limits. Xcel Energy arrived at this suite of pollution control technologies through years of evaluation of technologies to determine which can cost-effectively remove these materials.

E. Minnesota Mercury Emission Reduction Act of 2006

In 2006, the State of Minnesota passed legislation known as the Minnesota Mercury Emission Reduction Act of 2006 (the Act).[46] The Act provides a process for plans, implementation, and cost recovery for utility efforts to curb mercury emissions at certain power plants, including Sherco Units 1 and 2. In December 2009, NSP-Minnesota filed its mercury control plan for Sherco Units 1 and 2 with the MPUC and the MPCA. In October 2010, the MPUC approved the plan, which will require installation of mercury controls on Sherco Units 1 and 2 by the end of 2014. We have proposed to install sorbent injection systems on Sherco Units 1 and 2 to satisfy the Act. The MPCA and the Commission have approved this installation as satisfying the Act and installation is planned for completion prior to December 31, 2014, unless a superior solution is identified that can be implemented by that date.

II. ASH REGULATIONS – COAL COMBUSTION RESIDUALS (CCR)

EPA has been studying coal ash and other wastes associated with the combustion of fossil fuels for over two decades. In 1993 and again in 2000, EPA issued regulatory determinations that large volume wastes including coal ash did not warrant regulation as hazardous wastes. EPA subsequently began considering the need to regulate these materials under a federal program as a non-hazardous industrial waste. EPA accelerated its efforts in this area in late 2008 after the failure of a coal ash impoundment in Tennessee. After that event, EPA also embarked on a nation-wide program to assess the structural integrity of all coal ash impoundments in the country.

On June 21, 2010, EPA published a proposed federal rule for Coal Combustion Residuals (coal ash) for public review and comment.[47] EPA took the unusual step of

[46] Minn. Stat. sections 216B.68-216B.688.
[47] *Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule*, 75 *Fed. Reg.* 35128 (June 21, 2010).

co-proposing three alternative regulatory frameworks in order to solicit comments on all of them at once. The alternatives ranged from regulating coal ash as a listed hazardous waste to managing it in manner equivalent to the way ash is regulated by MPCA in Minnesota today. EPA reportedly received more that 450,000 comments on these proposals and is still evaluating them. On April 5, 2012, a coalition of environmental groups filed a RCRA citizen suit against EPA seeking a court-ordered deadline for a final rule. Other parties joined this litigation as plaintiffs and interveners, but the matter has not yet been decided by the court. In recent legal filings responding to the lawsuit, EPA said they need at least an additional year to complete their review and consideration of all comments before finalizing the rule. We do not anticipate a final rule until the fall of 2014 at the earliest.

In 2012 and again in 2013, bi-partisan legislation was introduced in Congress to address the issue of coal ash management within the framework of a non-hazardous State and Federal regulatory program. The 2013 legislation was recently passed out of the House Energy and Commerce Committee, and a floor vote of the full House could occur this summer. The Senate has not yet taken up similar legislation.

EPA's recent Effluent Limitations Guidelines rule proposal (discussed in the next section) has some overlap with EPA's CCR proposals. EPA is currently soliciting comments on how the coal combustion rules can be aligned to account for any final requirements adopted under the ELG rule.

The long-range impact on Sherco Units 1 and 2 of an eventual federal rule regarding the management and disposal of coal ash is difficult to determine, given the many variables involved. The fly ash and bottom ash disposal ponds at Sherco are well designed and constructed, and already substantially comply with the most likely technical requirements of a prospective federal rule, such as liners and groundwater monitoring systems. In 2010, EPA conducted an inspection of the Sherco ponds and gave them the highest possible rating for safety and structural integrity. Our current view is that the CCR rule, when eventually issued, is not likely to significantly affect Sherco Units 1 and 2 operations in the foreseeable future.

III. WATER REGULATIONS

EPA is currently working on new regulations that will affect power plant water appropriations and discharges, but it is unclear what those regulations may eventually require when finalized in the future. Sherco 1 and 2 are currently equipped with advanced technologies, such as special intake screens to protect fish and small aquatic organisms, closed-cycle cooling towers to minimize water withdrawals and thermal discharges, and closed-loop process water recycling systems to eliminate the need for discharges from ash management and storm water ponds. We believe these systems are likely to meet, or can be adapted to meet, any reasonably foreseeable science and technology based rules. The two most significant rulemaking activities are discussed in the following subsections.

A. Effluent Guidelines

EPA's Effluent Limitation Guidelines (ELGs) are national standards regarding the performance of treatment and control technologies for wastewater discharges to surface waters. The ELGs are issued to specific industry categories, one of which is steam-electric generating plants such as Sherco Units 1 and 2. EPA began the process of updating the rules for steam-electric generating plants in 2009. On June 7, 2013, EPA published a rule proposing new and updated ELGs for steam electric power plants, including the regulation of both wastewater and surface impoundments containing coal combustion residuals.[48] In recognition of the fact that the proposed ELG rule changes involve areas of overlap with the proposed CCR rules, EPA is currently soliciting comment on both.

It has been over 25 years since the ELG guidelines were last updated and there have been advancements in detection, treatment, and control technologies that suggest future reductions in allowable discharge levels are likely. A 2011 EPA Information Collection Request focused heavily on gathering operational information concerning metal cleaning wastes and surface water discharges from wet ash handling systems, and preliminary review of the recently proposed ELG rule signals that EPA intends to tighten requirements in these areas. However, neither of these issues should be of major impact to Sherco 1 and 2 since all process waste water, including ash transport and contact water, are recycled for use in the sulfur dioxide scrubbers and other in-plant systems. The only direct discharge to surface waters from the units is blow-down from the cooling towers, which meets all current discharge requirements and could be treated further if necessary.

We are still reviewing the proposed ELG rule to determine the long-range impact of the ELG rule on Sherco Units 1 and 2. Based on our preliminary review, we believe EPA is likely to receive many substantive legal and technical comments on the proposed rule, suggesting any final rule could be significantly different. In addition, EPA's recent experience with complex rulemaking efforts like this suggest the strong potential for litigation and change after the final rule is issued. Our current view of the ELG rulemaking is that, while it is possible that Sherco Units 1 and 2 may

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[48] *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Proposed Rule*, 78 *Fed. Reg.* 34432 (June 7, 2013).

eventually need to make some changes in the way process waste water is managed, it is very unlikely the final rule would significantly impact our ability to continue to operate the two units for the foreseeable future.

B. National Pollutant Discharge Elimination System (NPDES)

EPA continues to develop national regulations governing the design, maintenance, and operation of cooling water intake structures pursuant to Section 316(b) of the Clean Water Act. The intent of 316(b) is to ensure that industrial cooling water intakes are designed and operated to prevent adverse impact to aquatic organisms. EPA began work to update these rules over a decade ago, with the intention of issuing rules for different categories of regulated facilities in phases. In 2004, EPA issued a final "Phase II" rule for large electric generating facilities such as Sherco Units 1 and 2, but that rule was challenged and later remanded back to EPA by the court. EPA is now rewriting the rule in an effort to correct the issues that led to the remand. EPA is doing this work under a Court-ordered deadline and in April 2011 proposed a revised 316(b) Phase II rule which again attracted extensive public comment.[49] EPA then issued two Notices of Data Availability in June of 2012 to allow for public review and comment on new information that had been developed. EPA also requested and received an extension of time from the court and is now scheduled to issue a final rule by June 27, 2013.

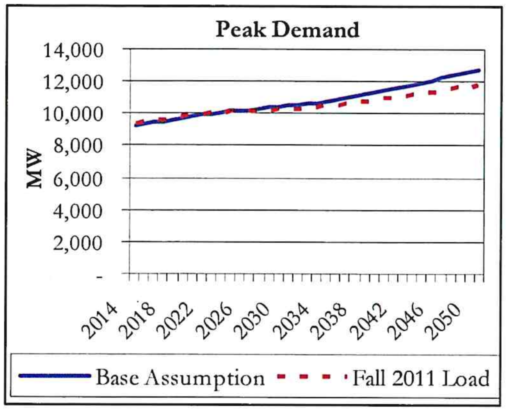
The common cooling water intake that supplies Sherco Units 1 and 2 is already equipped with advance screening technology to protect aquatic organisms, and both units are equipped with full capacity cooling towers that allow for closed-cycle cooling operations. The term "closed-cycle" refers to repeated recycling and reuse of the cooling water within the plant system, with only modest withdrawals of fresh water to maintain process water quality and to make up for evaporative losses. With the existing advanced intake screening and closed cycle design, Sherco Units 1 and 2 are likely to substantially meet the requirements of a future 316(b) rule. Our current view is that it is very unlikely the final 316(b) rule will significantly impact our ability to operate the two units for the foreseeable future.

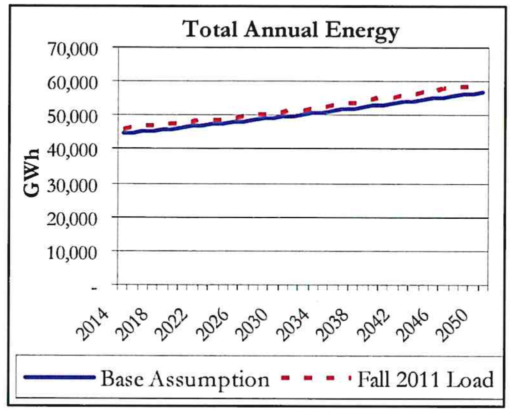
[49] *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities; Proposed Rule*, 76 *Fed. Reg.* 22173 (April 20, 2011).

Appendix B
Description of Strategist Sensitivities

<u>Sensitivity A – Fall 2011 Load Forecast</u>

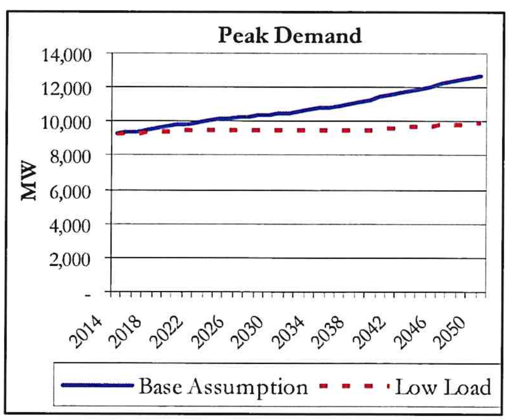
This forecast replaces the Spring 2013 forecast with the load forecast used in our last Resource Plan. This forecast has lower levels of peak demand and higher total energy sales.

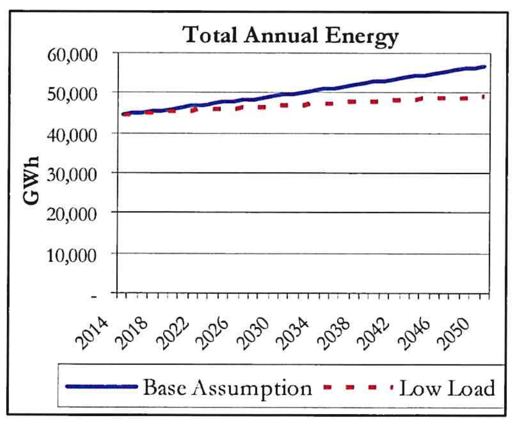




<u>Sensitivity B – Low Load</u>

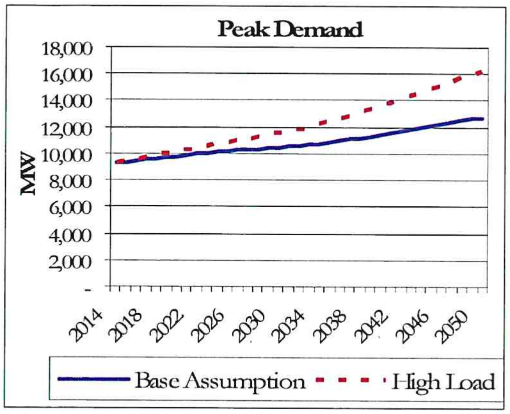
For this sensitivity the growth rates for peak demand and annual sales were decreased by 50%. Under base assumptions, peak demand grows at an average rate of 0.87% and total annual energy at a rate of 0.65%. Under the low load sensitivity, the growth rates for peak demand and annual energy are 0.19% and 0.26% respectively.

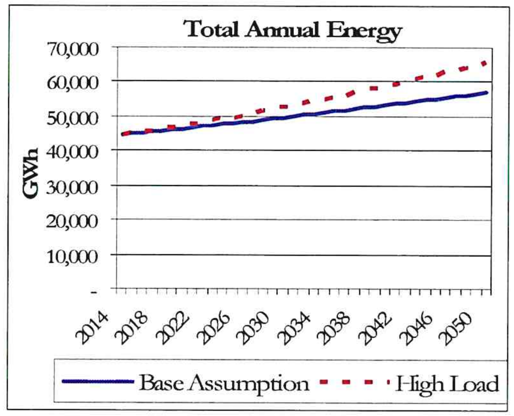




Sensitivity C – High Load

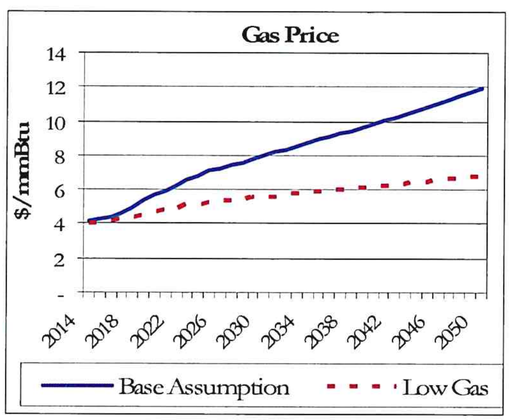
For this sensitivity the growth rates for peak demand and annual sales were increased by 50%. Under base assumptions peak demand grows at an average rate of 0.87% and total annual energy at a rate of 0.65%. Under the high load sensitivity, the growth rates for peak demand and annual energy are 1.54% and 1.04% respectively.





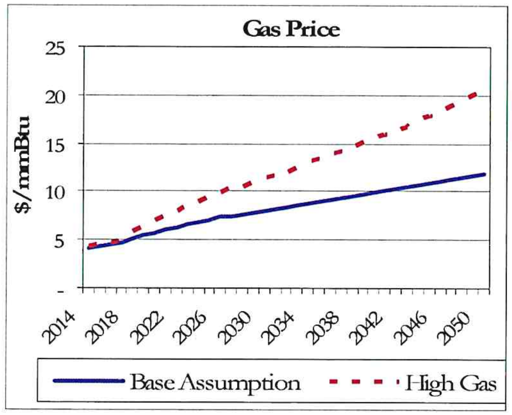
Sensitivity D – Low Gas Prices

For this sensitivity the growth rate for gas prices was decreased by 50%. Under base assumptions, gas prices grow at an average rate of 3.1%. Under the low gas prices sensitivity, the growth rate for gas prices is 1.5%.



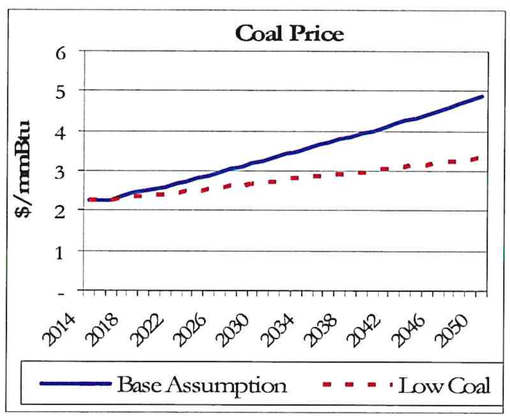
Sensitivity E – High Gas Prices

For this sensitivity the growth rate for gas prices was increased by 50%. Under base assumptions, gas prices grow at an average rate of 3.1%. Under the high gas prices sensitivity, the growth rate for gas prices is 4.6%.



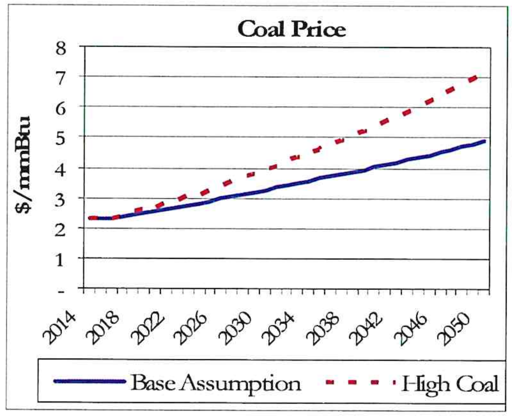
Sensitivity F – Low Coal Prices

For this sensitivity the growth rate for coal prices was decreased by 50%. Under base assumptions, coal prices grow at an average rate of 2.1%. Under the low coal prices sensitivity, the growth rate for coal prices is 1.1%.



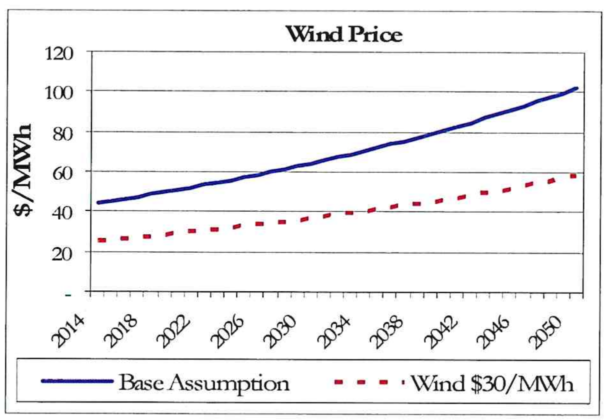
Sensitivity G – High Coal Prices

For this sensitivity the growth rate for coal prices was increased by 50%. Under base assumptions, coal prices grow at an average rate of 2.1%. Under the high coal prices sensitivity, the growth rate for coal prices is 3.2%.



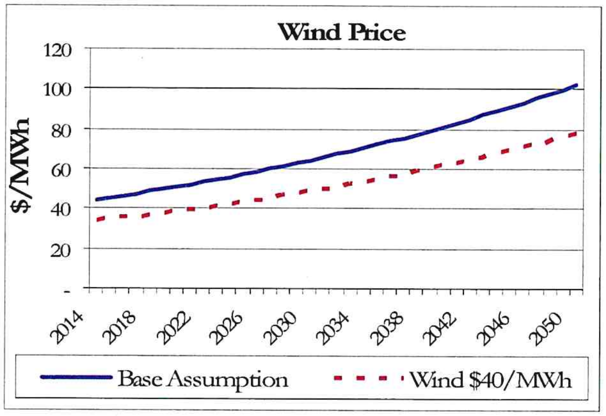
Sensitivity H – Wind $30/MWh Sensitivity

For this sensitivity the levelized price for future wind was decreased to $30/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



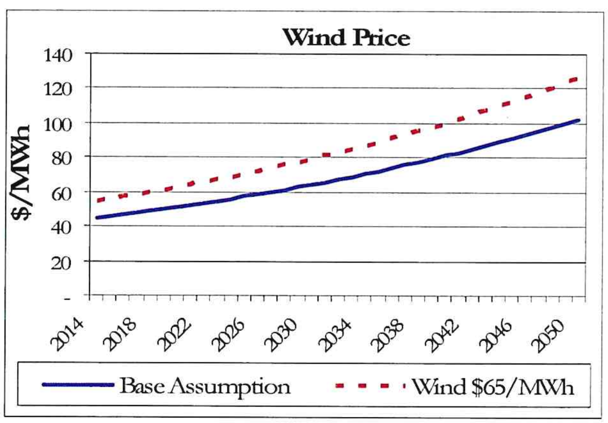
Sensitivity I – Wind $40/MWh Sensitivity

For this sensitivity the levelized price for future wind was decreased to $40/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



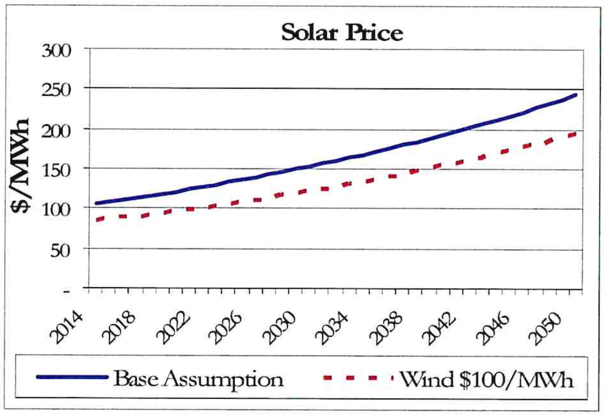
Sensitivity J – Wind $65/MWh Sensitivity

For this sensitivity the levelized price for future wind was increased to $65/MWh. Under base assumptions, the levelized price for future wind is $52.57/MWh.



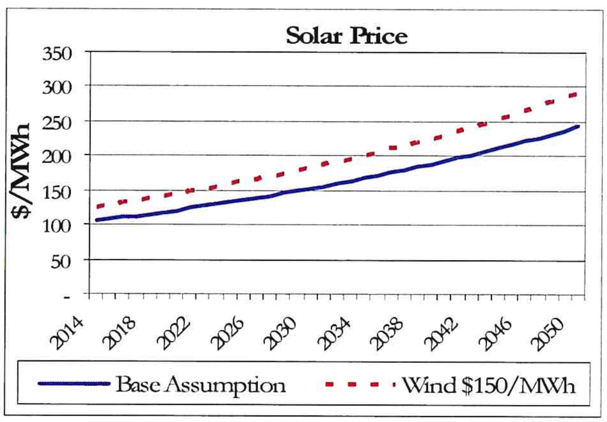
Sensitivity K – Solar $100/MWh Sensitivity

For this sensitivity the levelized price for future solar was decreased to $100/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



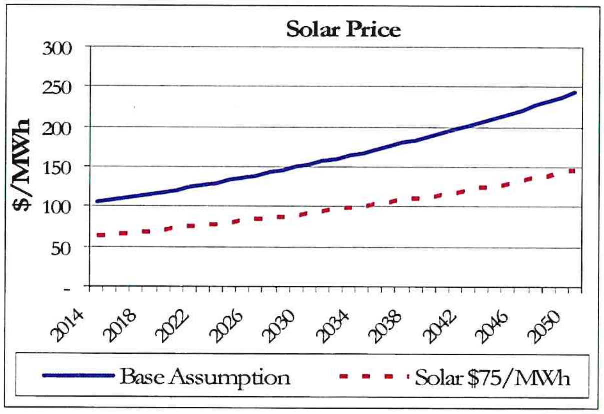
Sensitivity L – Solar $150/MWh Sensitivity

For this sensitivity the levelized price for future solar was increased to $150/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



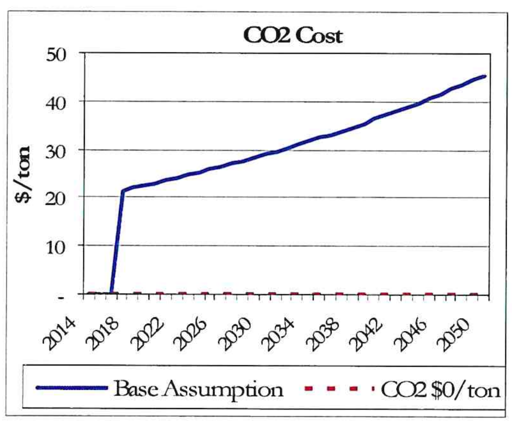
Sensitivity M – Solar $75/MWh Sensitivity

For this sensitivity the levelized price for future solar was decreased to $75/MWh. Under base assumptions, the levelized price for future solar is $125/MWh.



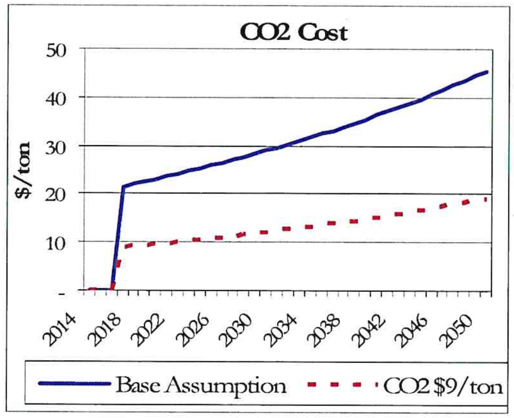
Sensitivity N – CO_2 $0/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to $0/ton. Under base assumptions, the cost for carbon dioxide emissions is $21.50/ton starting in 2017 and escalating at 2.3%.



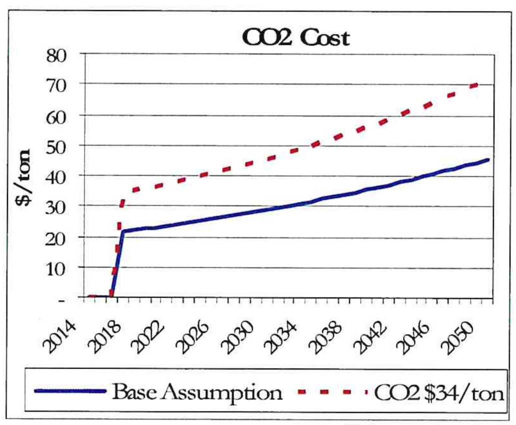
Sensitivity O – CO_2 \$9/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$9/ton starting in 2017 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



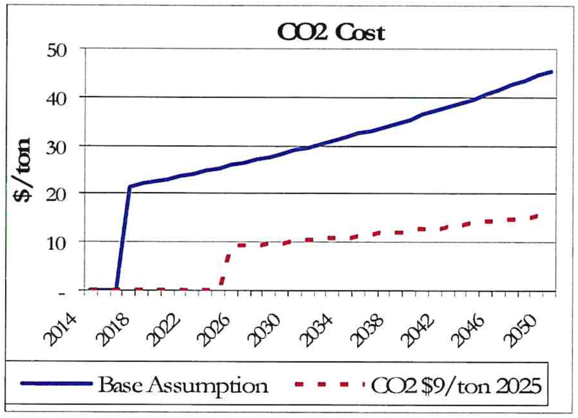
Sensitivity P – CO_2 \$34/ton Sensitivity

For this sensitivity the carbon dioxide cost for emissions was increased to \$34/ton starting in 2017 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



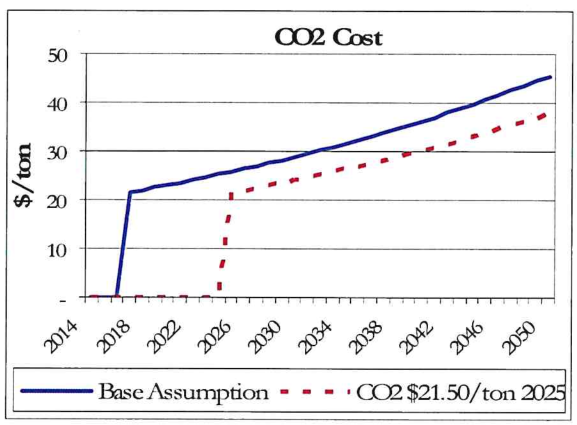
Sensitivity Q – CO_2 \$9/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$9/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



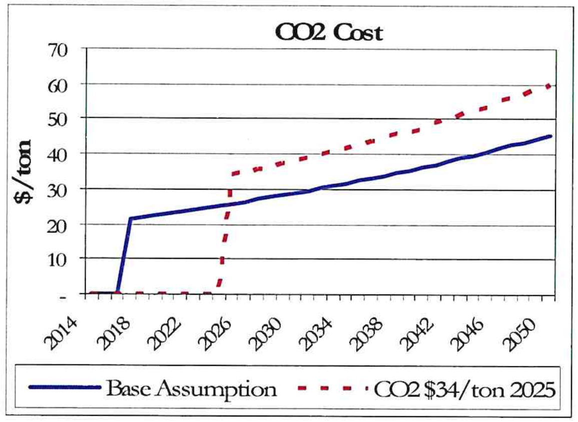
Sensitivity R – CO_2 \$21.50/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was decreased to \$21.50/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is \$21.50/ton starting in 2017 and escalating at 2.3%.



Sensitivity S – CO_2 $34/ton 2025 Sensitivity

For this sensitivity the carbon dioxide cost for emissions was increased to $34/ton starting in 2025 and escalating at 2.3%. Under base assumptions, the cost for carbon dioxide emissions is $21.50/ton starting in 2017 and escalating at 2.3%.



Sensitivity T – Sherco +25% Cost Sensitivity

For this sensitivity the costs of fixed O&M, variable O&M, and ongoing capital were increased 25% above the base assumptions. This includes the costs of the fixed O&M and variable O&M of the SCR in applicable cases.

Sensitivity U – SCR +25% Cost Sensitivity

For this sensitivity all costs associated with the SCR including the costs of initial construction capital, ongoing capital, fixed O&M, and variable O&M were increased 25% above base assumptions.

Sensitivity V – CC and CT Cost +25% Cost Sensitivity

For this sensitivity the costs of initial construction capital of new combined cycle and combustion turbine generators that would replace Sherco Units 1 and 2 in a shutdown case were increased 25% above base assumptions.

Sensitivity X – Changed State Policy Sensitivity

This sensitivity includes a high demand side management target, wind generation to meet 30% of forecasted 2030 sales, and solar generation to meet 10% of forecasted 2030 sales.

Sensitivity Y – Markets Off Sensitivity

This sensitivity did not allow any purchases from the MISO market or any other wholesale counterparty. All energy need is self generated.

Sensitivity Z – SCR 10-Year Book Life Sensitivity

This sensitivity reduced the 15-year book life of the SCR to 10 years.

Sensitivity AA – SCR 5-Year Book Life Sensitivity

This sensitivity reduced the 15-year book life of the SCR to 5 years.

Sherco Units 1 and 2 Life Cycle Management Scenarios and Sensitivities

Scenarios - Changes to Sherco and replacement alternatives

	Scenario Name	Sherco 1	Sherco 2	Replacement Generation
1	1 SCR Early - 2 SCR Early	Install SCR 2018 - Retire 2040	Install SCR 2019 - Retire 2040	-NA-
2	1 SCR Late - 2 SCR Late	Install SCR 2024 - Retire 2040	Install SCR 2025 - Retire 2040	-NA-
3	1 Ret Early - 2 SCR Early - Opt	Retire YE 2019	Install SCR 2019 - Retire 2040	Strategist Optimized
4	1 Ret Early - 2 SCR Early - CC	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combined Cycle
5	1 Ret Early - 2 SCR Early - CT Wind	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x3 + 800MW Wind
6	1 Ret Early - 2 SCR Early - CT Wind Solar	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x2 + 800MW Wind + 500MW Solar
7	1 Ret Early - 2 SCR Early - CT Wind Solar DSM	Retire YE 2019	Install SCR 2019 - Retire 2040	Natural Gas Combustion Turbine x2 + 600MW Wind + 400MW Solar + 55MW DSM
8	1 Ret Late - 2 SCR Late - Opt	Retire YE 2024	Install SCR 2025 - Retire 2040	Strategist Optimized
9	1 Ret Late - 2 SCR Late - CC	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combined Cycle
10	1 Ret Late - 2 SCR Late - CT Wind	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x3 + 800MW Wind
11	1 Ret Late - 2 SCR Late - CT Wind Solar	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x2 + 800MW Wind + 500MW Solar
12	1 Ret Late - 2 SCR Late - CT Wind Solar DSM	Retire YE 2024	Install SCR 2025 - Retire 2040	Natural Gas Combustion Turbine x2 + 600MW Wind + 400MW Solar + 55MW DSM
13	1 Ret Early - 2 Ret Early - Opt	Retire YE 2019	Retire YE 2020	Strategist Optimized
14	1 Ret Early - 2 Ret Early - CC	Retire YE 2019	Retire YE 2020	Natural Gas Combined Cycle x2
15	1 Ret Early - 2 Ret Early - CT Wind	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x5 + 3,000MW Wind
16	1 Ret Early - 2 Ret Early - CT Wind Solar	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x3 + 2,200MW Wind + 1,200MW Solar
17	1 Ret Early - 2 Ret Early - CT Wind Solar DSM	Retire YE 2019	Retire YE 2020	Natural Gas Combustion Turbine x3 + 2,000MW Wind + 1,100MW Solar + 55MW DSM
18	1 Ret Late - 2 Ret Late - Opt	Retire YE 2024	Retire YE 2025	Strategist Optimized
19	1 Ret Late - 2 Ret Late - CC	Retire YE 2024	Retire YE 2025	Natural Gas Combined Cycle x2
20	1 Ret Late - 2 Ret Late - CT Wind	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x5 + 3,000MW Wind
21	1 Ret Late - 2 Ret Late - CT Wind Solar	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x3 + 2,200MW Wind + 1,200MW Solar
22	1 Ret Late - 2 Ret Late - CT Wind Solar DSM	Retire YE 2024	Retire YE 2025	Natural Gas Combustion Turbine x3 + 2,000MW Wind + 1,100MW Solar + 55MW DSM
23	"Reference Case"	Business as usual with retirement in 2040	Business as usual with retirement in 2040	-NA-

Sensitivities - Changes to input assumptions, ran for all scenarios

	Sensitivity	
a	Load - Fall 2011	Forecast from the Resource Plan
b	Low Load	50% of base case growth rate
c	High Load	150% of base case growth rate
d	Low Gas Prices	50% of base case growth rates
e	High Gas Prices	150% of base case growth rate
f	Low Coal Prices	50% of base case growth rates
g	High Coal Prices	150% of base case growth rate
h	Wind $30	$30/MWh levelized price
i	Wind $40	$40/MWh levelized price
j	Wind $65	$65/MWh levelized price is approximately equal to 'no PTC'
k	Solar $100	$100/MWh levelized price
l	Solar $150	$150/MWh levelized price
m	Solar $200	$200/MWh levelized price
n	CO2 $0	$0/ton - note base case is $21.50
o	CO2 $9	$9/ton in 2017 escl @ inflation
p	CO2 $34	$34/ton in 2017 escl @ inflation
q	CO2 $9 2025	$9/ton in 2025 escl @ inflation
r	CO2 $21.50 2025	$21.50/ton in 2025 escl @ inflation
s	CO2 $34 2025	$34/ton in 2025 escl @ inflation
t	Sherco Cost +25%	125% of FOM, VOM, & Ongoing Capital
u	SCR Cost +25%	125% of Capital Cost & Ongoing Costs
v	CC & CT Costs + 25%	125% of Constuction Capital
x	Changed State Policy	10% Solar 35% Wind 5% other by 2030
y	Markets Off	Disable market pruchases in the model
z	SCR 10yr Depr	Accelerated depreciation of SCR 10yrs
aa	SCR 5yr Depr	Accelerated depreciation of SCR 5yrs

Appendix C
Review of Externality Values Based on Those Used by the Minnesota Public Utilities Commission and the Federal Government for Regulatory Impact Analyses

I. INTRODUCTION

The Commission requested that scenarios analyzed include "[a] range of updated externality values based on those used by this Commission and the federal government for regulatory impact analyses."[1] The scenarios presented by Xcel Energy in this study include the Commission's latest approved proxy values for carbon dioxide (CO_2) and the Commission's latest updated environmental externality values for other air pollutants. In this Appendix we discuss values reflecting federal government estimates of externality values for CO_2 that were developed for use in Regulatory Impact Analyses (RIAs) and values taken from a study conducted by the National Research Council (NRC).

We are not aware of any process undertaken at the federal level similar to that undertaken by the Commission to establish Minnesota's externality values. However, RIAs have been conducted by the Environmental Protection Agency (EPA) in conjunction with federal rulemakings. We investigated externality values in several of the most recent EPA rulemaking dockets to determine if there were values established that could be applied in the same way the Commission's environmental values are applied. We provide our analysis below and discuss how once National Ambient Air Quality Standards (NAAQS) have been established through RIAs, the associated externalities are eliminated or minimized, because NAAQS are set to protect human health and welfare without consideration of costs.

Other than for CO_2 emissions, which reflect generalized global impacts, the pollutants that are the subject of federal regulation have local or regional impacts. In the past 15 years, these pollutants have been the target of increasingly stringent regulations that have required emission reductions or compliance with ambient concentrations that seek to eliminate or minimize externalities associated with emissions of such pollutants. RIAs are conducted in an attempt to assess the macro benefits that may result from the specific emission reductions required by each individual final rule. The focus of an RIA is on the measurement of the benefits that may arise from a requirement to install pollution controls or to implement programs that will reduce emissions and, in some instances, general estimates of the costs associated with the

[1] Order Establishing Procedural Schedules and Filing Requirements at 11, *In the Matter of Xcel Energy's 2011-2025 Integrated Resource Plan*, Docket No, E-002/RP-10-825 (Nov. 30, 2012).

reductions. Because these analyses are general in nature, Xcel Energy was unable to identify consistent, appropriate, and relevant externality values to apply at the local level.

Xcel Energy asked the Environmental Intervenors in this proceeding for suggestions on a source of federal externality values we should consider and were referred to a study by the NRC entitled *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* While this study was not used as a basis for any EPA air quality regulations affecting NAAQS or limiting emissions of criteria air pollutants from the utility industry, we did examine the study to develop cost values to use in modeling scenarios.

In this Appendix we:

- review the Commission's development of environmental externality and carbon regulation proxy costs;
- present carbon dioxide externality values that have been developed by the federal government to assist in preparation of RIAs, noting that while these values have recently been updated, we believe they are too high;
- discuss the use of recent EPA RIAs associated with regulations addressing criteria pollutants and values from the NRC Report to estimate externality values for Minnesota facilities; and
- characterize the cost impacts of including these values.

II. COMMISSION ENVIRONMENTAL EXTERNALITY VALUES AND CARBON PROXY COSTS

The scenarios presented in this study include the environmental externality costs developed by the Commission. The Commission established its environmental cost values following extensive, contested proceedings that lasted more than two years.[2] As part of establishing these cost values, the Commission had to consider and decide several related conceptual issues.

First, the Commission decided it would base its range of values on "as many effects of by-products of generation as practical," focus on "the effects of by-products that cause the most significant costs," and "concentrate on the impacts that are easiest to quantify."[3] The Commission therefore concentrated on the six NAAQS pollutants,

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[2] Order Establishing Environmental Cost Values, Procedural History at 1-4, *In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3,* Docket No. E-999/CI-93-583 (Dec. 16, 1996) (noting that in several weeks of evidentiary hearings, over 50 witnesses presented testimony).
[3] *Id.* at 12.

mercury, and CO_2.[4] While noting that under the Clean Air Act (CAA), the NAAQS are to be set to protect public health with an adequate margin of safety, because EPA had not revised the NAAQS for many years, the Commission established cost ranges for these pollutants.[5]

Next, the Commission found the damage-cost approach to be superior, but noted that although it has shortcomings, the cost of control method "may be reasonable in certain circumstances. In some instances, it may be much easier or less expensive to estimate control costs than to estimate actual damages."[6] In establishing its environmental externality cost ranges, the Commission decided that "[w]ith the exception of the values for CO_2, which causes damages globally rather than regionally or locally, the Commission has quantified the costs of environmental damage occurring in Minnesota."[7]

Since first establishing the environmental cost values, the Commission has updated them using the Gross Domestic Product Price Deflator Index. The most recent externality values were issued by the Commission on June 13, 2012.[8] These values were used in the scenarios presented in this study. Since the establishment of the Minnesota externality values, emissions have decreased considerably from the power sector and many other types of emission sources, thereby reducing impacts on the environment. Due to these significant reductions, the externality values in use today in Minnesota may overestimate the impact of a ton of pollutant emitted, making the high end of the range a conservative estimate. However, because the Commission values were developed based on conditions specific to Minnesota, we believe these are the most representative values to use in an analysis such as the Sherco 1 and 2 study.

To address uncertainty over how carbon regulation may develop, Minn. Stat. § 216H.06 requires the Commission to establish an estimate of the likely range of costs of future CO_2 regulation on electricity generation, and to update the estimates annually following informal proceedings. After section 216H.06 became effective in 2007, the Commission made its initial estimates of the cost per ton of CO_2 emissions that carbon regulation might cost. The Commission also found that utilities did not

[4] *Id.* at 13. The Commission distinguished the generic nature of externality cost estimates from the specific circumstances of the resource options proposed in future individual planning dockets.
[5] *Id.* At 16.
[6] *Id.* at 14.
[7] *Id.* at 15. The Commission used a detailed, Minnesota-specific study to establish its environmental cost ranges. *Id.* at 17.
[8] Notice of Updated Environmental Externality Values, *In the Matter of the Investigation into Environmental and Socioeconomic Costs*, Docket Nos. E-999/CI-93-583 and E-999/CI-00-1636 (June 12, 2012).

need to continue to utilize the externality cost for CO_2 if they instead applied the carbon regulation costs.[9]

The carbon proxy cost is intended as a planning tool to estimate how future regulation of CO_2 emissions may affect the cost of generating electricity. The Commission's most recent order maintained the estimate of the range of likely costs of CO_2 regulation at between $9 and $34 per ton of CO_2 for 2012 and 2013. Utilities must apply the range of CO_2 values in their resource planning as of 2017.[10] The Company used carbon proxy costs of $9, $21.50 and $34 per short ton in this analysis.

III. CARBON DIOXIDE EXTERNALITY COSTS DEVELOPED BY FEDERAL GOVERNMENT AGENCIES FOR USE IN REGULATORY IMPACT ANALYSES

In 2010, an inter-governmental group consisting of EPA, the Department of Energy and ten other agencies developed a "Social Cost of Carbon for Regulatory Impact Analysis," which provides estimates for the social cost of carbon (SCC) to estimate the climate benefits of rulemakings. In this report, the Working Group states: "The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change."[11] The Working Group also states that, "to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by greenhouse gas (GHG) emissions."[12] In other words, the SCC is developed based on damages globally, not domestically. In various regulations that use the SCC, such as EPA's light-duty vehicles GHG proposed rule, the SCC has been part of the standard public comment process. In May 2013, the Interagency Working Group updated the SCC values.[13]

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[9] Order Establishing Estimate of Future Carbon Dioxide Regulation Costs, at 4 and Ordering Para. 3, *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes §216H.06*, Docket No. E-999/CI-07-1199 (Dec. 21, 2007).

[10] Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs, at 4, *In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes §216H.06*, Docket No. E-999/CI-07-1199 (Nov. 2, 2012).

[11] *Technical Support Document: - Social Cost of Carbon for Regulatory Impact Analysis-Under Executive Order 12866*, page 2, February, 2010.

[12] *Id.* at 10.

[13] *Technical Support Document: - Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis- Under Executive Order 12866*, May 2013.

On its website, the EPA states:

> The interagency group selected four SCC values for use in regulatory analyses. The first three values are based on the average SCC from the three integrated assessment models, at discount rates of 5, 3, and 2.5 percent. SCCs at several discount rates are included because the literature shows that the SCC is highly sensitive to discount rate and because no consensus exists on the appropriate rate to use for analyses spanning multiple generations. The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate, intended to show the potential for higher-than-average damages.

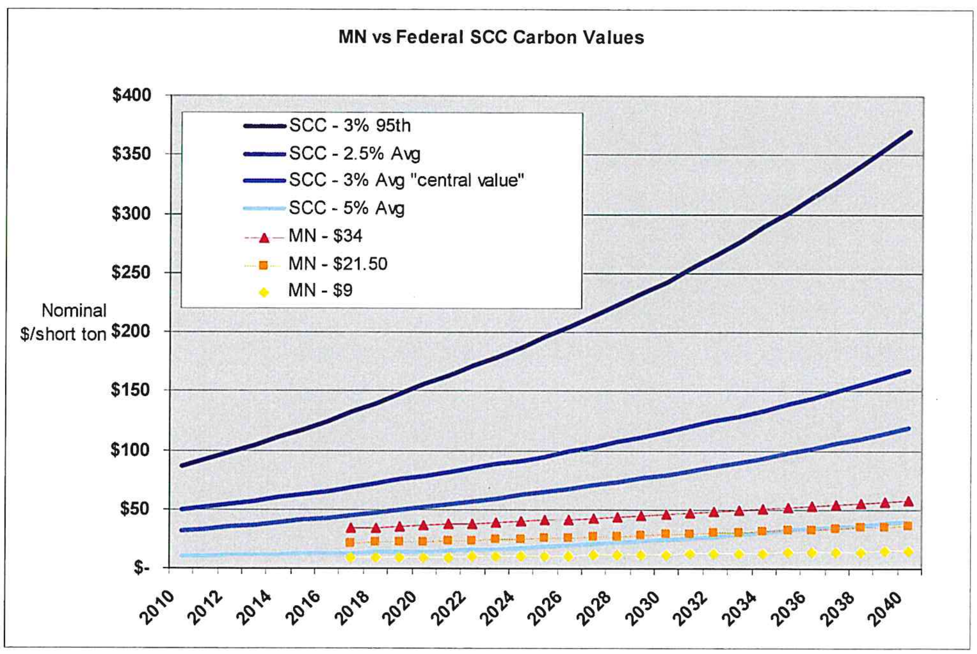
The updated SCC values from May 2013 are shown below:

Social Cost of CO_2, 2015-2050[a] (in 2007 Dollars)

	Discount Rate and Statistic			
Year	**5% Average**	**3% Average**	**2.5% Average**	**3% 95th percentile**
2015	$12	$38	$58	$109
2020	$12	$43	$65	$129
2025	$14	$48	$70	$144
2030	$16	$52	$76	$159
2035	$19	$57	$81	$176
2040	$21	$62	$87	$192
2045	$24	$66	$92	$206
2050	$37	$71	$98	$221

[a] The SCC values are dollar-year and emissions-year specific.

The figure below summarizes the carbon regulation proxy costs established by the Commission and the SCC values estimated by the federal interagency group.



The Company included the two middle SCC values – SCC – 2.5% Avg and 3% Avg "central value" – in its analysis. The SCC-5% Avg value was not run because it falls within the range of the Commission's values. The SCC-3% 95th values were not run because these values are significantly out of the range of costs expected to be imposed by reasonable climate policy that could be adopted in the near term.

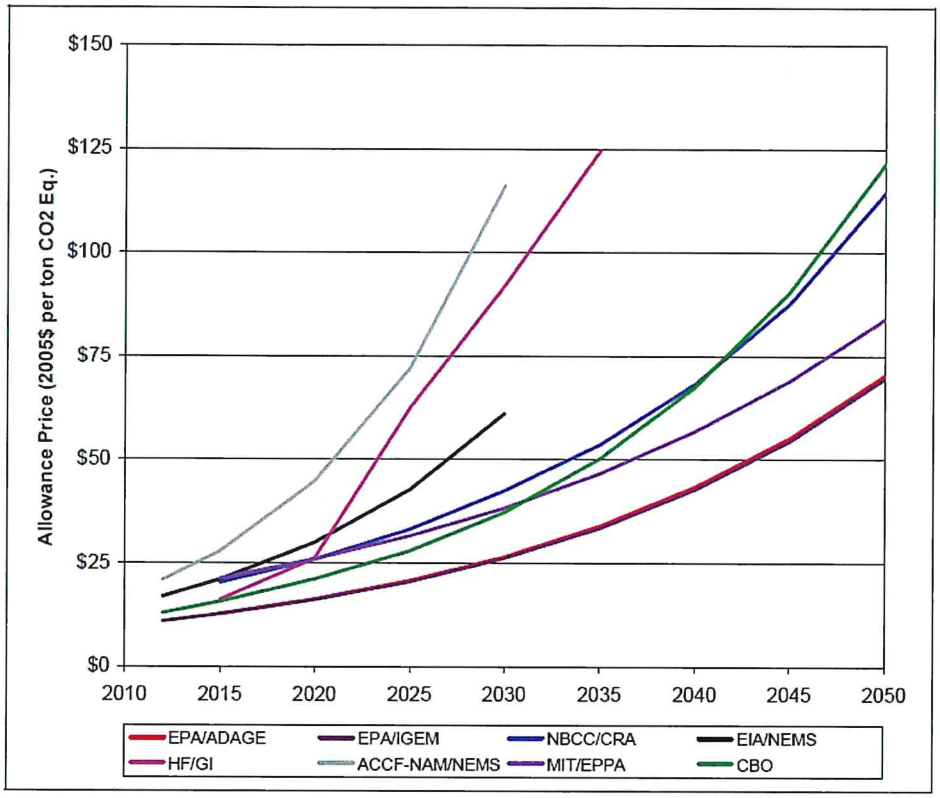
Furthermore, the Company does not believe that the values from the SCC – 2.5% Avg and 3% Avg "central value" are likely outcomes of any potential federal carbon policy. Those scenarios assume a carbon cost of $45 and $68 per ton in 2017, respectively, which are considerably higher than values developed through the Commission's stakeholder process to establish environmental costs.

As evidence, we discuss two recent carbon policy proposals that garnered the most attention by Congress in recent years. The American Clean Energy and Security Act of 2009 (ACES) and the American Power Act. Both policies estimated lower carbon compliance prices than the two middle SCC values, and neither policy moved forward, in part due to cost concerns.

In 2009, the American Clean Energy and Security Act of 2009 (ACES)[14] was passed by the U.S. House of Representatives. The chart below, taken from the Congressional Research Service's report prepared for members and committees of Congress,[15] shows allowance prices estimated under ACES, in 2005 dollars. The table following the chart shows the SCC values in 2005 dollars. The 2.5% and 3% values are significantly higher than all but one scenario considered for the congressional report.

[14] American Clean Energy and Security Act of 2009, H.R. 2454, 111th Congress, 1st Session.
[15] *Climate Change: Costs and Benefits of the Cap-and-Trade Provisions of H.R. 2454*, Congressional Research Service, Parker, Larry and Yacobucci, Brent, September 14, 2009.

Figure 12. Projected Allowance Prices Under H.R. 2454



Sources: EPA/ADAGE and EPA/IGEM: "Data Annex" available on the EPA website at http://www.epa.gov/climatechange/economics/economicanalyses.html MIT/EPPA: Sergey Paltsev, et al., "Appendix C" of Paltsev et al., *The Cost of Climate Policy in the United States*, MIT Joint Program on the Science and Policy of Global Change (2009). EIA/NEMS: EIA, *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009*, (August 2009). ACCF-NAM/NEMS: SAIC, *Analysis of The Waxman-Markey Bill "The American Clean Energy and Security Act of 2009" (H.R. 2454) Using The National Energy Modeling System (NEMS)*, report by the ACCF and NAM (2009). NBCC/CRA: CRA International, *Impact on the Economy of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (May 2009). CBO: CBO, *CBO Cost Estimate: H.R. 2454 American Clean Energy and Security Act of 2009 As ordered reported by the House Committee on Energy and Commerce*, (June 5, 2009). HF/GI: The Heritage Center for Data Analysis, *The Economic Consequences of Waxman-Markey: An Analysis of the American Clean Energy and Security Act of 2009* (August 5, 2009).

Note: Estimates converted to 2005$ using GDP implicit price deflator.

Revised Social Cost of Carbon from "May 2013" update, Technical Support Document				
Cost per ton, CO_2, 2005 dollars				
	5% Avg	3% Avg	2.5% Avg	3% 95th
2020	$12	$43	$65	$129

In 2010, the Senate proposed a similar GHG proposal, the American Power Act.[16] This proposal contained a cost containment mechanism for emission allowances, which would have been used to comply with the standard. This mechanism would likely not have allowed the allowance price to reach the $40 per ton level, which is lower than the two SCC scenarios indicate.[17] This Senate proposal stalled, and the new Congress elected in 2010 had a stronger opposition to cap and trade policies.

Because compliance costs were a main reason these proposals were opposed, we do not anticipate that carbon policies in the near future will have higher costs than the proposals Congress has most recently considered. Thus, we do not believe the SCC costs are reasonable to use in resource planning analysis, but believe the Commission's estimates of the cost of future carbon regulation are more appropriate.

IV. EPA REGULATORY IMPACT ANALYSES ASSOCIATED WITH RECENT AIR QUALITY REGULATIONS

Xcel Energy was asked to consider the results of EPA RIAs associated with recent air quality regulations. The purpose of regulation is to reduce or minimize externality costs imposed on society by establishing standards with which sources must comply. Such regulations either require emission reductions, impose control costs on sources to eliminate the externality or impose taxes to internalize externality costs (either directly or through a cap and trade program). EPA uses RIAs in its rulemakings to comply with an Office of Management and Budget (OMB) requirement to compare the estimated cost of achieving newly-required emission reductions with the estimated benefits that may be realized.

Xcel Energy reviewed EPA's RIAs in an attempt to find applicable cost-benefit values that could be used in this analysis. This section first reviews recent EPA regulatory actions, focusing on the suite of revised NAAQS and new regulations that impact emissions of NAAQS pollutants. This section then analyses the RIAs EPA prepared in association with these emission reduction rules.

A. EPA's Recent NAAQS Revisions and Significant Air Quality Regulations

Under the Clean Air Act, the EPA is obligated to establish NAAQS for a wide range of pollutants.[18] After the CAA was enacted in 1970, EPA adopted NAAQS for five pollutants: particulates, ozone, sulfur dioxide, nitrogen dioxide, and carbon

16 American Power Act, Section 726, May 2010 (Senators Kerry and Lieberman) (not enacted).
17 We estimate that under this proposed legislation, the allowable allowance price would reach a maximum of $35 per short ton in nominal terms, if escalated at 7% per year. The bill specified that the allowance price can rise at 5% plus the rate of inflation, which we have estimated as 2% per year.
18 The NAAQS program is described in Appendix A, section I.A.

monoxide.[19] In setting the NAAQS for these pollutants, EPA is obligated to set the standards at levels that, "in the judgment of the Administrator, based on such criteria and allowing an adequate margin of safety, are requisite to protect the public health."[20]

Importantly, these NAAQS are set without regard to costs: they must simply be set at levels that protect public health and welfare.[21] Once EPA establishes the NAAQS, each state is obligated to develop regulations to achieve them, through regulations that impose emission reduction or control requirements or that establish emission trading programs that internalize the costs of pollution. As described in detail in Appendix A, Minnesota currently meets all NAAQS, including the particulate matter NAAQS revised by EPA in early 2013.[22]

At the time of the Commission's extensive proceeding in the mid-1990s that established the environmental externality values for Minnesota resource planning purposes, EPA had either not reviewed or not revised the NAAQS for many years. This led the Commission to establish externality values for the NAAQS pollutants. Adopted in 1971, the NAAQS were not revised until the late 1970s, when EPA added a NAAQS for lead in 1978, and made the ozone NAAQS less stringent in 1979. In 1987, EPA adopted a NAAQS for particulate matter less than 10 microns (PM_{10}). Since 2008, EPA has concluded comprehensive scientific reviews for every NAAQS pollutant, with standards being made more stringent for all pollutants except for carbon monoxide. EPA has reviewed and revised the particulate NAAQS three times, the latest in 2013, and the ozone NAAQS twice since 1997. For the first time since the early 1970's, every NAAQS has been subject to a full scientific review within the last five years. The most recent NAAQS revisions and Minnesota's status with respect to attainment of the current NAAQS are described in Section I.A of Appendix A.

At the same time that EPA has been reviewing and revising the NAAQS, EPA has also adopted numerous air quality regulations that are focused on reducing criteria and hazardous air pollutants from mobile sources and multiple categories of stationary sources. The numerous air quality regulations directed at reducing emissions from the

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19 *See* www.epa.gov/ttn/naaqs, which includes tables showing the year review was completed and the resulting NAAQS for each pollutant.

20 *See e.g.* 42 U.S.C. §7409. The administrator also must set secondary ambient standards that are necessary to "protect the public welfare from any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air." See 40 U.S.C. §7409(b)(1) - (2).

21 See *id*, and *Whitman v. American Trucking Assocs., Inc.*, 531 U.S. 457 (2001) (CAA does not allow EPA to consider costs in setting NAAQS).

22 The MPCA submitted a SIP to EPA in June 2012 that addresses the lead nonattainment area in Eagan, Minnesota by requiring new controls for Gopher Resource Corporation, a lead smelter and battery recycler. MPCA reports that current monitoring shows ambient lead concentrations to be below the NAAQS. *See* http://www.pca.state.mn.us/index.php?option=com_k2&Itemid=2851&id=2585&layout=item&view=item

utility sector are described in Appendix A. In addition, a suite of mobile source regulations has been adopted, which include emission reduction requirements from cars and light duty trucks; heavy duty trucks, buses and engines; motorcycles; aircraft; diesel boats and ships; gasoline boats and personal watercraft; non-road diesel equipment; locomotives, lawn and garden equipment; and snowmobiles and ATVs. EPA has also recently adopted standards regulating new and existing stationary diesel generators and new and existing commercial, industrial, and institutional boilers and solid waste incinerators.

As a result of these multiple NAAQS revisions and air quality regulations, significant emission reductions have occurred. Without these reductions these impacts would have been previously treated as externalities. They have now however, become internalized through the costs incurred to meet the new, more stringent requirements.

B. Regulatory Impact Analyses Associated with EPA's NAAQS Revisions and Significant Air Quality Regulations

The White House, through Executive Order 12866 (Order), requires agencies to perform cost-benefit analyses of all "significant" rules and to submit these analyses to the Office of Management and Budget (OMB) for review. The Order requires agencies to conduct a macro-level cost-benefit analysis for purposes of informing the public and assessing regulatory alternatives. Executive Order 12866, § 1 requires agencies to:

> ...assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. Costs and benefits shall be understood to include both quantifiable measures (to the fullest extent that these can be usefully estimated) and qualitative measures of costs and benefits that are difficult to quantify, but nevertheless essential to consider.

EPA fulfills this mandate by developing RIAs for "significant" rulemakings.[23] As EPA explains, "RIAs contain descriptions of the potential social benefits and social costs of a regulation, including those that cannot be quantified in monetary terms and a determination of the potential net benefits of the rule including an evaluation of the effects that are not monetarily quantified."[24]

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[23] *See, e.g.*, EPA, Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter at ES-1 (Dec. 2012) (PM RIA) ("The RIA fulfills the requirements of Executive Orders 12866 and 13563 and guidelines of the Office of Management and Budget's (OMB) Circular A-4.1").
[24] *See* http://www.epa.gov/ttnecas1/ria.html.

When establishing NAAQS or adopting emission control regulations, EPA estimates the benefits expected from meeting or complying with the rule. This is done by examining the overall benefits of reducing ambient pollution concentrations on worker productivity, reduced hospital visits, medical costs, reduced mortality, and other health-related factors. These benefits are aggregated and compared to the estimated costs of implementing programs to achieve the new standard(s). EPA estimates macro-level benefits associated with significant rules on a national level and does not focus on assessing per-pollutant cost-benefit or externality values.

EPA is required to assess costs and benefits, even when quantification of those costs or benefits is difficult or uncertain. The usefulness of this type of analysis outside of the given regulatory rulemaking it is developed for is therefore extremely limited. When fulfilling the mandate of the Order during recent amendments to the nitrogen dioxide NAAQS, EPA cautioned that:

> As with other NAAQS RIAs, *it should be recognized that all estimates of future costs and benefits are not intended to be forecasts of the actual costs and benefits of implementing revised standards.* . . . Our estimates are intended to provide information on the general magnitude of the costs and benefits of alternative standards, rather than precise predictions of control measures, costs, or benefits.[25]

For a given rule, EPA typically calculates gross costs, gross benefits, and net benefits. This macro-level approach allows EPA to satisfy the Order and related OMB requirements, but does not result in specific analyses focused on assigning benefits or externality values to specific pollutants. EPA therefore generally expresses the benefits of its rules in terms of total net benefits and not on a dollar per ton of pollutant eliminated basis because to do so would imply accuracy where it does not exist.[26] Converting an aggregate number into a uniformly applicable value-per-ton of pollutant reduced is inaccurate and would be an inappropriate use of this data. EPA's analysis contains many points of uncertainty that may be acceptable for macro-level calculations, but that render the analysis methodologically flawed if applied on a local or facility basis.[27] EPA clearly indicates that the results of their cost-benefit analyses

[25] EPA, Final Regulatory Impact Analysis (RIA) for the NO2 National Ambient Air Quality Standards (NAAQS) at 5-3. (Jan., 2010) (NO_2 RIA) (emphasis added).

[26] In the instances where EPA uses a benefits-per-ton approach, EPA has not developed new benefits estimations, but rather used prior estimations and methodologies for purposes of estimating a specific rule's net benefit.

[27] The NAAQS are air quality standards set by EPA but implemented by the states. As such, specific pollution reduction measures are not required, and therefore EPA is unable to accurately assess the actual pollution reductions that will result from a given NAAQS amendment. As EPA recently explained when revising its particulate matter standards:

> The setting of a NAAQS does not compel specific pollution reductions and as such does not directly result in costs or benefits. For this reason, NAAQS RIAs are merely illustrative. The NAAQS RIAs illustrate the potential costs and benefits of additional steps States could take

are general estimates and are not intended to be presumed as actual costs and benefits. The actual externality impact in dollar per ton reduced will vary greatly depending upon where that ton is emitted – be it in an attainment or non-attainment area – and is also highly dependent upon site-specific data such as meteorology, topography, pollutant source, population exposure, baseline health incidence rates, and other local factors that affect the costs or benefits resulting from a national rule in a particular location or with respect to any particular source. While locally-specific factors are not taken into consideration in EPA's RIAs, the Commission recognized their importance in its environmental externalities proceeding by developing Minnesota-specific values for impacts by sources in various locations: Metropolitan, Urban, Rural, and Within 200 miles of Minnesota.

On another note, EPA's cost benefit analyses are specific to the incremental reductions projected for each particular rulemaking and are not applicable outside of a given rule or on a stand-alone basis. The recent PM NAAQS revisions provide a good example. Although EPA calculated the benefits of PM reductions across the entire country, those benefits depended exclusively on PM reductions occurring in California.[28] As EPA explained, "[f]or the revised annual [PM] standard of 12 µg/m3, *all of the estimated benefits occur in California because this is the only state that needs additional air quality improvement beyond the analytical baseline after accounting for the air quality improvements from recent rules.*"[29] Therefore, any cost-benefits estimated from implementation of the PM NAAQS are applicable only to those areas in California and not anywhere else in the country.

In summary, the benefits analyses conducted by EPA in RIAs is focused on generating high level estimates of net benefits to comply with OMB requirements and the Order. There are multiple uncertainties inherent in calculating any environmental benefit. While these uncertainties do not undermine EPA's goal of providing "information on the general magnitude of the costs and benefits" such uncertainties preclude downward extrapolation of high-level net benefits estimates to "precise predictions of control measures, costs, or benefits" (including per-ton benefit or externality values) for a specific plant.[30]

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to attain a revised air quality standard nationwide beyond rules already on the books. We base our illustrative estimates on an array of emission control strategies for different sources. The costs and benefits identified in this RIA will not be realized until specific controls are mandated by SIPs or other Federal regulations. In short, NAAQS RIAs hypothesize, but do not prescribe, the control strategies that States may choose to enact when implementing a revised NAAQS. (PM RIA at ES-18.)

[28] *See* PM RIA at ES-8; 5-67.

[29] PM RIA at 5-89 (emphasis added).

[30] *See* NO_2 RIA at 5-3.

Externalities are those costs incurred by society that are un-priced or not otherwise accounted for. The primary NAAQS are set at a level "requisite to protect the public health" with an adequate margin of safety, and the secondary NAAQS are set at a level "requisite to protect the public welfare."[31] In the recent PM NAAQS RIA, EPA explained that:

> [O]ne of the reasons a regulation such as the NAAQS may be issued is to address existing "externalities." An externality occurs when parties to a transaction do not bear its full consequences. An environmental problem, such as pollution generated from production of a good, which imposes health costs on those who neither produce nor consume it, is a classic case of an externality. In the presence of externalities, a free market does not ensure an efficient allocation of resources. *Setting and implementing primary and secondary air quality standards is one way the government can address an externality and increase air overall public health and welfare.*[32]

The RIAs for the SO_2, NO_2, and Ozone NAAQS each contain explanatory statements on the nature of externalities and various mechanisms people and governments use to address externalities.[33] These statements are nearly identical and conclude that:

> From an economics perspective, *setting an air quality standard is a straightforward case of addressing an externality*, in this case where entities are emitting pollutants, which cause health and environmental problems without compensation for those suffering the problems. Setting a standard with a reasonable margin of safety attempts to place the cost of control on those who emit the pollutants and lessens the impact on those who suffer the health and environmental problems from higher levels of pollution.[34]

Once NAAQS have been attained for a given pollutant, any associated externalities have been eliminated or minimized by imposing control requirements and associated costs on sources. Because NAAQS must be set to protect human health and public welfare without consideration of costs, emissions at levels below the NAAQS should not impose additional externality costs on public health and welfare. EPA's RIA analyses attempt to estimate the costs and benefits associated with a particular rule, and in that sense provide a macro-level picture of that rule's net benefits.

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31 42 U.S.C. § 7409.

32 PM RIA at 1-4 (emphasis added).

33 *See* NO_2 RIA at 1-3:4; *Final Ozone NAAQS Regulatory Impact Analysis* at 1-2:3, EPA (March 2008) (Ozone RIA); *Final Regulatory Impact Analysis (RIA) for the SO_2 National Ambient Air Quality Standard (NAAQS)* at 1-2:5, EPA (June 2010) (SO_2 RIA).

34 SO_2 RIA at 1-5 (emphasis added).

V. NATIONAL RESEARCH COUNCIL STUDY

Preceding the submission of this study, Xcel Energy asked the Environmental Intervenors for suggestions on a source for federal externality values. As the discussed above, except for CO_2, there is no proceeding where one set of potential cost ranges have been developed for consistent use in analyses of new air emission control rules. Xcel Energy was referred to a study by the NRC entitled *The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* Xcel Energy was unable to find this study used by EPA as a basis for any recent criteria and hazardous air pollutant benefits estimates for regulations affecting the utility industry.[35] However, we evaluated this study and present scenarios based upon the cost values found in the study. This section explains those scenarios and analyzes the study.

A. Examination of the National Research Council Study and Applicability to Sherco Units 1 and 2

The NRC study was examined to determine the appropriateness of applying its externality costs to Sherco 1 and 2 emission scenarios. NRC describes itself as an independent, objective, and nonpartisan body that conducts studies and reports on a variety of subjects. This study was developed to define and evaluate the health, environment, security, and infrastructure external costs and benefits associated with the production and consumption of energy. Specifically, the study looked at the costs and benefits that are not or may not be fully incorporated into applicable revenue measures related to the production and consumption of energy.

The NRC established a committee to conduct the study and to develop the report. The report was drafted by the committee and reviewed by individuals according to NRC Report Review process procedures. Comments from the reviewers were considered, though not necessarily incorporated. There was no public comment period for review of the final report, meaning that no opportunity for public comment exists on the report generated by the NRC.

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[35] The National Research Council (NRC) study, titled "The Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use" was cited in relation to CO_2 emissions in the RIAs for the Mercury and Air Toxics Standard, the Industrial Boiler MACT, and the proposed New Source Performance Standard for Greenhouse Gases from Electric Generating Units. These RIAs made no mention of the NRC study for criteria pollutant externality impacts. In addition, a review of the PM RIA, Ozone RIA, SO_2 RIA, and NO_2 RIA yielded no reference to the NRC study.

In general, Xcel Energy has the following observations on the NRC report:

- The NRC report notes on page 337 that "The external effects of energy are mostly negative, but the overall benefits of U.S. energy systems to society are enormous. However, the estimation of those benefits, which are mostly reflected in energy prices and markets, was not included in the committee's charge." While it is common practice to focus on the negative cost impacts of energy production, the positive system benefits should also be considered in order to offer an impartial, balanced evaluation of the energy system.

- The NRC study represents a broad cross-section of the power generation sector. As such it presents data on national impacts rather than localized impacts. In addition, it includes data from a broad range of generating plants with varying fuel types, control equipment and emissions profiles. The report does not focus on a specific facility, but instead looks at the entire coal fleet to arrive at its conclusions. While this may have value for developing broad policy approaches, it is not readily transferable to a site-specific analysis such as this study.

- The NRC study argues that an externality remains even when emissions are controlled at the economically optimal level. This is in conflict with the views of other economists that state that no externality exists if emissions are controlled to the economically optimal level. The latter viewpoint is applied by EPA in the RIAs discussed above.

- The data and assumptions used in the study are significantly out of date (*e.g.*, emissions data from 2005 is used in the NRC study). Since 2005, air emissions from Sherco Units 1 and 2 have been reduced through emissions reduction projects at the site. In addition, Xcel Energy has implemented its Metropolitan Emissions Reduction Project, which significantly reduced emissions in Minnesota. It should also be noted that EPA has developed a number of new regulations that require further emissions reductions from the power generation sector, which are summarized in Appendix A. After these new rules and regulations are fully implemented, the 2005 emissions dataset will significantly over-estimate actual emissions and therefore externality costs.

- The NRC study also makes now-obsolete assumptions regarding future generation and fuel use, such as predicting a 20% net increase in coal generation by 2030. The energy picture has changed dramatically since the time this report was written. The discovery of domestic natural gas resources, the impacts of the Great Recession and the change in the environmental regulatory landscape have changed generation outlooks and load growth forecasts. As a result the predictions made in the NRC study are not representative of current industry conditions.

- It should be noted that any attempt to apply NRC-developed externality costs to coal generation would also need to be applied to all generation alternatives being considered (*e.g.*, gas, wind, solar, nuclear).

- Xcel Energy is not aware of any effort to vet the NRC study's values through a robust public comment process.

In summary, the NRC study may provide some perspectives related to developing broad national energy policy, but has limitations that reduce its value for use in a site-specific analysis.

B. Estimation of Sherco Unit 1 and 2-Specific Values based on NRC Study

To incorporate the externality values from the NRC study into this analysis, an effort was made to extract values from the published data that would likely be applicable to Sherco Units 1 and 2. Table 2-11 in the NRC study presents data representing the distribution of pounds of criteria pollutant emissions per megawatt-hour by coal-fired power plants. This data represents criteria pollutant emissions rates for 406 coal-fired plants using 2005 emissions data.[36] In order to present a more up-to-date picture of how Sherco Units 1 and 2 compare to this dataset, we compared the specific emissions data from these units to the tabulated data. We specifically looked at SO_2, NO_x and PM_{10} data as we have a robust dataset for these pollutants for Sherco Units 1 and 2. The tabulated and Sherco data was plotted to determine the corresponding percentiles. The SO_2 plot showed that the Sherco Unit 1 and 2 emission rate equated to a 3rd percentile emission rate compared to the tabulated values while the NO_X and PM_{10} data corresponded to a 10th percentile and 29th percentile, respectively.

[36] We were unable to find Sherco Unit 1 and 2 specific data within the NRC Study.

TABLE 2-11. Distribution of Pounds of Criteria-Pollutant-Forming Emissions per Megawatt-Hour by Coal-Fired Power Plants, 2005

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO2	12	11	1.5	5.4	8.9	16	33
NOx	4.1	2.3	1.3	2.6	3.7	4.9	9.0
PM2.5	0.59	0.58	0.092	0.20	0.35	0.81	1.8
PM10	0.72	0.67	0.12	0.28	0.48	0.94	2.1

ABBREVIATIONS: SO2 = sulfur dioxide = NOx, oxides of nitrogen; PM = particulate matter.

Sherco Units 1 and 2 data: 1.1 lb SO2/MWh (expected value in 2015);
1.6 lb NOx/MWh (expected value in 2015);
0.31 lb PM10/MWh (2012 actual value).

In order to estimate the cost per kilowatt-hour values for Sherco Units 1 and 2, we then consulted Table 2-9 from the NRC study. This table contains data representing the distribution of estimated damages per kilowatt-hour with emissions from 406 coal-fired power plants in 2005 (in 2007 dollars). The Sherco Units 1 and 2 percentile values per pollutant, as determined above, were applied to Table 2-9 and plots were developed. The SO_2 plot showed that the SO_2 emission rate equated to a value of 0.15 cents/kWh while the NO_x and PM_{10} data corresponded to 0.095 cents/kWh and 0.0046 cents/kWh, respectively.

TABLE 2-9. Distribution of Criteria Air Pollutant Damages per Kilowatt-hour with Emissions from 406 Coal-fired Power Plants in 2005 (2007 Cents)

	Mean	Standard Deviation	5th Percentile	25th Percentile	50th Percentile	75th Percentile	95th Percentile
SO2	3.8	4.1	0.24	1.0	2.5	5.2	11.9
NOx	0.34	0.38	0.073	0.16	0.23	0.36	0.91
PM2.5	0.30	0.44	0.019	0.053	0.13	0.38	1.1
PM10	0.017	0.023	0.001	0.004	0.008	0.023	0.060
Total (equally weighted)	4.4	4.4	0.53	1.4	2.9	6.0	13.2
Total (weighted by net generation)	3.2	4.3	0.19	0.71	1.8	4.0	12.0

NOTE: In the first five rows of the table, all plants are weighted equally; that is, the average damage per kWh is 4.4 cents, taking an arithmetic average of the damage per kWh across all 406 plants. In the last row of the table, the damage per kWh is weighted by the electricity generated by each plant to produce a weighted damage per kWh.

ABBREVIATIONS: SO2 = sulfur dioxide = NOx, oxides of nitrogen; PM = particulate matter.

Sherco Units 1 and 2 data: 0.15 cents/kWh for SO_2 (expected value in 2015);
0.095 cents/kWh for NOx (expected value in 2015);
0.0046 cents/kWh for PM_{10} (2012 actual value).

C. Cost Estimate Impacts Using Values Derived From NRC Study

The cost impacts that result from using the NRC values in place of the Minnesota values do not add significant new insight to the analysis already performed. The federal CO_2 values confirm the same result that the other six CO_2 sensitivities already have: that higher CO_2 costs lower the cost effectiveness of continued operation of Sherco Units 1 and 2. Use of the NRC values for SO_2, NO_x, and PM_{10} also reduce the cost effectiveness of continued operations, however because emissions of these pollutants from Sherco Units 1 and 2 are already low and will be reduced even further, the cost impact is much smaller.

To model the cost impact of the NRC Values, the Company used the total annual emissions from the early retirement scenario (#1) and the early SCR scenario (#13) using the sensitivity assumption of no energy available to be purchased from the MISO market ("Markets Off"). In our standard Strategist dispatch simulations energy purchased from MISO has particularly high emission rates that are based on the current rates observed in MISO. In scenario #13, when Sherco Units 1 and 2 are retired the model increases its MISO purchases to partially compensate for the retired units. This would lead to abnormally high emissions of SO_2, NO_x, and PM_{10}.[37] Use of the "Markets Off" sensitivity results in the largest reduction in these pollutants and also the largest externality cost estimates, so is a conservative analysis.

Generally, the damage cost estimates found through use of the NRC values were higher than the externality values specified by the Commission, with the exception of PM_{10}. Table 1 compares the Minnesota values to the NRC values analyzed in this section. Note that Minnesota specifies a range of values to be used based on where generators are located, while the NRC values do not.

Table 1 – Comparison of Values

	Minnesota Externality Values	NRC / RIA Values
SO2	\$0/ton	\$3,190-\$4,303/ton
NOx	\$149-\$1,442/ton	\$756-\$1,983/ton
PM10	\$1,245-\$9,354/ton	\$28-\$978/ton
CO2	\$21.50/ton in 2017 escl@ 2.36%	\$37-\$57/ton in 2013 escl@ 4.2%

[37] It should be noted that a scenario that results in greater purchases from MISO may result in no overall criteria pollutant emission reductions for these pollutants, and might increase them, calling into question whether any assumed externality costs would actually be addressed.

As discussed in this study, the costs associated with CO_2 plays a large role in estimating the cost effectiveness of scenarios for Sherco Units 1 and 2. Through our Strategist analysis we determined that our base assumption of \$21.50/ton CO_2 increased the benefits of retirement by \$1.1 billion on a PVRR basis. The federal CO_2 RIA values are higher, start earlier, and escalate faster. As shown in Table 2, the PVRR impact was larger using the federal RIA CO_2 values, up to \$3 billion for the \$57.00/ton sensitivity. The cost impact from the other pollutants was much smaller. Despite substantially higher dollars per ton based on the NRC values for SO_2, NO_x and PM_{10}, the total cost impact is quite small at \$159 million. This is primarily a reflection of the fact that Sherco Units 1 and 2 will have even lower emission rates for SO_2 and PM_{10} upon completion of the sparger tube improvement in their wet ESPs and installation of SCRs assumed in the scenarios lowers the NO_x emission rate.

Table 2 – Impact of CO_2 RIA and NRC Study Values

NPV of SO2, NOx, and PM10 Values (\$millions)		
	Early SCRs (scenario 1)	**Early Retirement (scenario 13)**
NPV	\$1,179	\$1,020
	Net Impact	**(\$159)**
NPV Federal CO2 Values (\$millions)		
	Early SCRs (scenario 1)	**Early Retirement (scenario 13)**
Low	\$11,865	\$9,929
	Net Impact	**(\$1,936)**
High	\$17,509	\$14,692
	Net Impact	**(\$2,817)**

To calculate these values a spreadsheet model was utilized that took total annual emission estimates from the appropriate Strategist runs and multiplied the NRC Values and federal RIA CO_2 Value by those annual tons. Figures 1 through 4, illustrate the annual tons of emissions that were estimated using Strategist for the scenarios that were compared.

Figure 1: Strategist Annual SO2 Emissions

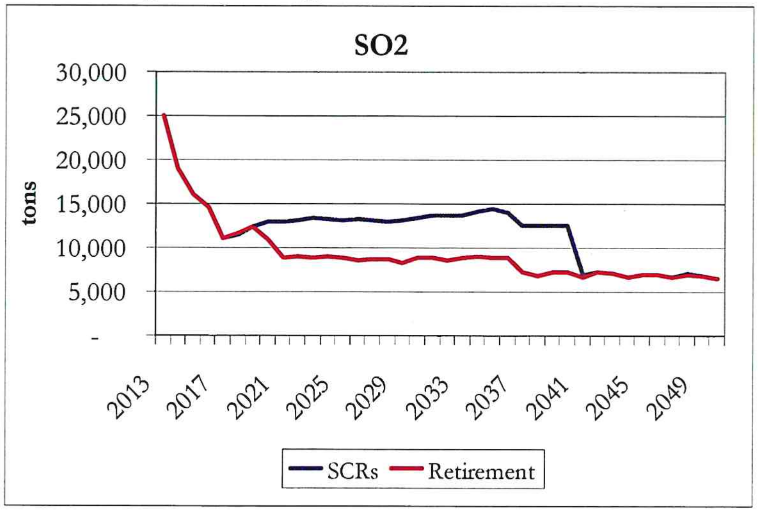


Figure 2: Strategist Annual NOx Emissions

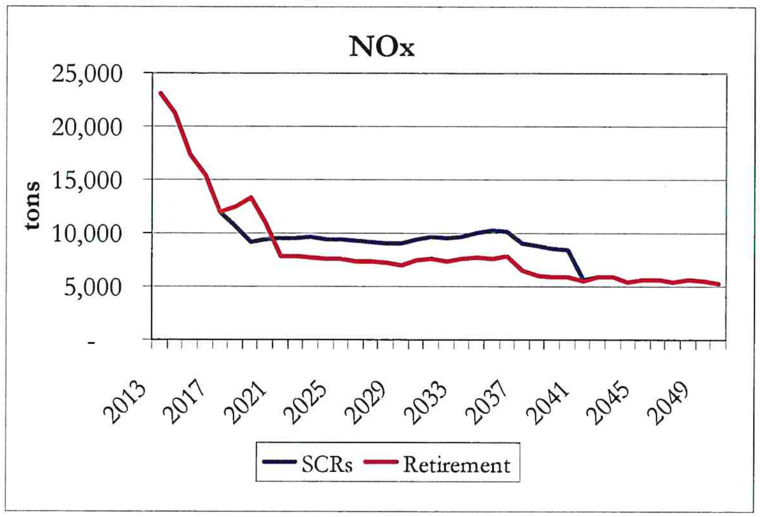


Figure 3: Strategist Annual PM10 Emissions

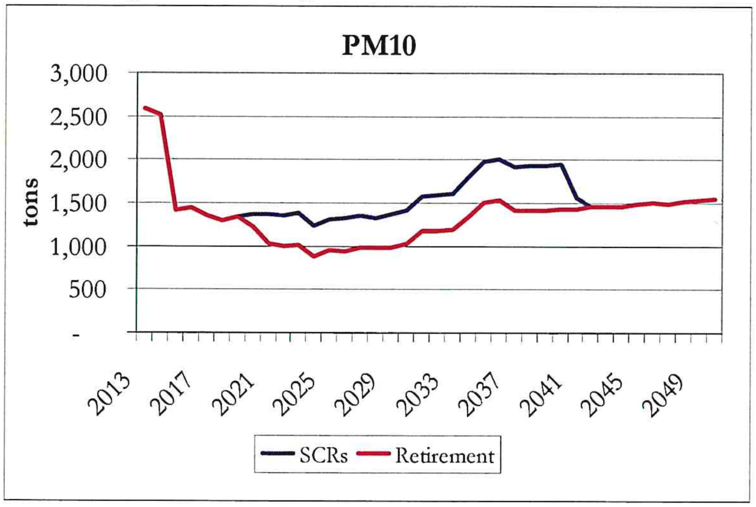
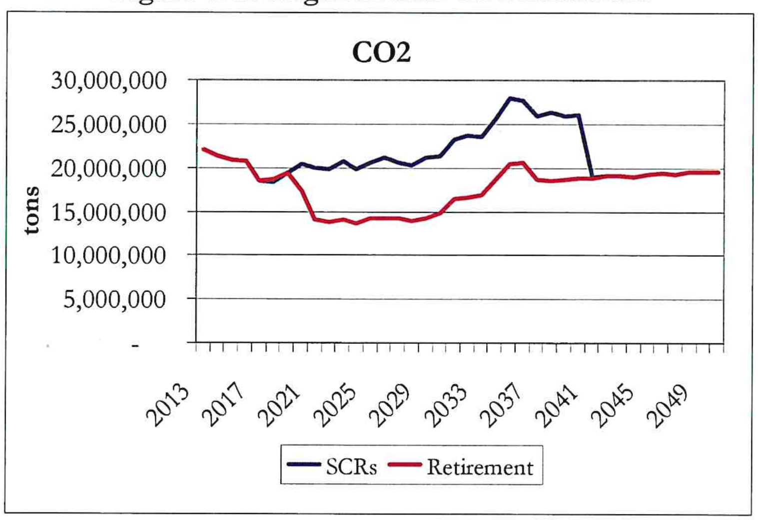


Figure 4: Strategist Annual CO2 Emissions



VI. SUMMARY

Since the establishment of externality values specific to Minnesota by the Commission, the NAAQS have been reviewed and made more stringent, multiple additional emission reduction requirements have been imposed (*see* Appendix A), and emissions from Minnesota power plants and multiple other sources have declined.[38] Xcel Energy believes that the Commission's updated externality values, carbon proxy costs, and the costs of control that have been estimated for Sherco Units 1 and 2 based on anticipated environmental regulatory developments for non-carbon emissions are a more appropriate indicator of any residual externalities than any values that might be extrapolated from EPA's varied RIAs or the NRC study.

Xcel Energy's scenarios, with the exception of the scenario requested by stakeholders and discussed in section V above, include both the cost of Selective Catalytic Reduction (SCR) control technology and the Commission's approved environmental externality costs. Sensitivity analyses also include the carbon regulation proxy costs at the high, midpoint, and low ends of the Commission-approved range. The detailed assessment in Appendix A of the impact of anticipated federal and state environmental regulation on non-carbon emissions from Sherco Units 1 and 2 establishes that the only additional control technology investment that could be made is SCRs.

[38] *Air Quality In Minnesota: 2013 Report to the Legislature* at 3 & 15, Minnesota Pollution Control Agency, January 2013.

Appendix D
Modeling Inputs and Assumptions

Load Forecast 2013-2040

Energy and Demand Forecast (Spring 2013)

	Energy (MWh)	Demand (MW)
2013	44,714	9,223
2014	44,679	9,271
2015	44,854	9,349
2016	45,211	9,437
2017	45,385	9,540
2018	45,675	9,644
2019	46,001	9,748
2020	46,370	9,864
2021	46,701	9,979
2022	47,041	10,102
2023	47,328	10,220
2024	47,600	10,338
2025	47,828	10,449
2026	48,119	10,572
2027	48,466	10,701
2028	48,863	10,837
2029	49,222	10,968
2030	49,571	11,111
2031	49,864	11,254
2032	50,233	11,398
2033	50,606	11,544
2034	50,975	11,703
2035	51,322	11,860
2036	51,702	12,017
2037	52,036	12,173
2038	52,400	12,339
2039	52,769	12,502
2040	53,168	12,671

Average Annual Growth - Forecasted

	Energy (MWh)	Demand (MW)
2013 - 2019	0.47%	0.93%
2020 - 2030	0.68%	1.19%
2030 - 2040	0.71%	1.31%
2013 - 2040	0.64%	1.18%

Coal Price Forecast ($/mmBTU)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
King	$2.18	$2.41	$2.36	$2.39	$2.53	$2.61	$2.67	$2.71	$2.78	$2.86
Black Dog	$1.94	$2.23	$2.23	$2.28	$2.36	$2.43	$2.49	$2.53	$2.59	$2.66
Sherco	$2.24	$2.27	$2.27	$2.27	$2.36	$2.43	$2.49	$2.52	$2.59	$2.66

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
King	$2.93	$3.01	$3.09	$3.17	$3.26	$3.33	$3.41	$3.49	$3.58	$3.66
Black Dog	$2.74	$2.81	$2.88	$2.96	$3.05	$3.12	$3.19	$3.27	$3.35	$3.43
Sherco	$2.73	$2.80	$2.88	$2.95	$3.03	$3.11	$3.18	$3.25	$3.33	$3.41

	2033	2034	2035	2036	2037	2038	2039	2040
King	$3.74	$3.82	$3.90	$3.98	$4.06	$4.14	$4.22	$4.31
Black Dog	$3.50	$3.58	$3.66	$3.73	$3.80	$3.88	$3.96	$4.04
Sherco	$3.48	$3.56	$3.63	$3.71	$3.78	$3.85	$3.93	$4.01

(1) - All-inclusive price forecast - contracted fuel and delivery
(2) - Spring 2013 Forecast

Environmental Externality Values - Metropolitan Fringe - Sherco

	PM10	CO	Pb	NOx
2013	$4,210	$1.95	$2,910	$388
2014	$4,309	$2.00	$2,978	$397
2015	$4,411	$2.05	$3,049	$407
2016	$4,515	$2.09	$3,121	$416
2017	$4,621	$2.14	$3,194	$426
2018	$4,730	$2.19	$3,270	$436
2019	$4,842	$2.25	$3,347	$447
2020	$4,956	$2.30	$3,426	$457
2021	$5,073	$2.35	$3,507	$468
2022	$5,193	$2.41	$3,589	$479
2023	$5,315	$2.46	$3,674	$490
2024	$5,441	$2.52	$3,761	$502
2025	$5,569	$2.58	$3,849	$514
2026	$5,701	$2.64	$3,940	$526
2027	$5,835	$2.71	$4,033	$538
2028	$5,973	$2.77	$4,129	$551
2029	$6,114	$2.84	$4,226	$564
2030	$6,258	$2.90	$4,326	$577
2031	$6,406	$2.97	$4,428	$591
2032	$6,557	$3.04	$4,532	$605
2033	$6,712	$3.11	$4,639	$619
2034	$6,870	$3.19	$4,749	$634
2035	$7,032	$3.26	$4,861	$649
2036	$7,198	$3.34	$4,976	$664
2037	$7,368	$3.42	$5,093	$680
2038	$7,542	$3.50	$5,213	$696
2039	$7,720	$3.58	$5,336	$712
2040	$7,720	$3.58	$5,336	$729

(1) "Notice of Updated Environmental Externality Values"
Dockets CI-93-583 and CI-00-1636, June 13, 3002
(2) Inflation adjusted values, 2011 $/ton, High values
(3) The Sherco site is located in the Metropolitan Fringe
(4) Inflation Rate = 2.36%

Reference Case 2013-2040 Expansion Plan

	Retirement	Combined Cycle	Combustion Turbine	Base Load	Solar	Wind Additions
2013				Monticello EPU 65MW	SolrRwds 1 MW	
2014					SolrRwds 1 MW	
2015	BlackDog 4 -156 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	BlackDog 3 -84 MW					Wind 100MW (13MW)
2016	Coyote 1 -92 MW		Fch Isld 3 57 MW		SolrRwds 1 MW	
2017	Rapidan -3 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Key City 4 -15 MW					
	Key City 3 -14 MW					
	Key City 2 -14 MW					
	Granite 4 -13 MW					
	Granite 3 -14 MW					
	Granite 2 -14 MW					
	Granite 1 -13 MW					
2018	Wilmarth 1 -12 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Viking -2 MW					
	Red Wing 1 -12 MW					
	HERC -24 MW					
	Flambeau 1 -12 MW					
2019	WSMorrn -6 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	WindPowr -3 MW					Wind 100MW (13MW)
	Moraine -7 MW					
	KODARAHR -11 MW					
2020					SolrRwds 1 MW	Wind 100MW (13MW)
2021	Fch Isld 4 -57 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Fch Isld 3 -57 MW					
2022	St.Cloud -8 MW				SolrRwds 1 MW	Wind 100MW (13MW)
2023	St Paul -23 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	MNDakota -19 MW					Wind 100MW (13MW)
2024	Fch Isld 1 -9 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Chanaram -11 MW					Wind 100MW (13MW)
	Bayfront 6 -12 MW					
	Bayfront 5 -20 MW					
	Bayfront 4 -11 MW					
2025	Stahl -1 MW	Generic CC 817MW	Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	MNWind -1 MW		Generic CT 226MW			Wind 100MW (13MW)
	MH375500 -488 MW		Generic CT 226MW			
	LkBnton2 -13 MW					
	Invenerg 2 -144 MW					
	Invenerg 1 -151 MW					
2026	Velva -2 MW				SolrRwds 1 MW	Wind 100MW (13MW)
	Tholen -2 MW					
	PineBend -5 MW					
	Norgaard -1 MW					
	Garmen -1 MW					
	Eastridg -1 MW					
2027	Laurentn 1 -35 MW	Generic CC 817MW			SolrRwds 1 MW	Wind 100MW (13MW)
	Inverhil 6 -45 MW					Wind 100MW (13MW)
	Inverhil 5 -42 MW					
	Inverhil 4 -40 MW					
	Inverhil 3 -41 MW					
	Inverhil 2 -44 MW					

Reference Case 2013-2040 Expansion Plan

	Retirement	Combined Cycle	Combustion Turbine	Base Load	Solar	Wind Additions
2028	WSWstrdg -1 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	LSCotGrv 1 -226 MW					Wind 100MW (13MW)
	Garmen -2 MW					
	Ewington -3 MW					
	Cisco -1 MW					
2029	LkBnton1 -14 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Jeffers -6 MW					Wind 100MW (13MW)
	FibroMN -46 MW					
2030	Anson 3 -87 MW		Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Anson 2 -87 MW					
2031	Ruthton -2 MW	Generic CC 817MW	Generic CT 226MW		SolrRwds 1 MW	Wind 100MW (13MW)
	Ridgewnd -3 MW					
	Monti 1 -597 MW					
	GrantCo -3 MW					
	BlueLake 4 -45 MW					
	BlueLake 3 -38 MW					
	BlueLake 2 -39 MW					
	BlueLake 1 -38 MW					
2032	SmllCBED -2 MW		Generic CT 226MW			Wind 100MW (13MW)
	SAF Hydr -4 MW					Wind 100MW (13MW)
	NthShaok -2 MW					
	GoodhuNS -10 MW					
	Danielsn -3 MW					
	CrownHyd -1 MW					
	CommWndN -4 MW					
	BigBlue -5 MW					
	BDog_CC 5 -246 MW					
	Adams -3 MW					
2033	NAEShaok -2 MW		Generic CT 226MW			Wind 100MW (13MW)
	Fenton -27 MW					Wind 100MW (13MW)
						Wind 100MW (13MW)
						Wind 100MW (13MW)
2034	WoodStck -1 MW	Generic CC 817MW				Wind 100MW (13MW)
	P Island 1 -503 MW					
	Lakota -1 MW					
	GrandMed -13 MW					
2035	WINDGEN -13 MW	Generic CC 817MW	Generic CT 226MW			Wind 100MW (13MW)
	WINDGEN -13 MW					Wind 100MW (13MW)
	P Island 2 -510 MW					Wind 100MW (13MW)
	BlueLake 8 -150 MW					
	BlueLake 7 -148 MW					
	Anson 4 -133 MW					
2036	Wheaton 6 -46 MW		Generic CT 226MW			Wind 100MW (13MW)
	Wheaton 5 -37 MW		Generic CT 226MW			Wind 100MW (13MW)
	Wheaton 4 -47 MW					
	Wheaton 3 -46 MW					
	Wheaton 2 -50 MW					
	Wheaton 1 -45 MW					
	Nobles -26 MW					
2037	WINDGEN -13 MW		Generic CT 226MW			Wind 100MW (13MW)
	AS King 1 -477 MW		Generic CT 226MW			
			Generic CT 226MW			
2038	WINDGEN -13 MW	Generic CC 817MW				Wind 100MW (13MW)
	HB_CC 1 -514 MW					
2039	WINDGEN -13 MW	Generic CC 817MW				Wind 100MW (13MW)
	WINDGEN -13 MW					Wind 100MW (13MW)
	RS_CC 1 -416 MW					Wind 100MW (13MW)
2040	WINDGEN -13 MW					Wind 100MW (13MW)

Capacity - Owned Generation Resource

Unit	Dependable Capacity (MW)	Accredited Capacity (MW)
COAL		
King 1	511	477
Black Dog 3	77	84
Black Dog 4	155	156
Sherco 1	681	676
Sherco 2	682	670
Sherco 3 - Xcel	515	496
NUCLEAR		
Monticello 1	652	597
Prairie Island 1	546	503
Prairie Island 2	546	510
BIOMASS		
Bay Front 4	15	11
Bay Front 5	15	20
Bay Front 6	20	12
French Island	17	9
Red Wing	18	12
Wilmarth	18	12
OIL		
Blue Lake 1	52	38
Blue Lake 2	52	39
Blue Lake 3	52	38
Blue Lake 4	59	45
French Island 3	0	0
French Island 4	81	57
Wheaton 5	70	37
Wheaton 6	70	46
Inver Hills D78		
Diesel Generation	6	6
WIND		
Grand Meadow	100	13
Nobles	200	26
HYDRO		
Hydro Generation	268	93

Unit	Dependable Capacity (MW)	Accredited Capacity (MW)
GAS CTs		
Angus Anson 2	120	87
Angus Anson 3	120	87
Angus Anson 4	181	133
Blue Lake 7	180	148
Blue Lake 8	180	150
Flambeau 1	18	12
Granite City 1	16	13
Granite City 2	16	14
Granite City 3	16	14
Granite City 4	16	13
Inver Hills 1	62	42
Inver Hills 2	62	44
Inver Hills 3	62	41
Inver Hills 4	62	40
Inver Hills 5	62	42
Inver Hills 6	62	45
Key City 1	0	0
Key City 2	16	14
Key City 3	16	14
Key City 4	16	15
Wheaton 1	62	45
Wheaton 2	70	50
Wheaton 3	62	46
Wheaton 4	62	47
GAS CCs		
Black Dog 52	276	246
High Bridge	582	514
Riverside	511	416

Energy Conservation and Direct Load Control

	Energy Conservation (MW)	Direct Load Control
2013	98	985
2014	98	995
2015	98	1,004
2016	102	1,013
2017	105	1,024
2018	105	1,035
2019	110	1,045
2020	114	1,056
2021	117	1,066
2022	125	1,077
2023	132	1,079
2024	141	1,075
2025	155	1,070
2026	163	1,066
2027	175	1,062
2028	179	1,058
2029	185	1,054
2030	184	1,050
2031	184	1,046
2032	190	1,042
2033	184	1,038
2034	186	1,034
2035	191	1,030
2036	191	1,026
2037	195	1,023
2038	202	1,019
2039	198	1,015
2040	204	1,012

Other Strategist Inputs

General Inflation Rate – 2.36%
Labor Inflation Rate – 2.51%
Non Labor Inflation Rate – 2.27%
Discount Rate – 7.56%
Composite Tax Rate – 40.75%
CO_2 - $21.50/ton starting in 2017 escalating at general inflation
Externality Costs – Based on midpoint of Commission established values

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist - PVRR Total ($000)

Strategist - PVRR Total ($000)		01 1 SCR Early - 2 SCR Early	02 1 SCR Late - 2 SCR Late	03 1 Ret Early - 2 SCR Early - Opt	04 1 Ret Early - 2 SCR Early - CC	05 1 Ret Early - 2 SCR Early - CT Wind	06 SCR Early - CT Wind Solar	07 SCR Early - CT Wind Solar DSM	08 1 Ret Late - 2 SCR Late - Opt	09 1 Ret Late - 2 SCR Late - CC	10 1 Ret Late - 2 SCR Late - CT Wind	11 SCR Late - CT Wind Solar	12 SCR Late - CT Wind Solar DSM
Base		47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,817,631	48,545,256	47,924,585	47,924,585	48,249,682	48,484,196	48,267,789
Load - Fall 2011	A	48,744,713	48,635,454	48,828,275	48,828,275	49,274,125	49,601,417	49,331,648	48,696,900	48,696,900	49,037,327	49,267,913	49,050,887
Low Load	B	44,883,659	44,774,467	44,948,497	44,948,497	45,450,617	45,775,495	45,494,833	44,818,693	44,818,693	45,217,719	45,437,608	45,224,463
High Load	C	51,593,786	51,484,502	51,676,053	51,676,053	52,051,555	52,396,584	52,128,585	51,545,774	51,545,774	51,811,721	52,059,746	51,845,817
Low Gas Prices	D	45,123,972	45,015,485	44,859,986	44,859,986	45,736,000	46,159,914	45,835,574	44,821,423	44,821,423	45,540,249	45,643,684	45,591,336
High Gas Prices	E	51,539,038	51,429,761	52,182,102	52,182,102	52,006,493	52,216,111	52,009,610	51,940,154	51,940,154	51,699,350	51,835,001	51,668,039
Low Coal Prices	F	47,369,538	47,260,068	47,588,213	47,588,213	48,030,044	48,363,906	48,088,347	47,434,036	47,434,036	47,769,665	48,003,223	47,784,678
High Coal Prices	G	48,636,836	48,527,687	48,542,704	48,542,704	48,968,377	49,300,722	49,031,450	48,439,882	48,439,882	48,761,709	48,994,961	48,780,575
Wind $30	H	47,977,585	47,868,345	48,053,659	48,053,659	47,599,848	48,038,874	47,915,351	47,924,585	47,924,585	47,532,638	47,871,919	47,762,746
Wind $40	I	47,977,585	47,868,345	48,053,659	48,053,659	47,991,268	48,383,882	48,194,413	47,924,585	47,924,585	47,850,302	48,143,171	47,986,490
Wind $65	J	47,977,585	47,868,345	48,053,659	48,053,659	48,969,971	49,246,529	48,892,172	47,924,585	47,924,585	48,644,589	48,821,403	48,545,938
Solar $100	K	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,560,240	48,329,167	47,924,585	47,924,585	48,249,682	48,284,549	48,097,897
Solar $150	L	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	49,075,044	48,761,361	47,924,585	47,924,585	48,249,682	48,683,859	48,437,695
Solar $75	M	47,977,585	47,868,345	48,053,659	48,053,659	48,483,374	48,302,825	48,113,060	47,924,585	47,924,585	48,249,682	48,084,884	47,927,988
CO2 $0	N	42,080,068	41,970,958	42,688,477	42,688,477	43,493,224	43,909,884	43,580,706	42,394,259	42,394,259	43,012,574	43,298,383	43,054,502
CO2 $9	O	44,496,328	44,386,983	44,902,084	44,902,084	45,545,866	45,926,934	45,622,266	44,670,031	44,670,031	45,165,725	45,429,311	45,197,372
CO2 $34	P	50,832,905	50,724,756	50,598,391	50,598,391	50,904,117	51,189,305	50,942,112	50,572,849	50,572,849	50,792,141	50,996,259	50,789,758
CO2 $9 2025	Q	43,343,216	43,234,106	43,830,683	43,830,683	44,530,566	44,928,348	44,615,070	43,536,979	43,536,979	44,049,941	44,316,867	44,088,889
CO2 $21.50 2025	R	45,076,096	44,966,986	45,385,287	45,385,287	45,951,754	46,325,476	46,032,320	45,092,232	45,092,232	45,471,152	45,714,020	45,506,164
CO2 $34 2025	S	46,744,641	46,635,531	46,857,612	46,857,612	47,309,650	47,657,944	47,383,372	46,565,585	46,565,585	46,829,071	47,046,505	46,857,233
Sherco Cost +25%	T	48,355,405	48,243,758	48,298,841	48,298,841	48,728,145	49,062,266	48,790,034	48,207,159	48,207,159	48,531,985	48,766,405	48,550,051
SCR Cost +25%	U	48,080,447	47,942,957	48,104,066	48,104,066	48,533,702	48,867,932	48,595,595	47,960,762	47,960,762	48,285,793	48,520,290	48,303,906
CC & CT Costs + 25%	V	48,082,963	47,973,723	48,343,410	48,343,410	48,660,452	48,942,270	48,669,894	48,156,513	48,156,513	48,389,194	48,581,531	48,365,124
Changed State Policy	X	50,755,673	50,646,783	50,671,930	50,846,160	52,095,032	52,506,489	52,114,465	50,492,601	50,761,805	51,832,460	52,108,327	51,811,562
Markets Off	Y	47,982,286	47,873,288	48,059,994	48,059,994	48,498,885	48,826,743	48,556,413	47,930,901	47,930,901	48,257,767	48,487,994	48,273,404
SCR Depreciation 10YR	Z	47,971,452	47,863,788	48,050,650	48,050,650	48,480,364	48,814,622	48,542,246	47,922,349	47,922,349	48,247,446	48,481,959	48,265,553
SCR Depreciation 5YR	AA	47,963,752	47,858,067	48,046,871	48,046,871	48,476,586	48,810,843	48,538,468	47,919,542	47,919,542	48,244,639	48,479,152	48,262,745

Strategist - PVRR Total ($000)		13 1 Ret Early - 2 Ret Early - Opt	14 1 Ret Early - 2 Ret Early - CC	15 1 Ret Early - 2 Ret Early - CT Wind	16 1 Ret Early - 2 Ret Early - CT Wind Solar	17 Ret Early - CT Wind Solar DSM	18 1 Ret Late - 2 Ret Late - Opt	19 1 Ret Late - 2 Ret Late - CC	20 1 Ret Late - 2 Ret Late - CT Wind	21 1 Ret Late - 2 Ret Late - CT Wind Solar	22 Ret Late - CT Wind Solar DSM	23 Reference Case
Base		47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
Load - Fall 2011	A	48,716,503	48,716,503	50,142,750	50,509,494	50,204,349	48,641,700	48,641,700	49,562,548	49,824,026	49,587,532	48,353,379
Low Load	B	44,832,048	44,832,048	46,408,491	46,742,540	46,368,768	44,758,914	44,758,914	45,802,616	46,030,321	45,735,473	44,492,593
High Load	C	51,565,600	51,565,600	52,905,316	53,292,599	52,926,562	51,494,208	51,494,208	52,325,310	52,604,649	52,304,110	51,202,391
Low Gas Prices	D	44,458,055	44,458,055	46,767,939	47,180,601	46,835,696	44,561,304	44,561,304	46,203,511	46,493,121	46,231,440	44,736,142
High Gas Prices	E	52,672,540	52,672,540	52,915,738	53,203,984	52,951,844	52,347,724	52,347,724	52,235,344	52,438,027	52,244,110	51,148,055
Low Coal Prices	F	47,626,214	47,626,214	49,093,028	49,447,703	49,139,121	47,500,660	47,500,660	48,443,929	48,693,995	48,457,230	46,978,230
High Coal Prices	G	48,276,176	48,276,176	49,683,725	50,058,540	49,756,613	48,263,096	48,263,096	49,158,118	49,424,030	49,192,056	48,247,175
Wind $30	H	47,940,046	47,940,046	47,243,571	48,167,127	48,010,655	47,870,028	47,870,028	47,257,749	47,916,118	47,788,890	47,586,216
Wind $40	I	47,940,046	47,940,046	48,188,028	48,864,068	48,641,649	47,870,028	47,870,028	47,935,507	48,416,521	48,241,785	47,586,216
Wind $65	J	47,940,046	47,940,046	50,549,453	50,606,629	50,219,323	47,870,028	47,870,028	49,630,165	49,667,716	49,374,197	47,586,216
Solar $100	K	47,940,046	47,940,046	49,375,382	49,262,442	48,998,419	47,870,028	47,870,028	48,787,599	48,702,472	48,497,765	47,586,216
Solar $150	L	47,940,046	47,940,046	49,375,382	50,218,102	49,871,469	47,870,028	47,870,028	48,787,599	49,388,830	49,124,612	47,586,216
Solar $75	M	47,940,046	47,940,046	49,375,382	48,784,587	48,561,872	47,870,028	47,870,028	48,787,599	48,359,275	48,184,326	47,586,216
CO2 $0	N	43,114,714	43,114,714	45,412,533	45,771,200	45,421,218	42,702,947	42,702,947	44,237,112	44,488,761	44,233,302	41,689,590
CO2 $9	O	45,122,198	45,122,198	47,047,555	47,409,191	47,078,034	44,840,178	44,840,178	46,113,454	46,367,705	46,121,025	44,105,359
CO2 $34	P	50,233,724	50,233,724	51,328,468	51,681,217	51,396,196	50,355,256	50,355,256	51,029,313	51,279,454	51,052,593	50,444,735
CO2 $9 2025	Q	44,127,391	44,127,391	46,191,202	46,554,062	46,216,942	43,727,593	43,727,593	45,037,953	45,291,812	45,049,563	42,952,496
CO2 $21.50 2025	R	45,491,157	45,491,157	47,257,605	47,625,820	47,305,426	45,109,187	45,109,187	46,134,993	46,391,808	46,166,713	44,685,165
CO2 $34 2025	S	46,771,580	46,771,580	48,279,187	48,647,459	48,342,812	46,408,408	46,408,408	47,185,907	47,440,693	47,231,789	46,354,590
Sherco Cost +25%	T	48,057,834	48,057,834	49,493,199	49,858,081	49,552,734	48,071,829	48,071,829	48,989,360	49,247,392	49,012,893	47,956,885
SCR Cost +25%	U	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
CC & CT Costs + 25%	V	48,363,120	48,363,120	49,602,349	49,889,831	49,584,506	48,192,318	48,192,318	48,960,876	49,159,852	48,925,392	47,691,594
Changed State Policy	X	50,638,703	50,638,703	53,926,772	54,140,157	53,712,035	50,406,984	50,651,406	53,174,648	53,289,153	52,966,025	50,366,142
Markets Off	Y	47,949,361	47,949,361	49,409,940	49,763,425	49,459,017	47,878,256	47,878,256	48,809,486	49,057,544	48,823,618	47,591,591
SCR Depreciation 10YR	Z	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216
SCR Depreciation 5YR	AA	47,940,046	47,940,046	49,375,382	49,740,248	49,434,923	47,870,028	47,870,028	48,787,599	49,045,634	48,811,174	47,586,216

Strategist - PVRR Deltas ($000)

Strategist - PVRR Deltas ($000)		01 1 SCR Early - 2 SCR Early	02 1 SCR Late - 2 SCR Late	03 1 Ret Early - 2 SCR Early - Opt	04 1 Ret Early - 2 SCR Early - CC	05 1 Ret Early - 2 SCR Early - CT Wind	06 SCR Early - CT Wind Solar	07 SCR Early - CT Wind Solar DSM	08 1 Ret Late - 2 SCR Late - Opt	09 1 Ret Late - 2 SCR Late - CC	10 1 Ret Late - 2 SCR Late - CT Wind	11 SCR Late - CT Wind Solar	12 SCR Late - CT Wind Solar DSM
Base		391,369	282,129	467,443	467,443	897,157	1,231,415	959,039	338,369	338,369	663,466	897,979	681,573
Load - Fall 2011	A	391,334	282,075	474,896	474,896	920,746	1,248,038	978,269	343,521	343,521	683,948	914,534	697,508
Low Load	B	391,066	281,874	455,904	455,904	958,024	1,282,902	1,002,240	326,100	326,100	725,126	945,015	731,870
High Load	C	391,395	282,110	473,662	473,662	849,163	1,194,193	926,194	343,383	343,383	609,330	857,356	643,425
Low Gas Prices	D	387,830	279,343	123,843	123,843	999,858	1,423,772	1,099,432	85,281	85,281	804,107	1,107,542	855,194
High Gas Prices	E	390,983	281,706	1,034,048	1,034,048	858,439	1,068,057	861,555	792,099	792,099	551,295	686,946	519,985
Low Coal Prices	F	391,308	281,838	609,983	609,983	1,051,613	1,385,676	1,110,117	455,806	455,806	791,435	1,024,992	806,447
High Coal Prices	G	389,661	280,512	295,529	295,529	721,202	1,053,547	784,275	192,707	192,707	514,534	747,786	533,400
Wind $30	H	391,369	282,129	467,443	467,443	13,632	452,657	329,135	338,369	338,369	-53,578	285,703	176,530
Wind $40	I	391,369	282,129	467,443	467,443	405,052	797,665	608,196	338,369	338,369	264,086	556,955	400,273
Wind $65	J	391,369	282,129	467,443	467,443	1,383,755	1,660,313	1,305,956	338,369	338,369	1,058,373	1,235,186	959,721
Solar $100	K	391,369	282,129	467,443	467,443	897,157	974,024	742,951	338,369	338,369	663,466	698,333	511,681
Solar $150	L	391,369	282,129	467,443	467,443	897,157	1,488,828	1,175,145	338,369	338,369	663,466	1,097,643	851,479
Solar $75	M	391,369	282,129	467,443	467,443	897,157	716,609	526,843	338,369	338,369	663,466	498,667	341,772
CO2 $0	N	390,478	281,368	998,887	998,887	1,803,634	2,220,294	1,891,117	704,669	704,669	1,322,985	1,608,793	1,364,913
CO2 $9	O	390,969	281,624	796,726	796,726	1,440,508	1,821,576	1,516,908	564,672	564,672	1,060,367	1,323,952	1,092,013
CO2 $34	P	388,170	280,021	153,656	153,656	459,382	744,570	497,377	128,114	128,114	347,406	551,524	345,023
CO2 $9 2025	Q	390,720	281,610	878,187	878,187	1,578,070	1,975,852	1,662,574	584,483	584,483	1,097,445	1,364,371	1,136,393
CO2 $21.50 2025	R	390,931	281,821	700,122	700,122	1,266,589	1,640,311	1,347,155	407,067	407,067	785,987	1,028,855	820,999
CO2 $34 2025	S	390,051	280,941	503,022	503,022	955,060	1,303,354	1,028,782	210,995	210,995	474,481	691,915	502,643
Sherco Cost +25%	T	398,520	286,872	341,955	341,955	771,260	1,105,380	833,148	250,273	250,273	575,099	809,520	593,166
SCR Cost +25%	U	494,231	356,740	517,850	517,850	947,485	1,281,716	1,009,379	374,546	374,546	699,577	934,074	717,689
CC & CT Costs + 25%	V	391,369	282,129	651,816	651,816	968,858	1,250,676	978,300	464,919	464,919	697,600	889,937	673,530
Changed State Policy	X	389,530	280,641	305,788	480,017	1,728,889	2,140,347	1,748,323	126,458	395,663	1,466,317	1,742,184	1,445,420
Markets Off	Y	390,695	281,698	468,403	468,403	907,294	1,235,153	964,822	339,310	339,310	666,176	896,404	681,813
SCR Depreciation 10YR	Z	385,235	277,572	464,433	464,433	894,148	1,228,405	956,030	336,133	336,133	661,230	895,743	679,336
SCR Depreciation 5YR	AA	377,535	271,851	460,655	460,655	890,369	1,224,627	952,251	333,325	333,325	658,423	892,936	676,529

Strategist - PVRR Deltas ($000)		13 1 Ret Early - 2 Ret Early - Opt	14 1 Ret Early - 2 Ret Early - CC	15 1 Ret Early - 2 Ret Early - CT Wind	16 1 Ret Early - 2 Ret Early - CT Wind Solar	17 Ret Early - CT Wind Solar DSM	18 1 Ret Late - 2 Ret Late - Opt	19 1 Ret Late - 2 Ret Late - CC	20 1 Ret Late - 2 Ret Late - CT Wind	21 1 Ret Late - 2 Ret Late - CT Wind Solar	22 Ret Late - CT Wind Solar DSM	23 Reference Case
Base		353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
Load - Fall 2011	A	363,124	363,124	1,789,371	2,156,115	1,850,970	288,321	288,321	1,209,169	1,470,647	1,234,153	0
Low Load	B	339,455	339,455	1,915,898	2,249,947	1,876,175	266,321	266,321	1,310,023	1,537,728	1,242,880	0
High Load	C	363,209	363,209	1,702,925	2,090,208	1,724,171	291,817	291,817	1,122,919	1,402,258	1,101,718	0
Low Gas Prices	D	-278,087	-278,087	2,031,797	2,444,459	2,099,554	-174,839	-174,839	1,467,369	1,756,979	1,495,298	0
High Gas Prices	E	1,524,486	1,524,486	1,767,683	2,055,929	1,803,789	1,199,669	1,199,669	1,087,290	1,289,972	1,096,056	0
Low Coal Prices	F	647,984	647,984	2,114,798	2,469,473	2,160,890	522,430	522,430	1,465,699	1,715,765	1,479,000	0
High Coal Prices	G	29,001	29,001	1,436,550	1,811,365	1,509,438	15,921	15,921	910,943	1,176,855	944,881	0
Wind $30	H	353,829	353,829	-342,646	580,910	424,438	283,812	283,812	-328,468	329,902	202,674	0
Wind $40	I	353,829	353,829	601,811	1,277,851	1,055,432	283,812	283,812	349,290	830,304	655,569	0
Wind $65	J	353,829	353,829	2,963,237	3,020,413	2,633,106	283,812	283,812	2,043,948	2,081,499	1,787,980	0
Solar $100	K	353,829	353,829	1,789,166	1,676,225	1,412,203	283,812	283,812	1,201,382	1,116,256	911,549	0
Solar $150	L	353,829	353,829	1,789,166	2,631,886	2,285,253	283,812	283,812	1,201,382	1,802,613	1,538,395	0
Solar $75	M	353,829	353,829	1,789,166	1,198,371	975,655	283,812	283,812	1,201,382	773,059	598,110	0
CO2 $0	N	1,425,124	1,425,124	3,722,943	4,081,610	3,731,628	1,013,358	1,013,358	2,547,522	2,799,172	2,543,712	0
CO2 $9	O	1,016,840	1,016,840	2,942,196	3,303,832	2,972,676	734,820	734,820	2,008,095	2,262,347	2,015,667	0
CO2 $34	P	-211,011	-211,011	883,733	1,236,482	951,461	-89,479	-89,479	584,578	834,719	607,858	0
CO2 $9 2025	Q	1,174,895	1,174,895	3,238,706	3,601,566	3,264,446	775,097	775,097	2,085,457	2,339,316	2,097,067	0
CO2 $21.50 2025	R	805,992	805,992	2,572,440	2,940,656	2,620,261	424,023	424,023	1,449,828	1,706,643	1,481,548	0
CO2 $34 2025	S	416,990	416,990	1,924,597	2,292,869	1,988,222	53,818	53,818	831,317	1,086,103	877,199	0
Sherco Cost +25%	T	100,949	100,949	1,536,313	1,901,195	1,595,848	114,943	114,943	1,032,475	1,290,506	1,056,008	0
SCR Cost +25%	U	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
CC & CT Costs + 25%	V	671,526	671,526	1,910,755	2,198,237	1,892,912	500,724	500,724	1,269,282	1,468,258	1,233,797	0
Changed State Policy	X	272,561	272,561	3,560,630	3,774,015	3,345,893	40,841	285,263	2,808,506	2,923,010	2,599,882	0
Markets Off	Y	357,770	357,770	1,818,350	2,171,835	1,867,426	286,666	286,666	1,217,895	1,465,954	1,232,227	0
SCR Depreciation 10YR	Z	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0
SCR Depreciation 5YR	AA	353,829	353,829	1,789,166	2,154,032	1,848,706	283,812	283,812	1,201,382	1,459,418	1,224,957	0

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual Total System Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,656,249	2,855,433	3,003,638	3,106,304	3,185,503	3,318,096	3,400,924	3,600,694	3,694,068
#1 SCR Late - #2 SCR Late	02	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,616,219	2,777,610	2,932,756	3,040,870	3,124,414	3,261,022	3,392,434	3,637,806	3,725,098
#1 Ret Early - #2 SCR Early - Opt	03	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,024,634	3,181,048	3,257,873	3,389,620	3,460,392	3,657,172	3,741,175
#1 Ret Early - #2 SCR Early - CC	04	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,024,634	3,181,048	3,257,873	3,389,620	3,460,392	3,657,172	3,741,175
#1 Ret Early - #2 SCR Early - CT Wind	05	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,064,904	3,209,328	3,287,907	3,420,398	3,497,244	3,692,991	3,779,242
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	1,880,854	1,890,741	1,967,086	2,010,668	2,546,928	2,617,145	2,815,195	3,096,670	3,232,361	3,312,310	3,445,894	3,526,002	3,722,500	3,811,133
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	1,880,854	1,890,741	1,967,086	2,019,897	2,553,899	2,622,627	2,837,047	3,106,311	3,186,973	3,266,467	3,399,382	3,477,371	3,674,907	3,762,268
#1 Ret Late - #2 SCR Late - Opt	08	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413	3,335,622	3,663,583	3,806,239
#1 Ret Late - #2 SCR Late - CC	09	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413	3,335,622	3,663,583	3,806,239
#1 Ret Late - #2 SCR Late - CT Wind	10	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413	3,335,622	3,710,398	3,840,818
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	1,875,924	1,885,398	1,961,336	2,007,329	2,546,237	2,619,517	2,779,259	2,935,104	3,045,469	3,126,086	3,258,413	3,335,622	3,743,703	3,863,423
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	1,875,924	1,885,398	1,961,336	2,016,558	2,553,208	2,624,935	2,801,113	2,968,892	3,025,239	3,105,253	3,236,836	3,313,754	3,693,666	3,812,183
#1 Ret Early - #2 Ret Early - Opt	13	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	2,976,916	3,167,685	3,288,519	3,423,025	3,491,144	3,682,005	3,762,490
#1 Ret Early - #2 Ret Early - CC	14	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	2,976,916	3,167,685	3,288,519	3,423,025	3,491,144	3,682,005	3,762,490
#1 Ret Early - #2 Ret Early - CT Wind	15	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	3,017,112	3,388,624	3,489,447	3,622,406	3,707,283	3,882,610	3,973,451
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	1,888,875	1,898,535	1,973,996	2,018,241	2,551,694	2,615,520	2,766,410	3,048,834	3,398,526	3,491,823	3,629,667	3,717,305	3,898,256	3,992,198
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	1,888,875	1,898,535	1,973,996	2,027,470	2,558,665	2,621,002	2,788,316	3,058,478	3,346,654	3,438,976	3,576,024	3,663,766	3,845,490	3,938,110
#1 Ret Late - #2 Ret Late - Opt	18	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046	3,336,681	3,608,220	3,798,481
#1 Ret Late - #2 Ret Late - CC	19	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046	3,336,681	3,608,220	3,798,481
#1 Ret Late - #2 Ret Late - CT Wind	20	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046	3,336,681	3,656,007	4,034,394
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	1,879,726	1,888,990	1,964,704	2,010,813	2,549,308	2,622,462	2,782,215	2,937,620	3,049,700	3,133,482	3,263,046	3,336,681	3,690,083	4,040,710
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	1,879,726	1,888,990	1,964,704	2,020,041	2,556,279	2,627,880	2,804,069	2,971,407	3,029,470	3,112,650	3,241,469	3,314,813	3,639,627	3,984,389
Reference Case	23	1,871,716	1,881,153	1,956,577	2,003,182	2,542,431	2,616,219	2,777,610	2,932,756	3,040,870	3,124,414	3,261,022	3,346,323	3,548,120	3,643,389

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	3,893,595	4,041,442	4,195,616	4,400,897	4,637,161	4,829,869	5,009,091	5,262,017	5,802,463	6,091,482	6,289,457	6,547,126	6,824,220	6,987,048
#1 SCR Late - #2 SCR Late	02	3,919,743	4,064,332	4,216,016	4,419,791	4,655,544	4,848,071	5,039,940	5,304,867	5,842,712	6,129,130	6,324,505	6,579,573	6,839,310	6,985,520
#1 Ret Early - #2 SCR Early - Opt	03	3,929,977	4,075,031	4,224,492	4,422,316	4,660,373	4,847,301	5,026,858	5,282,914	5,820,106	6,092,957	6,294,113	6,549,301	6,820,712	6,984,149
#1 Ret Early - #2 SCR Early - CC	04	3,929,977	4,075,031	4,224,492	4,422,316	4,660,373	4,847,301	5,026,858	5,282,914	5,820,106	6,092,957	6,294,113	6,549,301	6,820,712	6,984,149
#1 Ret Early - #2 SCR Early - CT Wind	05	3,967,337	4,115,330	4,266,466	4,466,781	4,695,470	4,887,147	5,071,838	5,325,970	5,848,980	6,122,794	6,331,040	6,586,624	6,861,140	7,026,737
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	4,003,617	4,155,287	4,307,906	4,510,232	4,738,405	4,934,528	5,120,413	5,374,281	5,901,202	6,176,697	6,384,775	6,644,142	6,921,778	7,090,274
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	3,953,245	4,103,513	4,255,086	4,471,014	4,705,478	4,900,062	5,113,660	5,390,178	5,851,196	6,125,970	6,335,319	6,593,257	6,869,814	7,037,707
#1 Ret Late - #2 SCR Late - Opt	08	3,990,079	4,131,558	4,278,163	4,473,732	4,710,450	4,896,607	5,075,520	5,344,320	5,879,654	6,150,646	6,349,943	6,603,271	6,872,822	7,018,412
#1 Ret Late - #2 SCR Late - CC	09	3,990,079	4,131,558	4,278,163	4,473,732	4,710,450	4,896,607	5,075,520	5,344,320	5,879,654	6,150,646	6,349,943	6,603,271	6,872,822	7,018,412
#1 Ret Late - #2 SCR Late - CT Wind	10	4,023,768	4,168,220	4,316,652	4,514,957	4,742,574	4,933,633	5,117,729	5,384,638	5,905,277	6,175,618	6,379,830	6,631,363	6,901,809	7,048,414
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	4,051,211	4,199,689	4,349,862	4,550,356	4,777,576	4,973,180	5,158,572	5,425,319	5,950,119	6,222,694	6,427,445	6,683,473	6,957,756	7,107,820
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	3,998,567	4,145,735	4,294,938	4,509,095	4,742,653	4,936,753	5,149,885	5,439,307	5,898,231	6,170,109	6,376,157	6,630,782	6,904,012	7,053,532
#1 Ret Early - #2 Ret Early - Opt	13	3,948,073	4,085,520	4,232,549	4,426,615	4,656,272	4,841,038	5,012,401	5,275,411	5,816,682	6,080,261	6,258,973	6,518,986	6,787,507	6,952,191
#1 Ret Early - #2 Ret Early - CC	14	3,948,073	4,085,520	4,232,549	4,426,615	4,656,272	4,841,038	5,012,401	5,275,411	5,816,682	6,080,261	6,258,973	6,518,986	6,787,507	6,952,191
#1 Ret Early - #2 Ret Early - CT Wind	15	4,161,039	4,312,862	4,466,483	4,657,548	4,847,681	5,044,079	5,228,857	5,460,897	5,957,873	6,227,819	6,411,894	6,677,970	6,960,386	7,127,107
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	4,186,365	4,339,657	4,497,211	4,693,111	4,894,427	5,094,691	5,285,686	5,528,132	6,039,076	6,315,064	6,502,133	6,774,325	7,058,267	7,233,055
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	4,131,712	4,282,412	4,439,257	4,650,980	4,855,171	5,057,253	5,273,627	5,539,994	5,985,562	6,259,654	6,447,227	6,717,447	7,000,141	7,173,728
#1 Ret Late - #2 Ret Late - Opt	18	4,031,227	4,165,477	4,309,738	4,501,524	4,729,359	4,912,734	5,083,022	5,345,066	5,885,344	6,148,061	6,325,757	6,585,042	6,852,541	7,015,610
#1 Ret Late - #2 Ret Late - CC	19	4,031,227	4,165,477	4,309,738	4,501,524	4,729,359	4,912,734	5,083,022	5,345,066	5,885,344	6,148,061	6,325,757	6,585,042	6,852,541	7,015,610
#1 Ret Late - #2 Ret Late - CT Wind	20	4,242,689	4,391,047	4,541,877	4,730,825	4,919,401	5,114,601	5,298,373	5,529,484	6,024,991	6,292,118	6,472,307	6,734,218	7,012,439	7,175,408
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	4,244,309	4,395,169	4,550,760	4,745,162	4,945,369	5,144,773	5,335,046	5,576,824	6,086,709	6,360,711	6,545,137	6,814,543	7,095,680	7,267,954
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	4,187,384	4,335,745	4,490,701	4,700,989	4,904,118	5,105,374	5,321,052	5,586,777	6,031,311	6,303,445	6,488,399	6,755,860	7,035,774	7,206,906
Reference Case	23	3,844,204	3,993,852	4,150,076	4,356,332	4,594,430	4,789,146	4,982,148	5,249,060	5,789,389	6,076,468	6,273,413	6,530,698	6,803,499	6,965,084

Strategist Output - Annual Capital Expenditures ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	49,352	33,286	64,608	181,149	327,171	309,819	145,937	33,195	83,341	196,663	328,646	961,999	513,793	658,812
#1 SCR Late - #2 SCR Late	02	49,352	33,286	61,984	137,556	170,838	188,175	87,611	30,840	80,112	242,877	505,937	1,095,216	576,669	658,812
#1 Ret Early - #2 SCR Early - Opt	03	49,352	33,129	58,418	144,645	266,957	431,000	748,709	173,010	62,050	191,057	310,515	926,459	498,608	621,560
#1 Ret Early - #2 SCR Early - CC	04	49,352	33,129	58,418	144,645	266,957	431,000	748,709	173,010	62,050	191,057	310,515	926,459	498,608	621,560
#1 Ret Early - #2 SCR Early - CT Wind	05	49,352	33,129	58,418	144,645	217,972	333,168	553,441	430,272	62,782	191,806	311,281	927,243	499,411	622,382
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	49,352	33,129	58,418	144,645	217,972	305,105	438,540	381,267	61,168	190,154	309,591	925,512	497,640	620,569
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	49,352	33,129	58,418	144,645	217,972	305,105	438,540	322,398	61,168	190,154	309,591	925,512	497,640	620,569
#1 Ret Late - #2 SCR Late - Opt	08	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	256,439	598,665	1,685,915	734,074	621,560
#1 Ret Late - #2 SCR Late - CC	09	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	256,439	598,665	1,685,915	734,074	621,560
#1 Ret Late - #2 SCR Late - CT Wind	10	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	488,731	1,466,492	1,023,160	622,382
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	457,197	1,337,377	968,093	620,569
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	49,352	33,158	61,773	137,345	170,594	182,353	81,597	30,461	76,943	201,395	457,197	1,337,377	901,942	620,569
#1 Ret Early - #2 Ret Early - Opt	13	49,352	32,972	55,495	129,332	203,319	375,940	819,856	651,472	158,795	157,102	309,192	915,006	472,169	616,889
#1 Ret Early - #2 Ret Early - CC	14	49,352	32,972	55,495	129,332	203,319	375,940	819,856	651,472	158,795	157,102	309,192	915,006	472,169	616,889
#1 Ret Early - #2 Ret Early - CT Wind	15	49,352	32,972	55,495	129,332	154,334	239,205	512,401	612,437	719,179	156,947	309,034	914,844	472,004	616,720
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	49,352	32,972	55,495	129,332	154,334	211,142	373,950	467,012	495,669	153,644	305,652	911,383	468,461	613,093
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	49,352	32,972	55,495	129,332	154,334	211,142	373,950	408,143	495,669	153,644	305,652	911,383	468,461	613,093
#1 Ret Late - #2 Ret Late - Opt	18	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	237,939	574,838	1,779,900	1,189,892	752,925
#1 Ret Late - #2 Ret Late - CC	19	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	237,939	574,838	1,779,900	1,189,892	752,925
#1 Ret Late - #2 Ret Late - CT Wind	20	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	421,188	1,434,412	1,146,029	1,382,631
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	389,654	1,278,835	952,614	1,131,472
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	49,352	33,031	61,561	137,135	170,350	176,530	75,583	30,081	76,052	182,895	389,654	1,278,835	916,463	1,131,472
Reference Case	23	49,352	33,286	61,984	137,556	170,838	188,175	87,611	30,840	77,094	192,735	326,120	955,299	509,580	656,104

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	369,688	310,389	457,235	914,026	499,760	527,787	1,073,215	1,137,123	747,496	968,867	1,276,510	1,159,457	872,975	1,916,059
#1 SCR Late - #2 SCR Late	02	369,688	310,389	457,235	914,026	499,760	527,787	1,073,215	1,137,123	747,496	968,867	1,276,510	1,159,457	872,975	1,916,059
#1 Ret Early - #2 SCR Early - Opt	03	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Early - #2 SCR Early - CC	04	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Early - #2 SCR Early - CT Wind	05	327,141	309,677	437,240	881,242	496,451	511,018	1,043,299	1,135,728	730,258	927,373	1,279,958	1,017,428	364,543	446,014
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Late - #2 SCR Late - Opt	08	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Late - #2 SCR Late - CC	09	326,300	308,816	436,358	880,340	495,527	510,072	1,042,331	1,134,738	729,244	926,335	1,278,896	1,078,370	542,306	917,298
#1 Ret Late - #2 SCR Late - CT Wind	10	327,141	309,677	437,240	881,242	496,451	511,018	1,043,299	1,135,728	730,258	927,373	1,279,958	1,017,428	364,543	446,014
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	325,285	307,778	435,295	879,252	494,413	508,932	1,041,164	1,133,543	728,021	925,083	1,277,614	1,015,029	324,540	289,765
#1 Ret Early - #2 Ret Early - Opt	13	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Early - #2 Ret Early - CC	14	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Early - #2 Ret Early - CT Wind	15	312,876	275,268	434,559	858,563	459,387	499,662	1,022,863	1,104,065	727,634	905,488	1,227,824	1,018,558	286,937	143,570
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Late - #2 Ret Late - Opt	18	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Late - #2 Ret Late - CC	19	313,050	275,446	434,740	858,748	459,577	499,857	1,023,062	1,104,269	727,843	905,702	1,228,042	1,018,782	287,166	143,805
#1 Ret Late - #2 Ret Late - CT Wind	20	312,876	275,268	434,559	858,563	459,387	499,662	1,022,863	1,104,065	727,634	905,488	1,227,824	1,018,558	286,937	143,570
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	309,164	271,468	430,669	854,581	455,312	495,491	1,018,593	1,099,695	723,160	900,909	1,223,136	1,013,760	282,025	138,543
Reference Case	23	362,502	305,871	454,330	906,319	494,915	524,672	1,064,949	1,131,926	744,155	960,002	1,270,937	1,155,874	863,468	1,916,059

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual Total Natural Gas Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	76,803	59,935	87,491	112,498	261,552	281,127	299,540	250,096	256,617	247,590	253,184	256,618	363,951	369,995
#1 SCR Late - #2 SCR Late	02	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	254,769	363,951	369,995
#1 Ret Early - #2 SCR Early - Opt	03	76,803	59,935	87,491	112,498	261,552	274,497	295,498	395,671	403,226	410,451	414,609	401,775	543,902	552,523
#1 Ret Early - #2 SCR Early - CC	04	76,803	59,935	87,491	112,498	261,552	274,497	295,498	395,671	403,226	410,451	414,609	401,775	543,902	552,523
#1 Ret Early - #2 SCR Early - CT Wind	05	76,803	59,935	87,491	112,498	261,552	274,497	295,498	316,375	315,871	323,092	328,121	321,060	450,443	463,921
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	76,803	59,935	87,491	112,498	261,552	274,497	295,498	292,666	290,441	297,758	302,355	295,703	420,835	432,417
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	76,803	59,935	87,491	111,788	260,382	271,691	290,544	303,769	302,115	309,104	314,693	305,595	435,132	447,851
#1 Ret Late - #2 SCR Late - Opt	08	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	529,200	552,523
#1 Ret Late - #2 SCR Late - CC	09	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	529,200	552,523
#1 Ret Late - #2 SCR Late - CT Wind	10	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	449,584	463,921
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	420,064	432,417
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	76,803	59,935	87,491	111,788	260,382	277,192	288,316	239,925	246,707	240,350	245,434	233,660	434,361	447,851
#1 Ret Early - #2 Ret Early - Opt	13	76,803	59,935	87,491	112,498	261,552	274,497	282,454	392,370	553,206	562,196	593,257	587,021	718,456	755,275
#1 Ret Early - #2 Ret Early - CC	14	76,803	59,935	87,491	112,498	261,552	274,497	282,454	392,370	553,206	562,196	593,257	587,021	718,456	755,275
#1 Ret Early - #2 Ret Early - CT Wind	15	76,803	59,935	87,491	112,498	261,552	274,497	282,454	314,381	278,500	286,564	308,765	308,987	406,726	437,659
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	76,803	59,935	87,491	112,498	261,552	274,497	282,454	290,623	266,957	272,937	294,031	294,644	393,104	422,833
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	76,803	59,935	87,491	111,788	260,382	271,691	277,348	301,727	275,321	280,876	302,167	302,249	404,620	433,744
#1 Ret Late - #2 Ret Late - Opt	18	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	505,957	759,089
#1 Ret Late - #2 Ret Late - CC	19	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	505,957	759,089
#1 Ret Late - #2 Ret Late - CT Wind	20	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	432,734	439,651
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	239,526	401,347	424,497
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	76,803	59,935	87,491	111,788	260,382	277,192	288,316	239,925	246,707	240,350	245,434	233,660	414,744	436,269
Reference Case	23	76,803	59,935	87,491	112,498	261,552	279,993	293,303	245,954	253,402	246,911	252,325	254,816	362,746	369,308

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	404,400	418,353	449,832	515,292	701,907	711,769	784,968	1,026,406	1,251,684	1,315,941	1,568,851	1,615,853	1,621,894	1,681,054
#1 SCR Late - #2 SCR Late	02	404,400	418,353	449,832	515,292	701,907	711,769	784,968	1,026,406	1,251,684	1,315,941	1,568,851	1,615,853	1,621,894	1,681,054
#1 Ret Early - #2 SCR Early - Opt	03	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Early - #2 SCR Early - CC	04	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Early - #2 SCR Early - CT Wind	05	486,746	534,017	563,776	619,318	824,865	848,896	885,844	1,160,270	1,386,758	1,455,551	1,714,371	1,758,053	1,770,271	1,845,206
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	453,220	495,953	529,369	578,479	787,890	806,569	846,127	1,118,451	1,345,068	1,401,949	1,672,446	1,710,293	1,724,509	1,797,003
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	467,832	511,916	545,576	594,746	812,314	826,529	863,642	1,137,123	1,369,450	1,426,230	1,696,267	1,736,732	1,753,575	1,828,850
#1 Ret Late - #2 SCR Late - Opt	08	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Late - #2 SCR Late - CC	09	571,811	616,935	654,039	716,168	947,682	964,643	1,009,513	1,311,124	1,552,981	1,586,857	1,902,273	1,942,980	1,961,540	2,018,756
#1 Ret Late - #2 SCR Late - CT Wind	10	486,746	534,017	563,776	619,318	824,865	848,896	885,844	1,160,270	1,386,758	1,455,551	1,714,371	1,758,053	1,770,271	1,845,206
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	453,220	495,953	529,369	578,479	787,890	806,569	846,127	1,118,452	1,345,068	1,401,949	1,672,446	1,710,293	1,724,509	1,797,003
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	467,832	511,916	545,576	594,746	812,314	826,529	863,642	1,137,123	1,369,450	1,426,230	1,696,267	1,736,732	1,753,575	1,828,849
#1 Ret Early - #2 Ret Early - Opt	13	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,386	1,867,179	1,901,388	2,191,246	2,283,511	2,294,064	2,377,900
#1 Ret Early - #2 Ret Early - CC	14	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,386	1,867,179	1,901,388	2,191,246	2,283,511	2,294,064	2,377,900
#1 Ret Early - #2 Ret Early - CT Wind	15	463,640	498,456	546,498	594,295	763,778	810,376	853,861	1,087,446	1,331,481	1,380,607	1,604,738	1,667,017	1,683,381	1,747,457
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	448,098	481,167	531,855	582,265	756,562	799,988	842,938	1,074,908	1,320,719	1,379,758	1,605,103	1,677,697	1,683,542	1,756,596
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	458,567	492,400	543,959	594,663	771,976	815,299	856,942	1,090,577	1,343,510	1,402,864	1,633,992	1,702,041	1,710,847	1,785,409
#1 Ret Late - #2 Ret Late - Opt	18	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,454	1,864,980	1,900,626	2,191,987	2,285,371	2,294,548	2,377,648
#1 Ret Late - #2 Ret Late - CC	19	777,454	807,666	879,232	946,576	1,172,318	1,224,357	1,267,863	1,563,454	1,864,980	1,900,626	2,191,987	2,285,371	2,294,548	2,377,648
#1 Ret Late - #2 Ret Late - CT Wind	20	463,640	498,456	546,498	594,295	763,778	810,376	853,861	1,087,446	1,331,481	1,380,607	1,604,738	1,667,017	1,683,381	1,747,457
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	448,098	481,167	531,855	582,265	756,562	799,988	842,938	1,074,908	1,320,719	1,379,758	1,605,103	1,677,697	1,683,542	1,756,596
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	458,567	492,400	543,959	594,663	771,976	815,299	856,942	1,090,577	1,343,510	1,402,864	1,633,992	1,702,041	1,710,847	1,785,409
Reference Case	23	402,604	416,669	449,198	513,949	700,165	708,780	782,759	1,024,583	1,249,759	1,313,275	1,566,130	1,612,782	1,620,696	1,679,893

Strategist Output - Annual Total Natural Gas Consumption (000mmBtu)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	19,374	14,245	20,153	25,103	55,249	55,552	55,373	43,294	42,523	39,504	37,795	37,174	50,758	50,292
#1 SCR Late - #2 SCR Late	02	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	36,902	50,758	50,292
#1 Ret Early - #2 SCR Early - Opt	03	19,374	14,245	20,153	25,103	55,249	54,232	54,625	68,314	66,621	65,320	61,785	58,041	75,870	75,096
#1 Ret Early - #2 SCR Early - CC	04	19,374	14,245	20,153	25,103	55,249	54,232	54,625	68,314	66,621	65,320	61,785	58,041	75,870	75,096
#1 Ret Early - #2 SCR Early - CT Wind	05	19,374	14,245	20,153	25,103	55,249	54,232	54,625	54,729	52,224	51,454	48,952	46,431	62,920	63,062
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	19,374	14,245	20,153	25,103	55,249	54,232	54,625	50,619	47,993	47,422	45,098	42,755	58,746	58,772
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	19,374	14,245	20,153	24,947	55,005	53,684	53,721	52,525	49,927	49,217	46,936	44,176	60,736	60,820
#1 Ret Late - #2 SCR Late - Opt	08	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	73,789	75,096
#1 Ret Late - #2 SCR Late - CC	09	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	73,789	75,096
#1 Ret Late - #2 SCR Late - CT Wind	10	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	62,759	63,062
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	58,639	58,772
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	19,374	14,245	20,153	24,947	55,005	54,790	53,316	41,531	40,904	38,358	36,650	33,850	60,629	60,820
#1 Ret Early - #2 Ret Early - Opt	13	19,374	14,245	20,153	25,103	55,249	54,232	52,198	67,737	91,288	89,274	88,329	84,659	100,189	102,545
#1 Ret Early - #2 Ret Early - CC	14	19,374	14,245	20,153	25,103	55,249	54,232	52,198	67,737	91,288	89,274	88,329	84,659	100,189	102,545
#1 Ret Early - #2 Ret Early - CT Wind	15	19,374	14,245	20,153	25,103	55,249	54,232	52,198	54,384	46,125	45,643	46,121	44,729	56,876	59,501
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	19,374	14,245	20,153	25,103	55,249	54,232	52,198	50,265	44,130	43,406	43,849	42,583	54,919	57,476
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	19,374	14,245	20,153	24,947	55,005	53,684	51,267	52,171	45,507	44,666	45,059	43,680	56,498	58,958
#1 Ret Late - #2 Ret Late - Opt	18	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	70,635	102,848
#1 Ret Late - #2 Ret Late - CC	19	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	70,635	102,848
#1 Ret Late - #2 Ret Late - CT Wind	20	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	60,457	59,819
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	34,685	56,047	57,623
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	19,374	14,245	20,153	24,947	55,005	54,790	53,316	41,531	40,904	38,358	36,650	33,850	57,906	59,323
Reference Case	23	19,374	14,245	20,153	25,103	55,249	55,337	54,226	42,565	42,002	39,394	37,667	36,908	50,588	50,197

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	53,782	54,406	56,878	63,319	84,673	84,434	90,703	116,050	138,294	142,753	166,942	168,946	166,441	169,427
#1 SCR Late - #2 SCR Late	02	53,782	54,406	56,878	63,319	84,673	84,434	90,703	116,050	138,294	142,753	166,942	168,946	166,441	169,427
#1 Ret Early - #2 SCR Early - Opt	03	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Early - #2 SCR Early - CC	04	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Early - #2 SCR Early - CT Wind	05	64,682	69,335	71,259	76,020	99,609	100,544	102,602	131,172	153,329	157,901	182,552	183,928	181,767	186,034
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	60,215	64,389	66,865	70,976	95,102	95,457	97,901	126,422	148,691	152,135	177,997	178,891	177,056	181,158
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	62,150	66,453	68,908	72,966	97,962	97,957	99,928	128,559	151,369	154,743	180,541	181,662	180,019	184,360
#1 Ret Late - #2 SCR Late - Opt	08	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Late - #2 SCR Late - CC	09	75,938	80,082	82,577	87,906	114,374	114,292	116,687	148,252	171,648	172,078	202,410	203,125	201,274	203,499
#1 Ret Late - #2 SCR Late - CT Wind	10	64,682	69,335	71,259	76,020	99,609	100,544	102,602	131,172	153,329	157,901	182,552	183,928	181,767	186,034
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	60,215	64,389	66,865	70,976	95,102	95,457	97,901	126,422	148,691	152,135	177,997	178,891	177,056	181,158
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	62,150	66,453	68,908	72,966	97,962	97,957	99,928	128,559	151,369	154,743	180,541	181,662	180,019	184,360
#1 Ret Early - #2 Ret Early - Opt	13	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,721	206,331	206,324	233,264	238,724	235,403	239,694
#1 Ret Early - #2 Ret Early - CC	14	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,721	206,331	206,324	233,264	238,724	235,403	239,694
#1 Ret Early - #2 Ret Early - CT Wind	15	61,618	64,793	68,924	73,013	92,248	96,007	98,946	123,120	147,284	150,005	171,028	174,422	172,954	176,351
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	59,490	62,459	67,019	71,417	91,260	94,699	97,516	121,609	146,019	149,801	170,960	175,443	172,902	177,093
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	60,874	63,958	68,544	72,929	93,136	96,537	99,159	123,297	148,534	152,298	174,030	178,012	175,695	180,017
#1 Ret Late - #2 Ret Late - Opt	18	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,730	206,088	206,246	233,346	238,920	235,464	239,671
#1 Ret Late - #2 Ret Late - CC	19	103,077	104,694	110,905	116,169	141,413	144,920	146,641	176,730	206,088	206,246	233,346	238,920	235,464	239,671
#1 Ret Late - #2 Ret Late - CT Wind	20	61,618	64,793	68,924	73,013	92,248	96,007	98,946	123,120	147,284	150,005	171,028	174,422	172,954	176,351
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	59,490	62,459	67,019	71,417	91,260	94,699	97,516	121,609	146,019	149,801	170,960	175,443	172,902	177,093
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	60,874	63,958	68,544	72,929	93,136	96,537	99,159	123,297	148,534	152,298	174,030	178,012	175,695	180,017
Reference Case	23	53,541	54,184	56,795	63,149	84,460	84,074	90,443	115,841	138,077	142,460	166,646	168,618	166,317	169,309

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual Total Coal Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	357,912	360,682	348,232	357,162	289,129	314,759	347,672	384,654	392,892	397,801	430,837	434,749	443,669	471,621
#1 SCR Late - #2 SCR Late	02	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	436,058	443,669	471,621
#1 Ret Early - #2 SCR Early - Opt	03	357,912	360,682	348,232	357,162	289,129	322,740	350,357	272,199	289,705	278,599	310,809	329,697	315,529	340,797
#1 Ret Early - #2 SCR Early - CC	04	357,912	360,682	348,232	357,162	289,129	322,740	350,357	272,199	289,705	278,599	310,809	329,697	315,529	340,797
#1 Ret Early - #2 SCR Early - CT Wind	05	357,912	360,682	348,232	357,162	289,129	322,740	350,357	266,154	284,674	272,654	302,134	318,209	306,985	331,401
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	357,912	360,682	348,232	357,162	289,129	322,740	350,357	263,134	281,385	269,614	299,113	314,703	304,192	328,587
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	357,912	360,682	348,232	356,933	288,542	321,620	348,903	265,670	284,209	272,477	302,484	318,253	307,094	331,817
#1 Ret Late - #2 SCR Late - Opt	08	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	316,522	340,797
#1 Ret Late - #2 SCR Late - CC	09	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	316,522	340,797
#1 Ret Late - #2 SCR Late - CT Wind	10	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	306,972	331,401
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	304,175	328,587
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	357,912	360,682	348,232	356,933	288,542	314,666	350,424	386,068	393,311	396,994	429,947	446,288	307,073	331,817
#1 Ret Early - #2 Ret Early - Opt	13	357,912	360,682	348,232	357,162	289,129	322,740	360,583	274,509	178,856	172,988	181,743	197,645	191,726	197,868
#1 Ret Early - #2 Ret Early - CC	14	357,912	360,682	348,232	357,162	289,129	322,740	360,583	274,509	178,856	172,988	181,743	197,645	191,726	197,868
#1 Ret Early - #2 Ret Early - CT Wind	15	357,912	360,682	348,232	357,162	289,129	322,740	360,583	267,691	155,992	150,420	156,954	168,736	165,527	170,426
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	357,912	360,682	348,232	357,162	289,129	322,740	360,583	264,773	162,257	156,455	163,600	175,815	172,061	176,009
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	357,912	360,682	348,232	356,933	288,542	321,620	359,008	267,327	164,424	158,644	165,811	178,795	174,254	180,580
#1 Ret Late - #2 Ret Late - Opt	18	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	333,465	198,165
#1 Ret Late - #2 Ret Late - CC	19	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	333,465	198,165
#1 Ret Late - #2 Ret Late - CT Wind	20	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	322,957	170,987
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	448,231	319,925	177,696
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	357,912	360,682	348,232	356,933	288,542	314,666	350,424	386,068	393,311	396,994	429,947	446,288	323,158	180,660
Reference Case	23	357,912	360,682	348,232	357,162	289,129	315,720	351,866	387,498	394,967	398,599	431,688	436,144	444,779	472,494

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	479,024	477,275	510,422	525,201	539,107	571,312	575,391	589,962	636,718	641,111	521,502	539,872	566,665	577,858
#1 SCR Late - #2 SCR Late	02	479,024	477,275	510,422	525,201	539,107	571,312	575,391	589,962	636,718	641,111	521,502	539,872	566,665	577,858
#1 Ret Early - #2 SCR Early - Opt	03	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Early - #2 SCR Early - CC	04	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Early - #2 SCR Early - CT Wind	05	350,284	329,059	358,910	383,415	370,155	398,051	419,724	402,924	441,899	463,107	315,832	330,170	352,974	359,542
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	347,181	325,900	356,277	380,327	368,161	395,659	417,303	401,453	440,622	462,439	314,706	328,792	351,616	358,552
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	350,482	328,830	359,581	383,587	370,135	399,294	420,798	404,257	443,332	465,304	316,626	331,197	354,328	361,492
#1 Ret Late - #2 SCR Late - Opt	08	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Late - #2 SCR Late - CC	09	359,754	337,301	368,129	393,253	376,043	405,930	426,398	409,084	447,970	469,915	320,511	333,687	357,265	365,801
#1 Ret Late - #2 SCR Late - CT Wind	10	350,284	329,059	358,910	383,415	370,155	398,051	419,724	402,924	441,899	463,107	315,832	330,170	352,974	359,542
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	347,181	325,900	356,277	380,327	368,161	395,659	417,303	401,453	440,622	462,439	314,706	328,792	351,616	358,552
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	350,482	328,830	359,581	383,587	370,135	399,294	420,798	404,257	443,332	465,304	316,626	331,197	354,328	361,492
#1 Ret Early - #2 Ret Early - Opt	13	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,244	254,341	274,406	140,057	126,002	145,580	148,574
#1 Ret Early - #2 Ret Early - CC	14	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,244	254,341	274,406	140,057	126,002	145,580	148,574
#1 Ret Early - #2 Ret Early - CT Wind	15	183,832	176,248	183,273	200,243	197,600	203,257	217,862	214,523	222,470	237,865	122,003	110,864	126,777	129,315
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	192,102	183,102	190,675	208,436	205,650	210,981	227,285	223,256	231,345	248,343	126,583	114,899	132,439	134,669
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	195,140	185,928	193,392	211,852	209,008	214,763	230,462	226,333	235,297	251,877	128,705	116,907	134,478	136,516
#1 Ret Late - #2 Ret Late - Opt	18	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,240	254,325	274,406	140,086	126,003	145,592	148,573
#1 Ret Late - #2 Ret Late - CC	19	213,168	205,112	213,078	231,679	225,673	232,654	251,347	244,240	254,325	274,406	140,086	126,003	145,592	148,573
#1 Ret Late - #2 Ret Late - CT Wind	20	183,832	176,248	183,273	200,243	197,600	203,257	217,862	214,523	222,470	237,865	122,003	110,864	126,777	129,315
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	192,102	183,102	190,675	208,436	205,650	210,981	227,285	223,256	231,345	248,343	126,583	114,899	132,439	134,669
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	195,140	185,928	193,392	211,852	209,008	214,763	230,462	226,333	235,297	251,877	128,705	116,907	134,478	136,516
Reference Case	23	480,427	478,527	511,129	526,556	540,685	573,772	577,167	591,541	638,424	643,198	523,563	542,136	567,997	579,174

Strategist Output - Annual Total Coal Consumption (000mmBtu)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
#1 SCR Early - #2 SCR Early	01	163,025	157,968	153,351	156,859	121,195	128,471	138,713	150,960	150,211	148,515	156,393	153,746	153,159	158,582
#1 SCR Late - #2 SCR Late	02	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	154,229	153,159	158,582
#1 Ret Early - #2 SCR Early - Opt	03	163,025	157,968	153,351	156,859	121,195	131,776	139,804	106,381	110,362	103,640	112,394	116,220	108,576	114,174
#1 Ret Early - #2 SCR Early - CC	04	163,025	157,968	153,351	156,859	121,195	131,776	139,804	106,381	110,362	103,640	112,394	116,220	108,576	114,174
#1 Ret Early - #2 SCR Early - CT Wind	05	163,025	157,968	153,351	156,859	121,195	131,776	139,804	104,034	108,465	101,451	109,268	112,179	105,645	111,034
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	163,025	157,968	153,351	156,859	121,195	131,776	139,804	102,847	107,207	100,316	108,172	110,939	104,682	110,088
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	163,025	157,968	153,351	156,758	120,948	131,316	139,222	103,838	108,283	101,380	109,391	112,191	105,680	111,172
#1 Ret Late - #2 SCR Late - Opt	08	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	108,921	114,174
#1 Ret Late - #2 SCR Late - CC	09	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	108,921	114,174
#1 Ret Late - #2 SCR Late - CT Wind	10	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	105,641	111,034
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	104,676	110,088
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	163,025	157,968	153,351	156,758	120,948	128,447	139,836	151,538	150,389	148,227	156,085	157,887	105,673	111,172
#1 Ret Early - #2 Ret Early - Opt	13	163,025	157,968	153,351	156,859	121,195	131,776	143,918	107,298	67,561	63,889	65,096	69,069	65,513	65,673
#1 Ret Early - #2 Ret Early - CC	14	163,025	157,968	153,351	156,859	121,195	131,776	143,918	107,298	67,561	63,889	65,096	69,069	65,513	65,673
#1 Ret Early - #2 Ret Early - CT Wind	15	163,025	157,968	153,351	156,859	121,195	131,776	143,918	104,645	58,977	55,620	56,271	59,021	56,594	56,604
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	163,025	157,968	153,351	156,859	121,195	131,776	143,916	103,499	61,342	57,852	58,652	61,496	58,833	59,124
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	163,025	157,968	153,351	156,758	120,948	131,316	143,288	104,497	62,158	58,658	59,442	62,536	59,585	59,976
#1 Ret Late - #2 Ret Late - Opt	18	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	114,813	65,775
#1 Ret Late - #2 Ret Late - CC	19	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	114,813	65,775
#1 Ret Late - #2 Ret Late - CT Wind	20	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	111,201	56,789
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	158,576	110,155	59,015
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	163,025	157,968	153,351	156,758	120,948	128,447	139,836	151,538	150,389	148,227	156,085	157,887	111,268	60,001
Reference Case	23	163,025	157,968	153,351	156,859	121,195	128,878	140,413	152,101	151,024	148,827	156,718	154,256	153,554	158,890

Scenario Name	Scenario #	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	155,380	151,459	158,114	158,985	159,510	165,125	162,691	163,536	172,604	170,466	138,037	140,117	144,226	144,248
#1 SCR Late - #2 SCR Late	02	155,380	151,459	158,114	158,985	159,510	165,125	162,691	163,536	172,604	170,466	138,037	140,117	144,226	144,248
#1 Ret Early - #2 SCR Early - Opt	03	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Early - #2 SCR Early - CC	04	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Early - #2 SCR Early - CT Wind	05	112,982	103,767	110,469	115,415	108,844	114,298	118,015	110,998	119,025	122,449	83,598	85,692	89,838	89,751
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	111,968	102,759	109,648	114,474	108,250	113,602	117,327	110,589	118,675	122,269	83,300	85,334	89,493	89,504
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	113,044	103,691	110,676	115,465	108,835	114,658	118,317	111,363	119,410	123,033	83,808	85,958	90,183	90,238
#1 Ret Late - #2 SCR Late - Opt	08	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Late - #2 SCR Late - CC	09	116,057	106,379	113,325	118,398	110,584	116,580	119,899	112,702	120,667	124,252	84,836	86,604	90,930	91,313
#1 Ret Late - #2 SCR Late - CT Wind	10	112,982	103,767	110,469	115,415	108,844	114,298	118,015	110,998	119,025	122,449	83,598	85,692	89,838	89,751
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	111,968	102,759	109,648	114,474	108,250	113,602	117,327	110,589	118,675	122,269	83,300	85,334	89,493	89,504
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	113,044	103,691	110,676	115,465	108,835	114,658	118,317	111,363	119,410	123,033	83,808	85,958	90,183	90,238
#1 Ret Early - #2 Ret Early - Opt	13	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,380	67,396	71,475	37,072	32,702	37,053	37,088
#1 Ret Early - #2 Ret Early - CC	14	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,380	67,396	71,475	37,072	32,702	37,053	37,088
#1 Ret Early - #2 Ret Early - CT Wind	15	58,412	54,819	55,494	59,383	57,311	57,412	60,348	58,297	58,959	61,957	32,293	28,773	32,267	32,280
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	61,027	56,945	57,726	61,811	59,644	59,583	62,950	60,665	61,304	64,684	33,505	29,821	33,708	33,617
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	61,997	57,830	58,549	62,823	60,623	60,655	63,832	61,501	62,351	65,605	34,067	30,342	34,227	34,078
#1 Ret Late - #2 Ret Late - Opt	18	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,379	67,391	71,475	37,079	32,703	37,056	37,088
#1 Ret Late - #2 Ret Late - CC	19	67,741	63,821	64,535	68,715	65,470	65,719	69,628	66,379	67,391	71,475	37,079	32,703	37,056	37,088
#1 Ret Late - #2 Ret Late - CT Wind	20	58,412	54,819	55,494	59,383	57,311	57,412	60,348	58,297	58,959	61,957	32,293	28,773	32,267	32,280
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	61,027	56,945	57,726	61,811	59,644	59,583	62,950	60,665	61,304	64,684	33,505	29,821	33,708	33,617
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	61,997	57,830	58,549	62,823	60,623	60,655	63,832	61,501	62,351	65,605	34,067	30,342	34,227	34,078
Reference Case	23	155,851	151,871	158,346	159,408	159,989	165,853	163,207	163,964	173,077	171,032	138,582	140,705	144,565	144,577

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual CO2 Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021
#1 SCR Early - #2 SCR Early	01	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,469,968	19,138,736	20,282,412	20,065,562
#1 SCR Late - #2 SCR Late	02	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Early - #2 SCR Early - Opt	03	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	17,426,228	17,348,986
#1 Ret Early - #2 SCR Early - CC	04	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	17,426,228	17,348,986
#1 Ret Early - #2 SCR Early - CT Wind	05	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	16,367,132	16,432,772
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,204,778	15,830,560	15,919,027
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,537,896	19,055,244	16,116,240	16,189,694
#1 Ret Late - #2 SCR Late - Opt	08	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 SCR Late - CC	09	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 SCR Late - CT Wind	10	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,375,626	19,093,598	20,166,822	19,934,612
#1 Ret Early - #2 Ret Early - Opt	13	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	17,482,488	14,512,024
#1 Ret Early - #2 Ret Early - CC	14	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	17,482,488	14,512,024
#1 Ret Early - #2 Ret Early - CT Wind	15	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	16,402,288	11,062,863
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,652,754	19,456,810	15,866,473	11,049,762
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,537,896	19,306,804	16,152,491	11,233,207
#1 Ret Late - #2 Ret Late - Opt	18	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 Ret Late - CC	19	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 Ret Late - CT Wind	20	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	22,121,398	21,226,352	20,852,500	20,636,262	18,427,550	18,375,626	19,093,598	20,166,822	19,934,612
Reference Case	23	22,121,398	21,226,352	20,852,500	20,675,298	18,508,858	18,491,124	19,242,694	20,350,676	20,117,010

Scenario Name	Scenario #	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
#1 SCR Early - #2 SCR Early	01	19,758,518	20,637,190	19,897,188	20,411,360	20,871,368	20,604,666	20,122,488	20,916,108	21,300,712	23,123,498
#1 SCR Late - #2 SCR Late	02	19,771,282	20,652,892	19,926,148	20,411,360	20,871,368	20,604,666	20,122,488	20,916,108	21,300,712	23,123,498
#1 Ret Early - #2 SCR Early - Opt	03	16,790,162	17,788,438	17,392,196	17,457,236	17,943,484	17,990,540	17,110,446	17,912,602	18,512,706	19,847,360
#1 Ret Early - #2 SCR Early - CC	04	16,790,162	17,788,438	17,392,196	17,457,236	17,943,484	17,990,540	17,110,446	17,912,602	18,512,706	19,847,360
#1 Ret Early - #2 SCR Early - CT Wind	05	15,851,618	16,769,631	16,362,045	16,502,067	16,955,712	16,957,928	16,101,767	16,917,306	17,547,274	18,896,406
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	15,327,839	16,244,110	15,830,763	16,002,621	16,459,709	16,480,517	15,650,396	16,440,813	17,095,002	18,416,210
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	15,602,552	16,522,310	16,104,190	16,259,403	16,704,409	16,731,751	15,887,773	16,680,963	17,335,036	18,639,920
#1 Ret Late - #2 SCR Late - Opt	08	19,771,282	20,652,892	20,193,612	17,616,708	17,943,484	17,990,540	17,110,446	17,912,604	18,512,706	19,847,360
#1 Ret Late - #2 SCR Late - CC	09	19,771,282	20,652,892	20,193,612	17,616,708	17,943,484	17,990,540	17,110,446	17,912,604	18,512,706	19,847,360
#1 Ret Late - #2 SCR Late - CT Wind	10	19,771,282	20,652,892	20,193,612	16,505,053	16,955,710	16,957,926	16,101,767	16,917,304	17,547,274	18,896,406
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	19,771,282	20,652,892	20,193,612	16,005,568	16,459,709	16,480,517	15,650,396	16,440,812	17,095,002	18,416,210
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	19,588,264	20,468,702	20,004,668	16,262,343	16,704,410	16,731,751	15,887,773	16,680,963	17,335,036	18,639,920
#1 Ret Early - #2 Ret Early - Opt	13	14,065,068	14,665,515	14,268,678	14,584,787	14,701,637	14,775,162	14,235,429	14,602,437	15,191,934	16,769,786
#1 Ret Early - #2 Ret Early - CC	14	14,065,068	14,665,515	14,268,678	14,584,787	14,701,637	14,775,162	14,235,429	14,602,437	15,191,934	16,769,786
#1 Ret Early - #2 Ret Early - CT Wind	15	10,721,401	11,187,283	10,876,297	11,195,469	11,335,113	11,323,442	10,850,459	11,269,784	11,788,930	13,100,129
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	10,681,722	11,181,825	10,824,819	11,147,056	11,296,737	11,296,499	10,779,658	11,202,975	11,735,592	13,118,588
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	10,863,271	11,362,012	11,019,984	11,322,365	11,485,772	11,500,783	10,964,177	11,382,340	11,944,963	13,332,216
#1 Ret Late - #2 Ret Late - Opt	18	19,771,282	20,652,892	20,193,612	17,977,492	14,749,847	14,775,161	14,235,430	14,602,437	15,191,935	16,769,786
#1 Ret Late - #2 Ret Late - CC	19	19,771,282	20,652,892	20,193,612	17,977,492	14,749,847	14,775,161	14,235,430	14,602,437	15,191,935	16,769,786
#1 Ret Late - #2 Ret Late - CT Wind	20	19,771,282	20,652,892	20,193,612	16,835,752	11,328,315	11,323,441	10,850,459	11,269,784	11,788,930	13,100,129
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	19,771,282	20,652,892	20,193,612	16,346,024	11,278,184	11,296,499	10,779,658	11,202,976	11,735,592	13,118,588
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	19,588,264	20,468,702	20,004,668	16,606,318	11,475,726	11,500,783	10,964,177	11,382,340	11,944,963	13,332,216
Reference Case	23	19,771,282	20,652,892	19,926,302	20,431,962	20,883,602	20,631,158	20,146,354	20,926,496	21,320,750	23,148,000

Scenario Name	Scenario #	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	23,610,804	23,652,838	25,542,680	28,000,730	27,959,658	26,212,086	26,368,510	26,530,686	26,632,396
#1 SCR Late - #2 SCR Late	02	23,610,804	23,652,838	25,542,680	28,000,730	27,959,658	26,212,086	26,368,510	26,530,686	26,632,396
#1 Ret Early - #2 SCR Early - Opt	03	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Early - #2 SCR Early - CC	04	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Early - #2 SCR Early - CT Wind	05	19,354,546	19,856,262	21,220,048	23,551,602	23,731,826	21,711,680	21,876,240	22,019,154	22,043,412
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	18,897,052	19,376,710	20,745,822	23,074,762	23,313,124	21,212,678	21,407,612	21,544,840	21,584,176
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	19,151,104	19,638,948	21,027,476	23,359,496	23,604,358	21,510,228	21,701,502	21,826,034	21,860,806
#1 Ret Late - #2 SCR Late - Opt	08	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Late - #2 SCR Late - CC	09	20,327,742	20,743,020	22,097,982	24,486,556	24,829,610	22,561,308	22,767,660	22,897,764	23,047,802
#1 Ret Late - #2 SCR Late - CT Wind	10	19,354,546	19,856,266	21,220,048	23,551,602	23,731,826	21,711,680	21,876,240	22,019,148	22,043,412
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	18,897,052	19,376,710	20,745,822	23,074,764	23,313,124	21,212,678	21,407,612	21,544,838	21,584,176
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	19,151,104	19,638,948	21,027,474	23,359,496	23,604,358	21,510,228	21,701,502	21,826,032	21,860,808
#1 Ret Early - #2 Ret Early - Opt	13	16,868,944	17,321,760	18,909,522	20,773,728	21,150,556	19,223,200	18,985,752	19,188,852	19,215,196
#1 Ret Early - #2 Ret Early - CC	14	16,868,944	17,321,760	18,909,522	20,773,728	21,150,556	19,223,200	18,985,752	19,188,852	19,215,196
#1 Ret Early - #2 Ret Early - CT Wind	15	13,254,104	13,775,245	15,173,800	16,752,290	17,020,204	15,474,942	15,345,909	15,468,689	15,504,804
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	13,259,996	13,794,679	15,279,909	16,967,082	17,197,696	15,573,580	15,399,684	15,574,697	15,578,415
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	13,476,853	13,999,642	15,526,268	17,231,164	17,452,850	15,796,827	15,638,604	15,800,882	15,801,619
#1 Ret Late - #2 Ret Late - Opt	18	16,868,944	17,321,760	18,908,834	20,786,558	21,154,602	19,217,958	18,975,260	19,185,122	19,216,316
#1 Ret Late - #2 Ret Late - CC	19	16,868,944	17,321,760	18,908,834	20,786,558	21,154,602	19,217,958	18,975,260	19,185,122	19,216,316
#1 Ret Late - #2 Ret Late - CT Wind	20	13,254,104	13,775,245	15,173,799	16,752,290	17,020,206	15,474,942	15,345,909	15,468,690	15,504,804
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	13,259,996	13,794,679	15,279,909	16,967,082	17,197,696	15,573,560	15,399,684	15,574,696	15,578,416
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	13,476,853	13,999,642	15,526,268	17,231,164	17,452,848	15,796,829	15,638,604	15,800,882	15,801,615
Reference Case	23	23,649,784	23,679,828	25,566,100	28,027,042	27,993,318	26,244,288	26,404,428	26,547,820	26,649,012

Strategist Output - Annual CO2 Costs ($000)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021
#1 SCR Early - #2 SCR Early	01	0	0	0	0	368,461	390,249	423,794	447,758	455,003
#1 SCR Late - #2 SCR Late	02	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Early - #2 SCR Early - Opt	03	0	0	0	0	368,461	396,370	425,446	371,113	387,389
#1 Ret Early - #2 SCR Early - CC	04	0	0	0	0	368,461	396,370	425,446	371,113	387,389
#1 Ret Early - #2 SCR Early - CT Wind	05	0	0	0	0	368,461	396,370	425,446	346,908	362,562
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	0	0	0	0	368,461	396,370	425,446	338,461	353,588
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	0	0	0	0	367,585	394,581	422,853	343,476	358,961
#1 Ret Late - #2 SCR Late - Opt	08	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 SCR Late - CC	09	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 SCR Late - CT Wind	10	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	0	0	0	0	367,585	389,215	423,802	446,815	453,229
#1 Ret Early - #2 Ret Early - Opt	13	0	0	0	0	368,461	396,370	432,243	372,605	312,972
#1 Ret Early - #2 Ret Early - CC	14	0	0	0	0	368,461	396,370	432,243	372,605	312,972
#1 Ret Early - #2 Ret Early - CT Wind	15	0	0	0	0	368,461	396,370	432,243	347,954	227,939
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	0	0	0	0	368,461	396,370	432,243	339,596	231,864
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	0	0	0	0	367,585	394,581	429,482	344,629	235,912
#1 Ret Late - #2 Ret Late - Opt	18	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 Ret Late - CC	19	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 Ret Late - CT Wind	20	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	0	0	0	0	368,461	390,936	426,391	449,599	456,340
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	0	0	0	0	367,585	389,215	423,802	446,815	453,229
Reference Case	23	0	0	0	0	368,461	390,936	426,391	449,599	456,340

Scenario Name	Scenario #	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
#1 SCR Early - #2 SCR Early	01	456,840	485,672	477,300	507,152	533,476	535,615	537,689	574,417	601,041	653,384
#1 SCR Late - #2 SCR Late	02	457,488	486,348	478,209	507,152	533,476	535,615	537,689	574,417	601,041	653,384
#1 Ret Early - #2 SCR Early - Opt	03	377,063	403,795	406,448	421,478	445,855	456,523	445,353	480,859	516,529	549,269
#1 Ret Early - #2 SCR Early - CC	04	377,063	403,795	406,448	421,478	445,855	456,523	445,353	480,859	516,529	549,269
#1 Ret Early - #2 SCR Early - CT Wind	05	351,627	376,832	378,102	393,539	418,109	429,624	420,242	453,493	487,190	518,209
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	343,041	368,398	369,389	384,637	408,890	419,675	409,255	443,733	475,735	508,529
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	348,344	374,249	374,860	390,386	415,107	425,838	415,355	450,229	482,170	515,327
#1 Ret Late - #2 SCR Late - Opt	08	457,488	486,348	486,747	419,154	445,855	456,523	445,353	480,859	516,529	549,269
#1 Ret Late - #2 SCR Late - CC	09	457,488	486,348	486,747	419,154	445,855	456,523	445,353	480,859	516,529	549,269
#1 Ret Late - #2 SCR Late - CT Wind	10	457,488	486,348	486,747	393,350	418,109	429,624	420,242	453,493	487,190	518,209
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	457,488	486,348	486,747	384,463	408,890	419,675	409,255	443,733	475,735	508,529
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	454,478	483,209	483,663	390,208	415,107	425,838	415,355	450,229	482,170	515,327
#1 Ret Early - #2 Ret Early - Opt	13	307,876	316,819	317,949	338,802	350,688	359,194	358,780	379,498	409,986	452,663
#1 Ret Early - #2 Ret Early - CC	14	307,876	316,819	317,949	338,802	350,688	359,194	358,780	379,498	409,986	452,663
#1 Ret Early - #2 Ret Early - CT Wind	15	223,753	231,227	231,047	247,960	257,754	266,441	267,647	282,712	308,117	341,735
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	227,090	235,035	234,902	251,513	262,079	270,694	270,162	286,322	312,939	347,432
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	231,077	238,999	239,386	256,027	266,827	275,684	275,206	291,337	318,633	353,781
#1 Ret Late - #2 Ret Late - Opt	18	457,488	486,348	486,747	430,757	351,347	359,194	358,780	379,498	409,986	452,663
#1 Ret Late - #2 Ret Late - CC	19	457,488	486,348	486,747	430,757	351,347	359,194	358,780	379,498	409,986	452,663
#1 Ret Late - #2 Ret Late - CT Wind	20	457,488	486,348	486,747	405,258	258,764	266,441	267,647	282,712	308,117	341,734
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	457,488	486,348	486,747	395,768	261,969	270,694	270,162	286,322	312,939	347,432
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	454,478	483,209	483,663	401,639	267,447	275,684	275,206	291,337	318,633	353,781
Reference Case	23	457,488	486,348	478,292	507,991	534,201	536,602	538,555	574,984	602,069	654,538

Scenario Name	Scenario #	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	686,257	705,170	771,391	862,629	883,512	833,619	864,626	895,051	921,918
#1 SCR Late - #2 SCR Late	02	686,257	705,170	771,391	862,629	883,512	833,619	864,626	895,051	921,918
#1 Ret Early - #2 SCR Early - Opt	03	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Early - #2 SCR Early - CC	04	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Early - #2 SCR Early - CT Wind	05	549,527	578,152	620,629	704,653	741,902	666,286	692,218	719,518	744,666
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	538,264	567,355	610,442	694,652	730,093	656,172	680,671	708,429	733,358
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	546,115	574,311	617,030	702,277	737,862	663,065	688,615	717,206	743,013
#1 Ret Late - #2 SCR Late - Opt	08	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Late - #2 SCR Late - CC	09	581,263	609,897	658,051	745,056	775,793	710,154	734,541	764,146	787,817
#1 Ret Late - #2 SCR Late - CT Wind	10	549,527	578,152	620,629	704,653	741,902	666,286	692,218	719,518	744,666
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	538,264	567,355	610,442	694,652	730,093	656,172	680,671	708,429	733,358
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	546,115	574,311	617,030	702,277	737,862	663,065	688,615	717,206	743,013
#1 Ret Early - #2 Ret Early - Opt	13	470,101	496,942	553,146	625,348	654,235	597,344	605,886	629,565	653,189
#1 Ret Early - #2 Ret Early - CC	14	470,101	496,942	553,146	625,348	654,235	597,344	605,886	629,565	653,189
#1 Ret Early - #2 Ret Early - CT Wind	15	356,589	379,803	426,424	484,193	511,228	456,589	460,868	481,778	500,043
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	361,325	385,865	431,674	489,955	520,544	460,868	466,841	487,164	506,826
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	368,058	391,764	437,640	498,358	528,662	468,998	473,991	494,935	514,830
#1 Ret Late - #2 Ret Late - Opt	18	470,101	496,942	553,159	624,872	654,084	597,533	606,284	629,703	653,138
#1 Ret Late - #2 Ret Late - CC	19	470,101	496,942	553,159	624,872	654,084	597,533	606,284	629,703	653,138
#1 Ret Late - #2 Ret Late - CT Wind	20	356,589	379,803	426,424	484,193	511,228	456,589	460,868	481,778	500,043
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	361,325	385,865	431,674	489,955	520,544	460,868	466,841	487,164	506,828
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	368,058	391,764	437,640	498,358	528,662	468,998	473,991	494,935	514,830
Reference Case	23	687,987	706,414	772,527	863,862	884,960	835,019	866,152	896,084	922,947

Appendix E
Present Value Revenue Requirements Results and Annual Details

Strategist Output - Annual SO2 Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	33,880	27,715	23,932	20,798	17,015	14,690	13,844	16,255	16,230	16,457	16,879	17,108	16,347	15,713	16,138	15,351	14,645	14,957	17,190	16,541	16,719	18,213	18,997	18,726	18,543	17,300	17,524	17,208
#1 SCR Late - #2 SCR Late	02	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	17,105	16,347	15,713	16,138	15,351	14,645	14,957	17,190	16,541	16,719	18,213	18,997	18,726	18,543	17,300	17,524	17,208
#1 Ret Early - #2 SCR Early - Opt	03	33,880	27,715	23,932	20,798	17,015	14,405	13,876	16,031	14,889	15,672	16,701	16,579	15,688	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Early - #2 SCR Early - CC	04	33,880	27,715	23,932	20,798	17,015	14,405	13,876	16,031	14,889	15,672	16,701	16,579	15,688	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Early - #2 SCR Early - CT Wind	05	33,880	27,715	23,932	20,798	17,015	14,405	13,876	15,730	15,260	15,899	16,693	16,588	15,924	15,114	15,064	13,867	13,388	13,485	15,980	15,000	15,653	17,258	17,958	16,397	17,461	16,410	16,449	15,562
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	33,880	27,715	23,932	20,798	17,015	14,405	13,876	14,886	14,581	15,084	15,833	15,697	15,180	14,413	14,508	13,537	12,764	13,151	15,289	14,573	15,040	16,600	17,231	16,113	16,610	15,823	15,751	14,933
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	33,880	27,715	23,932	20,709	16,826	14,221	13,685	15,268	14,867	15,423	16,119	16,050	15,417	14,557	14,704	13,697	12,897	13,308	15,291	14,648	15,271	16,952	17,485	16,427	17,049	16,145	15,964	15,056
#1 Ret Late - #2 SCR Late - Opt	08	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	16,756	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Late - #2 SCR Late - CC	09	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	16,756	15,152	15,477	14,501	13,703	13,510	15,714	14,869	15,232	16,181	16,802	16,860	15,782	15,159	15,020	14,952
#1 Ret Late - #2 SCR Late - CT Wind	10	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	15,967	15,114	15,064	13,867	13,388	13,485	15,980	15,000	15,653	17,258	17,958	16,397	17,461	16,410	16,449	15,562
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	15,220	14,413	14,508	13,537	12,764	13,151	15,289	14,573	15,040	16,600	17,231	16,113	16,610	15,823	15,751	14,933
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	33,880	27,715	23,932	20,709	16,826	14,482	13,704	15,953	15,990	16,115	16,563	16,667	15,457	14,557	14,704	13,697	12,897	13,308	15,291	14,648	15,271	16,952	17,485	16,427	17,049	16,145	15,964	15,056
#1 Ret Early - #2 Ret Early - Opt	13	33,880	27,715	23,932	20,798	17,015	14,405	13,825	16,049	14,216	14,335	16,057	15,907	14,924	14,275	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,306	14,034	14,187	13,319	12,156	12,661	11,736
#1 Ret Early - #2 Ret Early - CC	14	33,880	27,715	23,932	20,798	17,015	14,405	13,825	16,049	14,216	14,335	16,057	15,907	14,924	14,275	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,306	14,034	14,187	13,319	12,156	12,661	11,736
#1 Ret Early - #2 Ret Early - CT Wind	15	33,880	27,715	23,932	20,798	17,015	14,405	13,825	15,722	13,694	13,780	14,882	14,799	14,273	13,735	13,494	12,000	11,803	11,952	13,576	12,862	13,585	14,442	14,503	13,802	14,076	13,634	13,586	12,922
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	33,880	27,715	23,932	20,798	17,015	14,405	13,825	14,868	13,190	13,283	14,470	14,232	13,744	13,154	12,987	11,551	11,221	11,307	13,121	12,454	13,147	14,459	14,897	13,700	14,189	13,346	13,665	12,709
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	33,880	27,715	23,932	20,709	16,826	14,221	13,656	15,249	13,342	13,459	14,638	14,414	13,833	13,291	13,188	11,675	11,317	11,465	13,230	12,546	13,298	14,785	15,026	13,852	14,224	13,573	13,789	12,802
#1 Ret Late - #2 Ret Late - Opt	18	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	16,665	14,423	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,301	14,146	14,222	13,276	12,066	12,630	11,746
#1 Ret Late - #2 Ret Late - CC	19	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	16,665	14,423	14,674	13,473	12,446	12,536	14,231	13,208	13,680	14,301	14,146	14,222	13,276	12,066	12,630	11,746
#1 Ret Late - #2 Ret Late - CT Wind	20	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	15,691	13,578	13,494	12,000	11,803	11,952	13,576	12,862	13,585	14,442	14,503	13,802	14,076	13,634	13,586	12,922
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	16,998	15,071	13,073	12,987	11,551	11,221	11,307	13,121	12,454	13,147	14,459	14,897	13,700	14,189	13,346	13,665	12,709
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	33,880	27,715	23,932	20,709	16,826	14,482	13,704	15,953	15,990	16,115	16,563	16,667	15,311	13,158	13,188	11,675	11,317	11,465	13,230	12,546	13,298	14,785	15,026	13,852	14,224	13,573	13,789	12,802
Reference Case	23	33,880	27,715	23,932	20,798	17,015	14,672	13,893	16,271	16,252	16,417	16,850	17,094	16,320	15,668	16,122	15,343	14,619	14,917	17,157	16,506	16,692	18,186	18,975	18,716	18,535	17,299	17,494	17,179

Strategist Output - Annual NOx Emmissions (Tons)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	30,011	27,634	23,160	20,519	16,991	13,514	11,146	12,234	12,335	12,378	12,539	12,271	11,783	11,209	11,307	10,625	9,945	10,322	11,772	11,213	11,520	12,477	12,851	13,008	12,595	11,541	11,465	11,223
#1 SCR Late - #2 SCR Late	02	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	14,595	11,783	11,209	11,307	10,625	9,945	10,322	11,772	11,213	11,520	12,477	12,851	13,008	12,595	11,541	11,465	11,223
#1 Ret Early - #2 SCR Early - Opt	03	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,555	11,847	12,295	12,813	12,268	11,764	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Early - #2 SCR Early - CC	04	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,555	11,847	12,295	12,813	12,268	11,764	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Early - #2 SCR Early - CT Wind	05	30,011	27,634	23,160	20,519	16,991	15,119	13,520	12,336	12,110	12,474	12,839	12,303	11,941	11,259	11,020	10,149	9,599	9,806	11,464	10,699	11,234	12,325	12,635	11,960	12,359	11,412	11,195	10,606
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	30,011	27,634	23,160	20,519	16,991	15,119	13,520	11,770	11,633	11,922	12,259	11,707	11,437	10,783	10,634	9,896	9,174	9,551	10,998	10,392	10,819	11,884	12,156	11,743	11,803	11,016	10,743	10,199
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	30,011	27,634	23,160	20,457	16,862	14,982	13,380	12,035	11,840	12,161	12,467	11,950	11,612	10,900	10,777	10,018	9,279	9,673	11,026	10,474	10,986	12,124	12,336	11,955	12,087	11,226	10,882	10,283
#1 Ret Late - #2 SCR Late - Opt	08	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	12,462	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Late - #2 SCR Late - CC	09	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	12,462	11,245	11,239	10,498	9,756	9,784	11,265	10,578	10,937	11,632	11,905	12,203	11,296	10,603	10,284	10,189
#1 Ret Late - #2 SCR Late - CT Wind	10	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	11,966	11,259	11,020	10,149	9,599	9,806	11,464	10,699	11,234	12,325	12,635	11,960	12,359	11,412	11,195	10,606
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	11,461	10,783	10,634	9,896	9,174	9,551	10,998	10,392	10,819	11,884	12,156	11,743	11,803	11,016	10,743	10,199
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	30,011	27,634	23,160	20,457	16,862	15,028	15,115	16,672	16,559	16,630	17,152	16,661	11,636	10,900	10,777	10,018	9,279	9,673	11,026	10,474	10,986	12,124	12,336	11,955	12,087	11,226	10,882	10,283
#1 Ret Early - #2 Ret Early - Opt	13	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,819	11,833	11,802	12,799	12,249	11,637	11,094	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,806	10,611	10,947	10,098	9,132	9,185	8,568
#1 Ret Early - #2 Ret Early - CC	14	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,819	11,833	11,802	12,799	12,249	11,637	11,094	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,806	10,611	10,947	10,098	9,132	9,185	8,568
#1 Ret Early - #2 Ret Early - CT Wind	15	30,011	27,634	23,160	20,519	16,991	15,119	15,358	14,504	11,123	11,123	11,754	11,260	10,937	10,494	10,144	9,052	8,734	8,959	10,050	9,512	10,081	10,676	10,667	10,489	10,412	9,925	9,662	9,212
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	30,011	27,634	23,160	20,519	16,991	15,119	15,358	13,896	10,880	10,882	11,562	10,952	10,655	10,182	9,877	8,809	8,406	8,604	9,811	9,289	9,845	10,712	10,936	10,462	10,492	9,758	9,720	9,089
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	30,011	27,634	23,160	20,457	16,862	14,982	15,215	14,191	11,013	11,028	11,707	11,106	10,746	10,302	10,032	8,917	8,496	8,737	9,919	9,385	9,972	10,944	11,050	10,586	10,542	9,916	9,812	9,161
#1 Ret Late - #2 Ret Late - Opt	18	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	14,904	11,233	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,803	10,678	10,968	10,072	9,078	9,166	8,574
#1 Ret Late - #2 Ret Late - CC	19	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	14,904	11,233	11,131	10,214	9,383	9,582	10,701	9,958	10,371	10,803	10,678	10,968	10,072	9,078	9,166	8,574
#1 Ret Late - #2 Ret Late - CT Wind	20	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	14,176	10,407	10,144	9,052	8,734	8,959	10,050	9,512	10,081	10,676	10,667	10,489	10,412	9,925	9,662	9,212
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,904	13,716	10,131	9,877	8,809	8,406	8,604	9,811	9,289	9,845	10,712	10,936	10,462	10,492	9,758	9,720	9,089
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	30,011	27,634	23,160	20,457	16,862	15,028	15,115	16,672	16,559	16,630	17,152	16,661	13,926	10,224	10,032	8,917	8,496	8,737	9,919	9,385	9,972	10,944	11,050	10,586	10,542	9,916	9,812	9,161
Reference Case	23	30,011	27,634	23,160	20,519	16,991	15,170	15,267	16,899	16,762	16,849	17,368	16,787	16,428	16,111	15,940	15,280	14,895	15,084	16,729	16,460	16,424	17,582	18,389	18,228	17,903	17,193	17,082	16,845

Strategist Output - Annual Hg Emmissions (lbs)

Scenario Name	Scenario #	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
#1 SCR Early - #2 SCR Early	01	608	244	199	173	154	115	93	125	122	122	131	118	104	99	108	98	96	94	121	116	115	131	143	142	129	116	112	107
#1 SCR Late - #2 SCR Late	02	608	244	199	173	154	114	92	124	122	121	131	118	104	99	108	98	96	94	121	116	115	131	143	142	129	116	112	107
#1 Ret Early - #2 SCR Early - Opt	03	608	244	199	173	154	109	92	148	128	138	154	133	121	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Early - #2 SCR Early - CC	04	608	244	199	173	154	109	92	148	128	138	154	133	121	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Early - #2 SCR Early - CT Wind	05	608	244	199	173	154	109	92	146	135	143	157	136	126	120	119	106	106	100	135	126	128	150	161	139	147	137	130	118
#1 Ret Early - #2 SCR Early - CT Wind Solar	06	608	244	199	173	154	109	92	136	127	133	147	125	117	111	112	102	99	97	126	121	120	141	152	135	136	129	121	110
#1 Ret Early - #2 SCR Early - CT Wind Solar DSM	07	608	244	199	171	152	107	90	140	129	137	150	129	120	112	114	104	100	98	126	121	123	146	155	139	142	133	123	111
#1 Ret Late - #2 SCR Late - Opt	08	608	244	199	173	154	114	92	124	122	121	131	114	135	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Late - #2 SCR Late - CC	09	608	244	199	173	154	114	92	124	122	121	131	114	135	118	122	113	109	99	130	123	121	134	145	144	123	119	110	109
#1 Ret Late - #2 SCR Late - CT Wind	10	608	244	199	173	154	114	92	124	122	121	131	114	127	120	119	106	106	100	135	126	128	150	161	139	147	137	130	118
#1 Ret Late - #2 SCR Late - CT Wind Solar	11	608	244	199	173	154	114	92	124	122	121	131	114	118	111	112	102	99	97	126	121	120	141	152	135	136	129	121	110
#1 Ret Late - #2 SCR Late - CT Wind Solar DSM	12	608	244	199	171	152	112	90	120	119	118	127	110	120	112	114	104	100	98	126	121	123	146	155	139	142	133	123	111
#1 Ret Early - #2 Ret Early - Opt	13	608	244	199	173	154	109	90	147	142	142	173	150	135	134	139	123	120	114	137	130	129	136	139	139	118	110	109	97
#1 Ret Early - #2 Ret Early - CC	14	608	244	199	173	154	109	90	147	142	142	173	150	135	134	139	123	120	114	137	130	129	136	139	139	118	110	109	97
#1 Ret Early - #2 Ret Early - CT Wind	15	608	244	199	173	154	109	90	145	143	142	164	144	135	134	130	111	117	113	134	130	134	144	150	141	137	136	130	121
#1 Ret Early - #2 Ret Early - CT Wind Solar	16	608	244	199	173	154	109	90	135	135	135	158	135	126	125	122	104	109	103	126	124	127	143	154	137	136	131	129	116
#1 Ret Early - #2 Ret Early - CT Wind Solar DSM	17	608	244	199	171	152	107	88	139	137	137	160	137	127	126	124	104	109	104	127	124	128	147	155	139	135	133	129	116
#1 Ret Late - #2 Ret Late - Opt	18	608	244	199	173	154	114	92	124	122	121	131	114	130	135	139	123	120	114	137	130	129	136	140	139	117	108	109	97
#1 Ret Late - #2 Ret Late - CC	19	608	244	199	173	154	114	92	124	122	121	131	114	130	135	139	123	120	114	137	130	129	136	140	139	117	108	109	97
#1 Ret Late - #2 Ret Late - CT Wind	20	608	244	199	173	154	114	92	124	122	121	131	114	120	132	130	111	117	113	134	130	134	144	150	141	137	136	130	121
#1 Ret Late - #2 Ret Late - CT Wind Solar	21	608	244	199	173	154	114	92	124	122	121	131	114	113	124	122	104	109	103	126	124	127	143	154	137	136	131	129	116
#1 Ret Late - #2 Ret Late - CT Wind Solar DSM	22	608	244	199	171	152	112	90	120	119	118	127	110	115	125	124	104	109	104	127	124	128	147	155	139	135	133	129	116
Reference Case	23	608	244	199	173	154	114	92	124	122	121	131	118	103	98	107	97	95	93	120	115	115	130	142	141	128	115	111	107

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

October 2, 2015

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: 2016-2030 UPPER MIDWEST RESOURCE PLAN
REPLY COMMENTS
DOCKET NO. E002/RP-15-21

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the July 2, 2015 Comments received on its 2016-2030 Upper Midwest Resource Plan in the above-referenced docket.

In this Reply, we bring to the Commission a proposal that outlines a bold energy vision that benefits our customers, communities, and the states we serve. We expect our proposal will stimulate discussion, and we look forward to engaging in a constructive dialogue with the Commission, the parties to this docket, and our stakeholders. In the Reply, we propose to work with the Commission Staff and parties on a procedural schedule that provides an opportunity to build the record and advance our Proposal.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service lists. Please contact Aakash Chandarana at (612) 215-4663 or aakash.chandarana@xcelenergy.com if you have any questions regarding this filing.

/s/

CHRISTOPHER B. CLARK
PRESIDENT
NORTHERN STATES POWER COMPANY

Enclosures
cc: Service lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN

DOCKET NO. E002/RP-15-21

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Reply to the July 2, 2015 Comments received on its 2016-2030 Upper Midwest Resource Plan in the above-referenced docket. In this Reply, we share a bold energy vision that transitions our system from coal generation, advances the acquisition of significant levels of renewable generation, recognizes nuclear energy as a critical carbon-free baseload resource, and confirms our commitment to energy efficiency efforts.

In our initial Resource Plan, we shared a vision of a 40 percent reduction of carbon dioxide emissions from 2005 levels by 2030. Since that time, other parties filed comments recommending different approaches, and the Environmental Protection Agency has issued its final Clean Power Plan (CPP). We have reviewed and analyzed the comments filed by our stakeholders. We have also conducted a preliminary analysis of the CPP, though we recognize much more will develop around this rule. In these Reply Comments, we present our analysis to-date, outline our proposed actions, and suggest a procedural framework that allows us to continue to move forward quickly, work collaboratively with other parties, and at the same time recognize the many other cases before the Commission.

In these Reply Comments, we outline our vision of the energy future for our customers, communities, and states. We believe our proposal benefits our customers by supporting a cost-effective transition to the future, allowing adequate time to transition our workforce, creating new jobs and investments for our communities in the states we serve, and continuing our renewable and carbon-free energy leadership. Our proposal would result in a 60 percent reduction of carbon emissions from 2005 levels by 2030. We recognize many pieces of a complex effort need to come together to achieve these benefits. We outline this proposal to begin the necessary discussions and actions and to allow parties to consider how we may work together to achieve this outcome while weighing it against other alternatives. We look forward to a robust discussion around our proposal and welcome procedural guidance and input from the Commission and the Minnesota Pollution Control Agency (MPCA) on how best to coordinate between the agencies to further this important work.

Our proposal has four primary elements:

1. *Accelerate the transition from coal energy to renewables.* Our proposal includes:
    - Achieving 60 percent carbon emission reductions by 2030,
    - Ceasing coal generation at Sherco Unit 2 in 2023,
    - Ceasing coal generation at Sherco Unit 1 in 2026, and
    - Advancing the addition of substantial renewable generation (1,200 MW by 2020).

2. *Preserve regional system reliability.* We propose to continue operation of our nuclear units during the current resource planning period and construct sufficient gas fired generation and infrastructure to maintain reliability with an appreciation of regional, state, and local community economic and policy considerations. To that end, we envision:
    - Reaffirming our commitment to nuclear energy through the current licenses of our existing units,
    - Adding a combustion turbine in North Dakota by 2025,
    - Studying a Sherco Unit 2 boiler conversion or combustion turbine alternative,
    - Studying gas infrastructure and transmission expansion, and
    - Replacing Sherco generation with a combined cycle no later than 2026.

3. *Pursue energy efficiency gains and grid modernization.* We propose to continue our commitment to energy efficiency and new technologies, and we look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

4. *Ensure customer benefits.* We propose to work with the Commission, the MPCA, and our stakeholders to ensure our customers get the full benefit of our proposal by:
    - Working with the MPCA, along with its counterpart environmental agencies in our other states, on the CPP State Plans to maximize the benefits of compliance for our customers and communities, and

- Pursuing rate plans and cost recovery mechanisms that smooth costs for our customers.

Our Preferred Plan in our initial filing achieved substantial progress toward federal and state energy goals at a reasonable cost. During the course of this proceeding, however, parties have asked us to consider alternative proposals. In evaluating those alternatives, we have concluded that we can propose a plan that achieves even greater carbon reductions, invests in our communities, and maintains the affordability of our rates while assuring reliable service. Three key factors drive our decision to advance this proposal now and underscore why we believe it the best course of action for our customers, communities, and company.

First, we believe there is great benefit to the certainty our proposal provides. While additional studies, rule analysis, and CPP State Plan development will be necessary, there is significant value for the Company and our customers if we shift our focus to the future. This forward-focus allows for the following to begin now:

- We will have a full ten years to transition our workforce to support our future generation resources.
- We can begin planning the redevelopment of the Sherco site to accommodate a combined cycle unit and solar energy, extend sufficient gas infrastructure to the site, finalize transmission studies, and fully understand the operational issues presented by the new infrastructure in conjunction with Sherco Unit 3 and Monticello.
- We can begin work on our North Dakota-sited combustion turbine, which will require building out sufficient natural gas and transmission infrastructure to support that generation.
- We can begin readying Request For Proposal (RFP) processes for additional wind and solar generation that we expect to be located throughout our service territories – and, with that, start identifying ways to maximize our CapX 2020 investments.
- We can work with the MPCA, along with its counterparts in our other states, to create a straw proposal for the CPP State Plans and explore a trading system that benefits all of the customers and states we serve.

We believe there are tangible benefits to moving now. For instance, we will have the opportunity to maximize the anticipated Production Tax Credit extensions in the acquisition of renewable energy. Additionally, addressing the future of Sherco Units 1 and 2 now helps us avoid the situation where we are replacing all of our baseload energy generation in the early 2030s.

Second, environmental regulations will continue to place pressure on the operations of Sherco Units 1 and 2. The possibility that NOx reductions would require installation of Selective Catalytic Reduction (SCRs) at the Sherco Units in the mid-2020s was a factor that advanced this proposal. We do not believe committing significant amounts of capital to these Units represents a realistic view of our energy future. We have successfully operated Sherco Units 1 and 2 to produce cost-effective energy while exceeding environmental regulations; however, the environmental pressures on these Units will continue to build. Our vision for the future is cleaner, cost-effective energy, so – for us – moving forward now is the best choice and focus for our resources. We recognize that others in the region may not be able to make changes now due to recent investments in plants (for instance in South Dakota), higher percentages of coal energy (for instance in North Dakota), or the desire to see how various litigated issues are resolved. We believe our action here can help our region successfully make this transition, encourage the development of renewable energy in our states, and provide jobs and investments for our communities. Our plan will also help identify energy solutions and embrace new technologies, providing clear benefits for our customers from our energy leadership.

Third, our customers increasingly want cleaner energy. More of our customers are asking us to provide options for all renewable energy or are making individual or corporate commitments to sustainability and the environment. Likewise, our cities are making commitments to sustainability. Potential new customers deciding whether to locate their businesses in our states have asked for clean energy options. We believe the action we are taking here will position us well to serve customers into the future. At the same time, we are sensitive to the cost concerns of all our customers, and are aware that some of our customers compete in regional, state, national, and increasingly international markets. We believe we can deliver this proposal at a reasonable cost and do not believe cost concerns warrant delaying action. We prefer to implement a plan that provides cleaner energy and at the same time aggressively pursue actions to lower costs. For example, we will be ready to launch an RFP if the Production Tax Credit for wind generation is extended. In addition, we can focus on lowering costs of this plan through the development of a regional approach to the CPP and potential trading options. Finally, we believe longer-term rate plans are important as they can moderate any necessary rate increases over five-year periods and benefit customers by providing greater predictability. A longer-term rate compact has other benefits as it can free-up state regulatory, Company, and stakeholder resources to focus on issues other than ratemaking, such as the CPP State Plans and grid modernization. We have successfully entered into these longer-term compacts in North Dakota and South Dakota, and look forward to advancing proposals to do so in Minnesota based on legislation passed in the last legislative session.

With these factors in mind, over the past two months we developed alternative approaches to our Preferred Plan. The result is the proposal outlined in these Reply

Comments. While we have done the preliminary analysis to validate the plan, significant work is necessary to make it a reality. We recognize customers, communities in all of our states, and parties will want to react to this proposal and will want more details. We look forward to that exchange of information and further discussion. We intend to encourage additional public comment, but at the same time want to continue to work constructively and collaboratively with the parties to do the work that is necessary to move the plan forward. We want to move quickly, but deliberately, recognizing the need for input on the significant decisions that will be necessary. We believe that with the input and support of our stakeholders, we can begin the task of transitioning our fleet from baseload coal to cleaner energy resources.

For our part, a fleet transformation of this magnitude requires a diligent and thoughtful process to ensure our system remains safe, reliable, and cost-effective. We are at the beginning of the process to determine the best way to accomplish this transition, but much remains to be done. Among other things, we are currently studying how Sherco unit closures impact system reliability, how to efficiently deliver gas supply to a repowered Sherco site as well as a site in North Dakota, and how we can successfully transition our workforce and minimize the impacts on our current employees at the Sherco plant. These items and others need to be resolved to make the plan viable. If we are unable to reach resolution on these items, we would recommend the Department's proposed plan as an achievable fallback position. In that plan, we would convert one Sherco Unit to a gas boiler in 2025, and submit our next resource plan in January 2017 with additional detail on the impact of further actions at Sherco.

The last time we significantly transformed our fleet was in the early 2000s when we worked with the Commission and our stakeholders to repower Riverside and High Bridge plants, and make environmental improvements to our King plant. The Metro Emissions Reduction Project (MERP) construct effectively vetted generation alternatives and provided the Commission an opportunity to evaluate the costs and terms of the proposal.[1] We think the same approach could work here. A MERP-type construct would provide a forum for the Company to bring forward a definitive, thorough proposal for the Commission to consider and analyze. Prior to bringing the proposal forward, we would welcome the opportunity to work with parties to try and find areas of agreement and resolution, including working to align our proposal with the MPCA process.

In the balance of our Reply, we provide additional detail on our proposal, outline next steps, provide an initial analysis of the CPP, and respond to specific stakeholder

[1] Docket No. E002/M-02-633.

Comments.

Section I – *Our Proposal*
Section II – *Next Steps*

Attachment A – *Updated Load and Resources Information*
Attachment B – *Initial Analysis of the Clean Power Plan*
Attachment C – *Response to July 2, 2015 Comments*

I. OUR PROPOSAL

In our Resource Plan, we initially proposed to operate Sherco Units 1 and 2 to 2030 and to add a total of 1,800 MW of wind and 1,700 MW of large solar resources over the planning period. With our revised proposal, we can achieve a 60 percent carbon emissions reduction by 2030 (from 2005 levels). To achieve that goal, we propose three actions:

First, establish retirement dates for Sherco Units 1 and 2 that are technically feasible, allow for an orderly workforce transition, and align with our resource needs. To that end, we propose to cease coal operations at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026.

Second, accelerate the addition of wind and solar resources – a total of 800 MW of wind and 400 MW of solar in the pre-2020 timeframe. Advancing renewables benefits our customers in that we can capitalize on favorable market pricing and anticipated tax credits. The acceleration also brings replacement generation online to ensure reliable service for our customers during the Sherco transition.

Third, commit to the continued utilization of our carbon-free nuclear baseload resources through the existing plant licenses – and engage the Commission and our stakeholders in a multi-year study to better understand the evolving nuclear landscape, the expected costs to operate our units through their current licenses, and what the industry is considering for additional life extensions.

We outline below the four primary elements of our proposal.

A. Accelerate the Transition from Coal Energy to Renewables

1. Sherco Units 1 and 2

The first step in achieving a 60 percent reduction in our carbon emissions is to chart a certain path for Sherco Units 1 and 2. We considered the Clean Energy Organizations'

(CEO) recommendation to close the first Unit in 2021 and the second Unit in 2024, but moved those dates out to adjust for construction timelines, system reliability, workforce transition – and allow time for CPP State Plan development. We also considered the Department's recommendation to convert one Sherco Unit to a natural gas boiler in 2025. While the Department's recommendation sets forth a practical alternative, we believe that beginning a two-Unit transition effort now best positions our customers to benefit from favorable market pricing and a construction schedule for replacement generation in the early 2020s. This timing also demonstrates leadership on implementation of the CPP, provides an adequate planning horizon for our employees, and positions us for an orderly transition to the future.

In order to deliver an orderly transition, we will need to work aggressively to complete technical studies, create workforce transition plans, draft detailed construction plans, coordinate with the MPCA and other states on the CPP, and develop a thorough MERP-type proposal. Important to the success of our proposal will be the availability of tax credits, community and state outreach and support for generation and infrastructure investments, and longer-term cost recovery mechanisms to help smooth rates and facilitate the transition for customers.

2. *Technical Feasibility*

The technical feasibility of our proposal is still under study. In our March 16, 2015 Supplement, we noted that Sherco Units 1 and 2 are key components of our system, that the grid has grown up around them for nearly 40 years, and that the Units' size, location, and operating characteristics require detailed technical study to confirm that we fully understand the implications of their removal from the NSP and Midcontinent Independent System Operator (MISO) Systems.

To that end, we described the MISO Attachment Y2 and Xcel Energy Transmission Reliability studies we were initiating to examine the effects of phased retirement scenarios of one or both Sherco Units. We also explained that we would need to revisit our Black Start plan that currently relies on these Units to restore the system in the case of a catastrophic event. While we still need to complete our Transmission Study and Black Start analysis, we have received the MISO Y2 study results.

The MISO Y2 Study found that ceasing operations of one Sherco Unit will likely require some mitigation for expected reliability impacts. Ceasing operation of both Units, however, creates a significant voltage issue in the Monticello area. Importantly, MISO also declared Sherco Units 1 and 2 as System Stability Resources (SSR), which means that before we can cease operations of those Units, MISO must approve our plans to ensure we have sufficiently mitigated any anticipated impacts on the transmission system. The preliminary results from our Transmission Reliability Study are consistent with the MISO Y2 findings with respect to system impacts of a one versus two Unit closure.

The most significant reliability issues that require additional study include: (1) ensuring the Monticello Nuclear Plant meets Nuclear Regulatory Commission (NRC) requirements related to voltage during all system conditions; and (2) ensuring we can reliably serve Twin Cities area load by providing sufficient generation and voltage support. In January 2016, we anticipate receiving the results of our Transmission Reliability Study that will provide further insight into system stability and reliability under various Sherco retirement scenarios; this study is also likely to identify topic areas for additional study.

An important consideration in assessing the technical feasibility of retiring generating units is the replacement plan. We believe the replacement generation we are proposing at Sherco and in North Dakota will fulfill our expected energy and capacity needs and provide critical reliability solutions in their respective locations. We discuss our proposed replacement generation more fully in Section B.

3. Policy Considerations

We share the same goal as many of our stakeholders – delivering clean, reliable, and affordable energy to our customers while supporting our service territory communities. We have helped to lead the way to this objective through our early action to:

- Add significant and competitively-priced amounts of wind to our system,
- Develop sophisticated wind forecasting systems that facilitate our ability to reliably integrate significant amounts of wind onto our system,
- Avoid building approximately 3,100 MW of generation capacity by helping our customers achieve energy efficiency through our programs,
- Initiate one of the largest solar programs in the country, and
- Achieve significant carbon emissions reductions in a cost-effective manner while preserving jobs and maintaining our commitment to our communities through our MERP.

Once again, early action will help deliver value to our customers. With respect to the impact of environmental regulations, however, we are dealing in the unknown. We recognize there are many details to work through with the CPP, and that the State Plan will need to align well with our proposal in order to ensure benefits for all of our customers. We look forward to working with the MPCA, and expect to offer ideas to support regional solutions and a surplus compliance market to motivate utilities to go beyond compliance, providing substantial benefits to our customers and offering solutions to our neighboring states.

a. Evolving Environmental Regulations

In August 2015, the EPA issued its final CPP rules, which may prove to be the most significant environmental regulation affecting the electric power sector to-date. Our early efforts and environmental leadership will ease the remaining work we have to do to achieve our share of CPP compliance. However, we are just at the beginning of a significant effort that will require coordination and collaboration across many different stakeholder groups in Minnesota and across our Upper Midwest region.

Obtaining clarity on CPP State Plan requirements will take time. However, our preliminary understanding of the final rule is that this proposal will very likely exceed our requirements in the case of either a rate- or mass-based approach.

In the case of a mass-based CPP approach, we reasonably believe our proposal will generate a significant quantity of surplus allowances to facilitate interstate CPP solutions that would benefit our customers. Getting appropriate credit for our customers for the surplus compliance our plan generates is an essential part of this plan, and will help defray the costs our customers will incur as we transform our generation portfolio.

In Attachment B to this Reply, we provide a more detailed discussion of our initial analysis of the CPP. Additionally, in Attachment C, we address the National Ambient Air Quality Standards (NAAQS) and Regional Haze and Visibility regulations.

b. Socioeconomic Impacts

Charting a path certain for Sherco Units 1 and 2 is important for our employees, the City of Becker and surrounding area, and Liberty Paper, who relies on steam from the Units for its operations. With these stakeholders in mind, our proposal provides an eight to ten year transition period and proposes to replace generation onsite, which will preserve jobs, grow tax base, and reaffirm our commitment to Central Minnesota.

We have a successful history with transitions like this. Since 2007, we have closed six coal-fired generating units, including our High Bridge and Riverside plants, which we repowered on natural gas as part of our MERP. In terms of our employees, by working closely within the Company and our International Brotherhood of Electrical Workers union locals, we have successfully managed these transitions.

4. *Renewable Generation*

The second step in achieving our carbon emissions goal is advancing the addition of renewable resources. Technology is enabling a quicker and more cost-effective move toward a clean energy future. Solar costs have decreased by more than 60 percent in the last five years. The cost of wind generation energy is now on par with new natural gas combined cycle – and offers a great fuel hedge. We are also seeing storage technologies begin to come on the market and believe batteries will increasingly come down in cost, offering both new potential in transportation and also in providing reliability and support to renewable and Distributed Energy Resources (DER).

In recognition of these advancements, we believe we can add more renewable generation to our system earlier. Our proposal maintains the same total levels of renewable additions as our Preferred Plan proposed – 1,700 MW of large solar generation and 1,800 MW of wind generation – but proposes to add a total of 1,200 MW of renewable generation in the 2016-2020 timeframe. In advancing these additions, we are seeking to benefit our customers by capitalizing on favorable pricing and available tax incentives. Accordingly, our ability to advance the addition of early wind generation is dependent on an extension of the production tax credit.

We also see an opportunity to further our compliance with the CPP to obtain tradable surplus compliance credits that could serve to offset some of the costs of this plan for our customers. As the percentage of generation coming from renewables and DER continues to grow, it is important to understand how that growth impacts our grid. We recognize the Commission is already pursuing this knowledge with the Grid Modernization effort.

B. Preserve Regional System Reliability

The second element to our proposal is to preserve regional system reliability by constructing sufficient gas-fired generation infrastructure and committing to the continued utilization of our carbon-free nuclear baseload resources through the existing unit licenses.

1. *Natural Gas Generation*

The size, type, and timing of additional thermal generation involves multiple considerations, including system stability needs, resource needs, and regional, state, and local economic and policy considerations. While we do not propose to replace Sherco Unit 1 and 2 capacity megawatt for megawatt due to higher energy efficiency and the addition of renewable energy resources, we propose to add natural gas generation at both the Sherco site and in North Dakota to support system reliability.

With respect to Sherco, we are continuing to study the potential to convert one of the boilers to gas, as suggested by the Department; however, preliminary assessments suggest that refueling with natural gas poses significant operational challenges. Further study of this option, as well as combustion turbine alternatives is necessary.

When Sherco Units 1 and 2 are retired, we believe that a combined cycle generating unit at the Sherco location provides many needed benefits to the transmission system, including needed reactive power for voltage support and dynamic response for system stability. Replacing Sherco Units 1 and 2 with a combined cycle unit facility also reinforces our commitment to Central Minnesota generally, and Becker specifically. This would provide continued commitment through jobs, property taxes, and presence in the communities of Central Minnesota. We also believe the development of solar energy on the Sherco site further demonstrates our continued commitment to the community. Our customers will also benefit from replacement because the Company can capitalize on the existing infrastructure at the site, including transmission, land, water, and site services.

Replacing Sherco Units 1 and 2 with a combined cycle facility also benefits Liberty Paper, who relies on the steam output of Sherco Units 1 and 2 for their operations. A combined cycle onsite would enhance natural gas supply and provide options for continuing support of steam supply to Liberty Paper. Liberty Paper is a valued customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

We also propose to add a combustion turbine unit in North Dakota by 2025. Adding North Dakota-based generation is important from both a policy and reliability perspective. North Dakota is a growing part of our integrated system – and nearly all of the generation serving North Dakota customers is in Minnesota. Given that, North Dakota has requested that the Company commit to build generation resources in the state—and we agreed. From a reliability perspective, siting generation in North Dakota is preferable given its proximity to the growing load centers.[2] This proximity promotes system reliability and allows for a rapid and effective response in the event of a power outage due to an adverse weather event.

2. Our Nuclear Fleet

The second step to ensuring system stability – and achieving a 60 percent reduction in

[2] We have previously discussed the differing policy views between Minnesota and North Dakota with respect to the make-up of our generation portfolio, and note that the Agreement we filed with the North Dakota Commission on September 30, 2015 commits to site thermal generation in North Dakota before 2025.

carbon emissions – is committing to utilize our carbon-free nuclear baseload through the existing plant licenses. The nuclear industry is facing significant pressure and some companies are considering closing nuclear units. Our proposal calls for the continued operation of our nuclear units through the 2020s. The rationale to support our position is three-fold. First, our nuclear units are a critical baseload resource that ensures system reliability and stability—particularly as large coal units come off line. Second, in order to maintain system stability, promote an orderly workforce transition, and maintain affordable energy for our customers, we need to transition away from coal before taking on the issue of a nuclear transition. Third, our nuclear fleet is critical to meeting carbon emissions targets and provides a hedge against high gas prices.

As we prepare our system for the transition, we need to do so in light of what other resources will be on our system to assure we can provide reliable and affordable energy to our customers. Retaining nuclear generation provides our system with a baseload energy resource that helps ensure system stability. Although renewable technology has made significant strides, it is not yet capable of replacing baseload generation. Accordingly, one view of our system is that our nuclear units can act as a bridge—ensuring system reliability while allowing time for the development of storage technologies like batteries. This staged transition also provides time to understand and respond to system impacts as baseload generation shifts, allows for an orderly workforce transition, and spreads customer rate impacts over time. Another view is that nuclear should continue to be a resource beyond the current licenses of the units. To that end, the nuclear industry and the NRC are actively discussing the potential for additional license renewals (known as "life after 60").

Continuing to operate our nuclear fleet is also essential to achieving the emissions reductions contemplated by state and federal policies. Our nuclear units comprise more than half of the Company's carbon-free generation. Given the current limits of battery storage, nuclear units retired today would likely be replaced primarily by natural gas, which exposes our customers to gas price volatility and a significant increase in carbon emissions. For context, through 2030, our nuclear fleet is projected to generate about 14,000 GWh/year of clean energy. If all of that baseload generation were replaced with natural gas combined cycle generation emitting at 900 lbs CO_2/MWh, the resulting increase in carbon emissions would be 6.3 million short tons per year—equivalent to adding 1.2 million cars to the road.

Our proposal outlines a continued commitment to nuclear generation; however given the pressures in the nuclear industry and the higher costs many projects have encountered, we believe it is important to provide the Commission with a thorough assessment of what this commitment to nuclear could cost, what pressures the industry is facing and what alternatives could reasonably be explored.

Our most recent five-year capital forecast shows increased capital costs for Prairie Island over those used in our Changed Circumstances filing in 2012. As a result, we have undertaken a further review of life cycle costs for our Prairie Island Units. Unlike Monticello where most major equipment has been replaced, the Prairie Island life cycle management (LCM) program was scaled back to address immediate areas of concern; in particular, the electric generator and the generator step up transformer when the decision not to proceed with the Electric Power Uprate (EPU) was made. We have undertaken additional review of the likely costs we expect we would need to incur to run the Prairie Island nuclear units through their current life, and are continuing to assess and validate that information. We plan to undertake a similar review at Monticello, and would like to formalize a process to share and update our expectations about these expected costs and risks that those costs could be higher (for instance if the industry were to experience another significant rule change such as fire protection or cybersecurity.) To that end, we propose to engage the Commission and our stakeholders in a multi-year study to better understand the evolving nuclear landscape, including the expected costs to operate through the current life and beyond.

With respect to increased capital costs, at a high level, what we are seeing as the plant ages and we work to comply with regulatory requirements is that our projected capital spend at Prairie Island is outpacing some of the estimates included in the Changed Circumstance filing. That said, our fixed operating and maintenance (Fixed O&M) costs are lower than we modeled such that the increase in capital spend is offset by the Fixed O&M savings. While our costs from 2011-2015 tracked amounts anticipated in that filing, our review of future operations at Prairie Island indicates the need for substantially more capital. Our five-year capital expenditure forecast from 2016 to 2020 has increased by roughly $175 million above what was anticipated in 2012.

As a result, we also reviewed the capital that had been projected for the latter period of Prairie Island's license. We determined that operating the plant to the end of its current license would require substantial increases in capital for the period 2021 through 2034, primarily due to the reliability risks of aging equipment and anticipated costs for compliance with additional NRC requirements. While it is difficult to predict the specific investments that may be required in this timeframe, we believe that capital expenditures would likely need to increase by roughly $600 to $900 million over this fifteen-year period. Without a comprehensive LCM project as we completed for Monticello, we have increased the cost of planned equipment reliability investments to reflect that Prairie Island will continue to require more regular replacements on the non-reactor side of the plant. We have also created a larger contingency for anticipated capital expenditures for NRC-mandated compliance programs in the future.

Our capital expenditure forecast for 2011 to 2034 has increased between $650 and $950 million since our Changed Circumstance filing. Over the same period, however, we have not experienced the level of escalation that was modeled, and do not anticipate cost growth at the level we were previously modeling, so our Fixed O&M estimates have decreased by approximately $1 billion over the same period. Operations through the end of Prairie Island's licensed life compared to a natural gas combined cycle unit using the high end capital assumptions continues to produce Present Value of Societal Costs (PVSC) benefits in the neighborhood of approximately $500 to $1 billion. Notably, these results do not consider additional replacement variables, including transmission system costs, the timing and ability to deliver the significant amount of incremental natural gas to our system, the costs of accelerating funding of our decommissioning and associated worker retention costs.

For all of these reasons, we believe continuing to operate our nuclear Units makes sense for our customers. We also realize, however, that the costs of our nuclear fleet can change rapidly and are influenced by other events in the industry. As such, we believe this discussion would benefit from a formal review that could occur through a multi-year study to better understand the evolving nuclear landscape. In that process, we would propose to conduct a similar exercise on the costs of continued operations at Monticello. Such timing would allow the immediate actions related to Sherco to proceed, but position the Commission with substantially more information about nuclear in advance of our next Resource Plan.

C. Pursue Energy Efficiency Gains and Grid Modernization

The third element in our plan commits to pursue energy efficiency gains at the level recommended by the Department. We have seen tremendous advances in energy efficiency, and have discussed the challenges associated with our ability to continue to achieve significant levels of energy efficiency with our customers under the current regulatory construct, due largely to increasing codes and standards. Indeed, our position in this docket has been that we could not continue to achieve energy efficiency gains at the 1.5 percent level. However, we believe technology advancements may alter that future, and by leveraging technology to take advantage of the increasingly "smart" appliances and electronic devices, we may be able to unlock greater potential savings. Accordingly, we commit to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period, and to find ways to stimulate greater demand response with our customers. Additionally, we are open to continued collaboration and discussion on the conservation incentive. We understand that the Department and stakeholders will be working through this issue in 2016, toward a goal of implementing solutions in 2017.

We believe that modernization of the distribution system will be an important step in our ability to unlock greater DSM gains by enabling customer choice, savings, and control by creating a safe and efficient platform for new products, new services, and opportunities for accelerated adoption of new technologies. We know that some of our customers want more control of their energy choices and believe advancements in technology will help us deliver those consumer options.

For example, the Clean Energy Partnership with the City of Minneapolis represents our commitment to collaborate on innovative approaches and enhanced outcomes in energy efficiency and the use of renewable energy to help the city achieve its Climate Action Plan goals. We supported the approval of the Partnership's 2015-2016 work plan, incorporating a broad spectrum of concepts and ideas that have yet to be fully fleshed out to determine the level of impact this may have on a community focused concept such as the Clean Energy Partnership. Similarly, but on a smaller scale through our Partners in Energy program, we work with local stakeholders to develop custom action plans and provide implementation support services to help meet community energy objectives for delivering clean, affordable energy and achievement of their sustainability goals.

We are committed to be the preferred and trusted provider of the energy services our customers' need, which will require that we remain connected to our customers, think creatively to deliver solutions, and leverage the advancing technology. Our proposal sets us on a sustainable path to this future by committing to continue our strong achievement of DSM and Demand Response results.

D. Ensure Customer Benefits

We plan to work with the Commission, the MPCA, and our stakeholders to ensure our customers get the full benefit of our proposal. By working with the MPCA on the CPP State Plan, along with its counterpart environmental agencies in our other states, we hope to encourage adoption of a regional approach with trading options to maximize the benefits of compliance for our customers and communities. We also intend to work with the Commission and the Department to pursue longer-term rate compacts which will provide the runway we need to manage our business while smoothing the costs for our customers of this transition. Additionally, a longer-term rate compact will free-up Commission, stakeholder, and Company resources to focus on this proceeding, the State Plan, and other issues like Grid Modernization. We have successfully entered into these longer-term regulatory compacts in North Dakota and South Dakota, and look forward to advancing proposals to do so in Minnesota based on legislation passed in the last legislative session. Finally, we plan to develop a MERP-type proposal to provide predictable cost recovery and ensure an orderly transition to a cleaner energy future.

E. Customer Impacts

We have completed a preliminary analysis of our proposal and believe that we can begin the transformation of our generation fleet at a reasonable cost for our customers. We will complete a detailed customer impact analysis that will be filed with the Commission no later than January 29, 2016, but our initial analysis suggests that the plan can be implemented while keeping the overall cost impact through the planning period within an incremental two to three percent rate increase above our Reference Case. When we complete and submit our full resource planning analysis, it will include the same level of detail on estimated rate impacts that we submitted in our April 17, 2015 Reply Comments in this docket. In the interim, we provide a high level summary of expected cost impacts of our revised proposal as compared to our Preferred Plan:

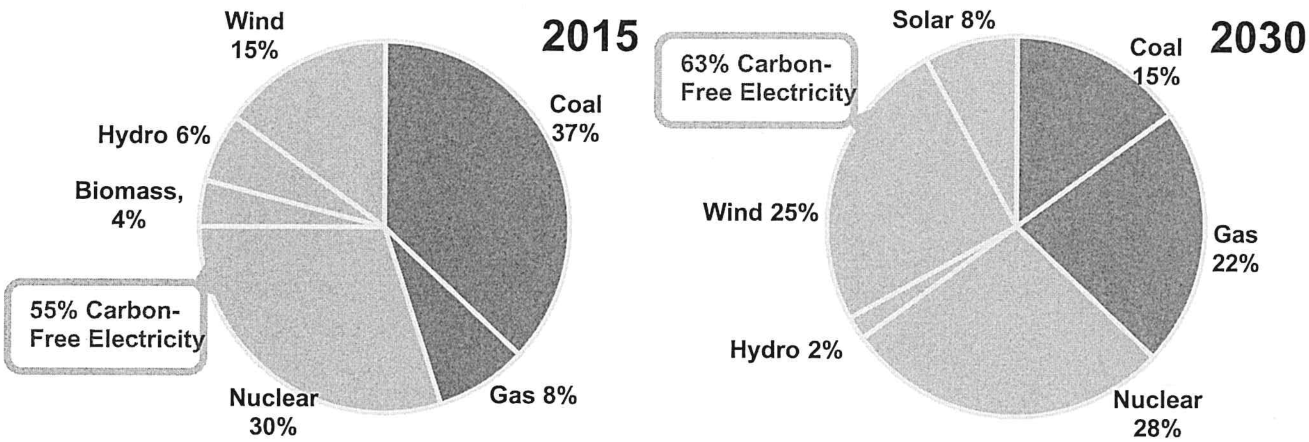
- Our Preferred Plan identified a one to two percent incremental rate impact above the Reference Plan for the period of 2016 to 2030; our revised proposal likely raises the incremental rate impact to two to three percent above the Reference Plan.
- Monetizing the value of the additional carbon emissions reduction of our revised proposal at the midpoint ($21.50) of the range of the Commission's regulatory cost of carbon, we show the incremental rate impact at the low-end of this range, and approximately two percent over the planning period.

We believe that there are opportunities to further offset the rate impact of our proposal by working with the MPCA and its counterparts in other states to develop a regional carbon market. We also believe there are regulatory tools, such as multi-year rate plans and the Emissions Reduction Rider statute (Minn. Stat. § 216B.1692) that can provide predictable cost recovery and help to smooth cost impacts for our customers.

F. Updated Metrics

Our proposal seeks to transform the energy supply for our Upper Midwest customers. Figure 1 below provides a side-by-side comparison of our energy mix today and how that energy mix changes as a result of our revised proposal. Overall, our carbon-free energy component increases to 63 percent.

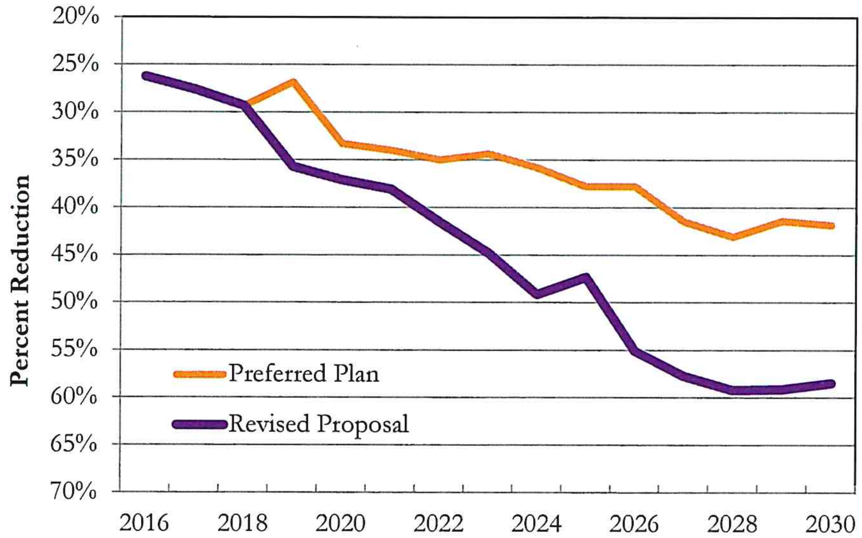
Figure 1: 2015 Energy Mix Compared to Revised Proposal in 2030



Key changes in our energy mix include a reduction to 15 percent for coal, and an increase in natural gas to 22 percent. With respect to renewables, solar increases to 8 percent, wind increases to 25 percent and—due to contract expirations—biomass and hydro drop to zero and two percent, respectively.

Figure 2 below demonstrates the projected carbon reduction of the revised proposal compared to the Preferred Plan. As shown, our revised proposal accelerates our reduction of carbon emissions and increases the level of reduction significantly – achieving nearly a 60 percent reduction from 2005 levels by 2030.

**Figure 2: Projected Carbon Reduction from 2005
Revised Proposal Compared to Preferred Plan**



As Attachment A to this Reply, we also provide an updated Load and Resources analysis that summarizes our capacity position through the planning period, and an Expansion Plan that outlines the generation additions we are considering to address the resource needs of our customers.

II. NEXT STEPS

We have outlined the Company's proposal for an energy future that is reliable, cost-effective, and cleaner. Our proposal optimizes the resource investments our customers have already made; provides the sustainability choices our customers want; creates the runway we need to successfully transition our workforce; creates the opportunity to reinvest in our communities; and motivates the Company to go beyond CPP compliance and generate valuable surplus allowances to the benefit of our customers.

We believe the level of collaboration that has ensued in this Resource Plan docket to-date has greatly improved stakeholder understanding of the evolving planning landscape and proposals that have been made. We have continued our outreach as we prepared these Comments and believe additional collaborative discussions will be beneficial. So that we can take advantage of the momentum of the current proceeding and continue our work with stakeholders to assemble the necessary support for and protections around our revised plan, we respectfully propose the following next steps:

- We propose to work with Commission Staff on a procedural schedule that continues to build the record for our revised proposal in this proceeding. With that in mind, we are open to supplementing the record incrementally as we complete various analyses and studies. We commit to supplement our revised proposal with a more detailed analysis and the results of our Transmission Reliability Study no later than January 29, 2016.
- Between now and January 2016, we propose to collaborate with parties to share our work, obtain valuable feedback (including in the form of filed Comments, if the Commission so orders), and identify areas of concern.
- Between now and January 2016, we propose to schedule additional stakeholder outreach meetings.
- We propose to immediately begin working with the Department and the MPCA on a schedule to accommodate the CPP State Plan, as well as collaborate regarding the scope of our nuclear study outlined above. Further, we look forward to similar collaboration with the Department and stakeholders regarding conservation potential and the associated financial incentives.
- We propose to develop a MERP-type proposal that we will be prepared to bring forward in the spring of 2016.

CONCLUSION

In these Reply Comments, we have outlined our vision for a cleaner energy future. We believe our proposal benefits our customers by supporting a cost-effective transition to a cleaner generation fleet, allows adequate time to transition our workforce, creates new jobs and investments for our communities, and continues our renewable and carbon-free energy leadership. There is much work to do be done, but we look forward working with the Commission, the Department, the MPCA, and our other stakeholders to bring our proposal forward.

Dated: October 2, 2015

Northern States Power Company

UPDATED LOAD AND RESOURCES INFORMATION

We provide below, an updated Load and Resources (L&R) analysis that summarizes our capacity position through the planning period, and an Expansion Plan that outlines the generation additions we are considering to address the resource needs of our customers. For clarity, we provide this resource summary in a format that builds on the L&R information included in our March 16, 2015 Supplement.

The final row of Table 1 below provides our updated capacity position before adding any of the new resources proposed in our revised proposal. More specifically, it shows we expect to have sufficient capacity to meet our customers' needs through 2023. However, starting in 2024 we have a capacity deficit that grows from 177 MW to over 3,500 MW by 2030.

Table 1: Updated Load and Resources (MW)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Existing Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar*	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Existing Resources	9,846	9,906	9,999	9,970	9,913	10,163	10,176	10,150	9,772	8,627	8,105	7,827	7,525	7,535	7,568
Position Jan 2, 2015 RP Initial Filing	**239**	**216**	**235**	**152**	**70**	**300**	**251**	**231**	**-165**	**-1,341**	**-1,936**	**-2,309**	**-2,788**	**-2,794**	**-2,862**
** Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)*															
Planned Resource Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Geronimo	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions**	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Additional Approved Resources	20	36	123	628	649	658	657	656	655	654	654	653	652	651	650
Position Mar 16, 2015 RP Supplement Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**
*** Solar Additions represent the revised solar implementation due to Community Solar Gardens.*															
Proposal	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Reductions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Position Oct 2, 2015 RP Reply Comments Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

As shown in Table 2 below, our proposal adds thermal and renewable resources in an incremental manner to limit customer rate impacts while also supporting a smooth transition of our generation fleet through 2030.

Table 2: Revised Proposal Expansion Plan[1]
(MW Additions, Nameplate Ratings)
(Accredited capacity is less - see Table 3)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	200	-	200	100	100	100	100	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	200	200	-	400	200	-	-	-	-	1,800
North Dakota CT	-	-	-	-	-	-	-	-	232	-	-	-	-	-	-	-	232
Sherco Gas Conversion/CT	-	-	-	-	-	-	-	-	-	-	562	-	-	-	-	-	562
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
CT	-	-	-	-	-	-	-	-	-	-	-	464	-	-	-	-	464
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

Note: The North Dakota CT is reflected in 2023 for planning purposes.

Relative to the Expansion Plan in our March 16 Supplement, we are proposing to accelerate the acquisition of 400 MW of large solar and an additional 200 MW of wind for a total acquisition of 800 MW of wind and 400 MW of large solar in the 2018 to 2020 timeframe. This timing will allow the opportunity to take advantage of possible cost-reducing incentives, while at the same time adding the energy resources necessary to allow Sherco Unit 2 to cease operations. Thermal resource additions, including a combined cycle at Sherco needed for system stability, a possible conversion of a Sherco Unit to use natural gas, and a combustion turbine in North Dakota are also staggered throughout the planning period to help manage costs and facilitate a smooth fleet transition.

To demonstrate how these proposed resources will meet the capacity needs of our customers through 2030, we provide a view of our net capacity position after these resources are added to the system as Table 3 below. Table 3 begins with the net capacity position from the final row of the L&R Table 1 above, and adds the MISO accredited capacity value of each of the proposed new resources. Table 3 concludes with our net capacity position.

[1] We clarify that with respect to Solar resource additions, we no longer show the expected 697 MW of Small Solar additions through 2030 or the 287 MW of Large Solar in 2017 already approved by the Minnesota Commission in the Expansion Plan. These resources are integrated into the L&R. Therefore, the total renewables additions we propose in this Reply are consistent with the total levels we proposed in our March 16 Supplement.

Table 3: Net Capacity Position after Resource Additions (MW Additions, UCAP Ratings)[2]

Position 10/02/2015 RP Reply Comments Filing	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	260	251	358	779	719	958	909	220	-177	-1,354	-2,643	-3,017	-3,497	-3,503	-3,573
Revised Proposal Resources															
Large Solar	0	0	0	0	0	261	314	366	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	148	178	178	237	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	208	208	208	208	208	208	208	208
Sherco Unit Gas Conversion	0	0	0	0	0	0	0	0	0	514	514	514	514	514	514
Sherco CC	0	0	0	0	0	0	0	0	0	0	763	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	0	417	417	417	417	417
CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
Total Plan Additions	*0*	*0*	*0*	*0*	*0*	*380*	*462*	*751*	*804*	*1,429*	*2,691*	*3,453*	*3,663*	*3,663*	*3,663*
Revised Proposal Position after Additions	260	251	358	779	719	1,338	1,370	972	627	75	47	436	166	159	89

Note: The North Dakota CT is reflected in 2023 for planning purposes.

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[2] MISO Unforced Capacity (UCAP) values, which are equal to the amount of accredited capacity, by resource type, that MISO allows the Company to count towards meeting its capacity obligations. Please note that MISO accreditation is by MISO Planning Year, so the timing may not align with the resource addition dates reflected in the above Table 2: Revised Proposal Expansion Plan.

PRELIMINARY ASSESSMENT OF THE FINAL CLEAN POWER PLAN RULES

In August 2015, the Environmental Protection Agency (EPA) issued its final Clean Power Plan (CPP) rules, which may prove to be the most significant environmental regulation affecting the electric power sector to date. As we have noted, our early efforts and environmental leadership will ease the remaining work we have to do to achieve our share of CPP compliance. However, we are just at the beginning of an effort that will require coordination and collaboration across many different stakeholder groups both in Minnesota and across our Upper Midwest region. In this attachment, we discuss our preliminary understanding of the impact of the final rule on our NSP System.

The EPA's CPP for existing power plants under section 111(d) of the Clean Air Act was a proposed rule at the time of our January 2, 2015 filing and March 16, 2015 Supplement. It became a final rule on August 3, 2015.[1] Thus, EPA's final targets in both rate (lbs CO_2/MWh) and mass (tons CO_2) terms for the NSP System's five states are now known. While the final rule lowered the reduction target for Minnesota and South Dakota, it significantly raised the reduction target for North Dakota, with smaller increases for Wisconsin and Michigan. That said, only the Minnesota targets affect the Company directly, since we own and operate CPP-regulated units only in Minnesota.[2] Despite announcement of the final rule, much remains unknown about what CPP compliance will require of the Company. Many of the key decisions that will ultimately shape the 111(d) State Plans, due to EPA by September 2018, remain undecided.[3]

In our filings to date, we noted that the Preferred Plan we proposed would allow us to meet the Next Generation Energy Act (NGEA) Greenhouse Gas (GHG) goals and our renewable energy requirements and objectives – and put us on a path to address EPA CPP requirements, based on our analysis of the proposed rule. We still believe the Preferred Plan will exceed the NGEA goals and our renewable energy mandates. Our preliminary analysis of the final rule suggests it would also achieve CPP compliance in rate-based terms, in the event the Minnesota Pollution Control Agency

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[1] Environmental Protection Agency. 40 CFR Part 60. *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* August 3, 2015. Posted at http://www2.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants.

[2] NSP owns no existing fossil units in North Dakota and Michigan, and our generating units in Wisconsin and South Dakota are exempt from the CPP definition of "affected electricity generating unit."

[3] States may file an "initial submittal" in September 2016, requesting an extension to September 2018 to file final plans. CPP final rule at pages 1475-1476.

(MPCA) designs a rate-based plan and assigns regulated utilities the same targets as EPA assigned to Minnesota.

Whether the Preferred Plan would achieve CPP compliance in mass-based terms is more difficult to say, since this requires assumptions about how MPCA might allocate the statewide allowance budget. Our preliminary analysis of the final CPP rule suggests that, based on conservative assumptions about allowance allocation, the Preferred Plan may not be sufficient to sustain carbon dioxide (CO_2) emissions below a possible allowance budget for NSP throughout the planning period.

Conversely, we believe that in either a rate-based or mass-based scenario, our revised proposal will likely exceed our CPP compliance obligation – generating valuable surplus reductions that would benefit our customers in an interstate collaboration scenario. We explain our reasoning below.

A. Proposed Rule

In the proposed CPP published June 18, 2014, Minnesota's and Xcel Energy's early efforts and environmental leadership were highlighted. However, the proposed rule did not give early action credit to the State of Minnesota, and generally assigned more stringent targets to states who had already achieved greater CO_2 reductions prior to the rule's baseline year of 2012. Minnesota's 2030 target in the proposed rule was 873 lbs CO_2/MWh. Under the Preferred Plan we initially proposed adding over 4 GW of wind and solar to reduce coal generation and bring the NSP System under the EPA's target for the state of 873 lbs. Thus, if MPCA assigned utilities a rate-based target equal to the state's target, the Preferred Plan we initially proposed would have been CPP-compliant in rate terms, without retiring coal units.

Mass-based compliance with the proposed CPP was more difficult to analyze, since the rule provided complex formulas for converting state rate goals into mass equivalents, and the mass goal for Minnesota appeared to be significantly more stringent than its rate equivalent, in part because of our Sherco Unit 3 having been offline for the entire baseline year of 2012. The MPCA, the Company, and others drew EPA's attention to these issues.

B. Final Rule

We worked with the MPCA and other stakeholders to advocate for revisions to the proposed rule that would make the final rule fairer to our Minnesota customers. In the final rule, Minnesota's 2030 target is 1,213 lbs CO_2/MWh in rate terms and 22.7

million short tons CO_2 in mass terms.[4] We note, however, that the target in the final rule is not comparable to the 873 lbs CO_2/MWh target in the proposed rule, since the formula significantly changed with the elimination of pre-2012 renewable energy, "at risk" nuclear, and energy efficiency from target-setting – as well as a regionalized rather than state-by-state approach to target-setting.

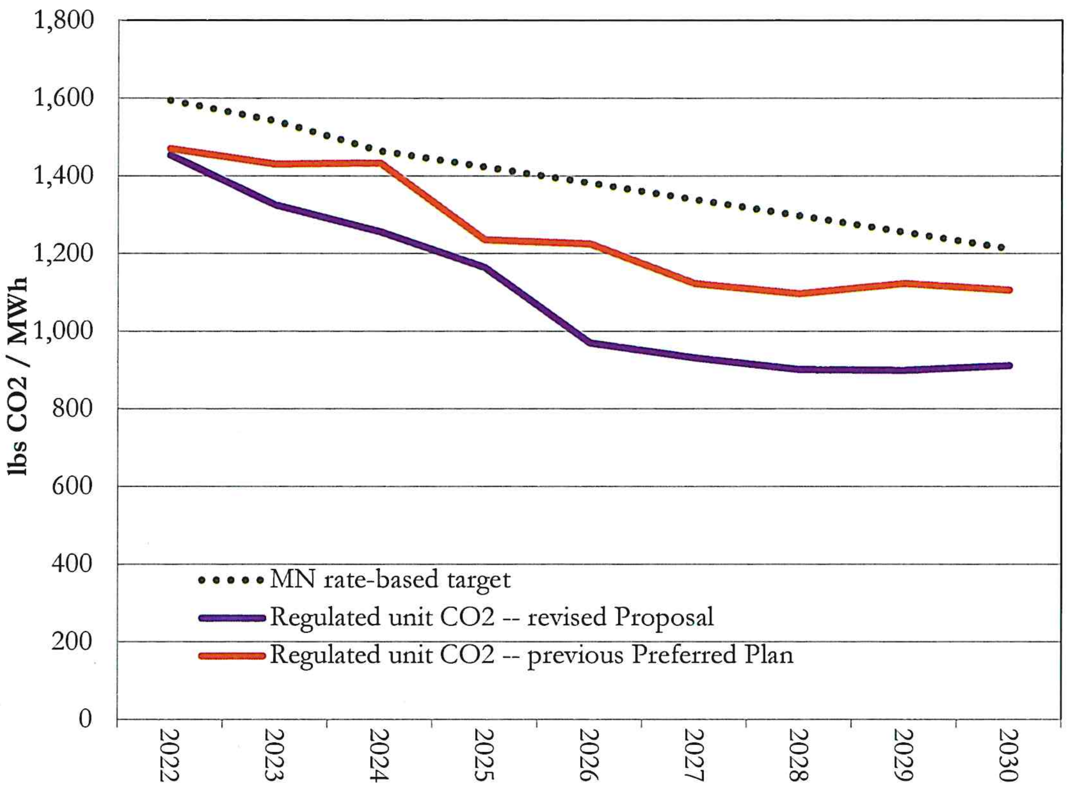
In any event, it is clear that Minnesota's interim and final targets are less stringent in the final rule than in the proposed rule. This is due to a different target-setting methodology that tended to bring all states' targets into a narrower band of values, as well as a technical correction the EPA made for Sherco Unit 3 having been offline for the entire baseline year of 2012. We believe the following discussion portrays a reasonable understanding of how the final CPP might apply to both our Preferred Plan and the revised proposal outlined in this Reply.

1. *Rate-Based Compliance*

Considering the new target of 1,213 lbs CO_2/MWh, the Preferred Plan continues to appear CPP-compliant in rate terms. The Preferred Plan would drive the NSP System to a CO_2 rate, under the final rule formula, of 1,107 lbs/MWh[5] in 2030 – below EPA's target for the state in that same year. Thus if MPCA assigns utilities a rate-based target equal to the state's target, the Preferred Plan would be CPP-compliant in rate terms without retiring coal units. Likewise, our revised Proposal would be CPP-compliant in rate terms, achieving a CO_2 rate under the CPP formula of 912 lbs/MWh in 2030, well below the state's 2030 target of 1,213 lbs/MWh. Figure 1 below demonstrates this rate-based compliance view; both the Preferred Plan (purple solid line) we initially proposed and our revised Proposal (orange solid line) would be below the MN rate-based budget (green dotted line) in all years.

[4] EPA target for total emissions from existing affected EGUs in Minnesota. The mass-based target for existing and new units (i.e. including the "new source complement") is slightly higher.
[5] This represents the NSP CO_2 rate according to EPA's formula in the final 111(d) rule, which is different from the NSP System's CO_2 rate under the more conventional metric of total emissions from owned and purchased power divided by total owned and purchased power. The NSP CO_2 rate under the latter metric would be 720 lbs/MWh in 2030 for the Preferred Plan.

Figure 1: Potential Final CPP Compliance Position in Rate Terms



2. *Mass-Based Compliance*

In mass terms, our previous Preferred Plan would reduce NSP's total CO_2 emissions from 111(d)-regulated units to 18.0 million short tons in 2030, while the revised Proposal would reduce total CO_2 emissions from 111(d)-regulated units to 9.8 million short tons in 2030.[6]

However, whether any plan achieves CPP compliance in mass-based terms is more difficult to assess than rate-based compliance. Mass-based compliance is determined by bringing total CO_2 emissions from the 111(d)-regulated units below a total budget of allowances allocated to NSP (plus any allowances purchased from others). Since MPCA has not yet made decisions about allowance allocation, any evaluation of mass-

[6] This represents total CO_2 emissions from 111(d)-regulated existing units, and does not include emissions from exempt units (simple-cycle CTs, biomass EGUs, etc.) or new units (units that commenced construction after January 8, 2014 and are thus regulated under section 111(b)).

based compliance is preliminary and depends on making reasonable assumptions about decisions MPCA has yet to make.

Under EPA's default method of allowance allocation in the proposed federal plan and model trading rules, allowances would be allocated among owners/operators of 111(d)-regulated units based on share of generation from those units in 2010-2012.[7] This would give NSP about 69 percent of the Minnesota budget. Our preliminary mass-based compliance evaluation assumes:

- MPCA creates a CPP plan for existing regulated units only, i.e. leaves new units outside its 111(d) plan,
- MPCA sets aside allowances, in the amounts suggested by EPA, for renewable energy, preventing emissions leakage from existing natural gas combined cycle (NGCC) units to new NGCCs, and the Clean Energy Incentive Program (CEIP), but does not set aside allowances for other purposes,[8]
- MPCA allocates the remaining mass budget to affected electrical generating units (EGU) on the basis of 2010-2012 generation, the default allocation in the proposed federal plan and model trading rules,
- NSP is able to win back a share of the allowance set-asides for renewable energy, existing NGCCs, and the CEIP, and
- MPCA does not adopt a provision in EPA's proposed federal plan that would only award allowances to a retiring unit for the remainder of a compliance period in which it retires, and award no allowances to units retiring more than two years prior to 2022.[9]

We note that states are not required to adopt this (or any other) allocation provision in the proposed federal plan or the model trading rules.

Under these assumptions, the CO_2 reductions associated with our Preferred Plan would exceed NSP's responsible share in the 2022-2024 compliance period, but would fall short in the 2025-2027 and 2028-2029 compliance periods. Under the rule, we would be allowed to "bank" allowances, or use surplus allowances from the first compliance period to make-up for some of the shortfall in the second and third periods. However, even with banking, we would be short allowances overall in the

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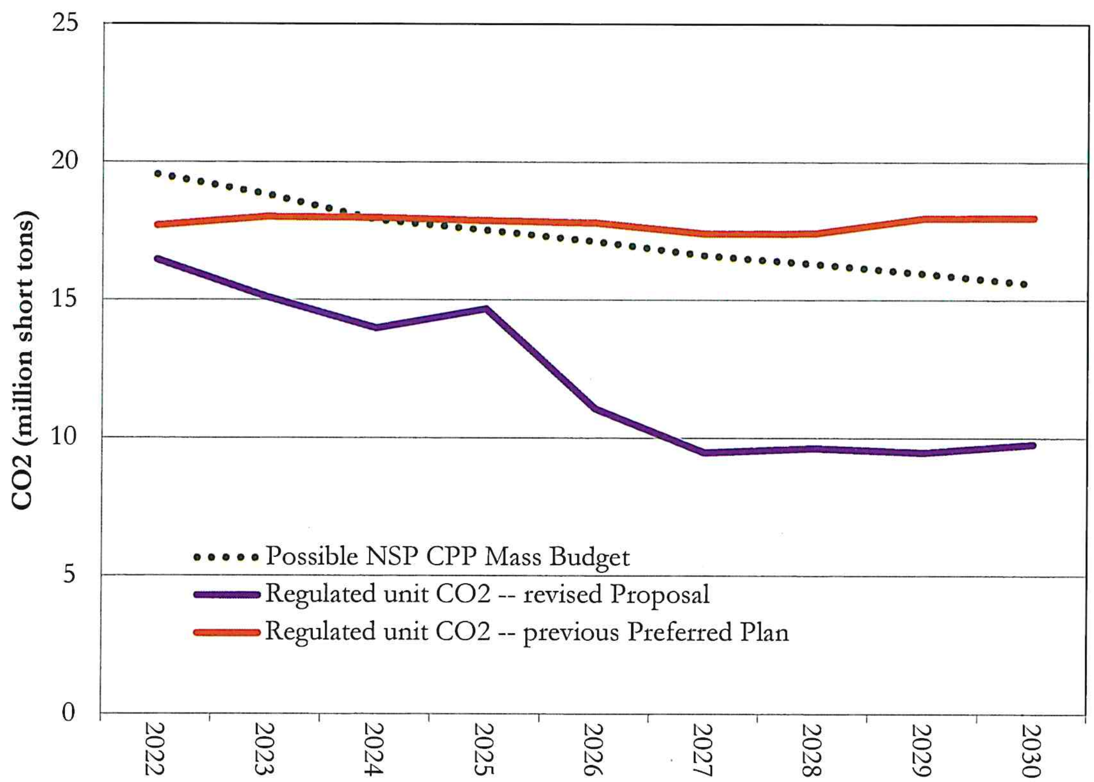
[7] Environmental Protection Agency. 40 CFR Part 62. *Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations.* August 3, 2015. Page 252.
[8] EPA, Federal Plan Requirements and Model Trading Rules, pages 477-484.
[9] EPA, Federal Plan Requirements and Model Trading Rules, page 486.

2022-2029 interim period, requiring the Company to purchase allowances from others in order to achieve CPP mass-based compliance.

We demonstrate this mass-based compliance view in Figure 2 below. The CO_2 forecast for the Preferred Plan (purple solid line) we initially proposed lies below the allowance budget allocated to NSP (green dotted line) initially, but above it after 2024 – and surplus allowances banked in 2022-2024 are not sufficient to fill the shortfall after 2024.

Figure 2: Potential Final CPP Compliance Position in Mass Terms



In contrast, under our revised proposal, CO_2 emissions from the CPP-regulated units (orange solid line) would be well below the NSP mass budget (green dotted line) in all years. We would not be required to purchase allowances to achieve CPP compliance, and in fact we could generate a significant quantity of surplus allowances to facilitate interstate CPP solutions that would benefit NSP customers in all five NSP System states.

It is important to note that this analysis is preliminary. At present we do not know if MPCA will implement a rate-based or a mass-based approach to Minnesota's 111(d) plan; whether the plan will regulate EGUs only ("emission standards" plan) or other entities as well ("state measures" plan); and what share of the statewide CO_2 reductions will be assigned to NSP. There are more unknowns as well. If MPCA implements a mass-based approach, we do not know how MPCA will allocate allowances; whether intra- or interstate trading will be available; whether new (built after January 2014) units will be brought into or remain outside the plan; or whether MPCA will implement the allowance set-asides suggested by EPA and/or any other set-asides. Accordingly, we cannot definitively say whether the Preferred Plan would or would not be sufficient to achieve CPP compliance for NSP.

We can, however, say that our revised proposal appears to go beyond CPP compliance, and has the potential to generate value for our customers. Retiring Sherco Units 1 and 2 and accelerating the addition of solar and wind renewable generation, will create a surplus of allowances or Emission Rate Credits that can be used to the benefit of our Upper Midwest customers, including the possibility of using this value on a regional basis to smooth rate impacts for our customers.

RESPONSE TO COMMENTS

A. Background

We submitted our 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the Competitive Acquisition Process (CAP) proceeding.[1] The Commission made determinations in the CAP proceeding in December 2014; due to the timing, we were unable to incorporate the Commission's resource determinations into our Initial Filing. In January 2015, the Commission issued a Notice requiring the Company to supplement its Resource Plan to incorporate the resource decisions made in the CAP proceeding, which we did on March 16, 2015 (Supplement).

In our Supplement, we also provided information that responded to several stakeholder requests, including: (1) an expanded explanation of our modeling assumptions and those that were updated; (2) a more detailed approximation of rate impacts of our Preferred Plan by customer class; and (3) additional modeling and discussion regarding the costs and other implications of potential retirements of our Sherco Units 1 and/or 2 generating facilities in the early 2020s.

On February 10, 2015, we held our first in a series of stakeholder meetings where we discussed our Preferred Plan and its assumptions and impacts. We followed that meeting with three additional stakeholder meetings where we outlined the details and assumptions underlying our plan and addressed key areas of stakeholder interest including Strategist modeling, Demand Side Management, and evolving environmental regulations. We have also met with individual stakeholders to discuss aspects of our Preferred Plan and participated in the technical conferences held by the Department of Commerce and the Clean Energy Organizations (CEO).

We believe the level of collaboration that has ensued to-date has furthered a shared understanding of the evolving planning landscape and the proposals that have been made. These collaborative efforts and the diverse perspectives parties shared in their July 2, 2015 Comments informed our thinking about our future system and contributed to the revised Proposal we make in this Reply.
In terms of Comments, in addition to commenting on aspects of our Preferred Plan, the Department and CEO each proposed alternative plans that relied on Strategist modeling. The Minnesota Pollution Control Agency (MPCA) commended our commitment to reduce greenhouse gases (GHG), and concluded that it is reasonable

[1] Docket No. E002/M-12-1240.

to assume that the mid-2020s represents the likely timeframe when Selective Catalytic Reduction (SCR) could be required on Sherco Units 1 and 2. Liberty Paper highlighted the importance of Sherco Units 1 and 2 to their operation and the important benefits Liberty Paper provides to Minnesota. The City of Becker expressed appreciation for our leadership role in maintaining a balanced fuel source portfolio and aggressive pursuit of renewable energy, noted the need for continued baseload resources, and supported the addition of natural gas resources, potentially located in Becker.

Xcel Large Industrials acknowledged the significant regulatory uncertainty around environmental issues and expressed concern over our rates. Community Power requested that the Minneapolis Clean Energy Partnership work plan be formally included in the Company's Resource Plan. Minnesota Utility Investors noted the importance of the flexibility of the plan we proposed and supported continued reliance on our Sherco and nuclear units in the future. St. Paul Cogeneration recommended the Commission ensure that biomass and Combined Heat and Power (CHP) are part of the Company's future resource mix. Finally, International District Energy Association recommended that we incorporate CHP as a utility generation asset in our plan.

We appreciate the parties' thoughtful comments, and note again that they were taken into consideration when we created our revised proposal. We do not specifically address all of the Comments in this Response; rather, we respond to specific requests for information and provide clarifications in response to certain aspects of Comments by the Department and CEO.

B. Strategist Modeling and Greenhouse Gas Emissions Accounting

We appreciate the alternative plans proposed by the Department and CEO, and the constructive dialogue that has ensued as a result. While we are now advancing the revised proposal outlined in our Reply, in this section, we touch on modeling-related issues, including GHG accounting calculations that we believe require clarification.

1. *GHG Emissions Accounting*

In this section, we explain the methodology we employed to calculate our baseline and target-year carbon dioxide (CO_2) emissions under the Next Generation Energy Act (NGEA) GHG goals (Minn. Stat. § 216H.02, subd. 1), and note the importance of using consistent calculations in both baseline and projected CO_2 emissions forecasts. We agree with CEO that the methodology we use to calculate our NGEA progress is different from the methodology MPCA employs to calculate NGEA progress at the statewide level. We note that while there is an established MPCA methodology for quantifying emissions and reporting on GHG reductions statewide, there is no approved MPCA methodology that applies to individual utilities.

MPCA itself acknowledges this difference:

> *In our reporting to the Legislature, we make no attempt to distribute total electric power sector emissions to individual utilities… It is the policy at MPCA that the Next Generation Energy Act goals are state-level goals covering, in aggregate, all economic sectors, and not targets that can be applied to specific economic sectors or any single firm.*[2]

MPCA's statewide methodology and the methodology we have used to calculate our emissions differ in several respects. First, MPCA's quantification for the electric power sector statewide includes GHG emissions from in-state power generating sources such as CO_2, methane (CH_4), and nitrous oxide (N_2O); emissions from area sources, such as sulfur hexafluoride (SF_6) emissions from the transmission and distribution (T&D) system; and a state-level term to account for emissions associated with the generation and transmission of net power imported across state borders, including T&D losses.[3] With respect to emissions from imported power, MPCA makes no attempt to allocate emissions to individual utilities.[4] So, while emissions from imported power are a portion of the 30.6 million short tons (MST) in our 2005 baseline, these would not be included in any MPCA estimate for the Company. Additionally, in MPCA's methodology, biogenic CO_2 emissions are estimated but reported separately, whereas they are included in our 2005 baseline.[5]

While MPCA does not generally apply its methodology to individual utilities, it did apply a version of this methodology to Xcel Energy in an October 2013 letter cited by the CEOs, but has since clarified that:

> *The estimate of emissions given in our letter to the MPUC is solely for fossil CO_2 from combustion at facilities owned or operated by Xcel Energy. No effort was made to allocate back to Xcel Energy emissions from net imports (or emissions from in-state area sources that, again, are calculated at a state-level) or to distribute emissions from*

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[2] Peter Ciborowski, MPCA, e-mail of September 11, 2015.
[3] The NGEA requires MPCA to include in its estimates of statewide GHG emissions those emissions that result from out-of-state electricity generation that is consumed within Minnesota. Total electricity consumption in Minnesota, net electricity generation in the state and all associated transmission and distribution (T&D) line losses are estimated (Minn. Stat. § 216H.01, subd. 2).
[4] Peter Ciborowski, MPCA, e-mail of September 11, 2015.
[5] *Greenhouse Gas Emissions in Minnesota: 1970 – 2008,* pages 5, 12, 21, 93.

combustion sources across state lines on the basis of, say, retail sales or retail sales plus sales for resale.[6]

Applying this methodology, MPCA estimated 2005 emissions for Xcel Energy of 27.25 MST. In contrast, when quantifying our CO_2 emissions – both for the 2005 baseline year and for the NGEA target years of 2015 and 2025 – we included all CO_2 combustion emissions (but no non-CO_2 GHG emissions) from owned and purchased power used to serve customers in all five NSP System states, regardless of emission source location. Stated another way, our calculations include CO_2 from:

- Generating units we own in Minnesota;
- Owned units in other NSP states;[7]
- Biogenic CO_2 from biomass and RDF plants;
- Power we purchase under long-term PPA with fossil resources throughout our five-state area;
- Power purchased from MISO; and
- A very small amount of power purchases with unknown environmental attributes.[8]

Our methodology is more comprehensive than MPCA's October 2013 estimate and, as such, the total is larger both in the baseline year (30.6 MST) and in the target years of 2015 and 2025. Because it only accounts for a subset of our emissions, the 2005 baseline emissions portrayed in the "Goal" line in Figures 9 and 11 through 14 of CEO Comments are inaccurate. Although the Goal line may correctly represent a "trend line" to the NGEA goals, it cannot serve as an accurate point of comparison with the CO_2 forecast of our Preferred Plan.

2. *Modeling Techniques and Assumptions*

Strategist modeling results are highly dependent on the input assumptions used and, in some cases, the application of different modeling techniques. Discussion and debate surrounding the different assumptions and techniques constitute an important part of any resource planning proceeding, and we believe that some of the assumptions and techniques employed by CEO and, to a lesser extent the Department, may have produced results that are less reliable than our modeling results.

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6 Peter Ciborowski, MPCA, e-mail of August 28, 2015.

7 Gas peakers and biomass in Wisconsin; a gas peaker in South Dakota. The Company currently owns no fossil generation in North Dakota or Michigan.

8 Assigned the MRO-W emission factor. See our response to Information Request No. DOC-56, question *b*.

a. Clean Energy Organizations

First, we appreciate the constructive dialogue we have had with CEO. We believe the dialogue has furthered a better understanding of each other's proposals and encouraged discussion about the future of our energy mix. We also applaud the efforts of CEO to develop Strategist modeling results in support of their recommendations in this proceeding. However, we believe CEO employed several assumptions and techniques in analyzing plan impacts that generated results that are imbalanced and lack a reasonable foundation.

Aside from citing differences from the MPCA statewide methodology and a different 2005 baseline, CEO cites three reasons why they believe our CO_2 emissions under the Preferred Plan will be higher than we forecasted:[9]

1) Adding 4 GW of wind and solar capacity to the NSP System will not necessarily result in reduced dispatch of and CO_2 emissions from NSP's own coal units,
2) The Company has underestimated emissions associated with MISO purchases,
3) The Company has overestimated emissions associated with "dump energy."

For each of these, CEO applies adjustments to "correct" the Strategist simulation results for a MISO/regional market-oriented regime, resulting in their conclusion that we will not achieve our "share" of the statewide NGEA goals. We discuss these *ex post facto* adjustments below:

Renewable Additions Impact Coal Operations. CEO "hard-wired" a level of coal generation into their modeling for the post-2020 period that was based on their model's forecasted coal operation data for 2017-2019. Fixing the operation of our coal fleet after 2020 at the same levels these Units operated in 2017-2019 (CEO Comments, footnote 24 at 20-21) is not a reasonable reflection of future coal dispatch and operation assumptions. We acknowledge that CEO disagrees with the amount of coal operation reduction that could occur in a MISO-controlled dispatch construct. However, suggesting that there will be *no* impact to our coal operations from the addition of significant levels of renewable generation is not reasonable. Strategist is a sophisticated tool that calculates changes in annual coal generation output levels based on key plan and system dispatch assumptions, which we believe forms a more reasonable basis than hard-wiring a flat level of operations based on a three-year

[9] CEO Comments at 19-28.

reference period.

Market Emission Rates. CEO also applied different emissions values to purchases and sales in the MISO market – using a higher market-wide rate for purchases and a lower NSP-specific system average rate for sales. This implies a carbon "arbitrage" between the market and a specific seller, which would most likely not materialize in a fully developed market that properly factors emission costs into prices and market design. We believe a more reasonable approach is to use the same emission values for MISO sales and purchases, since MISO purchases or sales need to reflect overall MISO system or MISO zonal emission levels. Employing this approach avoids any speculation of MISO purchase/sale emissions arbitrage. Additionally, our approach that used the artificially high emission factor of 1,624 lbs/MWh for both MISO purchases and sales will tend to conservatively overestimate our emissions, since (1) it does not reflect greening (decline in emission factor) from 2009 to present, and (2) our purchases from MISO have exceeded our sales in every year since 2005, as shown in our response to Information Request No. DOC-59.[10]

Purchase and Sales Volumes. For their "high" range of emissions projections for our Preferred Plan, CEO set purchase volumes to the highest level observed in the past five years, which was during the extended outage of Sherco Unit 3. It is not reasonable to expect that this abnormally high level of purchases will continue over time, and indeed recent purchase volumes since the return of Sherco Unit 3 have been well below these levels. Combined with the carbon arbitrage assumption, this makes the CEO projections of system carbon emissions much higher than would realistically be expected.

When combined, these "hard-wired" modifications to the Strategist modeling do not provide a reasonable basis to support the CEO conclusion that the Preferred Plan we proposed would not be compliant with the NGEA GHG goals.

We acknowledge that Strategist is limited to modeling a single utility system and cannot predict the interaction of proposed resources in the MISO market. Our

[10] The 1,624 lbs/MWh we used was based on the emission factor for the MRO region from EPA's Emissions & Generation Resource Integrated Database (eGRID). The latest eGRID emission factors available at the time of preparing our resource plan were for 2009 (EPA has since released data for 2010, where the MRO emission factor is 1,547 lbs/MWh). *See* eGRID 2012 Version 1.0, or the Eighth edition, for the MRO emission factor we used, and the Ninth edition for the later-released year 2010 data: http://epa.gov/cleanenergy/energy-resources/egrid/index.html. Because eGRID has a 3-4 year lag between the year reported and the year of release, the eGRID emission factors are always out-of-date and do not reflect recent declines in CO_2 intensity due to renewable energy additions, increased gas generation, reduced coal generation and coal retirements, etc.

decision to model our system with minimal MISO interaction has three primary advantages. First, by limiting the interaction with the MISO markets, our analysis provides the Commission valuable insight into the systems they regulate without complicating that analysis with hypothetical assumptions on how *other* utilities may modify or operate their systems over time. Second, it helps to determine what, if any, restrictions are necessary to ensure our fleet operates the governing framework. Third, it helps the Commission and other stakeholders understand the cost and profile of the NSP System without MISO interaction.

The incorporation of the NSP System into the MISO joint dispatch process should ultimately lower costs, yet still implement any operating or carbon restrictions that will be necessary to achieve the State's targets or compliance requirements. We, like other utilities and MISO, will have to figure out the process to incorporate the management of individual state carbon (or generation) targets into the dispatch process to ensure that all utilities can continue to achieve compliance with all of their individual states' Clean Power Plan (CPP) requirements. As a result, while the view we presented in our resource plan to-date does not simulate the exact operation of the system within the MISO construct, the Commission can use this view to establish cost and operating parameters to ensure the NSP System is positioned to achieve the State's carbon goals and CPP compliance obligations.

Development of the CPP State Plans remains in the early stages, with states just beginning to evaluate various compliance alternatives available under the rule. As the development progresses, we plan to evaluate the draft CPP State Plans, as well as any proposed MISO market changes, and use the most current information in developing our next Resource Plan.[11]

Financial Calculation Period. In addition to the concerns we have with the methodology CEO employed for CO_2 accounting, CEO's use of a 15-year calculation period for Present Value Revenue Requirements (PVRR)/ Present Value Societal Cost (PVSC) calculations do not account for the long-term impact planning decisions will have on customer costs.

Resource decisions, whether they are resource additions or retirements, are long-term decisions that have significant financial impacts well beyond the 15-year planning

[11] State plans under the CPP are due in September 2016 or, if states request an extension, September 2018. It is likely at least some of our states will request this extension, so will not have final plans submitted to EPA before the filing of our next Resource Plan. However, we believe we will have significantly more information on our states' CPP implementation strategies over the next year. In addition, EPA will release in summer 2016 the final version of its proposed model federal plan, for states that elect not to submit a state plan.

period of resource plans. Significant changes are projected to occur on the NSP System in the 2030's, including the possible retirement of our nuclear fleet as well as our remaining coal-fired baseload units. By not allowing Strategist to include the benefits or costs of these long-term significant changes, CEO oversimplifies the impact that planning decisions will have on customer costs.

b. Minnesota Department of Commerce

The most significant area of concern we have with the Department's modeling is their "end-effects" methodology. We have long differed on the appropriateness of using the Strategist end-effects methodology versus longer simulation periods. We raise it again here because, in this instance, use of the end-effects methodology may be driving inaccurate results. The other area we address is clarifying the extent to which we employed an iterative modeling technique.

End Effects. In Strategist, the end-effects modeling process employed by the Department holds "flat" the last year simulated, such that the same cost and benefits are repeated for a given number of years. As outlined above, holding the 2032 results constant skews the impact of the resource planning decisions being contemplated in this proceeding in that it ignores the significant changes projected to occur in the NSP fleet beyond the planning period

Iterative Modeling Technique. In explaining the development of their plan, the Department noted that it allowed economic consideration of renewable technologies in their simulations while we "forced" expansion alternatives in the model. As part of our resource planning discussions with the Department, it has become clear that we largely followed the same optimization process utilized by the Department.

We, like the Department, performed numerous simulations with renewable resources treated as "superfluous" units. Although these initial runs resulted in significant truncation of plans due to the number of states considered, it became clear that significant amounts of renewables were being considered as cost-effective energy-only resources. Through iterative processing, we identified and evaluated how much and at what times renewables were being added by the optimization engine, and sequentially added those repeatedly-chosen resources as "locked" resources in future runs to improve run time and reduce truncation.

Finally, as identified by both the Department and CEO, the treatment of excess or "dump energy" is a challenging issue from both a cost and CO_2 perspective. Fundamentally, the issues raised go to the best way to predict how both costs and carbon accounting for purchases and sales will be treated in the MISO system once the CPP is in effect. We propose to work with the Department and CEO to arrive at an agreed-upon methodology, and we believe this task will become clearer as states begin to develop their State Plans.

C. Demand Side Management

We appreciate the Department and CEO comments regarding the appropriate DSM goal for the 2016-2030 planning period. We are committed to find new ways to elicit greater levels of energy efficiency and Demand Response (DR) that will benefit not only our customers, but the whole system. To this end, we accept the Department's recommendation and commit to a goal of 1.5 percent DSM through the planning period. This translates to 444 GWh of savings for the planning period, which we note does not impact any near-term resource decisions.

We make this commitment despite the challenges we face in our ability to continue to achieve significant levels of energy efficiency with our customers under the current regulatory construct. A step change in DSM and DR achievement will require technology advancements and regulatory recognition of types of savings that may not be contemplated today.

In the balance of this section, we discuss the challenges to achieving a 1.5 percent savings goal, respond to the CEO recommendation to increase the goal to 1.7 percent in years 2016 -2021, and respond to requests for explanation of certain aspects of our potential study by the Department and CEO.

1. *History is not Always an Accurate Predictor of the Future*

Through extraordinary efforts, we have cost-effectively met and exceeded our DSM goals. In 2014, we achieved over 481 GWh of electric savings, which equates to 1.66 percent of sales. We are proud of our success and are striving to continue this level of savings through 2015 and 2016, in which our goal is 435 GWh (1.5 percent of sales).

We have been providing our customers the opportunity to reduce their usage through a myriad of energy efficiency programs for more than 20 years. Our experience is that significant historical achievements reduce future potential, as fewer eligible participants remain with standard efficiency equipment. New technologies represent a small fraction of the energy savings potential lost to increasing codes and standards, especially with the implementation of aggressive lighting standards. The resulting decline in potential requires a greater pursuit of DSM to maintain historical levels.

More aggressive pursuit of DSM translates to more costly programs. In order to incent customers we must increase our outreach and rebate levels. This is further exacerbated by the fact that: (1) as creditable energy savings from each installed measure decreases due to increases in codes and standards, the number of installations must increase to maintain the same level of energy savings; and (2) the costs of new technologies, while declining, are still more expensive for customers to implement than historical technologies. We discuss these issues below.

2. *Increased Codes and Standards are Eroding Creditable Savings*

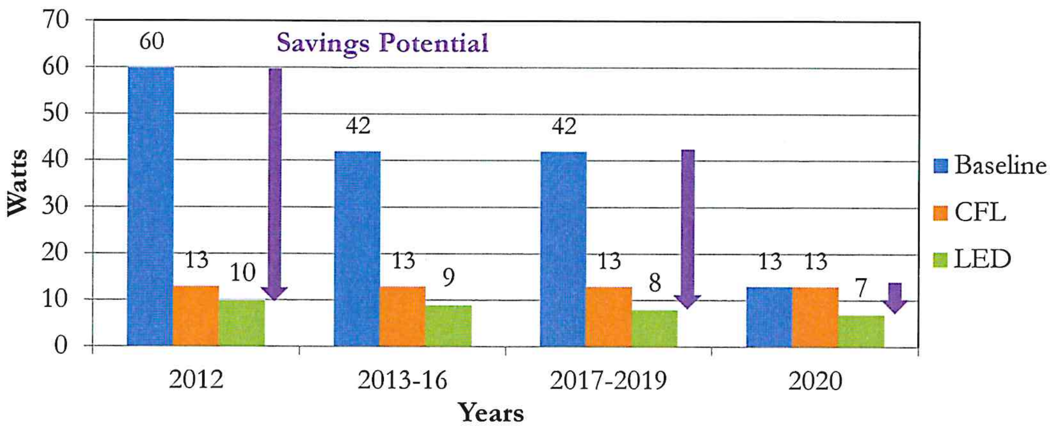
The greatest challenge to achieving future DSM program savings is the implementation of the codes and standards changes from the Energy Independence and Securities Act (EISA).[12] Since the EISA Standards were implemented in 2007, we have adjusted the baselines of more than a dozen savings measures and had to remove several lighting measures from our portfolio. These changes shrink the available pool of energy savings for which we can claim credit within our DSM programs, leaving the more expensive and complex savings opportunities for our customers. These savings opportunities require increased investment by our customers and higher incentives to motivate them to take action.

Residential lighting is the largest example of this phenomenon in practice. Light Emitting Diode (LED) technologies represent significant savings potential at the highest efficiency level. While the technology is becoming less expensive, allowing more customers to realize the benefits of the technology, *creditable* energy savings in utility DSM programs are measured as the difference between a baseline bulb as defined by the EISA Standards, and the efficient bulb. In the case of LEDs, the magnitude of the incremental efficiency creditable under utility DSM programs falls significantly short of the efficiency gains from codes and standards – eroding the energy savings potential we can claim.

We demonstrate the impact of the EISA Standards on baseline lighting technology for both Compact Fluorescents Lights (CFL) and LEDs in Figure 1 below.

[12] Public Law 110-140 (2007).

Figure 1: Residential Lighting Changes



In this graphic, the blue bars represent the EISA Standard, or baseline from which we can claim credit under our DSM program. As shown, our creditable potential was between 47-50 watts per installed CFL or LED bulb in 2012, which shrinks to 29-34 watts through 2019. In 2020, the EISA Standard will become a 13 watt CFL, so we will claim zero credit for installation of CFLs and only 6 watts of credit for installation of LEDs. This reduces our creditable potential by 88 percent when compared to the current savings, which is exacerbated by the fact that lighting programs have by far provided the majority of savings within our DSM Portfolio.

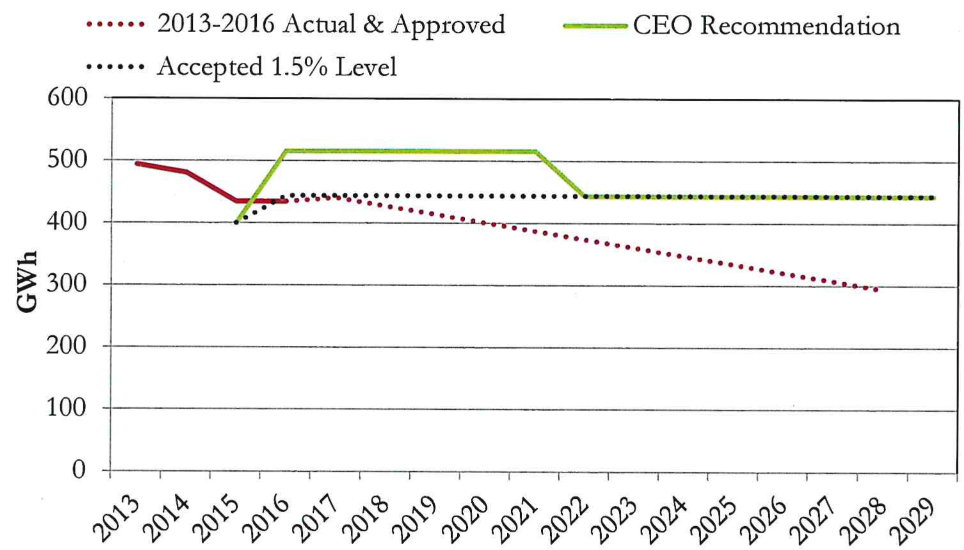
In Comments, CEO claims that despite the drop in savings attributable to utility DSM programs due to EISA lighting standards, we have still claimed an increase in energy savings. Figure 19 in the CEO Comments compares future DSM goals against historical DSM achievements from 2011-2014. However, it includes program years 2011-2012, which did not include the reduced savings from EISA standards, so the reference period is not representative of the impacts of EISA lighting standard changes.[13]

We provide as Figure 2 below, the impact of EISA lighting standards on our future potential by starting in 2013, which was the first year our creditable lighting potential ratcheted down due to the EISA Standards. We have included a comparison of the

[13] 2010/2011/2012 Triennial Plan (E,G002/CIP-09-198) p. 587 *Table 1 – Existing lighting wattage for residential lights* includes a 60 Watt baseline bulb for a 13-16 Watt CFL bulb. The same table in the 2013/2014/2015 Triennial Plan (E,G002/CIP-12-447) p. 454 includes a declining baseline wattage of 55.0 Watts (2013), 48.5 Watts (2014) and 43.0 Watts (2015) due to adoption of the EISA lighting standards.

forecasted impact based on our current 2013-2016 actual achievements and approved goals,[14] the CEO recommendation, and the 1.5 percent level we accept in this proceeding.

Figure 2: Actual and Projected Lighting Achievement – Impact of Increasing EISA Lighting Standards



This graphic demonstrates that:

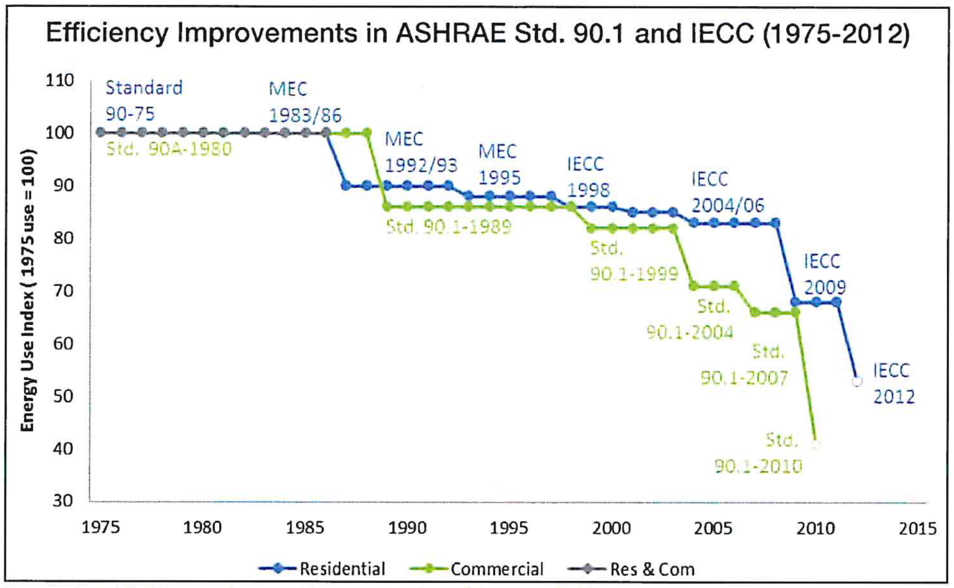
- CEO's proposed DSM 1.7 percent achievement in the early years of this resource plan significantly exceeds our historical performance, and
- The trajectory of our historical achievements, demonstrates that our commitment to 1.5 percent represents a significant increase in the pursuit of DSM.

We provide a graphic by the American Council for an Energy Efficient Economy (ACEEE) that illustrates the effect of declining potential from new technologies compared to the loss of creditable potential from increasing codes and standards in Figure 3 below. ACEEE's illustration of the efficiency improvements between the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) Std. 90.1 over the last several decades in Figure 3 below shows how

[14] *See* 2015 and 2016 goals, which are identified in the Xcel Energy 2013-2015 Triennial Plan, the 2016 Extension, and actuals from Xcel Energy's 2013 and 2014 Status Reports (Docket No. E,G002/CIP-12-447).

various codes and standards have lowered the energy intensity of buildings (Energy Use Index) by increasing equipment codes and standards.

Figure 3: ACEEE Illustration of Efficiency Standard Increases on Building Efficiency



Source: *http://sefaira.com/resources/us-energy-codes-could-surpass-leed/*

As the baseline energy intensity against which energy efficiency achievements are measured decreases, creditable energy efficiency potential also decreases. Figure 3 shows a downward trend of the baseline energy intensity that could be considered representative for future energy savings potential across many technologies – and exemplifies the necessity to take trends like this into consideration, rather than relying only on past achievements.

3. Our Potential Study Considered Other Technologies

In Comments, CEO suggests that there are other savings opportunities that we did not address, such as Conservation Voltage Reduction (CVR). We note that this technology was not included in our most recent Potential Study; the Study defined only customer-side opportunity, and CVR is a utility infrastructure opportunity, which we note may be one of the grid modernization/technology-enabling types of efforts that will help us to unlock future savings opportunities for our customers.

With regard to CVR and CEO's assertion that we have potential for 5,200 GWh over a 20-year period, CEO fails to note that we developed these estimates as part of a preliminary analysis we conducted and are continuing to test through summer 2015 to approximate a more true potential for Minnesota.[15] While CVR may offer benefits such as reduced energy consumption to customers and the Company, the integration and implementation of these technologies are complex and capital-intense, and must consider impacts to utility sales.

While we are continuing to analyze impacts and costs, our preliminary analysis found that the addition of CVR will require capital investment over a five-year period for changes to the system such as:

- Voltage sensors added throughout the distribution system to maintain service voltages within required levels,
- Two-way controls installed on Regulators and Load Tap Changers (LTC') to control voltage levels,
- Capacitor Controls must be retrofitted with new two-way controls in order to maintain system power factor through capacitors,[16] and
- Substations must be updated with Feeder load monitoring and Supervisory Control and Data Acquisition (SCADA) to monitor load, power factor, voltage and control substation devices.

Additionally, implementation of CVR will require an ongoing O&M component to operate, maintain, and manage the CVR system.

Finally, while we believe CVR may provide a vehicle for energy efficiency savings in the future, its implementation involves upgrades to the utility distribution system rather than customer actions, like other DSM initiatives. These changes are also more consistent with modernization-type changes that utilities are making to their systems to ready them for greater customer choice and control in their energy preferences, such as distributed generation. For that reason, we believe initiatives such as this are better suited to proposal and cost recovery through other mechanisms such as base rates, or other regulatory mechanisms. For the reasons we have discussed, it is unlikely we will be ready to propose and implement a CVR program for Minnesota in the next year as indicated by CEO in their assumptions.

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[15] Xcel Energy response to CEO IR No. 39 notes that preliminary analysis estimates that Distribution Voltage Optimization at a one percent voltage reduction would result in a reduction in MWh sales of 2.6 million.

[16] To-date, capacity controls have mostly been replaced through the SmartVAR program.

We note additionally that we actively monitor new technologies through our product development efforts, review other utility products, and conduct product research.[17] Some new technologies replace the traditional technologies, such as LED lighting, energy feedback programs, and holistic programs.[18] However, as we have discussed, the energy savings associated with these newer technologies and programs often have much less incremental savings potential than their predecessors – and there is also the potential that new codes and standards not yet contemplated may reduce the potential. Conversely, emerging technologies may develop that offer new potential that we and others have not yet fully contemplated in the context of the existing regulatory construct. We believe the Potential Study efforts we undertake examines and balances these trade-offs in how it treats potential associated with emerging technologies.

4. *The Potential Study Relies on Reasonable Inputs*

We rely on a Potential Study to help us identify future potential, which uses a cost analysis to determine the level of achievable savings. In Comments, CEO suggests that our Potential Study is not a reliable source for determining our future energy efficiency goals and future costs.[19] As we have discussed, we believe Potential Studies that consider the savings potential of currently available energy efficient equipment, the availability and cost of future energy efficient equipment, and the customer's likelihood of installing this equipment, provide a robust analysis and reasonable basis from which to identify sustainable, future potential.

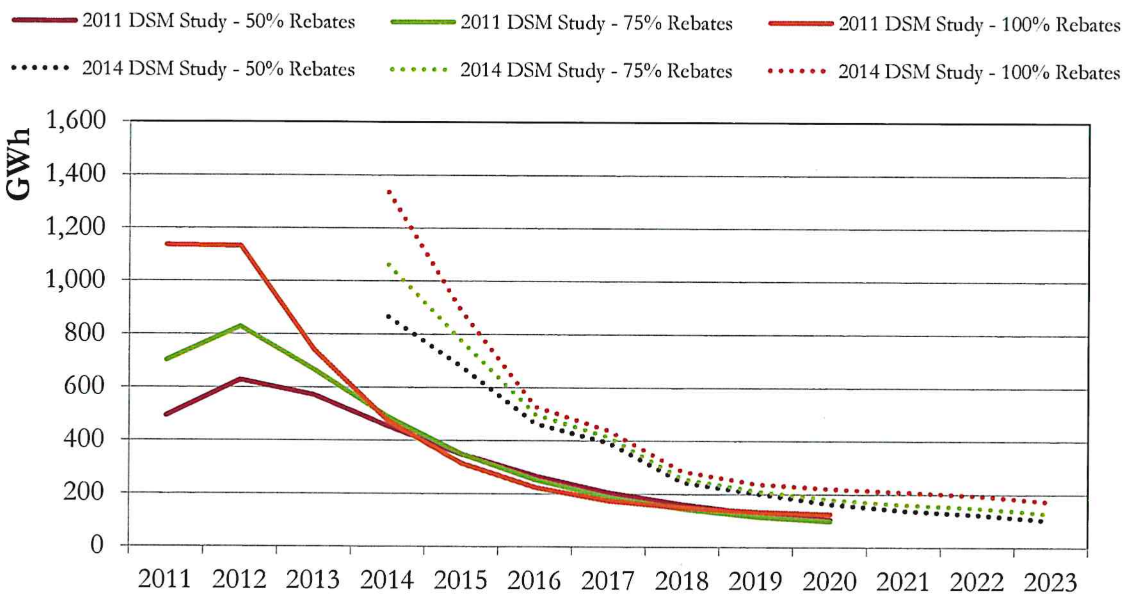
a. Study Results are Comparable

CEO appears to base their assumption on a comparison of results from our 2011 and 2014 Potential Studies, which CEO claims show significant differences in results.[20] However, this comparison does not take into consideration how the Potential Study estimates the annual pattern of achievable potential. The comparison must also include the first years of the 2011 Potential Study to accurately portray how the total

[17] We identify new products, technologies and measures through our Product Development group. We continue to participate and fund additional research through Conservation Applied Research and Development (CARD) grants. In the period of 2013 -2014, we made 48 program modifications, including adding additional programs and measures to existing programs.
[18] Holistic programs provide additional study and analysis to customers in order to make long-term energy adjustments to their facilities. Programs such as Process Efficiency and Energy Design Assistance are included in this category.
[19] The 2011 DSM Potential Study and 2014 Potential Study Update by KEMA were used for the Upper Midwest Resource Plan 2016 -2030 analysis.
[20] See CEO Comments at 29-30.

achievable potential over the ten-year period of the Studies compares. As demonstrated in Figure 4 below, the potential from the 2011 and 2014 Studies is very comparable.

Figure 4: 2011 and 2014 Study Results – Achievable Potential



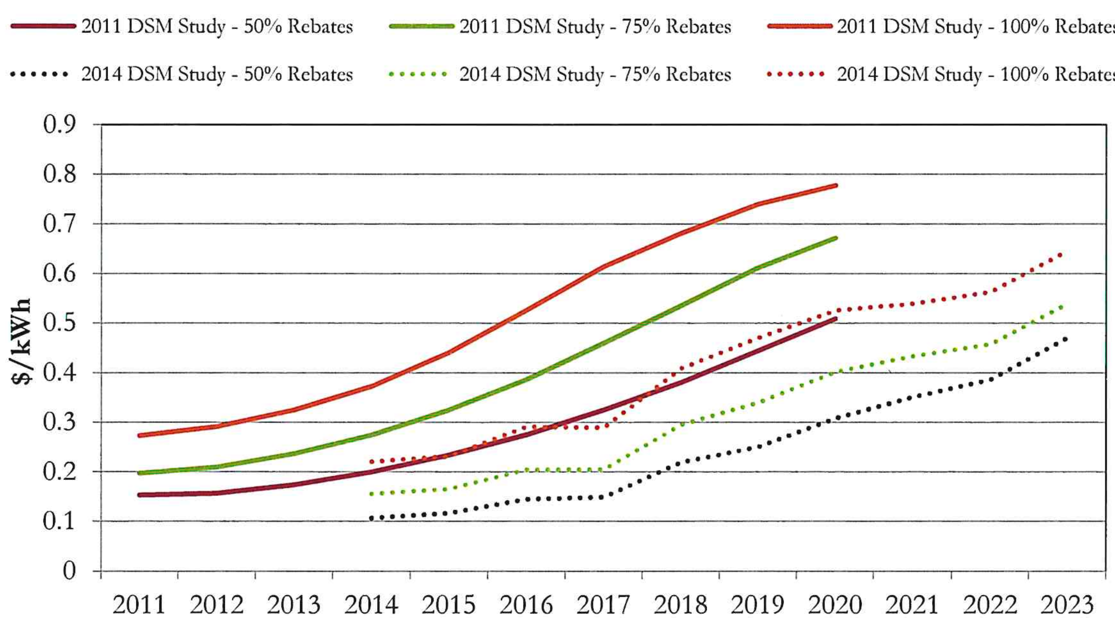
Another view of the comparability of the two most recent Potential Studies is to examine the average achievable potential over time, given the annual pattern of achievable potential. Again, the two Studies over their respective 10-year study periods are very similar as demonstrated in Table 1 below.

Table 1: 2011 and 2014 Study Results – Average Achievable Potential

	2011 Potential Study (Average kWh)	**2014 Potential Study** (Average kWh)
Study Period	***2011-2020***	***2014-2023***
50% Rebates	335,128,456	336,847,237
75% Rebates	382,514,195	382,330,087
100% Rebates	459,633,726	449,615,285

CEO also suggests that the 2014 Potential Study identified significant reductions in costs from the 2011 Study, relying on a view of annual achievable potential costs.[21] CEO Figure 16 shows costs increasing over the time period within each Study. However, a better measure of the difference in costs between the 2011 and 2014 Potential Studies is again a comparison of each Study's entire 10-year study period, which we provide below in Figure 5:

Figure 5: 2011 and 2014 Study Results – Costs Associated with Achievable Potential



As shown above, the 2014 Study identified price declines, but the declines are smaller when including the costs in the initial years (2011 vs. 2014) of each Study rather than by solely comparing the costs for each year (i.e., 2014 vs. 2014) in which the Studies overlap.

To determine the relative difference in costs between the two Studies, we averaged the cost estimates over the entire 10-year Study period and provide the results in Table 2 below. This demonstrates that the cost estimates from the 2014 Study were approximately $0.050/kWh lower than the 2011 Study, which is half the amount claimed by CEO in their Figure 16.

[21] *See* Figure 16, CEO Comments at 30.

Table 2: 2011 and 2014 Study Results – Average Costs Associated with Achievable Potential

	2011 Potential Study (Average $/kWh)	**2014 Potential Study** (Average $/kWh)
Study Period	***2011-2020***	***2014-2023***
50% Rebates	$0.224/kWh	$0.176/kWh
75% Rebates	$0.290/kWh	$0.235/kWh
100% Rebates	$0.372/kWh	$0.322/kWh

As these illustrations demonstrate, the costs used in the Potential Study are similar across the 2011 and 2014 Studies. We note however, the 2014 Potential Study includes a recent trend toward lower costs of various technologies, likely due to updated product costs in areas such as LED lighting. Our estimated achievable potential is based on these Potential Study scenarios and incorporates the trends in reduced product costs.

b. Rebate Levels Must Increase to Motivate Customer Action

The Department requested that we explain why the Potential Study calls for higher rebate levels to achieve lower levels of savings. In addition, CEO believes that we overestimated our costs to achieve various levels of potential. We explain below how we derived our estimates and why we believe they are reasonable.

Department of Commerce. In response to the Department, we note that the Study found that a rebate level of 50 percent results in only 1.3 percent of sales, in contrast to our achievements to-date, which have been *above* 1.5 percent of sales at rebate levels just above 30 percent. Figure 4 above (2011 and 2014 Study Results – Achievable Potential) shows that initially (2014-2016), the 50 percent rebate level results in achievement well-above 1.5 percent.[22]

So, as would be expected, higher rebate levels translate to higher potential. However, this potential greatly diminishes over time. Therefore, in order to determine a scenario that will provide a sustainable level of savings at a consistent level of percent-of-sales, we averaged the potential over a longer period (2014-2021) to estimate the rebate levels necessary to motivate customers to take creditable action. This resulted

[22] 2014 achievement in 2014 Potential Study equals 866 GWh of savings (nearly 3% of sales); 2015 of 677 GWh (approx. 2.3% of sales); 2016 of 464 GWh (approximately 1.6% of sales).

in our projection that it will require an average 50 percent rebate level to achieve 1.3 percent savings, and a 75 percent average rebate level to achieve 1.5 percent of sales, despite history.

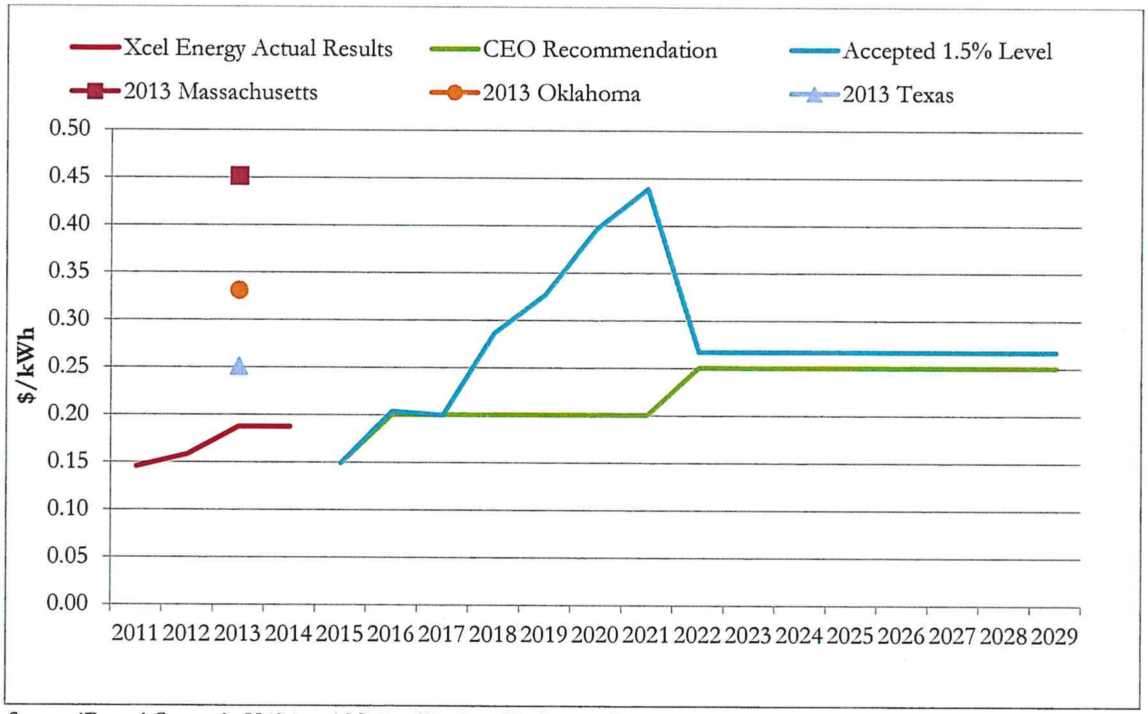
The cause of this significant increase in necessary rebate levels is attributable to the reduction in potential in the future for the reasons we have discussed. We have been able to maintain our 1.5 percent of sales achievements at lower rebate levels due in part to greater pursuit of programs that do not require rebates, such as Energy Feedback programs for Business and Residential customers, and the Home Energy Squad program. The reduction in potential worsens over the years, illustrated by the decline in achievable potential in Figure 3 above (ACEEE Illustration of Efficiency Standard Increases on Building Efficiency), requiring a continuing greater level pursuit of new DSM programs in the future. We believe this greater level of pursuit cannot be met with new programs alone; rather, rebate levels will also have to increase. The Potential Study serves as the best available projection of the expected achievement at these higher levels of creditable achievement.

Clean Energy Organizations. CEO used an illustration of actual costs of our lighting program compared to the initial ratcheting up of EISA lighting standards between 2012 and 2014 to support a claim that higher rebate levels are not necessary in the face of increasing codes and standards.[23] However, similar to what we explained previously, CEO Figure 20 also includes program years 2011-2012, which were not affected by a change in the EISA lighting standards. Therefore, the comparison of actual costs in light of increasing standards needs to begin in 2013 – the first year the EISA standards were implemented in the savings calculations.

By beginning in 2013, the costs per kWh to achieve savings increases significantly, as shown in Figure 6 below. To further illustrate the scope of these cost increases, we have also included the cost per kWh of other DSM programs as outlined in a May 2015 ACEEE report, including cost per kWh by Investor Owned Utilities in particular states with DSM portfolios.

[23] *See* Figure 20, CEO Comments at 34.

Figure 6: Historical Achievement and Plan Projections – Impact of Increasing Codes and Standards



Source: "Beyond Carrots for Utilities: A National Review of Performance Incentives for Energy Efficiency." ACEEE, May 2015
Note: State references (shapes) indicate point in time markers of cost, not a trend.

Our Potential Study demonstrates that significant increases in rebate levels and utility spending may be necessary to maintain historical energy savings levels, which corresponds to recent trends we and others have observed. Further, these costs are in line with those identified in other states with DSM portfolios, specifically those with comparably high energy standards such as Massachusetts.

c. New Technologies are Contemplated

CEO notes in Comments that the Potential Study did not consider most LED lighting measures in the commercial sector as either economic or achievable, with the implication that we are underestimating potential for technologies that are likely to be achievable during the planning period.[24] While it is true that we did not count specific achievements for these specific technologies, we did not directly take the achievable potential from the Study and make it our proposed DSM goal. Rather, we escalated

[24] CEO Comments at 36.

the potential the Study identified to account for savings such as these and other evolving technologies that we assume will be achievable at a future date.

Specifically, the Study concluded that achievable potential for the out-years of the planning period was less than one-half of one percent. Instead, we proposed a goal of nearly three-times larger – 1.3 percent – to account for evolving technologies and other cost efficiencies that are likely. Further, with this Reply, we now accept an even higher goal of 1.5 percent through the entire planning period.

We have delivered strong DSM program performance for more than 20 years and remain strongly committed to helping our customers continue to achieve savings.

D. Demand Response

We appreciate the Departments' analysis and recommendation that the Commission accept our proposed Demand Response (DR) growth of 76 MW over the planning period. We acknowledge the Department's comments regarding the importance of DR in a carbon-constrained future and repeat our commitment to leveraging technology to unlock additional potential for our customers. We also acknowledge and accept the Department's recommendation that we include in our next resource plan, a cost-effectiveness analysis taking into account possibilities for expanded and more dispatchable DR on our system.

In the balance of this section, we respond to the Department's request for information in the following aspects of our DR portfolio:

- Saver's Switch program usage,
- Dispatch process, including triggers for economic dispatch of load modifying resources,
- Impact from our 2015 Electric Rate Savings Program Waiver,
- Cost-effectiveness calculations, and
- DR Resource Value.

1. *Saver's Switch Program Usage*

The Department asked that we explain Saver's Switch's usage since 2007. As we noted in our 2014 Saver's Switch Annual Compliance Filing, we have had little need to control the program over the last several years.[25] Our Saver's Switch Tariff states

[25] *See* Saver's Switch Annual Compliance Filing, Docket Nos. E002/M-01-46 and E002/CI-01-1024 (Feb. 13, 2015).

that interruption will normally be based on meeting peak demands, system economic dispatch requirements and reliability concerns.[26] Our control history shows that these criteria have been met around ten times since 2007.

In terms of modeling our Saver's Switch program in this Resource Plan, the inputs are based on current program guidelines as defined by the Rider, and recent control history. Strategist is allowed to utilize the program up to the maximum amount of hours defined in the Rider. However, a minimum savings threshold was modeled based on the recent history of market conditions. Because the hourly savings of the program must exceed this threshold in order for the program to be dispatched in the Strategist simulation, this utilization only affects the energy savings value for the program, which is a very marginal component of the overall program economics. As with most DR programs, the vast majority of the economic benefit is realized in the avoided capacity value, i.e. avoidance of incremental resource additions in the expansion plan.[27]

2. *Dispatch Process*

As we explained in our response to Department Information Request No. 321 in our 2013 Electric Rate Case (Docket No. E002/GR-13-868), we have two DR procedures: (1) Peak Control Interrupt (PCI), and (2) Energy Control Interrupt (ECI). Saver's Switch customers can be controlled under both procedures. The two primary factors that contribute to the need to control are weather conditions and available generation resources. Over the last several years, customers and system operators have benefited from favorable weather conditions and the sufficient resources available on the NSP System to meet peak demand, resulting in fewer control events.

a. Peak Controlled Interrupt

PCI is used when reliability is at risk, and the NSP System is at risk of not being able to meet the peak demand of our customers. Saver's Switch is one of the programs that would be dispatched under our PCI procedure for system peaking conditions and reliability purposes during a system emergency. The PCI procedure may be activated to reduce customer demand that is associated with interruptible service tariffs when MISO's Reliability Coordinator (RC) instructs the NSP System to implement load management measures. Instructions from MISO's RC are given pursuant to MISO's Market Capacity Emergency Procedure for the protection of the overall system. NSP

[26] *See* NSP Electric Rate Book, Section 5, Tariff Sheet Nos. 97-99.1.
[27] For additional information, see DOC IR Nos. 19-24.

System Operations may also activate the PCI procedure if it in its opinion, the reliability of the NSP System is at risk.

These steps apply to all PCI customer classifications, including commercial and industrial, residential, retail, and wholesale under the Peak Controlled Tiers I and Tier II (1st Group, 2nd Group and 3rd Group), Peak Controlled Short Notice Rider, and Saver's Switch rates in the states of Minnesota, North Dakota, South Dakota, and Wisconsin.

NSP System Operations maintains the right to use the PCI procedure in the event of emergencies associated with the delivery system, as identified by NSP Transmission, NSP Distribution, or MISO. MISO will call on Load Modifying Resources (LMR) through their LMR automated process when system conditions warrant. An activation call identifies the total amount of LMR to be deployed; the call does not identify specific resources to be curtailed. NSP System Operations chooses which LMR to activate based on operational factors (i.e. constraints and locations).

b. Energy Control Interrupt (ECI)

The intent of the ECI procedure is to reduce the cost of service as compared to market/MISO energy prices. It is generally implemented when the cost to serve the energy needs of ECI customers exceeds certain thresholds as defined in the applicable rate schedule or as determined by the Company. These curtailments reduce the overall cost to supply total system load by requiring ECI customers to reduce load or by charging ECI customers a Control Period energy price if the ECI customer elects to buy through the interruption event.

For administration purposes, we have determined that we will call an ECI event only when the production cost is expected to exceed the applicable level for three consecutive, or five total hours in a day period. These conditions are likely any time that we are implementing PCI interrupts – and are expected at times to precede and/or follow a PCI event.

The steps above apply to all ECI customer classifications, including residential, retail, and wholesale. The majority of these customers are identified under the Tier 1 Energy Controlled Rider and the Energy Controlled Service (Non-Demand Metered) rate schedules. Saver's Switch for business and residential can also be controlled as an energy resource. As also explained in our 2014 Saver's Switch Compliance filing, we have not activated Saver's Switch for this purpose over the last several years, given favorable weather conditions and energy prices.

3. *Anticipated 2015 Electric Rate Savings Program Waiver Impacts*

In light of the increased expectation that MISO would begin calling emergency resources more frequently over the next several years as power supply resources become tighter, we believed it beneficial to have all customers participating in our rate savings programs verify their participation level and ability to comply with program requirements year-round. We requested a waiver from our Electric Rate Savings program tariff in order to work with customers throughout 2015 to help them determine their interest and ability to remain on the rate or to adjust their participation level to accurately reflect their current operations and capabilities.

Providing a one-time waiver allows customers the opportunity to adjust their participation without charge, essentially providing an incentive to make important adjustments prior to predicted change by MISO.

We have not yet conducted the necessary analysis to determine impacts from the waiver. In our Petition seeking the waiver, we noted that we believed this customer verification step would both help customers, and help the Company 'right-size' the current program and provide needed assurance that these resources will be available when called upon. In terms of reporting, we described in our Reply Comments that we complete an ongoing analysis of future control seasons through our load management forecast in the March/April timeframe, which is necessary to analyze the impacts of the waiver period. We accepted the Department's recommended reporting criteria and suggested certain modifications, one of which was extending the compliance reporting date to March 30, 2016 to incorporate the results of our load management analysis efforts – which the Department supported in its Response to our Reply Comments.[28] The Commission adopted the reporting criteria and timing into its May 22, 2015 Order approving the waiver.

Therefore, on or before March 30, 2016, we will submit a compliance filing in Docket No. E002/M-15-189 containing, at a minimum, the following:

- How many customers took advantage of the waiver,
- For customers that took advantage of the waiver, their annual and average monthly billed KW firm demand covered under the applicable or successor tariffs for years 2014, 2015, and estimated 2016,
- For customers that took advantage of the waiver, their annual and average

[28] *See* Response Comments of the Minnesota Department of Commerce, Division of Energy Resources, April 17, 2015, Docket No. E002/M-15-189.

monthly billed KW controllable demand covered under the applicable or successor tariffs for years 2014, 2015, and estimated 2016,

- The forecast MW of controllable demand for all customers covered under the applicable tariffs at the beginning of the waiver period (summer 2015),
- The forecast change in MW of controllable demand covered under the applicable tariffs following the waiver period (summer 2016) from customers that took advantage of the waiver,
- The final revenue impact of this tariff waiver, and
- A discussion on the overall results of this waiver and the Peak Controlled Services program reevaluation.

4. Cost Effectiveness Calculations

Minn. Stat. § 216B.241 defines DR, or load management, as referring to an action taken to change the timing or volume of a customer' use of energy use allowing the utility to respond to fluctuations in peak demand for the purposes of energy or capacity. Using this definition, noted by the Department[29], the Company refutes the premise that electric generation peaking resources change the timing or volume of a customer's use of energy.

There are many differences between the services and benefits of DR and those of electric generation peaking resources, which is why cost comparisons of the two sources is complex. We note that DR, unlike natural gas Combustion Turbine, can vary in predictability and reliability during peak load periods. Acknowledging this complexity, we compared DR to the economic carrying charge (ECC) of a generic CT for our cost-effectiveness calculations in the Resource Plan.

We performed cost-effective calculations in Strategist across the following four distinct scenarios: (1) low, (2) medium, (3) high, and (4) reference case. If the cost of the DR was higher than the comparative ECC of the generic CT, it was screened out and not modeled in Strategist. We created these portfolios from the programs, costs, and potentials from the Brattle Study (excluding Dynamic Pricing), provided as Appendix O to our initial Resource Plan filing. DR potential increases with incentive level; therefore, the high DR portfolio had the most programs, incentives, and potentials.

The cost-effectiveness calculations include the capacity obligation benefit of DR,

[29] See Comments of the Minnesota Department of Commerce, Division of Energy Resources, July 2, 2015. Docket No. E002/RP-15-21 page 48-49.

which is that it lowers the capacity obligation by an amount greater than the demand reduction it provides. The amount of DR reducing the capacity obligation is equal to the demand reduction multiplied by one plus the reserve margin. All else constant, this makes one DR unit of capacity worth more than one electric generation unit of capacity by a premium of the reserve margin. Since this is the only adjustment to the cost of the ECC of the CT, our cost-effectiveness calculations are giving a high-end value to the capacity of DR.

Table 3 below illustrates the comparison of the average costs of the Generic CT and the four scenarios we used in our Strategist modeling. We further note that these costs were derived using actual DR forecasts (Reference Case) and portfolios identified through our Demand Response Potential Study.

Table 3: Generic CT and the Low, Medium, and High DR Portfolio Costs used in the Strategist Modeling
($/kW per year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Generic CT ($/kW-yr)	57.72	59.04	60.36	61.68	63.12	64.44	66.00	67.44	68.88	70.44	72.00	73.68	75.36	77.04
Low Portfolio ($/kW-yr)	50.06	47.67	47.94	48.27	48.67	49.22	49.81	49.91	50.66	51.47	52.29	53.12	53.97	54.87
Medium Portfolio ($/kW-yr)	65.52	64.88	65.52	66.48	67.48	68.55	69.66	70.55	71.67	72.84	74.02	75.22	76.44	77.71
High Portfolio ($/kW-yr)	114.80	116.78	118.78	120.81	123.00	125.04	127.18	129.84	132.47	135.11	137.79	140.50	142.76	145.13
Reference Case ($/kW-yr)	105.01	107.03	109.04	111.08	113.11	115.11	117.14	119.20	121.27	123.16	124.91	126.68	128.48	130.33

The above table shows the $/kW per year costs used within the Strategist model to formulate the cost-effectiveness analysis as part of our review process. This information, along with Strategist sensitivities and the changing DR landscape were used in combination as we defined the DR goals outlined in the Resource Plan.

5. *DR Resource Value*

The Department requested we provide a comparison between the price assigned to DR resources in our modeling and the price of DR resources submitted to MISO. Interruptible loads can provide a lower cost way to meet reserve requirements compared to acquiring or building additional physical generation capacity, and are used to maintain an adequate reserve margin to fulfill our obligation to deliver adequate, reliable electric service to our customers – regardless of unforeseen factors impacting generation supply. As such, we register our DR resources under the MISO

Tariff[30] as emergency resources, which allows MISO to call a control event up to five times per Planning Year.[31] As an emergency resource, there is no price associated with the capacity provided. Within the Strategist model, we were consistent with how we register DR resources with MISO. Specifically, we placed no incremental cost hurdle in Strategist.

E. Potential Environmental Drivers Impacting Sherco Units 1 and 2

In this section, we provide additional discussion of National Ambient Air Quality Standards (NAAQS) as requested by the Department, and we respond to CEO Comments regarding future regulatory requirements that may impact the timeline for requiring SCRs on Sherco Units 1 and 2.

In summary, none of the regulations discussed by CEO currently requires emission controls beyond those already installed on Sherco Units 1 and 2, and the likely timeframe when SCRs could be required for Sherco Units 1 and 2 is the mid-2020s. The regulatory drivers that may drive SCR installation requirements are outlined below:

1. *National Ambient Air Quality Standards (NAAQS)*

The current status and expected revisions to each NAAQS are addressed in Appendix D, pages 12-18 of our January 2 filing. When Appendix D was prepared, only the then-pending Ozone (O_3) NAAQS revision represented a possible driver for further reductions in oxides of nitrogen (NO_x) from Sherco Units 1 and 2.[32]

EPA adopted the final ozone NAAQS of 70 parts per billion (ppb) on October 1, 2015. In Comments, CEO stated that a new standard of 65 ppb or lower could result in ozone non-attainment areas in several counties in Minnesota. While that was a possibility, with the standard at 70 ppb, Minnesota's air monitoring results currently comply with the new standard. Therefore, the MPCA will not need to require further

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30 Registering Demand Response resources with MISO allows the Company to obtain credit against our capacity requirements.

31 The MISO Planning Year includes the 12-months period beginning June 1.

32 As noted in Appendix D, page 14 of our January 2, 2015 filing, in December 2014, EPA finalized its area designations for $PM_{2.5}$ and did not classify any nonattainment areas in any state in which NSP operates. Therefore we do not anticipate a State Implementation Plan (SIP) process in Minnesota leading to additional NO_x and SO_2 control requirements for $PM_{2.5}$ purposes. EPA is not scheduled to review and potentially revise the $PM_{2.5}$ standard again for five years, until 2018-19. If needed, any future emission reduction requirements for such a standard issued in 2018-19 would be required in the 2025-2030 timeframe.

emission reductions to address the new standard. We note that EPA will next review the Ozone standard in 2020.

2. Regional Haze and Visibility

As described in Appendix D, pages 21-23 of our January 2 filing, SCR is not required for compliance with Minnesota's 2009 Regional Haze SIP. MPCA determined that the NO_x combustion controls currently in place at Sherco Units 1 and 2 constitute the "Best Available Retrofit Technology" (BART) for regional haze. EPA approved the State Implementation Plan (SIP) accepting these source-specific emission limits, as well as implementation of the Cross-State Air Pollution Rule (CSAPR) in Minnesota, as meeting the applicable requirements. Future developments in the regional haze program could require installation of SCRs, as described below.

a. Litigation of Minnesota's 2009 Regional Haze SIP

A lawsuit filed in August 2012 before the U.S. Court of Appeals for the Eighth Circuit (to which two members of the CEO are party) appealed EPA's approval of Minnesota's 2009 Regional Haze SIP. The parties to the proceeding disagree with MPCA's approval of the NO_x combustion controls at Sherco Units 1 and 2 as BART, and reliance on CSAPR. They believe EPA should not have approved Minnesota's 2009 SIP and should have required additional controls. In Comments, CEO states that if EPA's decision is reversed, we would almost certainly be required to install SCR at Sherco 1 & 2 to comply with BART.

A decision is expected from the Eighth Circuit in 2016. If the court finds fault with EPA's approval of Minnesota's 2009 Regional Haze SIP, the matter would be remanded to EPA, and likely the state, for further evaluation. That evaluation would first re-evaluate whether or not the adoption of CSAPR as BART is appropriate for Minnesota. If not, it would then consider the current emissions from the Units, the progress that has occurred in emission reductions for the 2009-2018 planning period beyond what the MPCA anticipated, and whether or not SCRs should nevertheless be found to be BART.

Thus, whether the Regional Haze litigation ultimately leads to a requirement for SCR will not be known for some time.

b. 2018 Regional Haze SIP

The CEOs also assert that Minnesota's 2018 Regional Haze SIP is likely to require

SCRs for Sherco 1 Units and 2, "because with current emissions the state will not achieve the rate of process necessary to achieve natural visibility by 2064."[33] This proceeding has not yet started, thus any conclusions about the likely outcome of the SIP are speculative at this time.

c. Reasonably Attributable Visibility Impairment (RAVI)

Since our January 2 initial filing, we have reached agreement with EPA and six environmental advocacy organizations, including three of the CEOs, to resolve litigation related to RAVI claims by agreeing to additional emission limitations at Sherco. As part of the settlement agreement, SCRs for NOx will not be required under RAVI.

3. The Externalities Docket[34]

The CEOs state that we should have assigned higher externality values to CO_2 and three criteria pollutants (NO_x, SO_2 and particulate matter) than the Commission's currently approved values, in anticipation of these values being set higher in the current Externalities Docket (No. E999/CI-14-643), in which a Commission decision is expected in 2016.[35]

Our base assumptions for Strategist modeling include the following:

- The high end of the Commission's current externality ranges for NO_x, PM_{10}, SO_2, CO and lead;
- The \$21.50/ton midpoint of the Commission's regulatory cost range for CO_2 starting in 2019, as specified by the Commission; and
- The high end of the Commission's currently approved CO_2 externality range in any year where the CO_2 regulatory value is not applied.[36]

We are required by Minn. Stat. § 216B.2422, subd. 3 to use the values established by the Commission in resource planning proceedings. Accordingly, when the Commission establishes new values, we will apply those values in future resource proceedings.

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33 CEO Comments at 48.
34 Also referred to by the CEOs as the "true cost of pollution" docket.
35 State of Minnesota Office of Administrative Hearings. Second Prehearing Order. *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs under Minn. Stat. 216B.2422, subd. 3.* MPUC Docket No. E999/CI-14-643, OAH Docket No. 80-2500-31888.
36 *See* Xcel Energy January 2, 2015 filing, Appendix J at 8; Appendix D at pages 40-41; and the March 16, 2015 Supplement – Appendix at 2-3.

Certificate of Service

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached lists of persons.

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

xx by electronic filing.

Docket No. E002/RP-15-21

Resource Plan Interested Parties

Dated this 2nd day of October 2015

/s/

SaGonna Thompson

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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January 29, 2016

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—Via Electronic Filing —

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: SUPPLEMENT – CURRENT PREFERRED PLAN
2016-2030 UPPER MIDWEST RESOURCE PLAN
DOCKET NO. E002/RP-15-21

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Supplement to its 2016-2030 Upper Midwest Resource Plan to the Minnesota Public Utilities Commission as required by its January 6, 2016 ORDER REQUIRING SUPPLEMENTAL FILING in the above-referenced docket.

This Supplement provides the detailed analysis supporting the proposal we outlined in our October 2, 2015 Reply Comments, as well as the information required in the Commission's January 6 Order. It also provides a detailed discussion of Prairie Island and our support for operating the plant through the end of each unit's respective current licensed life.

Our plan consists of the following:

- Accelerating our transition away from coal by ceasing coal operations at our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

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Collaboration has been the hallmark of this proceeding. We developed the changes to our initial plan with input from stakeholders and believe our plan offers an energy vision that will benefit our customers, communities, and the states we serve. Together, the actions outlined in our Current Preferred Plan will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in our carbon emissions by 2030 without significantly impacting customer costs, reliability, Company employees, or the communities we serve. In fact, due to recent extensions to federal tax credits for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments.

Request for Protection of Trade Secret Information

The Company recognizes and supports the need for transparency in review of our Resource Plan. Non-Public data included in this filing is limited to certain portions of the Supplement and four attachments as discussed below. We have identified the Trade Secret and other Non-Public information pursuant to Minn. Rule 7829.0500.

1. Forecasted Capital and O&M Costs

Section V of the Supplement contains forecasted cost details. This information is Trade Secret information as defined by Minn. Stat. §13.37(1)(b), because it derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as a trade secret.

2. Attachment D – Grid Primer and Study Summary Report

Attachment D is a summary of the technical studies analyses the Company conducted to examine the technical impacts of potentially retiring Sherco Units 1 and 2. It is marked as Non-Public, as it contains Critical Electrical Infrastructure Information (CEII) including a summary of the results of the Midcontinent Independent System Operator Attachment Y2 Study and the Xcel Energy Transmission Reliability Study provided as Attachments D1, D2 and D3. Attachment D also discusses the Company's analysis of its Black Start Plan, which specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Portions of this analysis are also CEII and marked as Trade Secret for the same security purposes noted in parts 3 and 4 below.

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3. Technical Study Reports

- *Attachment D1 - System Support Resource Attachment Y2 Study – The Sherburne County Generating Plant ("Sherco") Units 1 & 2 (Final Report of Midcontinent Independent System Operator (MISO) – August 28, 2015)*
- *Attachment D2 - Sherco 1 Replacement Power Study – Phase 1 (Siemens Power Technologies International - January 22, 2016)*
- *Attachment D3 - Sherco 1 and 2 Replacement Power Study – Phase 2 (Siemens Power Technologies International - January 22, 2016)*

Attachment D1 is marked as Non-Public in its entirety and is provided with critical infrastructure and highly-sensitive information redacted. Attachment D1 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Sherburne County Generating Plant (Sherco) Units 1 and 2. While MISO has redacted all critical infrastructure and highly-sensitive information from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Attachments D2 and D3 are marked as Non-Public in their entirety and contain CEII and highly-sensitive information redacted for the same reasons noted for Attachment D1. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). The reports by Siemens Power Technologies International resulted from studying the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated with replacement of one or both Units at alternate locations on the NSP System. We believe that the information could potentially be used to determine vulnerabilities in the grid or in disrupting electric service to our customers, in the event Sherco Units 1 and or 2 were not in service. The public disclosure or use of this information creates an unacceptable risk, because those who want to disrupt the electrical grid may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the study results provided with this filing.

We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to

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discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Interested parties will be able to obtain copies from our web site at:

http://www.xcelenergy.com/Company/Rates_&_Regulations/Resource_Plans.

Please contact me at (612) 215-4663 or Aakash.Chandarana@xcelenergy.com if you have any questions regarding this filing.

/s/

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

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SUPPLEMENT TO XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN

DOCKET NO. E002/RP-15-21

JANUARY 29, 2016

2016-2030 Upper Midwest Resource Plan – Supplement
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ATTACHMENT B: Updated Strategist Modeling and Outputs

ATTACHMENT C: Resource Plan Comparisons

ATTACHMENT D: Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

ATTACHMENT D: Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

ATTACHMENT E: Estimated Rate Impacts

ATTACHMENT F: Demand Response, Grid Efficiency, and Distributed Energy Resources as Alternative Resources

ATTACHMENT G: Socioeconomic Study Summary

ATTACHMENT H - Preliminary Assessment of CO_2 Markets under the Clean Power Plan

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I. EXECUTIVE SUMMARY

Partnerships with communities, customers, and stakeholders have helped to make Minnesota a leader in energy policy - collaboration has been the hallmark of this proceeding. As our industry enters an era of increasing responsiveness to evolving expectations – from those of individual customers, to federal and state carbon emissions goals – these partnerships will become even more important to charting a path that provides certainty in uncertain times.

The Commission noted in its January 6, 2016 Order that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders. The Commission also explained that the process of analyzing future energy needs and preparing to meet them is not a static process, and that strategies for meeting future needs evolve in response to changing conditions. We agree. Through significant collaboration with our stakeholders, our Current Preferred Plan has evolved from a plan that would achieve a 40 percent carbon dioxide emissions reduction from 2005 levels to one that achieves a nearly 60 percent reduction in the same timeframe.

After filing our initial resource plan in January 2015, we engaged in informal discussions and conducted several technical workshops to receive feedback from our stakeholders. We listened carefully to this feedback, we reviewed and analyzed the comments filed in this docket, and we shared an updated vision of our energy future that resulted from this collaboration in our October 2, 2015 Reply Comments.

As described in those Reply Comments, we envision an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon and by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. It will also mitigate environmental regulatory risks that could affect the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, states, and the communities we serve in a variety of ways. It will benefit our customers by providing for a cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect. As discussed further below, we can accomplish this transition for just a fraction of a percent more in incremental cost over earlier plans.

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Our Current Preferred Plan will also benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. Finally, our Current Preferred Plan will benefit our communities. It allows adequate time to transition our workforce during this fleet evolution, and provides for new investments and the creation of new jobs in current and future host communities. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

Our Current Preferred Plan consists of the following course of action:

- Accelerating our transition away from coal by ceasing operation of our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

As we make this transition, maintaining the reliability of the system is critical. Our reliability studies confirm that, before ceasing coal operations at the second Sherco unit in 2026, we must take measures to maintain reliability. Our operational analysis confirms that the most cost-effective way to stabilize the transmission system and meet our customers' load requirements is to build a combined cycle plant at the existing Sherco site. By locating the plant at Sherco, we are able to use existing infrastructure and interconnection rights, which will result in significantly lower costs as compared to locating it elsewhere. We can also use our existing water allocation to wet-cool the plant, further improving cost and performance. Finally, we believe that the impacts on the Becker community should be properly considered in this proceeding, and the siting of a combined cycle at Sherco will promote economic development for the community. We also propose to add a combustion turbine near one of our load centers in North Dakota. This will balance the interests of the states that we serve and maintain the benefits of an integrated system for all of our customers, while also addressing the reliability concerns of the North Dakota commission, which wants the Company to build cost-effective and dispatchable generation in their state.

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We recognize that site-specific generation is not typically a part of traditional resource planning analysis. However, the plan components we are proposing will have wide-ranging impacts on our system and region, making a locational analysis imperative to ensuring continued reliability and maximizing customer benefits. For these reasons, and those discussed later in this Supplement, we believe that a locational analysis is appropriate and in the public interest.

Our ownership of these assets, along with a balanced portfolio of the renewable generation we propose to add to the system, is a critical component of our vision, because it results in a balanced generation portfolio that will minimize customer costs and mitigate risk. The specific benefits of ownership include investment in our communities, continued use of our interconnection rights at Sherco, long-term value for our customers arising from the asset life of owned resources, increased diversity in our generation portfolio, and a demonstration of our commitment to being a leading provider of cleaner and greener energy. Our ability to secure these benefits for our customers is a critical component of our Current Preferred Plan and, we believe, an important factor in the public interest analysis.

Finally, because our nuclear fleet comprises more than half of the Company's carbon-free generation, it is a cornerstone to our carbon-reduction goals. We continue, therefore, to support operating our nuclear fleet through the end of each plant's respective current licensed life. In October, we acknowledged our projected increase in the capital costs necessary to run the Prairie Island nuclear plant to the end of its current licensed life. At the hearing on December 3, 2015, the Commission sought additional information on the increased capital forecast, and we have since studied the Prairie Island numbers in greater depth. Two key conclusions emerged from this study. First, the lower fixed operating and maintenance costs we have experienced relative to our 2008 modeling projections more than offset the increased capital projections – by more than $950 million. Second, even with the increased capital costs (the bulk of which occur in 2021 and beyond), Prairie Island has been, and continues to be, a cost-effective resource.

We recognize however, that stakeholders would like to better understand the implications of our updated forecast, as well as the potential for future updates. To help promote a better understanding of these costs, we are including a detailed discussion of Prairie Island in this Supplement. We believe that this information supports our continued operation of the plant, including the near-term investments we must make to safely and reliably operate our plants over the next few years. We acknowledge, however, that it is impossible to perfectly forecast costs for the

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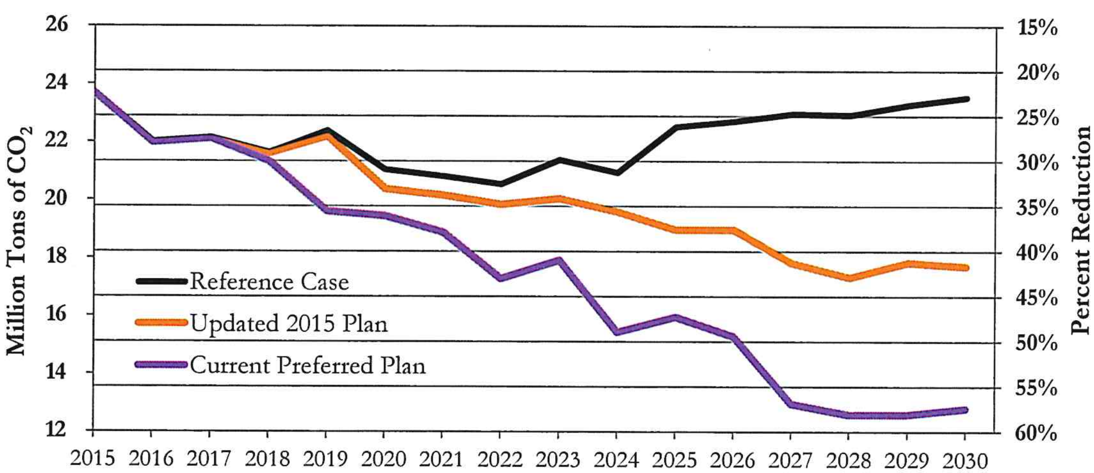
remaining 19 years of the plant's licensed life and recognize that stakeholders may want to explore alternatives based on that uncertainty. We therefore provide some preliminary analysis relating to an alternative path for Prairie Island (an "off-ramp") sometime in the mid-2020s. We recognize that there are other alternatives, but our analysis confirms that any near-term retirement would be significantly more costly than one in the mid-2020s or beyond. We agree that it makes sense to continue a dialogue regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current licenses, we are committed to doing the work necessary to advance this discussion, and anticipate that it could be completed within 18 months. At the same time, we believe that this Supplement demonstrates that the continued operation of Prairie Island is cost-effective and in the public interest in the near term, such that our continuing dialogue should not impede approval of our Current Preferred Plan.

Together, these actions will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in carbon emissions by 2030. The following graph shows the dramatically reduced carbon emissions that would result from our Current Preferred Plan, as compared to both our Updated 2015 Plan and Reference Case:



While the Updated 2015 Plan would have achieved substantial progress toward federal and state energy goals, the Current Preferred Plan – which grew out of the 2015 Plan through hard work and collaboration with stakeholders – does more. It

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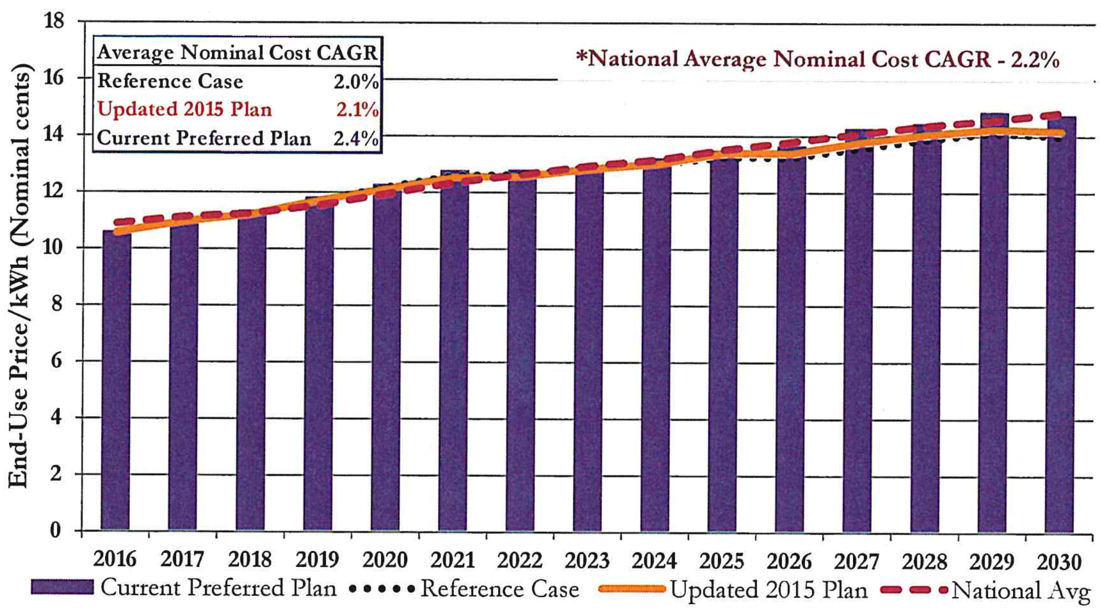
moves Minnesota significantly closer to achieving its goal of 80 percent carbon reduction by 2050, and it is the only scenario that is nearly certain to be compliant with the Clean Power Plan.

Our Current Preferred Plan achieves these goals without significantly impacting customer costs, reliability, our employees, or the communities we serve.
In fact, due to recent extensions to federal tax incentives for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments. We can now offer a plan that achieves 50 percent more carbon reduction than our Updated 2015 Plan for a nominal customer cost of less than one-half of one percent Compound Annual Growth Rate (CAGR) over that plan. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in customer cost is one of the principal benefits of our Current Preferred Plan, which is reflected in the Strategist modeling discussed in detail later in this supplement.

As we would expect, the trajectory of our Current Preferred Plan deviates from our Reference Case and Updated 2015 Plan mostly in the out years of the planning period, after we complete the transition away from coal operations at Sherco Units 1 and 2. The following graph shows the relative cost growth of our Current Preferred Plan, Updated 2015 Plan, and Reference Case, in comparison to the national average:



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*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.

As shown above, the cost of the three plans are comparable and roughly consistent with the expected national average increase in energy prices over the planning period.

Our Current Preferred Plan is in the public interest. It builds on our strong foundation of environmental performance, and ensures we will continue to reliably meet our customers' electricity needs in a cost-effective manner. It puts the Company on a path to transform its fleet in a planful, coordinated way that ensures we will meet our obligations under the Clean Power Plan and the most stringent of our state renewable energy and carbon reduction requirements. Implementation of our plan will put Minnesota at the forefront to lead the nation in clean energy, and at the same time, acknowledges and constructively addresses the unique policy preferences of the NSP System states. It provides our customers, employees, and communities with certainty while also maintaining flexibility to adjust and respond to changes along the way. Our Current Preferred Plan maintains a balanced diversity of energy sources and provides investment opportunities that will benefit the economies and communities in the states we serve. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

To be sure, the process for approving this Resource Plan has taken longer than anticipated, and our Current Preferred Plan charts a path that is longer still. We believe, however, that a fleet transformation of this magnitude and scope requires a deliberate process, and that our Current Preferred Plan is a direct result of our deep engagement with stakeholders throughout this process. We have completed an extensive analysis since our October Reply, as well as in response to the Commission's January 6, 2016 Order. We are therefore appreciative of this opportunity to share our analysis and additional information in support of our Current Preferred Plan and look forward to engaging with our stakeholders to continue the constructive dialogue that brought us this far.

II. BACKGROUND

The Company submitted its 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the Competitive Acquisition Process (CAP) proceeding, which was an outcome from our last

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Resource Plan.[1] The Commission made determinations in that proceeding in December 2014, which, due to the timing, we were unable to incorporate into our Initial Filing.

On January 16, 2015, the Commission issued a NOTICE requiring the Company to supplement its Resource Plan with a revised Preferred Plan that incorporated the CAP resource decisions. On March 16, 2015, we submitted a Supplement incorporating the CAP resources, the 187 MW Solar RFP Portfolio the Commission approved in February 2015 in Docket No. E002/M-14-162, an acceleration of small solar additions to reflect the Community Solar Gardens proceeding, and additional modeling and discussion that resulted from our stakeholder engagement.[2]

Parties commented on the completeness of our Resource Plan on April 3, 2015, and as part of our April 17, 2015 Reply to those Comments, we submitted a detailed five-year rate analysis of our updated Preferred Plan. On July 2, 2015, parties commented on our Preferred Plan.

On October 2, 2015, we replied to parties' comments, in part committing to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period and find ways to stimulate greater demand response with our customers – and in addition, outlined a Revised Proposal that would transition our system from coal generation, advance the acquisition of significant levels of renewable generation, recognize nuclear energy as a critical carbon-free baseload resource, and confirm our commitment to energy efficiency efforts. We also proposed to supplement the record with a detailed analysis supporting our Revised Proposal on January 29, 2016.

On January 6, 2016, the Commission approved our request to submit a Supplement on January 29, 2016, and set forth several informational requirements for the Supplement.[3] The Commission's Order additionally set a 30-day period within which the Minnesota Department of Commerce (Department) is to submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a Reply Comment period.

[1] Docket No. E002/M-12-1240.
[2] Docket No. E002/M-14-162.
[3] *See* ORDER REQUIRING SUPPLEMENTAL FILING, Docket No. E002/RP-15-21 (January 6, 2016).

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We note that in this Supplement, we have updated the naming of our scenarios from our past filings to properly reflect our Current Preferred Plan for which we seek regulatory approval as follows:

January 2, 2015 Initial Filing	March 16, 2015 Supplement	October 2, 2015 Reply Comments	January 29, 2016 Supplement
Reference Case	Reference Case	Reference Case	Reference Case
Preferred Plan	Updated Preferred Plan	Preferred Plan	Updated 2015 Plan
N/A	N/A	Revised Proposal	Current Preferred Plan

The Updated 2015 Plan in this Supplement is named as such because we allowed our updated modeling for this scenario to select Production Tax Credit (PTC)- and Investment Tax Credit (ITC)-priced renewable resources, as a result of the December 2015 extension of these Federal tax incentives. Implementing this change allows for improved comparability of our Current Preferred Plan and our previous filings in this proceeding.

III. CURRENT PREFERRED PLAN

Our Current Preferred Plan proposes a bold energy vision that is centered around four principles:

First, accelerate the transition from coal energy to lower- and zero-carbon resources. Specifically we propose to:

- Achieve a reduction of in carbon dioxide (CO_2) emissions of nearly 60 percent (from 2005 levels) by 2030,
- Cease coal generation at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and
- Advance the addition of substantial renewable generation (1,200 MW by 2020).

Second, preserve regional system reliability. The preservation of system stability will be critical as we make the transition from coal energy to renewables, and we will preserve it by adding natural gas to our system and by continuing to operate our carbon-free nuclear fleet. We therefore propose to:

- Reaffirm our commitment to nuclear energy through the current licenses of our existing units,
- Add a combustion turbine (CT) in North Dakota by the end of 2025, and

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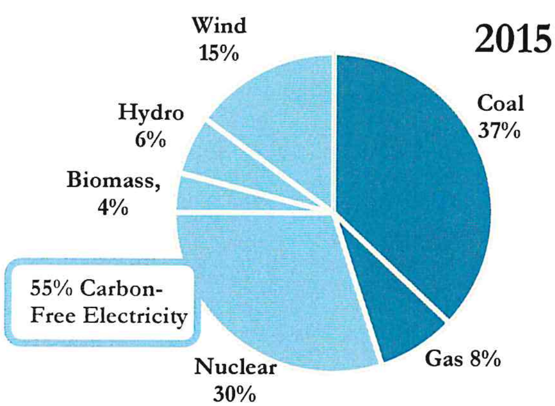
- Replace Sherco generation onsite with a combined cycle (CC) no later than 2026.

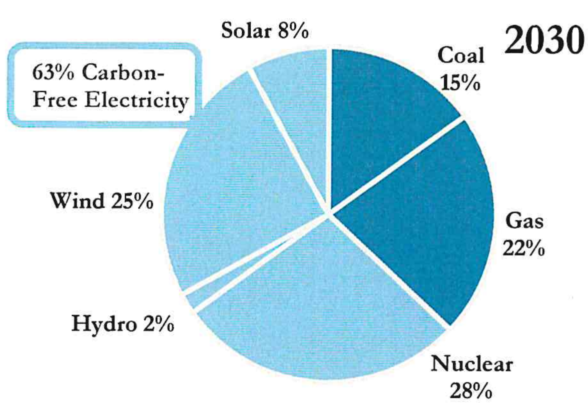
Third, pursue energy efficiency gains and grid modernization. We will continue our commitment to energy efficiency and new technologies and look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

Fourth, ensure customer benefits. We will work with our state Commissions, the Minnesota Pollution Control Agency (MPCA) along with its counterpart environmental agencies in our other states, and our stakeholders to ensure our customers get the full benefit of our proposal. Specifically, we will work to maximize the benefits of complying with the Clean Power Plan (CPP) State Plans for our customers and communities.

In short, our vision for the future is cleaner at an affordable price. While our Current Preferred Plan includes slight variations in the timing and siting of our resource additions as compared to the proposal we outlined in our October 2 Reply, the resulting 2030 energy mix is the same. Likewise, the primary resource changes – ceasing coal operations at Sherco Units 1 and 2 and more than doubling the renewable resources on our system – remain unchanged. Figure 1 below provides a side-by-side comparison of our energy mix in 2015 and 2030.

Figure 1: 2015 Energy Mix Compared to Current Preferred Plan in 2030





Our Current Preferred Plan dramatically changes the NSP System energy mix at the end of the planning period. Coal *reduces* from 37 to 15 percent; natural gas *increases*

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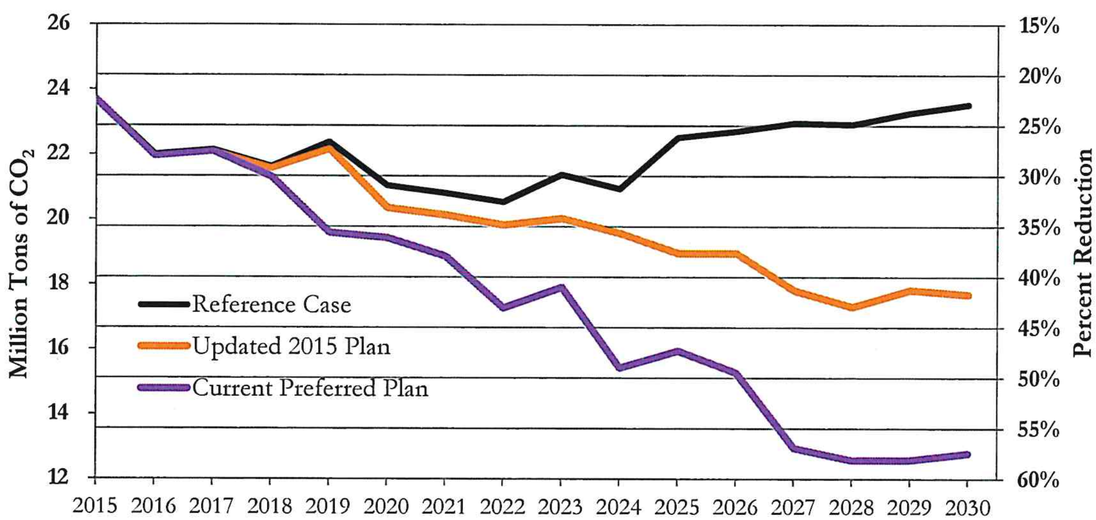
from 8 percent to 22 percent; solar, which makes up less than 1 percent of our energy mix in 2015, *increases* to 8 percent by 2030; wind *increases* from 15 to 25 percent; biomass and hydro *drop* to zero and two percent, respectively (due to contract expirations), while nuclear remains relatively constant at around 30 percent.

While our Updated 2015 Plan would have reduced our 2030 CO_2 emissions 40 percent from 2005 levels, our Current Preferred Plan puts us on an even greater CO_2 reduction trajectory. It will reduce CO_2 emissions by nearly 60 percent from 2005 levels by 2030, and it will move us significantly closer to achieving Minnesota's policy objective of an 80 percent reduction by 2050.

Figure 2: Projected Carbon Reduction from 2005 Levels



As discussed in greater detail below, we will achieve this dramatic reduction for just a fraction of a percent in incremental cost over our Updated 2015 Plan. Figure 2 below compares the projected CO_2 reduction of our Current Preferred Plan to our Updated 2015 Plan and the Reference Case.

It is also important to note that – given what we now know about the final CPP rules – the Reference Case would clearly not comply with the CO_2 reductions required of the Company under Minnesota's state plan to implement the CPP, nor may the Updated 2015 Plan. Further, we believe additional environmental compliance regulations will continue to place pressure on coal operations at Sherco. It is possible that installation of Selective Catalytic Reduction (SCR) equipment for tighter nitrogen oxide (NOx) control might be required near the end of the planning

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period.[4] We believe the actions we are proposing to take with our Current Preferred Plan positions us well to serve our customers into the future, and reduces the risk of potential future increased costs to maintain environmental compliance.

IV. MINIMUM SYSTEM NEEDS & EXPANSION PLAN

In this section, we discuss our strategy and proposal to address the future capacity deficit that results from our proposal to cease coal operations at Sherco Units 1 and 2, combined with a number of other large changes in our generating resources.

A. Load & Resources Analysis and Future Capacity Deficits

We provide in Table 1 below an updated Load and Resources (L&R) analysis that reflects our excess/deficit capacity position for the planning period, starting with the approved and existing resource additions reflected in our March 2015 Supplement. It also addresses the impact of the resource changes we propose as part of our Current Preferred Plan and summarizes our resulting capacity position through the planning period. Consistent with our January 2015 initial filing and all subsequent filings, we have used the same fall 2014 load forecast in this analysis, and maintained the same available resources to the Strategist model.

[4] In January 2016, the Eighth Circuit issued an opinion that upheld EPA's approval of the Minnesota regional haze plan, which did not require installation of SCRs on Sherco Units 1 and 2. The next regulatory developments that could include a requirement to install SCRs on these units will occur in the early 2020s, with installation potentially required in the late 2020s. The ozone standard, if made more stringent in 2020, might drive SCR installation in the 2027-2032 timeframe. The next round of regional haze planning is expected to occur in the early 2020s (EPA has announced plans to delay the 2018 deadline by 2-3 years), which could drive SCR installation in the late 2020s. We estimate that the capital cost for the installation of an SCR is approximately $250 million per unit in 2015 dollars.

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Table 1: Updated Load and Resources (MW UCAP[5])

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Existing/Approved Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Biomass/RDF/Hydro/Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar (1)(3)	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Aurora (3)	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions (2)(3)	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Resources – Existing & Approved	9,866	9,942	10,122	10,597	10,562	10,821	10,833	10,806	10,427	9,282	8,758	8,479	8,177	8,186	8,218
Capacity Excess/ Deficit March 16, 2015 Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**

(1) Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)
(2) Solar Additions represent the revised solar implementation due to Community Solar Gardens.
(3) Solar resources may be accredited up to 1 year earlier than forecasted based on changes to MISO's Business Practices for 2016/2017. This recent proposal has not been incorporated into the current L&R.

Current Preferred Plan – Existing Resource Changes	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Changes	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Capacity Excess/Deficit Jan 29, 2016	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

The "Capacity Excess/Deficit March 16, 2015 Filing" line in Table 1 represents our updated capacity position before adding any of the resource changes proposed in our Current Preferred Plan. Consistent with our March 2015 Supplement and our October 2015 Reply, it shows we expect to have sufficient capacity to meet our customers' needs through 2024. However, beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas Power

[5] MISO Unforced Capacity values, summer ratings.

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Purchase Agreements (PPAs) during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

The "Capacity Excess/Deficit Jan 29, 2016" line represents our position after applying the changes to existing resources that are part of our Current Preferred Plan.[6]

B. Current Preferred Plan Expansion Plan

Our Current Preferred Plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions in our Current Preferred Plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal ITC and PTC tax incentives, reducing the cost impacts of our Current Preferred Plan.

Our modeling results, described in more detail below, consistently show the addition of a CC in 2027.[7] We propose to locate the CC at Sherco because it will allow us to cost-effectively address the transmission issues identified by the Midcontinent Independent System Operator (MISO) Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

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[6] Unit retirements typically occur during a period of the three to nine months following the summer peak (months October-May). Commercial operation of replacement generation would commence between the months of October and March to maintain adequate capacity resources to meet MISO obligations.

[7] 2027 represents the year the CC resource is needed to address a capacity deficit; our Current Proposed Plan proposes that a replacement CC unit go in-service at Sherco such that there will be no gap in MISO capacity accreditation.

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In order to balance the perspectives of the stakeholders in the states we serve and maintain the benefits of an integrated system for all of our customers, we also propose to add a CT near our North Dakota load. This would address the reliability concerns of the North Dakota commission, while preserving the objective of both the North Dakota and Minnesota commissions for the Company to develop cost-effective generation proposals.

We show the resource additions we propose with our Current Preferred Plan in Table 2 below.

Table 2: Current Preferred Plan Expansion Plan[8] (MW ICAP[9])

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

Note: Resources are shown in their first full year of operation and will go into service the year prior.

We note that, with respect to solar, only the utility-scale resource additions proposed as part of our Current Preferred Plan are identified in this Expansion Plan. All small solar and previously-approved large solar resources are included as available resources in the L&R in Table 1 above. We discuss an update to our *small* solar forecast in Attachment B to this Supplement. To the extent small-scale solar additions out- or under-pace our updated small solar forecast, we will make corresponding adjustments to our large solar acquisition plan.

For reference, we provide updated Renewable Energy Standard and Solar Energy Standard compliance information, as well as the Expansion Plans for the Reference Case and Updated 2015 Plan in Attachment C.

V. RESOURCE PLANNING ANALYSIS

We provide as Attachment B details regarding our revised modeling assumptions, the scenarios and sensitivities analyzed, potential alternatives, an economic analysis,

[8] We clarify that we do not show the small solar additions, the 187 MW Solar RFP, or the competitive acquisition process resources in our Expansion Plan. These are included as existing/approved resources in the Updated L&R (Table 1).
[9] MISO Installed Capacity values.

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a discussion on our treatment of dump energy, and a methodology for our long-term rate impact projections – which we also summarize below.

We analyzed and compared five key scenarios in our analysis. We summarize the assumptions underlying these scenarios in Table 3 below.

Table 3: Summary of Scenarios Analyzed

Scenario Name	Description
Current Preferred Plan	• Ceases operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026 • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • All renewable costs updated for Federal ITC/PTC extension • Includes goal of 50 percent ownership of renewables • Adds Company-owned Fargo CT by 2025 and Sherco CC in 2027
Current Preferred Plan – All Generics	Same resource changes as Current Preferred Plan, with all generic thermal replacements
Reference Case	• Continues operation of Sherco Units 1 and 2 through the end of the planning period • Adds 400 MW of wind • Includes 400 MW of small solar additions • Includes 287 MW of large solar additions
Updated 2015 Plan	• Continues operation of Sherco Units 1 and 2 through the planning period • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • Updated for Federal ITC/PTC extension
North Dakota Plan	No additional renewables beyond currently committed 750 MW of wind; no assumptions changes.

We additionally considered the following alternative scenarios, which we discuss in Attachment B:

- A scenario that converts a Sherco Unit to a Gas Boiler, and
- A scenario that relies only on renewables.

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We also discuss Demand Response, Distributed Energy Resources, and Grid Modernization as Alternative Resources in Attachment F.

We evaluate these scenarios holistically by analyzing their environmental performance, strategic flexibility, and cost using a "Run Key" to summarize and compare key Strategist modeling metrics. The Run Key below includes the results of the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) analysis for each of our key scenarios to provide a reference point, but it also identifies key policy outcome metrics such as the reduction in CO_2 emissions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario. We note that the PVRR and PVSC results are the result of the Strategist model, which extends beyond the planning period to 2053.

Table 4: Run Key[10]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the strongest performance in terms of CO_2 reductions and renewable energy additions to the NSP System. The amount of renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership assumptions have shifted. Our Current Preferred Plan continues to provide the best value for our customers – achieving a balance between multiple objectives including reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and sustained reliability on our system.

[10] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch (Sensitivity T, explained in detail in Attachment B). Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

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A. Modeling Approach

This resource planning process begins the transformation of our generating fleet and signals a step change. It is additionally important to the states in the Upper Midwest Region in terms of alignment and compliance with the requirements of the CPP.

Over the last 20 years, resource plans have traditionally centered on meeting the needs of a growing system, or replacing smaller generators that have reached the end of their lives. In this Resource Plan, we are proposing to cease operation of 1,400 MW of coal generation at Sherco Units 1 and 2, which represents over 30 percent of our baseload generating capacity within the short 2023-2026 timeframe. Because these resources are concentrated in a single geographic area and proximate to other baseload generation, it is important to consider the location of replacement generation. This is a departure from traditional resource planning. In this instance however, the location of new or replacement generation requires additional consideration due to the potential impact to the system of removing such large important assets.

In considering the replacement of key components of an existing system, such as Sherco Units 1 and 2, the analysis must take into account a number of additional considerations that cannot always be captured in economic modeling or analysis terms. These other considerations are both technical and policy-based and include the security and reliability of the combined operation of the generation fleet and the transmission system.

We therefore conducted both traditional "generic" and location-specific Strategist modeling to inform the Current Preferred Plan we propose. We provide an optimized capacity Expansion Plan that considered only generic capacity alternatives as Table 5 below.

Table 5: Generic Unit Expansion Plan (MW ICAP)

Current Preferred Plan - All Generic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	690	690	230	460	-	-	2,070
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

These analyses resulted in the same conclusions in terms of the size and type of expansion resources and nearly identical in their timing. Both the site-specific and

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generic modeling shows a need for CT capacity in the 2025 timeframe and a CC addition in 2027.[11]

However, as part of the determination to cease coal operations at Sherco Units 1 and 2, we believe it is important and appropriate to also consider the impacts to the transmission system, the local community, state and federal policies, customer and community preferences and cost impacts. We have undertaken numerous studies to better understand these and other implications of our Current Preferred Plan. We believe our plan addresses these issues through our proposal to locate a CT in North Dakota by the end of 2025 and to locate a CC at the Sherco site in 2026 in order meet the capacity deficit resulting from ceasing coal operations at the second Unit.

Table 6 below outlines our capacity surplus/deficit position after applying the proposed resource additions of our Current Preferred Plan.

Table 6: Capacity Position with Current Preferred Plan Expansion Plan (MW UCAP)

Current Preferred Plan Proposed Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	0	0	0	0	0	209	261	314	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	178	178	178	266	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	0	0	219	219	219	219	219	219
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	439	1,097	1,316	1,535	1,535	1,755
Total Plan Additions	**0**	**0**	**0**	**0**	**0**	**328**	**439**	**491**	**596**	**1,365**	**2,105**	**3,087**	**3,516**	**3,516**	**3,735**
Revised Proposal Capacity Excess/ Deficit	**260**	**251**	**358**	**779**	**719**	**1,286**	**1,348**	**1,379**	**419**	**11**	**156**	**70**	**19**	**12**	**162**

As shown above, our resulting capacity position is a surplus through the planning period. In 2025 and beyond, our position reflects the expiration of significant capacity resource PPAs and peaking retirements we discussed above, resulting in our more narrow capacity position in the out-years of the planning period. Because

[11] The Department noted in its November 6, 2015 Comments that the Updated 2015 Plan we filed in our initial January 2015 filing and March 2015 Supplement did not include the addition of a CC resource prior to 2030. We note that at the time of those filings, we had not proposed to cease operation of any major generating units in the planning period like we now propose with Sherco Units 1 and 2. Ceasing coal operations of Sherco Units 1 and 2 results in the loss of nearly 1,400 MW of high-capacity-factor generation, which drives our need to add a CC resource prior to 2030. The model selects a natural gas CC unit in 2027 as a cost-effective resource addition to fill this gap. In addition to the favorable economics of adding a CC instead of a CT, at the time the second Sherco Unit ceases coal operation, we must also consider the technical system benefits the Sherco Units provide through their spinning mass to help maintain system reliability. We would not expect a simple-cycle CT to be online very often – nor would that be cost-effective as compared to a CC.

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these changes will occur in the out-years, we can continue to monitor our position over time and through the course of upcoming resource planning cycles. Addressing any potential necessary resource additions to meet capacity needs in the mid to late 2020s will be analyzed in our next Resource Plan filing, which we expect to occur by 2018.

B. Locational Analysis

As we have discussed, Resource Plans typically do not analyze location-specific alternatives. However, we believe that our Current Preferred Plan – as well as state and federal policies – present unique challenges that are not easily addressed through a traditional resource planning framework. Sherco Units 1 and 2 are critical components of our energy supply and the Upper Midwest grid. In addition to the energy and capacity they provide to customers, the sheer mass and operating characteristics of these Units provide important system benefits that impact customer reliability. For these reasons, and because the maintenance of system reliability is critical to serving the public interest, a location-specific analysis is essential. With respect to the CT needed in 2025, our North Dakota regulators have stated a preference, and the Company has agreed, to have dispatchable generation located close to our largest load centers in North Dakota, which we discuss in part 3 below.

In order to examine various aspects of the technical and policy-based issues associated with Sherco Units 1 and 2, we undertook several studies to understand the impacts of ceasing coal operations at Sherco Units 1 and 2. The studies we conducted to examine the implications of potentially ceasing coal operations at Sherco Units 1 and 2 are as follows: (1) a MISO Attachment Y2 Study, which assessed grid implications if Units were no longer operating; (2) an Xcel Energy Transmission Reliability Study, which assessed grid implications of replacing all or a portion of the Units' capacity at other locations on the NSP System; (3) a Black Start Plan Analysis that assessed the implications associated with altering our system restoration path and would be necessary because the Units currently play an essential role in the event of a major system outage; and (4) a socioeconomic analysis conducted by the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth.

We discuss each of these location-specific resources below.

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1. *On-Site Combined Cycle Unit at Sherco*

First, we are proposing to construct a 786 MW (ICAP) natural gas CC onsite at the current Sherco site. Because we are not replacing all of the MWs that result from ceasing coal operations at Units 1 and 2 with the CC unit, there will be additional interconnection injection capabilities at the site, which we are proposing to partially utilize by also constructing photovoltaic (PV) solar generation on existing property.[12]

As outlined in Attachment B, our updated modeling for this Supplement includes several options for a CC: (1) at the site of the current Sherco 1 and 2 Units, (2) at a generic brownfield site, and (3) at a generic greenfield site. We developed the option of onsite replacement to incorporate into our Strategist modeling an economic analysis of locating generation at the Sherco site. We believe there are significant benefits associated with siting the CC at the Sherco site, which we discuss below.

a. Benefits of Onsite Generation at Sherco

There are number of benefits to locating a replacement CC at the Sherco site. Importantly, our Strategist demonstrates that the addition of a CC unit onsite at Sherco is part of a least-cost capacity expansion plan. However, not all relevant factors are easily converted to an economic basis for inclusion in Strategist. For instance, there are benefits to using existing infrastructure and an existing brownfield site that do not easily reduce to economic terms, including the fact that the transmission grid has been studied, designed, engineered and operated for decades to provide a high degree of reliability and resiliency for customers by incorporating significant generation injection at the Sherco site. Similarly, it is important to consider that our host community of Becker, Minnesota and the greater Sherburne County area has come to depend on local employment opportunities, property taxes, and other economic benefits associated with the existing units. We discuss these factors below.

Use of Existing Infrastructure. As an existing brownfield generation site, the Sherco site offers a number of advantages over new greenfield sites, both in terms of operations and cost. For example, we can use our existing interconnection rights and existing substation and transmission outlet capacity once Units 1 and 2 cease

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[12] We have identified two areas on the existing Sherco site for solar development. One location would be atop the closed and capped ash ponds 1 and 2 and the second would be on open land on the north side of the Mississippi River between the Sherco plant and the Monticello plant.

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coal operations. The existing Sherco site also comprises sufficient available land to site a CC unit and is already permitted for a large industrial generating facility. Further, existing water and wastewater treatment facilities can support the proposed CC unit, and existing facility staff, administration, warehousing, and maintenance facilities can likewise be utilized. Finally, the site's water allocation is sufficient for cooling approximately 2,300 MW of generation (the current combined installed capacity of Sherco Units 1, 2 and 3), which means that once Units 1 and 2 cease coal operations, an allocation equivalent to approximately 1,400 MW will become available. Consequently, portions of the Unit 2 cooling system can be reused by the new CC facility, allowing the replacement CC at the Sherco site to be wet-cooled, improving both performance and cost.

The System is Designed to Reliably Operate with Significant Generation Injection at Sherco. From the technical studies conducted by MISO and the Company we concluded that we can avoid anticipated impacts on the electric transmission system and related costs by replacing generation at Sherco. In contrast, siting replacement thermal generation at other locations on the NSP System have disadvantages compared to siting a CC at Sherco, including a significant level of uncertainty with regard to final costs and performance. The *Xcel Energy Transmission Reliability Study* confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Unlike an onsite CC that will have injection capability and interconnection rights, replacement generation at other locations will be subject to the MISO generator interconnection process, and may incur additional network upgrade costs beyond those we have identified. The MISO interconnection queue has changed significantly since these technical studies were initiated in early 2015. Since March 2015, requests to add nearly 10,000 MW of wind have entered the queue in the Iowa, Minnesota, North Dakota, and South Dakota area.[13] Nearly 70 percent, or 7,000 MW have paid all required study deposits and achieved milestones, qualifying them to participate in MISO's upcoming interconnection studies. This significant

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[13] MISO Generator Interconnection Queue is located at: https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx.

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number of projects that have entered MISO's interconnection queue creates uncertainty with respect to the identified transmission impacts and associated interconnection costs. Replacement generation at the Sherco site, as we have proposed, has the added benefit of not being impacted by this uncertainty.

Locating a CC at the Sherco Site Avoids Significant Transmission Costs. Our technical studies each identified costs associated with siting replacement generation at locations other than Sherco. We summarize the study results below and provide a full summary of the studies and our conclusions as Attachment D.

MISO Y2 Study. MISO concluded that retirement of Sherco Unit 1 and Sherco Unit 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for Units to be designated as System Support Resources (SSR). Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Units 1 and 2, if replacement generation is not located at Sherco. Specifically, the MISO Y2 study identified significant thermal and voltage violations in the Twin Cities if Sherco Units 1 and 2 are retired. The voltage violations impact our Monticello Nuclear Plant's operation and Nuclear Regulatory Commission (NRC) requirements. Both the thermal and voltage violations would need to be addressed through transmission investment in the Sherco area, regardless of the location of any replacement generation at an alternative site before the units could cease operation. Additional transmission upgrades that may be necessary due to the location of replacement generation, were not within the scope of the MISO Y2 study, but were studied in the Xcel Energy Transmission Reliability Study we discuss below. We provide this study report as Attachment D1.

Xcel Energy Transmission Reliability Study. Our study, conducted in conjunction with Siemens Power Technologies International, involved a full thermal analysis, full voltage analysis, and transient stability analysis. As noted above, it confirmed that the existing transmission system with significant generation injection at Sherco works well, and that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location. We provide these study reports as Attachments D2 and D3.

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Black Start Plan Analysis. Our analysis of our current Black Start Plan examined impacts if our current Sherco Units 1 and 2 target units cease coal operations.[14] Our analysis concluded that our proposal to construct a natural gas CC unit at the Sherco site would provide for use of the current and most efficient restoration path. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities and results in a longer restoration period, which is of greatest concern in winter/cold months. We have included the approximate costs of altering our restoration path as part of the costs associated with siting the 2027 CC at alternative locations.

If replacement generation is not sited at Sherco, we must mitigate the reliability issues our technical studies identified. For example, the Monticello Plant cannot operate if its voltage is outside the permissible range. As discussed further in Attachment D, we have determined that the best option to address these issues is to convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser (SC). Importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. These additional costs stem from transmission upgrades and the need for additional equipment onsite at Sherco and other locations on the NSP System. We refer to these costs as "leave-behind" costs, which are therefore appropriately added to the cost of any combined cycle generator at an alternative location. The total leave-behind costs are shown below in Table 7.

[14] A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full or partial black out. Black Start Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO.

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Table 7: Leave-Behind Costs – PVRR
($Millions – 2015)

Cost Components	PVRR
[TRADE SECRET BEGINS…	
Installation of Synchronous Condenser	
O&M for Synchronous Condenser	
Upgrade Brainerd - Riverton 115 kV Line	
Rebuild Helena - Scott County 345 kV Line	
Installation of Additional Capacitors	
New Blackstart Path	
…TRADE SECRET END]	
Total	**$150**

Retiring Sherco Units 1 and 2 would have negative impacts on employment, GDP, and disposable personal income in Sherburne County. We understand the Commission has previously expressed interest in understanding the socioeconomic impacts on the Becker area, so therefore commissioned a socioeconomic study. We summarize the study below and provide a full summary and the study itself as Attachments G and G1, respectively. This Study assessed impacts on employment, Gross Domestic Product (GDP), and disposable personal income on the locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates resulting from Unit retirement and replacement at an alternative location. The scenarios analyzed in the Study, included various potential Unit retirement dates and a scenario that included the replacement of the two Sherco Units with one CC at the Sherco site and one CC located in Dakota County. The Study found that all early retirement scenarios, when compared to a baseline where the Units continued operations through the planning period, result in moderately slower growth in the Minnesota economy. The closure of the Units showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, if the generation is replaced elsewhere in Minnesota, those impacts are partially offset by positive economic impacts in the replacement location – mitigating on an overall state-level, the negative impacts. While the Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 dates fall within the range of scenarios analyzed.

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As we stated in our October 2, 2015 Reply, ceasing coal operations at Sherco Units 1 and 2 will impact our employees and their families, the City of Becker and surrounding area, and Liberty Paper, which relies on steam from the Units for its operations. Charting a path certain for these stakeholders particularly, will provide an 8-10 year transition period, and with our proposal to site replacement generation onsite, will promote economic development, and reaffirm our commitment to central Minnesota. We are committed to mitigating impacts on our employees by working closely with our International Brotherhood of Electrical Workers union local to successfully manage the transition. Finally, our proposed onsite CC will provide additional options to continue to supply steam to Liberty Paper, who is a valued Xcel Energy customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

b. Costs of Onsite CC

Generating Equipment. We developed the costs for the onsite CC generation based on the installation of a 2x1 CC wet-cooled facility in 2026, which would begin commercial operation prior to the second Sherco Unit ceasing coal operations. The summer-rated capacity of the CC facility would be approximately 763 MW UCAP (786 MW ICAP). We developed our initial capital cost estimates for the onsite Sherco CC by adjusting the cost of the generic CC used in the modeling throughout this proceeding for the site-specific benefits associated with utilizing existing infrastructure. Because of the site's available water allocation, the replacement CC at the Sherco site is to be wet-cooled, improving both performance and cost. We expect the initial capital cost of the generic CC to be approximately **[TRADE SECRET BEGINS... ...TRADE SECRET ENDS]** higher than our proposed onsite CC at Sherco.[15]

Because we have not obtained formal estimates for the turbine equipment or performed detailed engineering, we have developed delta cost estimates in order to compare the unique attributes of locating a CC onsite and at alternative locations. The ultimate project pricing will vary based on the final design definition, equipment price negotiations, contractual commercial terms, and other factors.

[15] 2015 dollars on a PVRR basis. We use the same Fixed Operating and Maintenance (Fixed O&M) costs and on-going capital costs as the generic CC alternative.

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Natural Gas Infrastructure. Our proposed CC unit at Sherco will be fueled entirely by natural gas. Even though the community of Becker enjoys the benefits of heating their homes and commercial businesses with natural gas from Xcel Energy, there is not currently adequate pressure and capacity with the existing natural gas infrastructure to serve a new CC unit.

Therefore we performed a high-level cost analysis of bringing new natural gas infrastructure to serve the proposed CC unit at Sherco, so as to estimate a gas demand charge, which we estimate to be approximately **[TRADE SECRET BEGINS…**
… TRADE SECRET ENDS] to the Sherco site. We based this estimate on our experience in designing, engineering, and constructing competitive natural gas infrastructure, which we do through the use of a competitive bidding process for each component or phase of the construction process. We also benchmarked the costs of some of our past significant, similar construction projects within the industry to ensure that our estimates are in-line with other contractors. We will leverage our knowledge, expertise, and competitive advantage to minimize costs for our customers. We note that we are also assessing opportunities arising from the new natural gas infrastructure that may afford numerous adjacent Minnesota communities along the proposed route greater access to a natural gas supply.

In determining the cost to construct the natural gas infrastructure, there are two primary aspects to consider: (1) the cost of the facilities from the source of supply to the new market (in this case, Sherco); and (2) the costs from the source of the supply, to ensure the new infrastructure has adequate pressure and capacity. We evaluated several alternatives to determine the best way to source the new supply to Sherco.

The associated capital cost estimates incorporated into our modeling are indicative. The cost estimates we provide for this analysis are based on current system constraints and associated capital construction project costs required to alleviate those constraints, which are subject to change. We believe however, they are reasonable and appropriate for planning purposes.

Transmission Infrastructure. As discussed above, because the new CC unit can use existing transmission interconnection rights, there will not be any associated network upgrade costs. Generators located at other locations would have to go through the MISO generator interconnection process in order to obtain

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interconnection rights, and may additionally incur transmission upgrade costs. We estimate onsite substation modifications to cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. We note that we are proposing a 786 MW CC unit, which is below the current 1,400 MW capacity and associated energy output of Sherco Units 1 and 2. We also intend to locate a portion of the proposed solar resource additions at the Sherco site.

We outline the cost deltas from a generic CC on a PVRR basis below.[16] This approach allows us to show the site-specific costs associated with locating a CC at the Sherco site and to compare the site-specific costs of onsite replacement to alternative site locations.

Table 8: Site-Specific Cost Comparison – Onsite CC Replacement ($Millions – 2015 dollars)

[TRADE SECRET BEGINS…

PVRR Delta from Generic Unit	
Site Specific PVRR Costs	
Transmission Facilities[17]	
Gas Demand Charge	
…TRADE SECRET ENDS]	
Total	***$155***

2. *Alternatives to Retirement and Onsite Replacement*

We considered several alternatives to our proposed partial replacement of the Sherco Units with an onsite CC generating unit. In addition to examining another brownfield site and a greenfield site, we explored alternatives such as all renewables and alternative resource such as Distributed Energy Resources, Demand Response, and grid efficiencies. We discuss the brownfield and greenfield alternatives below and the renewables and alternative resources in Attachments B and F, respectively.

[16] All costs have been discounted to 2015 dollars. Actual costs will be influenced by the year in which they are incurred. Therefore, in order to compare these estimates with future expenditures, these estimates must be escalated.
[17] The substation modification costs noted above are included in the delta from the generic unit.

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Our Current Preferred Plan does not propose to replace all of the Sherco Units 1 and 2 capacity with gas-fired generation. As explained in our October Reply, we are committed to reducing the CO_2 emissions of the NSP System and advancing the acquisition of significant levels of renewable generation. Thus, we plan to acquire significant amounts of wind and solar resources to help meet our future energy and capacity needs. Below we discuss alternatives to replacing the Sherco Units with an onsite CC, in conjunction with additional renewable generation.

a. Offsite Brownfield CC

The Offsite Brownfield CC alternative included in our updated modeling is based on representative costs associated with locating a CC at the existing Black Dog site in Burnsville, Minnesota. Black Dog coal-fired Units 3 and 4 were suspended in early 2015, and the coal and ash storage and handling areas are currently being remediated and closed. When this work is complete, there will be sufficient land area protected from the 100-year flood plain to construct a 2x1 CC facility and 345 kV switchyard. The Twin Cities 345 kV ring is nearby – approximately just one-half mile from the plant site – and could be used as the transmission outlet from the new facility, making this site an appropriate proxy for an off-site brownfield CC.

Current information indicates that a new 345 kV substation would be required to accommodate the installation of this CC Unit. However, as noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility are based on anticipated demand charges for use of the Northern Natural Gas (NNG) system. The site has significant water allocations and would be able to support a wet-cooled CC facility through conversion of the existing Black Dog facility from a once-through cooling system to a cooling tower system.

Similar to the onsite Sherco alternative, locating generation on a brownfield site results in savings related to transmission upgrades, gas infrastructure, and other existing infrastructure such as land, access to water supplies, and existing maintenance facilities and facility staff.[18] As we did for the onsite CC alternative, we have adjusted the generic CC cost to incorporate the advantages of a brownfield location. However, this analysis must include the costs to mitigate the loss of

[18] While the Brownfield site is located near existing transmission facilities, the availability of interconnection capacity is uncertain until the MISO interconnection process is complete.

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generation at the Sherco site. Table 9 below summarizes the cost deltas from a Generic CC in the representative Offsite Brownfield CC alternative:

Table 9: Site-Specific Cost Comparison – Offsite Brownfield Alternative ($Millions – 2015 dollars)

	Brownfield Alternative	Sherco CC
	[TRADE SECRET BEGINS...	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		...TRADE SECRET ENDS]
Total	***$221***	***$155***
PVRR Delta from Sherco Site	**$66**	

The Offsite Brownfield CC results in approximately $66 million in additional costs as compared to siting the CC at Sherco. In addition, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

b. Offsite Greenfield CC

We also included an Offsite Greenfield CC alternative in our updated modeling. The Greenfield site is based on a location in Western Minnesota near existing transmission and interstate natural gas lines. Water resources are limited, and it is expected that such a facility would have to be dry-cooled to minimize water use. We have evaluated the costs for transmission interconnection and upgrades and natural gas infrastructure, and included those costs in our analysis. As noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility assume construction of new infrastructure. Table 10 below summarizes the costs included in the representative Offsite Greenfield alternative:

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Table 10: Site-Specific Cost Comparison – Offsite Greenfield Alternative ($Millions – 2015 dollars)

	Greenfield Alternative	Sherco CC
	[TRADE SECRET BEGINS...	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		...TRADE SECRET ENDS]
Total	*$172*	*$155*
PVRR Delta from Sherco Site	$17	

The Offsite Greenfield CC results in approximately $17 million in additional costs as compared to siting the CC at Sherco. The Offsite Greenfield alternative is a CC located along the Brookings 345 kV line, so will use available transmission outlet capability that could otherwise be used for renewables in the wind-rich western and southwestern areas of Minnesota, which may increase transmission upgrade costs for those types of facilities during the planning period. These costs are difficult to quantify, but could be significant. As with the offsite brownfield alternative, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

c. Conclusion

The addition of a CC at the Sherco site is a critical part of our proposal to cease coal operations of Sherco Units 1 and 2 and ensure reliability at a reasonable cost to ratepayers. By locating a CC at Sherco, we eliminate the need to address the issues identified in the MISO Y2 Study, avoid the costs associated with locating the CC offsite, support economic development in the Becker area, and mitigate reliability risks and implications stemming from the shutdown of two of the largest baseload generating units in the Upper Midwest. Our Strategist analysis, transmission studies, and socioeconomic studies support this proposal, and we believe it best advances the interest of our customers, as well as the Becker economy and our employees.

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3. *North Dakota Combustion Turbine*

a. Policy Considerations

Our regulators in North Dakota have stated that they believe it would be in the best interest of our customers to have cost-effective, dispatchable generation located in North Dakota and close to major load centers in that state. In an effort to balance the interests of the states that we serve and to maintain the benefits of an integrated system for all of our customers, the Company set out to find CT options that address the reliability concerns of the North Dakota commission, while preserving the Company's desire to develop cost-effective generation alternatives. To that end, we embarked on a review of possible generation sites located reasonably close to Company load centers in North Dakota that could also satisfy traditional resource planning criteria. We discuss the results of that review below.

b. Alternative Sites

In our review, we identified two potential areas where a CT could be located that satisfies the common desires of Minnesota and North Dakota commissions for a selection of a cost-competitive and reliable generation resource. The two locations include an area west of Fargo (Fargo CT) and a location in the south-central portion of North Dakota (South Central CT). These two sites appear to satisfy the traditional resource planning criteria, while also aligning policies regarding energy security, reliability, and energy policy objectives.

Recognizing that the Company is the largest utility in North Dakota, and that the Company does not yet have any dispatchable generation (either owned or in the form of a PPA) in that state, we decided to start the search for potential generation sites with a focus on North Dakota. While a formal project development and engineering estimate has yet to begin, it appears that both sites have adequate access to natural gas supplies and transmission injection capacity as well as available land and workforce.[19]

We also looked at alternative locations in Minnesota and Wisconsin. The potential site in Minnesota included the development of a second CT at our existing Black

[19] While generators at both sites would be required to go through the MISO generation interconnection process, a CT has an advantage over a CC as it is a peaking resource and will only be studied on-peak where we believe significantly more transmission capacity exists in the locations considered for the alternative CTs.

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Dog site. Consistent with the Black Dog 6 CT that was recently approved by the Minnesota and North Dakota commissions, the Black Dog 7 site takes advantage of an already owned brownfield location with access to transmission and an existing workforce.

While we also identified a possible site for a CT in Wisconsin, we did not perform any additional development work on that site at this time due to the need for more robust transmission studies. While all of the sites in Minnesota also appear to satisfy traditional resource planning criteria, they obviously do not address the concerns about the lack of dispatchable generation near the Company's North Dakota load.

Table 11 below contains a summary table of the key resource planning characteristics of the three locations investigated by the Company.

Table 11: Summary of CT Alternatives

	Fargo	South Central	Black Dog 7
Generator	Generic 230 MW Dual-Fuel CT[20]	Generic 230 MW Gas-Fired CT	Generic 230 MW Gas-Fired CT
Gas Supply	Lateral Gas Pipeline	Lateral Gas Pipeline	Demand Charges on NNG
Transmission	345 kV Interconnection Facilities	345 kV Interconnection Facilities and 230 kV Line Upgrades	345 kV Interconnection Facilities

Since both the Minnesota and North Dakota commissions have a keen interest in determining if the proposed CT alternatives are cost-effective and reliable when compared with other alternatives, we have performed an initial analysis of the three sites identified by the Company. While we have not obtained formal estimates on the turbine equipment or performed detailed engineering on the projects, as with the analysis of CC site alternatives above, we developed delta cost estimates from the generic CT unit used in the modeling. The deltas show the site-specific cost differences for each location based on the unique factors of the generator site, including transmission access, gas supply costs, and operation and maintenance costs. We summarize this cost comparison in Table 12 below.

[20] We are proposing oil back-up at the Fargo site to allow for the unit to have firm accreditation year-round, similar to the Company's Angus Anson Units 2 and 3 in South Dakota.

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Table 12: Site-Specific Cost Comparison – CT Alternatives ($Millions – 2015 dollars)

	Fargo	South Central	Black Dog 7
	[TRADE SECRET BEGINS...		
PVRR Delta from Generic Unit			
Site-Specific PVRR Costs			
Transmission			
Annual Gas Demand Charge			
			...TRADE SECRET ENDS]
Total	*$79*	*$106*	*$85*
PVRR Delta from Fargo Site		$27	$6

This preliminary cost analysis shows that the Fargo CT site is cost competitive to the Black Dog 7 CT project, while the South Central North Dakota CT site is somewhat higher in cost.

4. *Conclusion*

The impact to our customers, reliability, the transmission system, the local community, and state and federal policies are all appropriately considered as part of the determination to cease coal operations at Sherco Units 1 and 2. We have undertaken numerous studies to better understand the implications of our Sherco proposal and believe our Current Preferred Plan addresses these issues in a cost-effective manner. For these reasons, we believe our location-specific expansion plan is in the public interest.

C. Ownership of New Resources

We propose to own the Sherco and North Dakota natural gas plants, along with a portion of the renewable generation additions contemplated by our Expansion Plan. Our ownership of these assets is a critical component of our vision, as it will result in a balanced generation portfolio that will minimize customer costs and mitigate risk of future cost increases. We discuss the specific benefits of ownership in greater detail below and explain how our customers will realize these benefits.

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1. *Proposed CC at Sherco Site and CT in North Dakota*

By owning the CC that we propose to add at the Sherco site, we are able to use our existing site and interconnection rights, we will continue to employ current Sherco-based Xcel Energy employees, we will preserve options to continue to supply a large customer with steam, and we will avoid additional cost and risks associated with modifying our Black Start Plan. Our ownership of the CC allows the Company to secure these important benefits for our customers, and we believe it is in the public interest.

Ownership of a CT in North Dakota provides important options to be able to expand generation onsite in the future to serve our customers in the Red River Valley region. Expansion options could include a partnership with another utility or converting the facility to a CC. If a third-party owns the CT, these options may not be available or may be more expensive and difficult to implement. In addition, the North Dakota commission has expressed a preference for an ownership model to a PPA model. Thus, ownership best allows us to provide reliable service to our customers in the region.

2. *Proposed Renewable Resources*

An important and significant component of our proposed plan is the accelerated acquisition of renewable resources. Table 13 below, shows our proposed renewable resource additions during the planning period.

Table 13: Proposed Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800

As discussed below, we propose that approximately half of the renewable additions be Company-owned resources, which we have assumed in the Strategist modeling supporting our Current Preferred Plan. A balance between PPA and Company-owned resources ensures that our customers obtain the benefits of each ownership structure, and that the cost and risks are appropriately balanced. Table 14 below shows the renewable additions that we propose to own.

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Table 14: Proposed Owned Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	100	-	100	50	50	100	50	50	-	200	-	-	700
Wind	-	-	-	-	400	-	-	200	-	-	200	200	-	-	-	-	1,000

Table 15 below summarizes our current portfolio of wind resources, which contains approximately two-thirds purchased wind resources and one-third owned resources.[21]

Table 15: Current Wind Generation by Asset Type (MW)

Asset Type	Capacity Type	MW	Percent of Total
Owned	Nameplate	851.5	33%
PPA	Contracted*	1,759.9	67%

** Since we contract for a specific amount of energy, we do not maintain nameplate capacities in our records.*

Our solar portfolio, which primarily includes the Aurora project and the 187 MW resulting from our 2014 RFP is exclusively PPAs and third-party providers.

While we will also continue to acquire renewable resources through PPAs and third-party providers, concentrated efforts to improve the balance of our portfolio through expanded ownership of renewable resources is appropriate and necessary to minimize customer costs and balance risks. In this way, we believe our plan will capitalize on the strengths of each structure while ensuring that resources are acquired at reasonable costs for our customers.

Understanding the customer impacts of utility ownership versus purchased power is important to assessing the benefits of a balanced portfolio. While utility participation in competitive bidding may on its face be a means for such comparison, we have found that it is difficult to obtain an accurate assessment of the full economic and life-cycle costs and other benefits solely through this perspective. We believe a framework that allows the relative costs and benefits of our future acquisition of renewable resources to be assessed is a more reasonable and appropriate approach.

[21] Includes the most recently-approved Odell, Courtenay, Pleasant Valley, and Border Winds projects.

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Given similar access to suppliers, sites, and transmission, we also believe it is reasonable to assume that the capital costs of renewable development will be very similar between a utility-owned project and third-party development; thus, customer impacts will stem from the respective cost recovery mechanisms of the projects rather than development costs. Key issues affecting customer costs include differences regarding contract versus asset life and balance sheet impacts. We discuss each of these issues below.

3. Contract vs. Asset Life

Asset life affects the comparative costs of utility-owned versus purchased wind energy. A PPA is for a specific term that is likely shorter than the useful life of the facility. After the expiration of a PPA, the Company must return to the marketplace to procure replacement renewable energy. The market price of this replacement renewable energy will be based on a number of factors, including:

- Costs for new wind and solar generating facilities,
- Costs of capital,
- Market prices for electricity,
- The value of embedded environmental attributes, including Renewable Energy Credits (RECs) and Emission Rate Credits (ERCs) under the CPP, and
- PTC and ITC status and values.

Under utility ownership, by contrast, the asset remains in the utility portfolio until it is retired. Customers benefit when the actual useful life of the asset exceeds a comparable PPA's term, as they will continue to receive the capacity and energy for a longer period of time, lowering lifecycle costs. While we have modeled a 25-year life for both utility-owned and PPA renewable resources, there is the potential that the 25-year PPAs may not be widely available and also that utility-owned assets will exceed a 25-year life.

Based on our 2013 Wind RFP and 2014 Solar RFP, wind projects typically have PPA terms of 15 to 20 years with an asset life of 25-30 years, and solar projects typically have PPA terms of 20 to 25 years with an asset life of 25-30 years. While utility-owned assets may require refurbishment to extend their useful life, we would expect such costs to be lower than the market price of replacement renewable energy that would be required when a PPA expires. Life extension options for utility assets have traditionally offered cost-savings benefits for customers.

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The tradeoff for these long-term benefits is that relative to a PPA, utility-owned assets generally have higher costs in the early years when the rate base value is highest. For wind resources, direct pass-through to customers of the PTC will help offset this impact. Although there is no guarantee that ownership will provide significant present value savings compared to a PPA, it is certain that by using only PPAs to meet renewable resource needs, customers lose the opportunity for overall longer-term savings from the value of depreciating plant.

Figures 3 and 4 below illustrate the potential benefits provided by Company ownership of wind and solar resources. Customers could obtain significant benefits as shown by the shaded areas in the below figures.

Figure 3: Benefit Provided by Ownership
Illustrative 200 MW Wind Resource

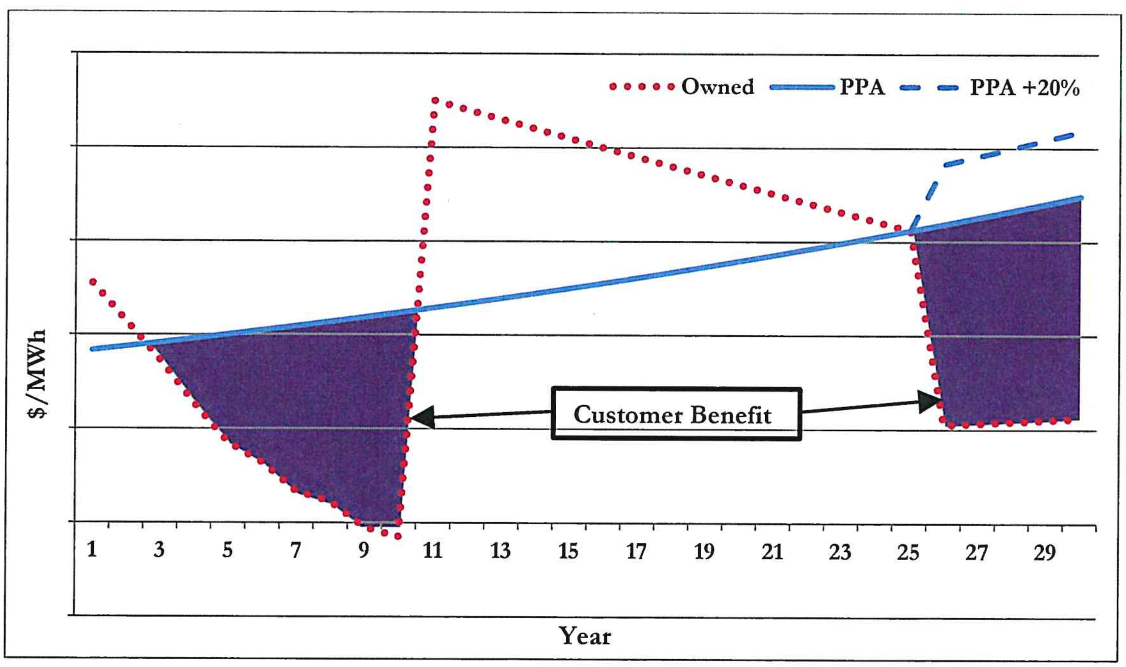

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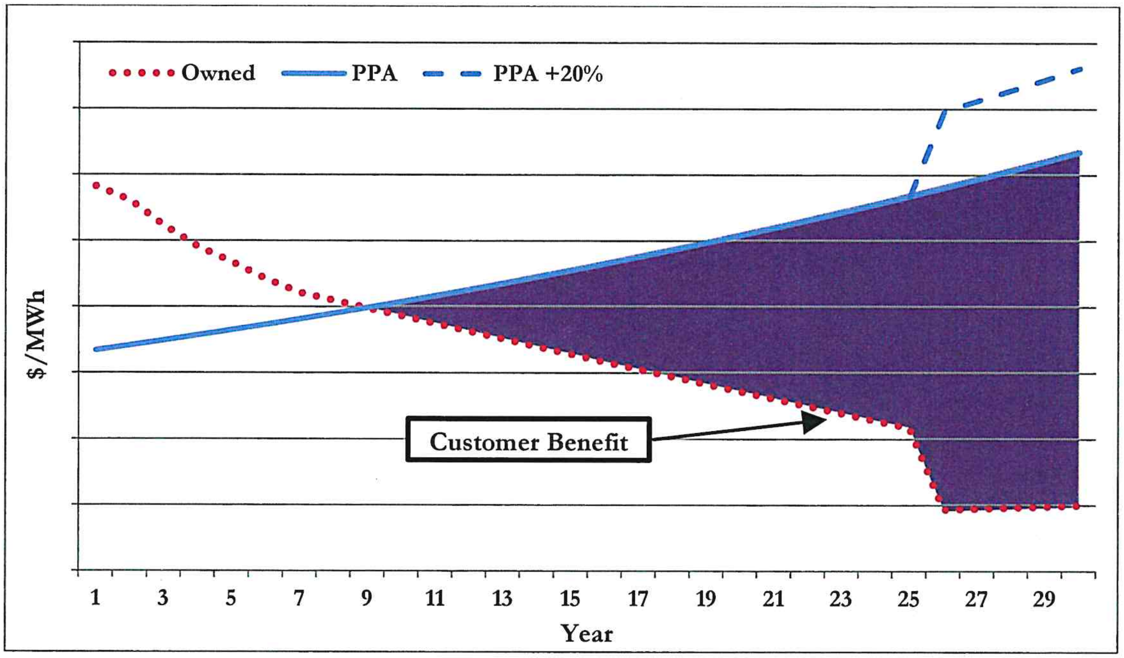
Figure 4: Benefit Provided by Ownership
Illustrative 50 MW Solar Resource



The cost per MWh for the PPA and utility-owned resources were derived from the wind and solar resources included in our modeling which assume a 25-year life. The utility-owned wind resource costs show additional reductions in the first 10 years due to the PTC while the PPA wind costs spread the benefits over the PPA term. The solar resources include the benefits of the ITC. These benefits are not achieved under a PPA structure, as the PPA must either be renegotiated or replaced when the contract term expires. In addition, ownership may help smooth rate impacts as the renewable resources procured in the near term will experience several years of depreciation prior to our projected procurement of significant additional resources in the mid-2020s.

4. *Balance Sheet Impacts*

Debt accounts for approximately half of the Company's total capital structure. The cost of debt is highly dependent on the credit profile of the utility, and higher-cost debt results in higher costs for customers. Generally speaking, companies with higher percentages of debt in their capital structure are considered riskier and pay higher rates for this debt, due to concerns that the company may be over-leveraged.

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PPAs are obligations the utility must pay that are viewed as additional debt on the utility's balance sheets – affecting the credit profile of the utility, which in turn affects costs to customers. Credit rating agencies also consider off balance sheet obligations in their risk assessment to determine credit ratings. These agencies impute additional debt to a utility's balance sheets based on the size, type, and terms of PPAs, thus increasing the financial leverage and risk of a company and also its cost of debt.

Likewise, auditors scrutinize PPAs to evaluate the effects of imputed debt and the lease-like characteristics of PPAs to ensure fair representation of obligations and creditworthiness on financial statements. Imputed debt and lease accounting effects have the potential to add significant debt-like obligations to the balance sheet used to determine the credit rating for the Company. In contrast to a PPA, owned projects are financed through both equity and debt which allows us to maintain our capital structure.

These issues highlight some of the implications of PPAs. Imputed debt has the potential to raise costs for customers in one of two ways: (1) through higher debt costs, as already described; and (2) through additional equity costs, as the utility may require additional equity in its capital structure to compensate for the additional debt-like obligations associated with the PPAs. Because these impacts affect the overall capital structure and capital costs, the costs of financing other utility infrastructure requirements are higher than they otherwise would be. While wind and solar PPAs are viewed more favorably than more traditional PPAs due to their energy-based payment structure, they nonetheless have imputed debt implications for the utility that will, over time, raise costs for customers.

Finally, we believe there are additional factors to consider when determining an appropriate balance between owned and purchased assets:

Potential unknown valuable attributes. If and when new value is attached to attributes of renewable resources (such as renewable energy credits were in the past), ownership of resources ensures that customers benefit from those attributes. If the resource is purchased through a PPA, those attributes may not accrue to customers. In the Silent REC Docket, the Commission was presented with this issue.[22] Under a PPA structure, there is uncertainty and risk associated with the allocation of any new valuable attribute that was not anticipated by the PPA. If the resource is utility-

[22] *See* Docket No. E002/M-08-440.

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owned, however, our Commissions will have increased control over how the value associated with any attribute is allocated.

Increased diversity in supply portfolio. Our proposed portfolio reflects an appropriate resource mix that achieves compliance with regulatory requirements, such as the CPP, and state policy objectives. Investors would be appropriately concerned if a utility's owned assets did not include the renewable assets required to achieve compliance. Thus, the financial health of the utility can be affected both by the aggregate mix of resources used to supply customers and the Company's mix of owned resources.

Complement to Xcel Energy's overall business plan. A key component of our overall business plan is environmental leadership. We believe that a balanced, clean energy portfolio is in the long-term best interests of our customers. Ownership of renewable resources is one means of demonstrating this commitment for our customers, regulators, and shareholders. We believe we must increase our investment in owned renewable resources to help maintain our financial health, minimize risks through a balanced portfolio, and reduce costs for our customers.

D. Proposed Acquisition Process

In this section, we describe our plan to acquire the replacement generation resources that will be necessary to address the capacity deficit created by our proposal to cease coal operations at Sherco Units 1 and 2.

Consistent with the Commission's January 6, 2016 Order, we will not submit a Sherco conversion plan proposal pursuant to Minn. Stat. § 216B.1692 (Emissions Reduction Statute) any earlier than one month following the Order in this Resource Plan proceeding. We expect that our proposal will take a similar approach to our 2002 Metro Emissions Reduction Project (MERP) petition under the Emissions Reduction Statute.[23] Following an overview and summary of the proposed projects, we will present further details including projected book life, capacity, capital cost, annualized emissions reductions, and proposed project schedule for the proposed thermal and renewable projects. We will address the benefits of our proposal, along with costs, customer impacts, and an analysis of alternatives. Our proposal will also contain a suggested procedural schedule, which we intend to develop in consultation with appropriate state agencies.

[23] Docket No. E002/M-02-633.

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Also similar to our approach in 2002, we intend to submit a cost recovery petition within 60 days of our proposal. The Emissions Reduction Statute gives the Commission the authority to implement rate riders to recover the cost of qualifying projects if they appropriately achieve environmental benefits without unreasonable consumer costs. Our filings will provide the factual and analytical support necessary for the Commission to affirm the two key issues in the matter:

- Whether the selections in our Proposal are appropriate, given their environmental benefits and costs, and
- If so, whether our proposed rate mechanism is appropriate and consistent with the terms of the statute.

Following approval of the Sherco conversion plan and associated cost recovery filing we would proceed using a similar approach to our previous MERP conversion efforts. The Company would commence the project under an owner-managed multi-contract approach similar to the previous MERP, CapX2020 and other major projects we have successfully completed in the NSP regions over the past 13 years. We would establish an agreed upon scope, schedule, and budget with the Commission prior to proceeding and would expect to provide regular updates to the Commission on the status of the project through completion.

We would utilize a competitive request for proposal (RFP) process to purchase the major equipment and acquire specialized engineering design and construction resources. An RFP bidding process for the major components of the project ensures we obtain the most competitive pricing. As with the MERP projects, the Company's Engineering and Construction organization would provide overall project management and oversight with support from departments within the Company for environmental, purchasing, safety, and startup & commissioning. Maintaining direct control through project management and oversight of contracts for associated equipment, materials, and service contracts will reduce costs and ensure project quality and timeliness.

We have demonstrated through our successful large scale, multi-year MERP and CapX2020 initiatives, a transparent owner-managed approach that includes regular Commission updates and project costs that stem from competitively-bid contracts for all materials and services delivers on-time and on-budget projects that are in the public interest.

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VI. CUSTOMER COST IMPACTS

As we have discussed, our Reference Case is a continuation of the plan we laid out in our 2010 Resource Plan. We now know that it would not achieve compliance with CPP requirements, nor is it consistent with our vision of being a leading provider of cost-effective clean energy. The Updated 2015 Plan that we proposed in January 2015 began to shift the Company to a significantly lower-carbon system; however, with the information currently available it is not certain that the Updated 2015 Plan will be sufficient to achieve CPP compliance under reasonable assumptions of the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. Conversely, we are confident that our Current Preferred Plan will achieve CPP compliance, and also provide the reasonably-priced clean energy that our customers are asking for, appropriately balance state energy policy priorities, and optimize the system investments our customers have made to-date with new investments that will maintain reliability.

In this Section, we provide a long-term view of the cost impacts of our Current Preferred Plan. Additionally, at the request of the Commission and the Department at the December 2015 hearing regarding the procedural schedule for this proceeding, we discuss our view and provide illustrative concepts of a potential future market for CO_2 allowances.

A. Long-Term View

To show the cost impact of our proposal over the course of the planning period, we provide a Compound Average Growth Rate (CAGR) comparison of our Current Preferred Plan, Updated 2015 Plan, and Reference Case. We derived this long-term projection using a shorter-range financial forecast and a special purpose Strategist model, similar to how we projected the long-range cost of our plans in previous filings in this proceeding.[24]

Figure 5 below illustrates the cost differences between the Reference Plan, Updated 2015 Plan and our Current Preferred Plan, compared to the national average nominal cost CAGR. Specifically, the annual average cost delta between our Reference Case and our Current Preferred Plan is less than one-half of one percent. Our Current Preferred Plan also achieves significantly greater CO_2 emissions reductions and is the only one of the three plans that is virtually certain to achieve

[24] We describe this methodology in more detail in Attachment B.

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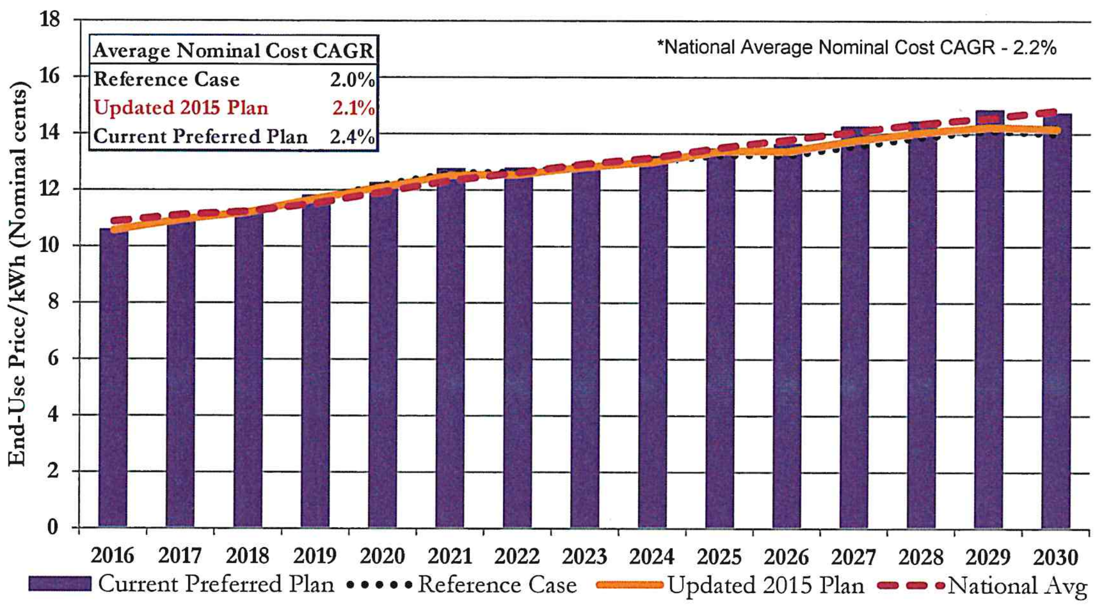
CPP compliance. Moreover, Figure 5 shows that the cost impacts associated with our Current Preferred Plan are roughly consistent with the expected national average increase in electricity prices, and over the long-term closely mimic the rate of inflation.

Figure 5: Current Preferred Plan Average Nominal Cost Comparison (NSP System)



*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.[25]

While this view of the estimated long-term plan costs is different than presented in previous filings, the relative values are consistent.

B. Potential Customer Benefits of CO_2 Allowance Proceeds

While our Current Preferred Plan is not primarily driven by the CPP, based on what we know now of the state implementation plan, we believe this plan not only achieves, but likely exceeds, the CO_2 emissions reductions that could be required of

[25] The EIA's Annual Energy Outlook was published in April of 2015, and based on federal, state, and local laws and regulations in effect as of the end of October 2014. Therefore, the potential impacts of pending or proposed legislation, regulations, or standards such as the CPP would not be reflected in these projections.

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the Company. As a result, the Current Preferred Plan may generate surplus reductions in the form of CO_2 allowances (if Minnesota's CPP state plan is mass-based) or Emission Rate Credits (if the plan is rate-based). Depending on the design of the state plan, the Company could monetize these surplus reductions on our customers' behalf to mitigate some of the cost impacts of transitioning to a significantly lower-carbon system.

We provide as Attachment H a preliminary analysis of the potential value of CO_2 allowances, in excess of compliance needs, under two hypothetical State Plan scenarios and assuming different CO_2 allowance prices. This analysis is preliminary and speculative because the size of the allowance budget allocated to the Company under the State Plan is not yet known; further, and CO_2 allowance prices in future markets can only be estimated. We describe in Attachment H the rationale we used for the CO_2 allowance prices used below, and provide details of the hypothetical State Plan scenarios labeled "Scenario 1" and "Scenario 2."

If we assume a constant CO_2 allowance price of \$21.50 per ton (the midpoint of the Commission's regulatory cost range under Minn. Stat. §216H.06), and assume a "Scenario 1" State Plan that regulates existing units only, contains no allowance set-asides other than the Clean Energy Incentive Program, allocates allowances based on 2010-2012 generation at CPP-regulated units,[26] and does not limit the number of years of allowance allocation to a retired unit, the Current Preferred Plan would generate allowance revenues of about \$540 million over 2022-2030 (\$258 million in Net Present Value or NPV terms). At the same CO_2 allowance price, if we assume a "Scenario 2" State Plan that contains many allowance set-asides and only allocates allowances for two years after unit retirement, the Current Preferred Plan would generate allowance revenues for our customers of only \$75 million over 2022-2030 (\$33 million NPV). We have not reflected these speculative potential revenues in any of the cost estimates of our Current Preferred Plan, and provide them here as only a preliminary analysis.

Table 16 below shows the value at three different CO_2 allowance prices that correspond to the Commission's low, midpoint, and high regulatory cost values.

[26] We note that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

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Table 16: Value of Potential CO_2 Allowance Sales Under Two State Plan Scenarios
(millions, undiscounted, over 2022 to 2030)

Allowance Price	State Plan Scenarios –1– Customer Value	State Plan Scenarios –2– Customer Value	Value Impact to Customers
$9/ton	$226	$31	($194)
$21.50/ton	$540	$75	($465)
$34/ton	$853	$119	($735)

The "Value Impact to Customers" column in this table represents the estimated CO_2 allowance value transferred from the Company's customers to other parties by a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-unit retirement.

Since all allowance values are assumed to accrue to the Company's customers, a "Scenario 1" State Plan would provide around $540 million to help mitigate the cost impacts of transitioning to a lower-carbon energy system. A "Scenario 2" State Plan would provide only $75 million, which is $465 million *less* value to mitigate customer cost impacts, shifting much of the value from our customers to other parties.

We believe that through our involvement in the MPCA's CPP State Plan development process, we can identify opportunities to further offset the cost impact of our proposal and achieve the greatest value for our customers. We also believe there are rate mechanisms, described in more detail below, which can provide predictable cost recovery and help to smooth cost impacts for our customers.

C. Near-Term Customer Rate Impacts

In compliance with the Commission's January 6, 2016 Order and in order to approximate the near-term impacts of plan implementation on customer rates and bills, we provide as Attachment E a detailed rate analysis of our Current Preferred Plan and Updated 2015 Plan. This includes a five-year detailed rate impact analysis with the estimated impacts by class per year.

We note the following factors could impact rates in 2016-2020:

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- *Tax credit extension*: With the extension of the Production Tax Credit, the costs of 600 MW wind PPAs beginning in 2020 is reduced significantly from the Base Cost of Energy forecast (Docket No. E002/MR-15-827), which assumed those PPAs would not benefit from PTCs. Wind PPAs are recovered through the fuel clause, which is where the cost reduction would appear for customers.
- *Renewables ownership:* The addition of 200 MW of owned solar and 400 MW of owned wind would result in an increase in base rates or rider rates due to the ownership of 200 MW of solar and 400 MW of wind, presumably recovered in the RES Rider.
- *Ceasing coal operations at Sherco:* The ceasing of coal operations at Sherco Units 1 and 2 would result in increased depreciation expense.

Primarily due to the tax credit extension, both our estimated Updated 2015 Plan and our Current Preferred Plan forecasts show lower fuel costs than our 2016-2020 fuel forecast prepared at the time of the Base Cost of Fuel filing. For example in 2020, the ITC and PTC tax incentives would reduce fuel costs by $99 million in the Current Preferred Plan, while the Updated 2015 Plan results in a $66 million reduction.

VII. NUCLEAR RESOURCE UPDATE

In our October 2 Reply, we expressed our support for utilizing our carbon-free nuclear baseload resources through the existing plant licenses as a means of achieving our goal of a 60 percent reduction of CO_2 emissions from 2005 levels by 2030. At the same time, we explained that our projected capital spend for Prairie Island is outpacing the estimates included in our Changed Circumstance filing in 2012.

We noted specifically that our five-year capital expenditure forecast from 2016 through 2020 has increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the thirteen-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We also noted that our fixed operating and maintenance (Fixed O&M) costs are lower than previously modeled and that our decreased Fixed O&M forecast largely offsets the increase in our forecasted capital spend.

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The Commission expressed understandable concern over our updated capital forecast during hearings in December 2015. We address those concerns here by providing additional information and analysis relating to our support for nuclear and to the costs associated with the continuing operation of Prairie Island. In particular, we provide modeling that takes into account our updated capital and Fixed O&M forecasts and demonstrates that Prairie Island has been, and continues to be, a cost-effective resource for our customers. We also discuss our updated capital expenditure forecasts for the periods from 2015-2020 and 2021-2034 at Prairie Island.

We believe the information provided in this section supports our continued operation of Prairie Island, including the investments we need to make to safely and reliably operate the plant over the next few years. We nevertheless recognize that our opinion is one of several that need to be considered in this process, that stakeholders would like to better understand the implications of our updated forecasts, and that there is some uncertainty at play when considering the costs to operate a two-unit nuclear plant for the remaining 19 years of its licensed life. Utilities, regulators, and stakeholders around the country are grappling with similar issues as they try to balance the increased regulatory pressure and costs associated with nuclear against emerging policies aimed at reducing CO_2 emissions.

We believe that any decision regarding the long-term future of Prairie Island should be made after a deliberate and thoughtful dialogue between the Company, our regulators, and our stakeholders. We further believe this dialogue should be informed by a longer-term, in-depth analysis of the cost-effectiveness of Prairie Island and the alternative paths that could be taken with respect to the plant. In fact, we have begun this work and share a preliminary analysis of one potential alternative later in this section. If the Commission and our stakeholders want to further explore this or other alternatives, we are committed to doing the additional work necessary to advance a fully informed and thoughtful decision-making process. We expect that a full analysis of the operations, economics, and potential alternatives for Prairie Island could be completed in the next 18 months, and we welcome the opportunity to cooperate with our regulators and our stakeholders on such a significant decision.

A. Relation to Supplemental Rate Case Testimony

Following our October 2 Reply, the Commission ordered the Company to file supplemental schedules and testimony in its pending electric rate case that describe

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and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs) from 2008 through 2020 by generating unit and year, including the proposed 2016 test year, and the 2017 and 2018 plan years. As part of those descriptions and comparisons, the Company was ordered to include all changes and updates to projected costs from 2008 onward and to include all cites to relevant certificate of need, resource plan, and general rate case dockets. The Commission also ordered the Company to provide as part of those schedules and testimony a comparison of the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending Resource Plan proceeding.

In compliance with that Order, we are filing supplemental Direct Testimony in our pending rate case docket from Company Witnesses Christopher B. Clark (President), Timothy J. O'Connor (Senior Vice President and Chief Nuclear Officer), Scott L. Weatherby (Vice President for Nuclear Finance and Planning), and John J. Reed (Chief Executive Office at Concentric Energy Advisors). That testimony focuses on the period from 2016 through 2020, the additional $175 million of capital expenditure above what was anticipated in 2012 for that period, and why the capital projects underlying that forecast are necessary during those years and in our customers' best interest.

In this Resource Plan Supplement, by contrast, we address not only the next five years but also the latter portion of Prairie Island's licensed life and the additional $600 to $900 million in capital that we anticipate spending between 2021 and 2034. Because resource planning takes this longer view, we believe it is the appropriate forum to consider whether it is economic and prudent to operate Prairie Island through the end of its licensed life. We therefore welcome an in-depth discussion regarding the future of Prairie Island and, to that end, propose a process to continue that discussion after we have had additional time to study the impacts of continued operations, as well as potential alternatives.

B. Prairie Island's Past and Current Cost-Effectiveness

Our support for utilizing our nuclear baseload through the existing plant licenses is primarily driven by our conclusion that it is beneficial for our customers to do so. We recognize that the principal question in this regard is the plant's cost-effectiveness on a going-forward basis. We believe that it is also helpful, though, to consider the forecasts and modeling we presented in connection with our 2008 certificate of need and 2012 changed circumstance filings. These demonstrate that

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Prairie Island has always been cost-effective, even when we account for our updated capital forecast. We therefore briefly address these earlier forecasts and models before turning to our prospective analysis.

1. *Past Forecasts & Modeling*

At the time we filed our certificate of need in 2008, we provided an estimate of capital costs running to the end of Prairie Island's licensed life in 2034 in an effort to measure the plant's cost-effectiveness compared to either a super critical pulverized coal unit or a natural gas CC unit. We provided this information in response to Minn. Stat. §216B.243, subd. 3b, which states that "[a]ny certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought."

Because we sought authorization for enough casks to operate Prairie Island until 2034, we provided our best judgment with respect to the "impacts of continued operations" until that time. Looking to historical capital expenditures, we estimated that our routine capital investment would average approximately $20 million annually ($10 million per unit) and that we would spend an additional $600 million on large capital investments from 2008 through 2034. Using these numbers, we concluded that continued operation of Prairie Island was cost-effective by a margin of $2,194 million in PVRR. We then updated our capital forecast for Prairie Island in our 2012 changed circumstance filing and included additional capital expenditures in that model.

For a number of reasons that are discussed below, our 2008 capital forecast has proven to be lower than the actual costs incurred to-date. Likewise, our 2012 forecast appears to be lower with respect to our updated forecast for the out-years of Prairie Island's licensed life. As an initial matter, however, it is important to contrast our 2008 capital expenditure forecast from one more typically associated with a certificate of need filing and from the Monticello prudence review. In the Monticello docket, for instance, we had already spent more than forecasted in our LCM/EPU certificate of need filing, and we sought recovery of those capital expenditures after the construction project was completed.

There is no construction project at issue here. Our 2008 filing related to dry-storage casks and provided a forecast related to the "impacts of continued operation" for a two-unit nuclear plant over a twenty-six-year period. It was the first time we

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provided such an estimate and the first time we forecasted capital expenditures for the out-years of an extended-life nuclear plant. And unlike Monticello, we are updating the Commission with respect to our increased capital forecast having not yet exceeded our 2008 forecast and not expecting that we will exceed the total cost (capital plus Fixed O&M) we forecasted in our 2008 filing.

That said, one reason for the higher-than-anticipated capital expenditures is that our Nuclear Regulatory Commission (NRC) mandated compliance expenses have increased substantially in recent years, both as a result of new NRC requirements following the Fukushima Daiichi incident, and as a result of increased oversight and regulation by the NRC generally. Additionally, our estimate of spending $10 million per unit annually for routine capital investment has proven to be insufficient, despite that having been a reasonable estimate in light of historical spending up to and including 2008. Our experience with routine capital investment over this period mirrors that of other utilities operating similar nuclear plants.

Although our capital expenditure forecasts have increased since 2008, our Fixed O&M forecasts have decreased in nearly equal measure. In 2008, we provided a conservative estimate of Fixed O&M costs in connection with our certificate of need filing, which was based on our historic spending up to that point. Since that time, however, we have observed significantly lower-than-forecasted Fixed O&M spend, which caused us to revisit that forecast in conjunction with our resource plan and to reconsider what future Fixed O&M growth will be over the next 19 years of Prairie Island's licensed life. Based on historical spending from 2008 to present, we now forecast spending more than $1 billion less in Fixed O&M at Prairie Island from 2015 through 2034. And if we look at total spend (capital plus Fixed O&M) in connection with Prairie Island, our current forecast results in PVRR that is $981 million less than our 2008 certificate of need forecast and $91 million less than our 2012 changed circumstance forecast. Thus, our revised Fixed O&M forecast not only offsets our revised capital expenditure forecast, it results in a projected total project cost that is substantially less than we anticipated in both 2008 and 2012.

Had we used our current capital expenditure projections in our 2008 model, it would have shown that Prairie Island remained a valuable, cost-effective resource by a margin of approximately $2.04 billion in PVRR. Likewise with our 2012 changed circumstance proceeding, Prairie Island would have remained a cost-effective resource by a margin of approximately $305 million in PVRR, using the model from that filing. Further, because our 2012 modeling assigned no cost to CO_2, the PVSC of Prairie Island under that analysis would have been substantially higher. As a

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result, our updated capital and Fixed O&M forecasts would not have changed our conclusions with respect to the continued operation of Prairie Island in either the 2008 certificate of need or 2012 changed circumstance proceedings.

2. *Prairie Island's Current and Future Cost-Effectiveness*

We now turn to the present-day cost-effectiveness of Prairie Island. For this analysis, we used our current Strategist modeling from this docket and considered a base case with the current forecast for ongoing capital and O&M expenditures compared with a scenario where Prairie Island is retired immediately. In a number of ways, this analysis is highly conservative. First, we have assumed that all of the capital and O&M expenditures for Prairie Island for 2016 through end of life can be avoided entirely, despite the fact that nuclear units continue to experience significant Fixed O&M costs during the various stages of decommissioning and despite the fact that the NRC would likely require a number of Fukushima-related and other mandated projects to be completed even following a shutdown.

Second we have not included any adjustments for accelerated depreciation of the existing asset, or changes to decommissioning costs or fund accruals, both of which we address in greater detail later in this section. Third, we have not included the costs of addressing transmission system impacts that would be caused by shutting down a significant baseload unit, as we have not yet studied these transmission effects in detail. Finally, we have assumed that replacement capacity could be installed "overnight" in 2016, and Strategist was allowed to optimize both the immediate replacements and balance of the expansion plan through the end of the study period. For a number of reasons discussed later in this section, it is simply not possible to immediately retire Prairie Island, or any nuclear plant. Major system transitions of this sort take years to study, plan, and execute, and industry experience teaches that unplanned shutdowns can be enormously expensive by comparison.

The results of this very conservative analysis are shown below in Table 17:

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Table 17: Prairie Island Compared to a Natural Gas Combustion Turbine

Resource	PVSC	PVRR
Prairie Island	$52,519	$46,618
Combustion Turbine	$53,750	$46,824
Difference	$1,231	$206

Even our most conservative analysis, then, shows that "overnight" replacement of Prairie Island would result in $1.231 million of additional PVSC. We also evaluated the PVSC and PVRR associated with the capital expenditure and Fixed O&M forecasts over the near-term period from 2016-2020. Continued operations of Prairie Island through this period results in a PVSC savings of $456 million and PVRR savings of $177 million compared to the overnight replacement scenario.

To be sure, the PVRR of running Prairie Island results in a closer call. In this way, the social cost of carbon plays a role in driving our support for continuing to operate Prairie Island through its licensed life, just as it does our decision to cease coal operations at Sherco Units 1 and 2 in the 2020s. We further recognize that changes to certain modeling assumptions, such as lower gas forecasts, could cause the PVRR numbers to suggest – under this limited analysis – that retiring Prairie Island in the near term might result in lower PVRR. It is important to keep in mind, however, this is a theoretical analysis intended to provide a preliminary look at Prairie Island's baseline economics, that it cannot substitute for an in-depth study that accounts for actual retirement and replacement costs, and that there are significant benefits to our nuclear fleet that are not captured by this, or any, Strategist model.

3. Operational & Policy Concerns

We believe that continued operation of our nuclear fleet is also the best path forward from both a policy and reliability perspective. Nuclear comprises more than half of our carbon-free generation and – at the same time – provides our system with a baseload energy resource that ensures critical system reliability. In this way, it is a keystone of the carbon-reduction goals set forth in our Current Updated 2015 Plan. Renewable technology such as wind and solar cannot fulfil this role at a reasonable cost today. As a result, any near-term replacement of our nuclear plants would involve the addition of more natural gas to our fleet, meaning the closure of Prairie Island would have twin effects of heightening our customers' exposure to gas

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price volatility and significantly increasing our CO_2 emissions. We do not believe this is in the best interest of our Company, our customers, or the states we serve.

We recognize, however, that battery technology is evolving, that renewable costs have decreased in recent years, and that reliable renewable baseload energy may be on the horizon. With that in mind, we see our nuclear units as critical to meeting our carbon-reduction and reliability goals in the near-term (including our compliance with the CPP) and also as a bridge that can facilitate a transition to even greater renewable generation in the longer-term as battery technology improves and costs decline. At the same time, our nuclear fleet is an integral part of our diversified generation portfolio and provides an important hedge to gas price volatility.

Finally, combining the cessation of coal operations of Sherco Units 1 and 2 along with the shutdown of Prairie Island all in the 2020s would present enormous challenges and costs with respect to replacement generation, transmission, and system reliability. The continued operation of our nuclear fleet as a bridge resource will allow for a careful and focused transition away from coal generation in the 2020s before addressing the future of other baseload units.

C. Forecasted Investments

1. Forecasted Investments from 2016-2020

In total, we anticipate investing approximately $490 million in capital at Prairie Island from 2016 through 2020. This is roughly $175 million more than we forecasted as part of our 2012 changed circumstance filing. There are a few key drivers of our increased capital spend during this period. First, $84 million of this increase is due to regulatory mandates from the NRC. As described in our previous two rate cases, these NRC Fukushima, fire safety, physical security, and cyber security requirements did not exist or were not fully known between 2008 and 2012.

More than half of the remaining $90 million is a result of our decision to defer certain projects from the rough timeframes anticipated in our 2008 and 2012 forecasts. In fact, we invested $51 million less from 2008-2015 than we forecasted in our 2012 changed circumstance filing. The remaining capital expenditures during this period simply reflect our inability to perfectly forecast costs in a certificate of need proceeding broadly focused on the remaining life of a plant, as well as increasing costs of nuclear construction and life-cycle maintenance across the industry.

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As detailed in Mr. O'Connor's Supplemental Direct Testimony in our pending rate case, the major capital investments forecasted for 2016-2018 include reactor coolant pump replacements, heater drain tank pump speed controls, motor rewinds/replacements, cooling tower replacements, and the main electrical generator replacement for Prairie Island Unit 1. In his Supplemental Direct Testimony, Mr. O'Connor describes each of these projects and explains why they are necessary to safely and reliably operate the plant, even if Prairie Island were not to operate until the end of its licensed life.
Department of Commerce Information Request No. 74 in our currently pending electric rate case requested that we provide an estimate of the necessary retirement dates for Prairie Island Units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures would not occur starting in 2016. Our forecasted capital expenditures for the combination of mandated compliance projects and dry fuel storage alone total $38.9 million in 2016, $36.1 million in 2017, and 34.8 million in 2018. These expenditures are necessary to operate the plant within the NRC's mandates and would leave very little additional capital within the $40 million annual budget to complete basic and necessary LCM projects during these years. Given this, and the fact that any single outage could require more than the remaining amount of budgeted capital to resume operations, it is impossible to predict how long Prairie Island could operate under these budget constraints.

2. *Forecasted Investments from 2021-2034*

In our October 2 Reply, we explained that our forecast for the fifteen-year period of 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We revised our forecast following a project-by-project analysis of anticipated capital investments at Prairie Island from 2015 through 2034, and we believe that it is responsible to anticipate and plan for all of the projects underlying our forecast. In other words, our updated forecast reflects our best judgment regarding these costs, which we presented to the Commission in October so that it can undertake a thorough assessment of our Current Preferred Plan. That said, it is not possible to accurately predict not only which projects will be necessary over a 19-year period, but also what those projects will cost. It is likewise not possible to predict what regulatory mandates will arise in the future, and what compliance with those unknown mandates might cost. Given this uncertainty, we understand certain stakeholders' desire to explore and maintain future optionality with respect to Prairie Island, and we address those concerns below.

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D. Future Optionality at Prairie Island

As already discussed, we believe that Prairie Island continues to benefit our customers by producing cost-effective, carbon-free baseload energy that is a keystone to our carbon-reduction goals and a bridge to additional renewable development in the future. We recognize, however, that it is impossible to perfectly forecast costs for the remaining 19 years of Prairie Island's licensed life and that certain of our stakeholders may want to explore alternatives based on that uncertainty. To that end, we have begun to identify and analyze one potential alternative for the plant around the 2025 timeframe. We recognize that other alternatives exist. We present this preliminary analysis as an example of the considerations and analyses that would go into an in-depth discussion of alternatives, and we welcome further dialogue regarding this or other alternatives.

Before proceeding with any in-depth discussion of alternatives for Prairie Island, we would need to conduct a detailed study of its effect on our transmission system, as we did in connection with our proposal to cease coal operations of Sherco Units 1 and 2. This would include a MISO Y2 Study, our own reliability study, and a black start study – just as we are providing in connection with our Current Preferred Plan. And as we did for Sherco, we would need to conduct impact studies relating to our employees at Prairie Island and the community around Red Wing, Minnesota. Finally, the technical studies completed in connection with our Sherco proposal may need to be reconsidered, as the study models assumed that Prairie Island would continue to operate.

If the Commission and our stakeholders wish to have a longer-term discussion concerning the future of Prairie Island, we are committed to completing this work, which we expect would take approximately 18 months. At that point, we would welcome input from stakeholders and the Commission, and we believe that a decision could be made with respect to Prairie Island's future sometime in 2018. If a decision was reached to pursue an early retirement for Prairie Island, we would need an additional seven years to plan for the shutdown and decommissioning, including the construction of replacement generation and any transmission projects that would be needed to maintain system stability. This planning period is critical, as recent industry experience teaches that hastily planned (or unplanned) shutdowns can be extraordinarily expensive as compared to shutdowns that are preceded by several years of planning. Company witness Mr. John Reed discusses the importance of advanced planning for nuclear retirements in his Supplemental Direct

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Testimony, which is being filed in our pending rate case contemporaneously with this Supplement. The seven-year timeline is also similar to the one we have proposed in connection with Sherco Units 1 and 2, and would result in a shutdown of Prairie Island around 2025.

To be clear, we do not currently foresee an economically prudent time to retire Prairie Island prior to the end of its licensed life. That said, we believe that an off-ramp in the 2025 time period would result in certain financial benefits as compared to an earlier retirement. Net plant balance is set to peak in 2018 at $1.127 billion. A retirement in that time period would result in substantially increased stranded costs, in addition to the costs otherwise associated with early retirement. During the early 2020s, however, net plant balance begins to decrease and, by 2025, would be within approximately $125 million of today's value of $917 million. That additional $125 million of net plant would itself be more than offset by the additional 10 years of investment growth in our decommissioning fund, which has a current market value of approximately $725 million and earns a return of approximately 5-6 percent (or between $36 million and $43 million) annually.

Additionally, if a decision were made around 2018 to retire Prairie Island in the mid-2020s, we could reduce our capital expenditures during the intervening years, as we normally anticipate lower capital spend in the years leading up to a plant's planned retirement. While we have not yet studied this capital adjustment in-depth, we estimate that our capital expenditures could be reduced such that net plant in 2025 would be significantly less than today's value of $917 million—provided we have several years to plan for the retirement. The strategy of reduced capital expenditures in the 2020s would come with a risk of a modest capacity derate at Prairie Island beginning around 2022 due to decreased capital investment, but we see this as a reasonable risk if the Commission and our stakeholders wish to pursue an early retirement.

The growth of our decommissioning fund is a significant factor that should be taken into account when considering alternatives to operating Prairie Island through its licensed life. Table 18 below compares the approximate amounts of customer contributions versus investment growth that would be needed to fully fund decommissioning at Prairie Island for three examples of potential retirement years:

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Table 18: Decommissioning Funding Broken Into Customer Contributions and Investment Growth

	2020	2025	2034
Customer Contributions	$518 million (58.67%)	$374.5 million (40.87%)	$10 million (0.64%)
Investment Growth	$319 million (41.33%)	$541.8 million (59.13%)	$1.552 billion (99.36%)

In short, the longer our decommissioning fund enjoys market growth, the less our customers will be required to pay to fund decommissioning at Prairie Island. This, in combination with the decreasing trend in forecasted net plant balance over the early 2020s, suggests that a retirement significantly before 2025 would involve substantially higher decommissioning and stranded costs.

As already discussed, we have conducted some preliminary modeling around the replacement of Prairie Island with a natural gas CT plant in 2025. Doing so would result in an increase of $929,614 million in PVSC and $601,257 million in PVRR. This analysis incorporates our current best judgment as to the costs of building replacement generation, the depreciation associated with Prairie Island, and the acceleration of decommissioning costs at Prairie Island – including most significantly, the elimination more than a dozen years of investment growth. Our PVSC model also incorporates the regulatory cost of emitting additional CO_2, which we have valued at $21.50 per metric ton beginning in 2019.

It is important to note that we have not conducted an in-depth replacement study with respect to Prairie Island. That analysis would include many of the technical studies that have already been completed for Sherco and the inclusion of specific costs related to transmission remediation and decommissioning that we are not currently in a position to forecast. We view this high-level analysis as buttressing our earlier cost-effectiveness modeling and as supporting the continued operation of the plant, at the very least through the next few years as we further study alternative scenarios.

E. Next Steps

There is much work to be done if the Commission wishes to pursue an in-depth discussion concerning the future of Prairie Island. As already discussed, we would need to complete several technical and impact studies, as we did in connection with

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our Sherco proposal. We may also need to reevaluate the technical studies completed in connection with our Sherco proposal, in which we assumed the continued operation of Prairie Island on our system. We believe this analysis is critical to making a fully informed judgment on this significant planning issue, and we are committed to doing this work over the next 18 months if the Commission wishes to further explore alternatives to operating Prairie Island through its current licensed life.

Prairie Island remains cost-effective, and our near-term investments are necessary to continue operating the plant today. Additionally, the bulk or our anticipated capital investments will occur in the out-years of Prairie Island's licensed life. As a result, there is time to engage in a thoughtful process, and we welcome this opportunity to dialogue with our stakeholders in hopes of charting a path that is best for our customers and the states we serve.

VIII. ACTION PLANS

A. Five Year Action Plan (2016-2020)

Our Five Year Action Plan discusses near-term actions by resource type, which is primarily focused on wind and solar resource additions.

Wind. The remaining 400 MW of the 750 MW of wind generation resulting from our 2013 RFP is expected to achieve commercial operation in 2016, which includes the 200 MW Courtenay project for which the Company took over ownership in 2015. In light of the recent PTC extension, we plan to develop and finalize our acquisition plan later in 2016 for securing an additional 800 MW of PTC wind by 2019. Currently, in order to obtain the full benefit of the PTC, wind projects must secure a "safe harbor" designation by the end of 2016 by incurring at least 5 percent of the project costs. Construction must be completed by the end of 2018. The PTC is reduced in subsequent years for projects meeting these milestones. We believe it is in the best interest of our customers to obtain the full PTC value; it may therefore be necessary to bring a wind acquisition proposal before the Commission in the latter half of this year for approval on an accelerated schedule.

Solar. The 187 MW of utility-scale solar generation resulting from our 2014 RFP, and the 100 MW Aurora Solar project resulting from the 2012 CAP proceeding are expected to achieve commercial operation in 2016. In light of the recent federal 30 percent ITC extension, we plan to develop and finalize an acquisition plan later in

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2016 to secure an additional 400 MW of 30 percent-ITC eligible utility-scale solar resources by 2020. There are similar safe-harbor provisions for the ITC as there are for the PTC for wind, however we have a longer runway. We note that we may adjust the amount of utility-scale solar resources we would seek based on the amount of small solar resources added to our system. The amounts indicated in our Expansion Plan (Table 2) are based on the updated small solar forecast we discuss in Attachment B to this Supplement.

Hydro. We will continue to evaluate the potential and value of hydro resource options including the potential for hydro resources from Manitoba Hydro beyond the current contracts that expire in the mid-2020s.

Natural Gas/Oil Peaking. We will continue to analyze older CTs on the NSP System to avoid impact of increased forced outages due to a major equipment failure and associated unexpected loss of capacity.

Coal. After this Resource Plan proceeding concludes, we will develop and submit a proposal that seeks to implement our proposal to cease operation of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and construct replacement generation resources needed as a result of these changes

Nuclear. Continue to utilize our cost-effective nuclear resources to achieve carbon-reduction goals and maintain reliability. Continue to dialogue with our regulators and stakeholders regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current license, complete the economic, technical, socioeconomic studies necessary to advance that discussion.

North Dakota. If the North Dakota commission takes action to approve our proposed Negotiated Agreement, we expect to begin working with Commission staff in 2016 toward developing a Resource Treatment Framework that would likely be filed with the Commission sometime in 2017. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address divergent energy policies and changes in cost allocations that may result.

B. Long Term Plan Action Plan (2021-2030)

Proposed actions during the 2021-2030 period:

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- Complete preparations for ceasing coal operation of Sherco Unit 2 in 2023 and Sherco 1 in 2026.
- Complete preparations to add our proposed natural gas CC at the Sherco site in 2026, achieving commercial operation prior to ceasing coal operations at Sherco Unit 1.
- Complete the natural gas infrastructure to supply the proposed Sherco CC.
- Complete preparations to add the proposed natural gas CT in North Dakota by the end of 2025.
- Effectively manage planned retirement of older CTs.
- Evaluate and determine the merits of extending or renewing expiring wind, thermal and hydro generation PPAs.
- Actively work to identify and act on opportunities to implement cost-effective and reliable distributed generation, electric storage units and other commercial ready technologies that are responsive to customer needs and comply with applicable requirements.

Minn. Stat. § 216H.02, subd. 1 requires that we provide an update on our progress toward the goal of achieving 80 percent CO_2 reduction by 2050. We expect our Current Preferred Plan to achieve at least at 35 percent CO_2 reduction from 2005 levels by 2020 and nearly 60 percent by 2030 – positioning us well to help Minnesota achieve its objective to reduce CO_2 by 80 percent by 2050. We note that our Monticello and Prairie Island nuclear facilities are essential to achieving the reductions we propose in our Current Preferred Plan and the 2030 CPP objectives. We discuss our nuclear units and their role on the NSP System more in depth in Section VII of this Supplement.

Our Current Proposed Plan achieves a 60 percent reduction in CO_2 emissions by 2030 milestone by adding 3,200 MW of new renewables and ceasing coal operations at Sherco Units 1 and 2 during the 2016-2030 planning period. Renewable additions begin with an 800 MW addition of competitively-priced PTC wind additions by 2020 and an additional 1,000 MW of non-PTC wind by 2030. Solar additions include adding 400 MW of competitively priced utility-scale ITC solar by 2020 and additional 1,000 MW by 2030. This adds to the 287 MW of utility-scale solar going into service in 2016. We note that we now expect small-scale solar resources to potentially reach 1,100 MW by 2030, which we discuss in Attachment B.

IX. PUBLIC INTEREST ANALYSIS

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Based on our detailed analysis, we conclude that the Current Preferred Plan is in the public interest. It puts the Company on a path to transform its fleet in a planful, coordinated manner that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy and carbon reduction requirements, while effectively managing costs and preserving flexibility on behalf of our customers. It provides our customers, employees, and our communities with certainty, while also maintaining a balanced diversity of energy sources, and investment opportunities that benefit our state economies and communities. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

Minnesota Commission rules (Minn. R. 7843.0500, subp. 3) identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest. More specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

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

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

A. Reliability

Our Current Preferred Plan is designed to maintain the adequacy and reliability of the NSP System and will allow the Company to continue to provide safe and reliable service to its customers. Our plan promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

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B. Impact to Customers' Bills

We developed our Current Preferred Plan with impacts to customers in mind. Given the regulatory and other constraints of the planning landscape, we sought to achieve additional flexibility and achievement of policy goals at a reasonable additional cost. For an incremental increase of less than one-half of one percent over the planning period compared to business as usual, we achieve nearly 60 percent reduction in our CO_2 emissions from 2005 levels, near certain CPP compliance, and assured reliability for our customers.

C. Socioeconomic and Environmental Effects

Our Current Preferred Plan will benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. It will also benefit our communities by allowing adequate time to transition our workforce and promoting economic development during this fleet transition. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

D. Flexibility to Respond to Change

Our Current Preferred Plan was developed to position the Company well in the current planning landscape. Obtaining strategic flexibility is a key component of doing so. This flexibility enhances our ability to respond to changes in the financial, social, and technological factors affecting our operations during the planning period – and preserves optionality for us to respond to these factors beyond the planning period.

E. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Current Preferred Plan limits the risk of adverse effects on the Company and our customers from financial, social, and technological factors beyond our control. Key to limiting such risk is our planful and coordinated fleet transition that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy objectives and carbon reduction requirements.

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We envision an energy future that includes a dramatic reduction in carbon emissions so that, by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period along with environmental regulatory risks to the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, communities, and the states we serve. Our customers will benefit from our cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect, which we can accomplish for just a fraction of a percent more in incremental cost over earlier plans. Our Current Preferred Plan represents the best option to meet customers' needs in light of the planning landscape and presents the best path forward for the Company, our customers, and the energy future of the Upper Midwest area. For these reasons, we believe our Current Preferred Plan is in the public interest, and we respectfully request the Commission's approval for planning purposes.

Compliance Matrix

This Supplement to Xcel Energy's 2016-2030 Upper Midwest Resource Plan in part responds to the Minnesota Public Utilities Commission's ORDER REQUIRING SUPPLEMENTAL FILING issued January 6, 2016 in Docket No. E002/RP-15-21. The following table lists each Order requirement and cross-references the section in Supplement where we address each item.

The Supplement also responds to the November 6, 2015 Minnesota Department of Commerce request for various information , as well as the Department's December 17, 2015 Information Requests Nos. 66 through 74, in which the Department requested responses be provided concurrently with the Supplement. We have addressed the IRs either in IR format via standard email delivery and uploaded to the eDockets site or in the Supplement as noted below.

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 1	Xcel shall file a supplement to its resource plan no later than January 29, 2016, and shall continue to share information with stakeholders. Upon submission, the Department will review Xcel's supplemental resource plan filing to determine the time the Department will need to analyze the new filing. Within 30 days of the supplemental filing, the Department will submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a reply comment period.	January 29, 2016 Supplement to the 2016-2030 Upper Midwest Resource Plan ("Supplement")
Order Point 2	As part of its January 29, 2016 supplement, Xcel shall file:	
	a. A rate impact analysis of the revised proposal;	Supplement Sections VI, Attachment E

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
	b. A copy of the "Y-2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities;	Attachment D1
	c. An analysis of alternatives to all or part of the energy and capacity that would otherwise be provided by natural gas combined cycle and combustion turbine resources, including alternatives such as demand response, improved system or grid efficiencies, and distributed energy resources;	Attachment F
	d. A proposed method to acquire proposed combined cycle and combustion turbine resources (e.g., a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Section V.C.
	e. Information about potential sites for any proposed combined cycle facility;	Supplement Sections I., V.A., V.B.1.,2. Attachment B
	f. If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site; and	Supplement Section V.B.
	g. Estimated total costs, including costs of any extension of natural gas service and transmission lines, for adding a combustion turbine in North Dakota by 2025.	Supplement Sections V.A., V.B., Attachment B

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 3	If Xcel files a Sherco Conversion Plan Proposal, it shall do so no earlier than one month following the issuance of a Commission order ruling on the merits of Xcel's resource plan. In any such initial filing, Xcel shall include a suggested procedural schedule, following consultation with the MPCA.	Supplement Sections V.D., VIII.A.

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	A copy of the "Y2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities as discussed on pages 7-8 of Xcel's October 2, 2015 Reply Comments;	Attachment D1
Page 3	Costs and options for addressing potential reliability concerns of Xcel's proposal, and expected timelines for the "additional study" noted above;	Supplement Sections V.A., V.B. Attachments D, D1, D2, D3
Page 3	A copy of MISO's declaration of Sherco Units 1 and 2 as System Stability Resources (as noted above) and whether that declaration applies to shutting down both facilities or only one;	See Company's response to Clean Energy Organizations' Information Request No. 79, Attachment B submitted November 9, 2015. Available at https://www.edockets.state.mn.us

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	Identification of the process required and options available to address a MISO declaration of a facility or facilities as System Stability Resources;	Supplement Sections V.B., Att. D
Page 3	The basis for building a combined cycle, natural gas generation facility "no later than 2026" given that no party in this proceeding has previously recommended adding a combined cycle plant prior to 2030, the significant level of "dump energy" on Xcel's system, and the preference for renewable energy resources in Minnesota Statutes;	Combined Cycle: Supplement Section V.A Dump Energy: Attachment B Renewables: Attachment B
Page 4	How the Company proposes to acquire the combined cycle and combustion turbine resources (a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Sections V.C, V.D.
Page 4	Any information about potential sites for such a combined cycle facility;	Supplement Sections V.A., V.B.
Page 4	If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site;	Supplement Sections V.A., V.B.
Page 4	Estimated total costs, including costs of any extension of natural gas service and transmission lines, for "adding a combustion turbine in North Dakota by 2025."	Supplement Sections V.A., V.B.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-66	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an updated *.FSV file for the reference case used by the Company in the new supplement or confirm that the most recently provided *.FSV file remains valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-67	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the contingencies explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-68	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the scenarios explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-69	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide the post-processing spreadsheets, if any, which adjust the Strategist outputs to match those reported by the Company in the new supplement. Please provide such post-processing spreadsheets for the base case in each scenario explored by the Company in the supplement.	Submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-70	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a macro file (*.INP) which adjusts the reference case to retire the A.S. King power plant in 2027. As part of the macro file, please include any expected impacts on: • Variable operations and maintenance costs; • Fixed operations and maintenance costs; • On-going capital expenditures; and • Any other expected impacts. (See pages 11-12 of Xcel's March 16, 2015 supplement for background information on such adjustments). If such adjustments are better incorporated in a post-processing spreadsheet, please provide such a post-processing spreadsheet.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.
DOC-71	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a discussion of the potential transmission impacts of retiring the A.S. King power plant in 2027, to the extent they are known.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-72	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a brief discussion of whether the generating unit shut down scenarios explored by the Company in the new supplement include the present value of the expected impact of an earlier shut down on depreciation expense and related rate base costs (return on equity, deferred taxes, and so forth).	Submitted in IR format via email and uploaded to eDockets.
DOC-73	Regarding the generating units at Monticello and Prairie Island, at the time Xcel files the January 29, 2016 supplement in this proceeding, please explain why the fixed cost input in the most recent Strategist database are lower than the non-fuel production expenses (subtracting line 20 from line 34) listed in Xcel's FERC Form 1 for 2014.	Submitted in IR format via email and uploaded to eDockets.
DOC-74	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an estimate of the necessary retirement dates for Prairie Island units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures do not occur starting in 2016.	Reference Supplement Section IV.D.1.

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Attachment B
Updated Strategist Modeling and Outputs

In addition to the summary provided in body of the Supplement document, this Attachment presents and explains detailing Strategist modeling analysis that supports our Current Preferred Plan. Included here are a description of the revised modeling assumptions, the scenarios and sensitivities analyzed, and the results of an economic analysis comparing the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) outputs for each scenario. We also respond here to the Department of Commerce's July 2, 2015 Comments related to the treatment of dump energy in our modeling.

I. REVISED MODELING ASSUMPTIONS

Our January 2, 2015 Initial Filing detailed the Planning Framework, Strategist Assumptions and Sensitivities, and Scenarios Analyzed that formed the basis of our resource planning analysis. The updates and additional modeling presented in this Supplement build on all the planning analysis done since initially filing this Resource Plan. We clarify that we made no changes to our base assumptions, such as our underlying sales and natural gas price forecasts.

Our March 16, 2015 Resource Plan Supplement forms the basis of the analysis supporting the Current Preferred Plan we present in this Supplement. Two key changes that have occurred since the March 2015 Supplement and the October 2015 Reply filing are the extension of federal tax credits for renewable energy and the growth in our Community Solar Garden forecast. In the narrative below, we explain the impact to our Current Preferred Plan of these changes on our resource additions and the associated costs.

We have included the impacts of the tax credit extension in all of our economic analysis of our Current Preferred Plan, to incorporate the changed circumstances related to renewable energy costs. We have outlined the impact of the small solar adjustments to in the section below, but have not reflected those cost changes in the PVRR and PVSC comparisons in Section III below. As these changes are the result of policy recommendations outside the scope of our Current Preferred Plan, we felt it was appropriate to include only those resource changes proposed in our plan, in our cost impact analysis. Although we did not submit a detailed economic analysis with our October 2015 revised proposal, we note that the extension of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) reduces the PVRR of our Current

Preferred Plan by $202 million; the changes to the small solar increases the PVRR by approximately $760 million.

A. Tax Extender (PTC, ITC) Updates to Wind and Solar Prices

Legislation was enacted in December 2015 that extended the availability of PTCs (primarily relating to wind projects) to 2019 and the 30 percent ITC (primarily related to solar projects) to 2022. The Consolidated Appropriations Act of 2016 also provided step downs in tax incentives in various years depending on the type of project and the date construction commences and/or the project is placed into commercial operation.

To incorporate these changes into the modeling, it was necessary to develop updated pricing for wind and solar for the varying tax levels, as well as develop additional alternatives to capture the year-by-year changes. In developing these new alternatives, it was assumed that the Internal Revenue Service will ultimately promulgate a safe harbor memorandum for the new law that has similar timing requirements related to construction start and in-service dates as the current memorandum (i.e. approximately two years of construction time allowed for safe harbor). The assumptions used are shown below in Table 1.

Table 1: Wind and Solar Tax Benefit Assumptions

Construction Start	COD, by End of:	First Full Year of Ops	PTC	ITC
2016	2018	2019	100%	30%
2017	2019	2020	80%	30%
2018	2020	2021	60%	30%
2019	2021	2022	40%	30%
2020	2022	2023		26%
2021	2023	2024		22%
2022	2024	2025		10%

The pricing for each alternative was developed in the same manner as described in the Appendix to the March 16, 2015 Resource Plan Supplement document, using a spreadsheet financial model to convert an owned project to Power Purchase Agreement (PPA) equivalent pricing. For the Current Preferred Plan that includes owned renewables, the original ownership revenue requirements were used, resulting equivalent costs on a net present value basis of owned vs. PPA projects for a given tranche. The PPA equivalent pricing is shown below in Table 2.

Table 2: PPA Equivalent Pricing for Wind and Solar ($/MWh)

Tech Type:	Solar	Solar	Solar	Solar	Solar	Solar	Wind	Wind	Wind	Wind
Construction Start:	2016	2018	2019	2020	2021	2022+	2016	2017	2019	2020+
First Full Year of Ops:	2019	2021	2022	2023	2024	2025+	2019	2020	2022	2023+
Tax Benefit:	30% ITC	30% ITC	30% ITC	26% ITC	22% ITC	10% ITC	100% PTC	80% PTC	40% PTC	0% PTC
2019	67.30						21.98			50.78
2020	68.80						22.48	26.78		51.92
2021	70.35	69.54					22.98	27.38		53.08
2022	71.92	71.09	69.73				23.49	27.99	37.87	54.27
2023	73.53	72.69	71.29	70.96			24.02	28.62	38.72	55.49
2024	75.18	74.31	72.89	72.55	72.20		24.56	29.26	39.58	56.73
2025	76.86	75.98	74.52	74.18	73.82	95.00	25.11	29.91	40.47	58.00
2026	78.58	77.68	76.19	75.84	75.47	95.00	25.67	30.58	41.38	59.30
2027	80.35	79.42	77.90	77.54	77.16	95.00	26.25	31.27	42.30	60.63
2028	82.14	81.20	79.64	79.28	78.89	95.00	26.83	31.97	43.25	61.99
2029	83.98	83.02	81.43	81.05	80.66	95.00	27.44	32.68	44.22	63.38
2030	85.87	84.88	83.25	82.87	82.46	95.00	28.05	33.42	45.21	64.80
2031	87.79	86.78	85.12	84.72	84.31	95.00	28.68	34.17	46.22	66.25
2032	89.76	88.72	87.02	86.62	86.20	95.00	29.32	34.93	47.26	67.73
2033	91.77	90.71	88.97	88.56	88.13	95.00	29.98	35.71	48.32	69.25
2034	93.82	92.74	90.97	90.55	90.10	95.00	30.65	36.51	49.40	70.80
2035	95.92	94.82	93.00	92.57	92.12	95.00	31.34	37.33	50.51	72.39
2036	98.07	96.94	95.09	94.65	94.19	95.00	32.04	38.17	51.64	74.01
2037	100.27	99.12	97.22	96.77	96.30	95.00	32.76	39.02	52.80	75.67
2038	102.52	101.34	99.39	98.94	98.45	95.00	33.49	39.90	53.98	77.36
2039	104.81	103.61	101.62	101.15	100.66	95.00	34.24	40.79	55.19	79.09
2040	107.16	105.93	103.90	103.42	102.91	95.00	35.01	41.70	56.42	80.87

This extension provides material reductions in the cost of renewable energy acquisitions proposed in our each of our Resource Plan scenarios. We have therefore adjusted our proposed wind additions in 2020 to be PTC-eligible in all scenarios analyzed in this Supplement, to allow for an apples-to-apples comparison between the plans. These changes were made to all scenarios in order to reflect how the current law impacted changing individual plans differently and therefore changes the delta analysis of the various plans.

The impact of this change on our Current Preferred Plan is a decrease in the overall PVRR of $202 million and a decrease in the overall PVSC of $203 million.

B. Small Solar Forecast Update

We launched our Solar*Rewards Community program in December 2014. As we have previously noted, we received an overwhelming response to our program – receiving nearly two thousand applications to-date. Modeling data regarding distributed solar was developed for the January 2, 2015 Initial Filing prior to the Company or Commission finalizing the tariffs and program offerings for individual distributed solar or community solar gardens installations. Subsequent to development of the initial models, the regulatory structure for distributed solar has become much clearer. We have more information on issues in the Community Solar Gardens proceeding (Docket No. E002/M-13-867) that were previously unresolved, and have therefore been able to update our forecast for purposes of this Supplement.

The initial data for cost and payment terms was estimated by the Company using its experience in other jurisdictions, primarily Colorado. In the Initial Filing, and carried forward into the Supplemental filing in March 2015, the assumption used was payments for 10 years at 8¢/kWh. Due to the magnitude of the solar programs proposed and modeled in these scenarios, the cost assumptions should be adjusted closer to current practice. In the alternative analysis with the small solar forecast adjustment discussed here, the costs and payment terms have been revised to payments for 20 years at 12¢/kWh.

In Table 3 below, we have accelerated the addition of small solar resources – a total of 422 MW in the pre-2020 timeframe in anticipation of the completion of several Solar*Reward Community projects and continuing our commitment to growing renewable resources.[1] While the current project pipeline for community solar gardens

[1] We adjusted our forecast for small solar, including community solar gardens and distributed generation (DG) in this Supplement based on a mixture of regulatory adjustments, detailed design, and project movement in the pipeline for our Solar*Rewards Community program.

exceeds this projection, we anticipate that some projects will experience difficulties in permitting, financing, or interconnection, therefore never reaching full operation.

Although the ITC has been extended, we believe that a majority of projects will be completed in the next year for the Solar*Rewards Community program based on established financing. Therefore, we have forecasted 259 MW of projects reaching operation by the end of 2016, and lowered the forecast after this time. Table 3 below shows the impact this adjusted small solar forecast has on our capacity/deficit position from the L&R analysis in the Supplement document.

Table 3: Small Solar Forecast Adjustment (MW) ICAP

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Current Preferred Plan – Proposed Solar Additions																
Small Solar Additions	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	675
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	400	0	0	1,400
Total Additions by Year	42	45	49	253	58	217	120	124	229	134	141	49	459	71	85	2,076
Current Preferred Plan – Altcrative Analysis w/Small Solar Forecast adjustment																
Small Solar Additions	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	1,097
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	0	0	0	1,000
Total Additions by Year	259	159	91	283	76	217	120	124	229	134	141	49	59	71	85	2,097
Impact of Small Solar Forecast Adjustment on Current Preferred Plan																
Increased Small Solar	217	114	43	31	18	0	0	0	0	0	0	0	0	0	0	422
Adjusted Large Solar	0	0	0	0	0	0	0	0	0	0	0	0	-400	0	0	-400
Change in Total Additions by Year	217	114	43	31	18	0	0	0	0	0	0	0	-400	0	0	22

The impact of this adjusted small solar forecast is a shift in the type and timing of solar additions in our plan, which impacts the overall cost of the Current Preferred Plan. In order to accommodate the increase to the small solar forecast in the early years of the plan, the utility-scale solar additions we propose in our Current Preferred Plan would be reduced. As Table 3 above shows, we would remove the remaining 400 MW of utility-scale solar in the plan in 2028 at a fixed flat price of $95/MWh in order to add the more than 400 additional MW of small solar between 2016 and 2020 at a fixed flat price of $120/MWh. While this change does not significantly impact the net solar additions in the plan, it accelerates the installation of the solar, but would also increase the cost of the plan by moving to a different, less cost-effective form of solar.

The impact of this change is an increase in the overall PVRR of our Current Preferred Plan by approximately $759 million. The PVSC impact of this change on our Current Preferred Plan is an increase of $737 million.

C. Updated Nuclear Forecast

Certain fixed costs that do not affect the relative economics of plans being considered are typically not included in the Strategist database. As an example, costs related to the distribution and corporate services business areas, transmission costs not related to generation plans, and recovery of current ratebase for owned units that are not subject to change are not typically included in the model. Strategist does include all costs related to the operations of owned and PPA units (fuel, variable and fixed O&M, PPA payments), and the models used for this resource plan do include future capital expenditures and recovery of ratebase for the Sherco units, as the costs for Sherco vary among the different retirement scenarios. In total, the Strategist model represents about 46 percent of the total system revenue requirements that go into rates, with the other 54 percent being unrelated to decisions around resource selection or planning.

In an effort to provide increased transparency around our nuclear cost assumptions, we have elected to include an analysis of scenarios with the full costs of nuclear in the Scenario Outcomes below. We have updated the model for that analysis to include specific forecasted Capital and Fixed O&M (FOM) costs for the planning period for the Monticello and Prairie Island units.

The O&M costs that were in the model previously for those units have been updated to the most recent estimate of future O&M. In addition, costs that were not in the model previously related to future capital expenditures and recovery of current rate base were added to the model. The net results of adding these costs in, as well as the much lesser impact of adjusting the O&M forecast, results in an increase in the net present value of revenue requirements (or societal cost) that Strategist reports of around $3.6 billion. We clarify that this total Capital and FOM cost is not the "increase" in our nuclear cost forecast that we discussed in our October 2, 2015 Reply Comments; we discuss the $600-$900 million forecasted cost increase in Section VII of the Supplement document.

This does not result in an increase to the relative cost of any plan, but simply adds in costs that were never reported before. Essentially, Strategist was adjusted from reporting 46 percent of total system costs to around 51 percent of total system costs and, as the same adjustment was made to all plans, the delta in costs between the various plans is unchanged. The impact of these adjusted cost assumptions to the overall PVRR/PVSC of the modeling scenarios is shown below in Section VII on Table 10.

II. SCENARIOS AND SENSITIVITIES SUMMARY

A. Scenario Summary

To analyze our Current Preferred Plan, we included five key scenarios from our previous Resource Plan filings. Each of these scenarios was updated with the assumptions described above. All previous scenarios were run as they were described in the Initial Filing; however Sherco 2 is now the first unit retiring instead of Sherco 1.

1. *Updated Previous Scenarios*

Each of the scenarios described below used the baseline data from our March 2015 Supplemental filing, updated with the relevant modeling assumption revisions described above.

- *Reference Case:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 400 MW of wind additions, over 400 MW of small solar additions, 287 MW of large solar additions, no assumptions changes.
- *Updated 2015 Plan:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 1,800 MW of wind additions, over 1,600 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC.
- *North Dakota Plan:* Consistent with March Supplement, contains no additional renewables beyond currently committed 750 MW of wind, no assumptions changes.

2. *Current Preferred Plan and Variants*

The scenarios below reflect the Current Preferred Plan, with various alternatives for replacement capacity of the Sherco unit retirements. We allowed the model to select both site-specific and generic replacement capacity alternatives for the Sherco units. The modeling of the site-specific alternatives is discussed in detail in Section V of the Supplement.

- *Current Preferred Plan*: Cease operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026, 1,800 MW of wind additions, over 1,400 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC extension, goal of 50 percent ownership of renewables, Company-owned Fargo CT and Sherco CC.

- *Current Preferred Plan – All Generics*: Same as Current Preferred Plan, but with all generic thermal alternatives. Leave behind costs for not replacing generation at the Sherco site are not modeled within Strategist so are not included in the PVSC/PVRR's, but are calculated outside of models. Updated for tax credit extension.

3. *Full Optimization Scenarios*

We performed an unconstrained optimization incorporating the option of adding incremental Demand Response and Distributed Energy Resources.

- *Resource-Need Optimization:* Unconstrained optimization simultaneously filling energy and capacity needs.
- *Capacity-Need Optimization:* Unconstrained optimization filling capacity needs only.

The results of this analysis are included in Attachment F. A summary of the primary scenarios included in this Supplement is shown in Table 4 below.

Table 4: Summary of Scenarios Analyzed in this Supplement

Primary Sherco / Carbon / Renewable Alternatives	Strategist Output Code
Continued Operation (Run Both Units to 2030)	
Reference Case	1
Updated 2015 Plan	
Updated 2015 Plan - PTC Wind in 2020	10
North Dakota Plan	
Original North Dakota Plan - No additional renewables beyond currently committed	15
Current Preferred Plan	
Current Preferred Plan - Retire Sherco 2023 and 2026, accelerate renewables, Sherco CC, Fargo CT	28
Current Preferred Plan with all generic thermal replacements, excluding leave behind costs	28_A

B. Sensitivity Summary

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examined our plans under a number of sensitivities. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we could conceivably propose an expansion plan that is less sensitive to assumption changes, but slightly more costly than the least-cost scenario under starting assumptions. For this Supplement, we used a subset of the same sensitivity cases that were used in the January 2, 2015 Initial and March 16, 2015 Supplemental Filings, selecting the sensitivities that are most relevant to the decisions being contemplated and that are of the most interest to the various parties to this case. Additionally, what was referred to as the "Traditional View" in the March 2015 Supplement (Sensitivity "R", Do Not Maintain CAPCON Length) is incorporated into all cases and is no longer considered a sensitivity.

Table 5 below gives a summary of the Modeling Sensitivities included in this Supplemental filing.

Table 5: Modeling Sensitivities

Base CO_2 (Mid) Costs	**Strategist Output Code**
Low Gas Prices	C
High Gas Prices	D
Zero CO_2 Costs	
No Regulated CO_2 (Contains Externality CO_2)	K
ND Assumptions (No Extern, No CO_2 Costs)	T
"Customer impact" (No Cap Credit, No Extern, No CO_2 Costs)	U
Other CO2 Sensitivities	
CO_2 \$9, Start 2019	L
CO_2 \$34, Start 2019	M
CO_2 \$9, Start 2024	N
CO_2 \$34, Start 2024	O
CO_2 at Federal SCC 3%	P

III. ECONOMIC ANALYSIS

After identifying the scenarios and sensitivities to update for this Supplement, we performed an updated resource planning analysis in largely the same manner we used for both our Initial Filing and our March 16, 2015 Supplement. To provide a comparison between the various cases we considered, we use a traditional resource planning method and rank the scenarios based on cost. In addition to a least-cost analysis, we perform a more holistic analysis to determine if our Current Preferred Plan is appropriately balanced within our planning framework when compared to the other scenarios.

We analyze the economics of the scenarios in both PVRR and PVSC terms. The PVSC results provide a baseline ranking of the overall societal benefits of each of the scenarios analyzed – applying the Minnesota Commission's regulatory cost of carbon dioxide and externalities values for criteria pollutants – and the externality for carbon in non-regulated years in the modeling period of 2015-2053. The PVRR-based analysis excludes carbon costs and all externalities values over the modeling period.

Because actual customer cost impacts are a key consideration within our planning framework, and due to the fact that not all of the NSP System states allow for an analysis that includes carbon costs or externalities, we also perform a least-cost analysis on a PVRR basis (North Dakota Plan). We present the results of these analyses in this section, and demonstrate that our Current Preferred Plan provides the most reasonable outcome under both a least-cost analysis and under a more comprehensive analysis.

1. *Traditional Resource Planning Analysis*

We first analyzed our modeling outputs on a PVSC basis to determine the least-cost plan including societal impacts. Table 6 below provides the PVSC outcomes for each of the key scenarios we analyzed for this Supplement.

Table 6: PVSC Results ($Millions)

Scenarios	PVSC Results
Current Preferred Plan	$51,293
Current Preferred Plan, All Generics	$51,280
Updated 2015 Plan	$51,458
Reference Case	$52,422
North Dakota Plan	$52,620

As shown above in Table 6, our Current Preferred Plan is the second lowest cost plan on a PVSC basis. Only the Current Preferred Plan with a generic Sherco Unit replacement ranks higher on a PVSC basis – with a minimal $13 million difference in PVSC. This difference is due to the exclusion of leave-behind costs for not replacing generation at the Sherco site, which are not modeled in Strategist.

Table 7 below provides the PVRR rankings of the same key scenarios.

Table 7: PVRR Results ($Millions)

Scenarios	PVRR Results
Current Preferred Plan	$45,606
Current Preferred Plan, All Generics	$45,582
Updated 2015 Plan	$45,302
Reference Case	$45,605
North Dakota Plan	$45,473

From a strictly PVRR perspective, as Table 7 above shows, the Reference Case is the lowest-cost plan. Table 7 also indicates that the North Dakota Plan ranks the next best on a PVRR basis, since it relies heavily on natural gas generation additions as compared to the Preferred or Current Preferred Plans. As we have mentioned previously, we do not believe that either of those plans would meet Clean Power Plan (CPP) compliance. Our Current Preferred Plan, with variations for site-specific and generic replacements for Sherco capacity, has the lowest PVRR ranking, as the benefits of the carbon emissions impacts of the plan are not captured in a PVRR analysis. A full matrix of PVRR and PVSC results is included in Section VII below.

After performing the PVSC and PVRR analyses, we evaluate the scenarios more holistically by analyzing their environmental performance, strategic flexibility, and cost. Table 8 below, the Run Key carries forward the PVSC and PVRR ranking of each scenario to provide a reference point for the broader analysis, but it also identifies key policy outcome metrics such as amount of CO_2 emissions reductions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario.

Table 8: Run Key[2]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref. Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the stronger performance in terms of carbon reductions and renewable energy additions to the NSP System. The renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership has shifted, as shown in our Expansion Plans. This plan continues to provide the best value for our customers – achieving a balance between multiple objectives, including: reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and maintaining reliability on our system. Our Current Preferred Plan proposes to time these resource changes such that we minimize the socioeconomic and technical impacts by allowing sufficient time to plan for fleet transitions.

IV. ALTERNATIVE SCENARIOS CONSIDERED

As part of the process of developing our Current Preferred Plan, we evaluated a broad range of alternatives. Our updated Strategist modeling included consideration of several alternative scenarios, including conversion of a Sherco Unit to a Boiler, and solar and wind resources in addition to generic and site-specific CT and CC alternatives. Here, we discuss these alternative Scenarios in greater detail.

[2] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch. Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

2. *Conversion of a Sherco Unit to Gas*

As noted above, one unit at Sherco could be converted to a gas boiler, as the Department recommended in its July 2, 2015 Comments. We commissioned an external study of impacts and costs for converting either of Sherco Units 1 or 2 boilers to gas-fired and to evaluate the economic aspects of such a conversion. We note that a gas-fired boiler would be a capacity resource only, as the technical limitations of a long start-up time, a slow ramp rate, high O&M, and a high heat rate as compared to gas fired turbines would likely result in very low annual capacity factors of less than two percent due to the Unit's economic dispatch order position. Compared to our Current Preferred Plan, replacing a unit at Sherco with a gas boiler and adding a CC increases the PVSC by $36 million dollars.

In addition, continued operation of a large coal boiler that is converted to utilize gas also results in a number of operational issues. While the unit can be counted as a capacity resource after conversion, we believe that in order to qualify as a capacity resource in the Midcontinent Independent System Operator's (MISO) evolving capacity construct, firm gas supply may be required. The current capacity construct in MISO is on an annual basis from June 1 to May 31. If MISO changes to a seasonal capacity construct, firm gas may not be required during the summer season. However, as one Sherco unit is a large portion of the entire system capacity, it may not be practical from an operations perspective to have the unit available for only part of the year. In addition, the operating characteristics of the large unit that was designed for base load operation will push it to near the bottom of the dispatch order even with low gas costs being directly competitive with coal, if not better.

A converted gas unit would have a ramp rate of approximately 5 MW per minute from a minimum load level of 260 MW to full load. This is considerably slower than a CT, which has a ramp rate of approximately 10 MW per minute. We would expect that when the unit is dispatched it could be kept online for several days in order to cover the start costs, anticipated to be approximately $100k for labor plus 3,500 to 4,000 MMBTU of start fuel. Once taken through and orderly shut-down the unit will not be available for restart for at least one to two days.

3. *All Renewables*

We also considered replacing the capacity and energy from retirement of Sherco Units 1 and 2 with replacement of the capacity and energy entirely from renewable sources, as is required under Minn. Stat. § 216B.2422, subd. 4. Our Current Preferred Plan includes 1200 MW of renewable additions by 2020. However, in addition to the significant amount of renewable generation we plan to add to our system, gas-fired generation plays an important role on the system and was also selected as a cost-effective resource addition to meet customer needs.

Variable resources such as wind and solar must be integrated with dispatchable gas-fired generation in order to ensure adequate system reliability. Gas-fired generation will likely be distributed at several locations around the NSP System to provide grid support and to efficiently utilize existing transmission infrastructure. If replacement generation is not located at the Sherco site, we would need to otherwise resolve a voltage deficiency in the Becker, Minnesota area and for the Monticello nuclear plant, which would require the conversion of one of the Sherco units to a synchronous condenser, a Static Var Compensator (SVC) or Statcom device.

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of utility-scale and distributed renewable resources. In particular, modernized transmission and distribution systems are critical to meet the challenges of emerging technologies, expanding renewable policies, and a comprehensive view of resource planning. Appendix H of our initial filing discussed some of the effort undertaken at both the transmission and distribution level to ensure increased levels of renewable generations can be accommodated.

V. TREATMENT OF DUMP ENERGY

As the Department noted in their July 2, 2015 Comments, our modeling shows a significant level of dump energy. In Strategist, DSM, wind, and solar are modeled as must-run resources and their generation is used to reduce customer load prior to performing thermal dispatch. The thermal dispatch includes several must-run units, such as large coal plants, as well as must-take PPAs, such as biomass. There are hours during which the modified load (customer load less DSM, wind, and solar generation) is less than the minimum physical operating level of the must-run thermal resources. Strategist reports the energy when generation is greater than load as dump energy. Dump energy occurs because Strategist does not allow the must-run thermal units and must-take PPAs to reduce their generation to balance load. The Department correctly explained in its comments that dump energy increases as more wind resources are added to the system. This occurs because the modified load will decrease as wind additions are increased. This results in more instances where the modified load is less than the must run thermal resources and there is a corresponding increase in dump energy.

In our analyses we assign a revenue credit to dump energy equal to 50 percent of the market energy price. In addition, by requiring the thermal units to operate at their minimum, the costs and emissions for the thermal generation related to the dump energy are included. Dump energy does not impact the optimization of the expansion plans or the dispatch of the generators in the model. We assigned the revenue credit outside the model after the optimization and dispatch is complete. We believe this modeling approach is appropriate and provides for the full value of wind to be accounted for, as it allows all the energy available from both wind and thermal units to be included in the analysis.

It is also important to note that over-builds would be immediately apparent if the reserve margin significantly exceeded the required reserve margin. This does not occur in our modeling. We conclude that our approach provides a consistent comparison of renewable and thermal resources.

The Department has also expressed concern that dump energy may indicate there is excess energy that can be applied to reduce the resource additions needed to meet customer load. Dump energy typically occurs, however, during low-load or off-peak periods. While the resources available during these low load periods may greater than the resources needed to serve these lower loads, it is not possible to "save" this energy and use it later when loads are higher.

Finally, as the Department noted, dump energy is a challenging issue from both a cost and CO_2 perspective. We propose to work with the Department to arrive at an agreed-upon methodology.

VI. LONG-TERM RATE IMPACT METHODOLOGY

Figure 5 in the body of the Supplement illustrates the estimated cost impact of our proposal over the course of the planning period. To calculate these long-term rate impacts of the Current Preferred Plan as compared to the Reference Case, we first developed a forecast of total rates through 2020 under the Reference Case assumptions. To do this, we used a combination of the Company's shorter range financial forecasts and a special-purpose Strategist model used to project total system revenue requirements for extended periods.

Typically, the Strategist model develops projections for generation-related costs. To derive a total system (including transmission, distribution, A&G, etc.) forecast, we expanded the standard Strategist model by adding capital and expense items associated with the other costs that are not typically modeled. We input starting net plant and deferred tax balances, capital spend forecasts and O&M forecasts for the existing generation, transmission, distribution and overhead business areas, and calibrated the model such that the total revenue requirements through 2020 approximately tracked the more refined short-term financial forecasts during those years.

Developing a total rate forecast beyond 2020 when detailed company financial models are not available would depend on making assumptions for capital expenditures and O&M expenses for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions would be highly speculative, and the resulting total rate forecast would be similarly speculative. As discussed in this Attachment in describing the modeling changes for the nuclear fleet, Strategist normally models only the generation-related portion of the business, or around 50 percent of the total revenue requirements. For the period beyond 2020, the costs not typically modeled in Strategist were escalated at a generic "inflation-proxy" rate of 2 percent, and were added to the annual costs from the IRP Scenario 1 (Reference Case) model results that are presented throughout this filing. This approach avoids speculation on areas of the business not related to resource planning, while preserving the detailed generation-related information from the Strategist model.

The annual deltas of the various scenarios (including the Updated 2015 Plan and the Current Preferred Plan) to the Reference Case were added to this underlying Reference Case total rate forecast to determine the total rates for these scenarios.

VII. SCENARIO OUTCOMES

An updated summary of the Strategist model's PVRR/PVSC outputs for the various scenarios and sensitivities is shown below in Table 9. Table 10 below shows the results including the nuclear cost assumptions described in Section I, Part C above.

Table 9: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUMPTIONS T	CUSTOMER IMPACT U
Reference Case	1	52,422	49,050	57,073	47,587	48,781	55,882	48,320	53,235	66,308	45,605	45,934
Original 2015 Plan	10_A	52,083	49,225	56,063	47,755	48,818	55,193	48,386	52,663	64,863	45,924	46,229
Updated 2015 Plan	10	51,458	48,599	55,439	47,132	48,195	54,568	47,763	52,040	64,237	45,302	45,606
Current Preferred Plan (no Boiler)	28	51,293	48,283	55,463	47,317	48,293	54,155	47,896	51,805	63,457	45,606	45,956
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	51,280	48,261	55,465	47,295	48,273	54,148	47,876	51,797	63,464	45,582	45,934
Current Preferred Plan (Boiler + SHC CC x1)	B28	51,329	48,319	55,499	47,352	48,328	54,191	47,931	51,841	63,492	45,641	45,995
North Dakota Plan	15	52,620	49,013	57,568	47,535	48,792	56,252	48,305	53,464	67,051	45,473	45,761

Table 10: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities with Nuclear Costs

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUMPTIONS T	CUSTOMER IMPACT U
Original Reference	1	56,033	52,662	60,684	51,199	52,393	59,494	51,932	56,847	69,919	49,217	49,545
Original 2015 Plan	10_A	55,694	52,836	59,675	51,367	52,430	58,805	51,997	56,274	68,474	49,536	49,840
Updated 2015 Plan	10	55,070	52,211	59,051	50,743	51,806	58,179	51,374	55,652	67,848	48,913	49,218
Current Preferred Plan (no Boiler)	28	54,904	51,895	59,074	50,929	51,905	57,766	51,508	55,417	67,069	49,218	49,567
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	54,891	51,873	59,076	50,907	51,885	57,760	51,488	55,409	67,075	49,193	49,546
Current Preferred Plan (Boiler + SHC CC x1)	B28	54,940	51,931	59,110	50,964	51,939	57,802	51,543	55,453	67,103	49,253	49,607
Original ND Plan	15	56,231	52,624	61,180	51,146	52,403	59,864	51,916	57,076	70,663	49,085	49,373

Attachment C
Resource Plan Comparisons

As our Resource Plan has evolved substantially since our initial January 2015 filing, we provide here a comparison and update on the Expansion Plans for our Reference Case, Updated 2015 Plan, and Current Preferred Plan, to provide readers an easy reference between the scenarios. We have also included data on our updated Renewable Energy Standard (RES) and Solar Energy Standard (SES) Compliance positions under the Current Preferred Plan.

A. Expansion Plans

The Expansion Plans below represent only those resource additions we are proposing in each scenario. The Updated Load and Resources Table in the body of the Supplement included all of the existing and approved resource changes that we anticipate over the course of the planning period. Table 1 below provides our Reference Case Expansion Plan.

Table 1: Reference Case Expansion Plan – Installed Capacity (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	690	690	460	-	-	-	1,840
Combined Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778

Only the utility-scale resource additions proposed as part of our Reference Case are identified in Table 1. All small solar, as well as the 187 MW Solar Request for Proposals Portfolio[1] and the competitive acquisition process[2] (CAP) resources, are reflected as existing/approved resources, and therefore not included in the Expansion Plans. The 400 MW of wind in 2020 represents non-Production Tax Credit (PTC) additions, as we did not update the Reference Case to include the tax credit extension.

Table 2 below shows the Expansion Plan for our Updated 2015 Plan, referred to in previous filings as the Preferred Plan.

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[1] Approved by the Commission in February 2015 in Docket No. E002/M-14-162.

[2] Docket No. E002/M-12-1240, includes 100 MW Aurora Solar project, 345 MW Calpine Mankato project, and the 232 MW Xcel Energy Black Dog 6 project.

Table 2: Updated 2015 Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	-	-	-	-	-	-	300	200	200	500	-	200	1,400
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	1,800
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	460	460	230	230	-	-	1,380

The Updated 2015 Plan Expansion Plan is largely consistent with what we filed in the March 2015 Supplement, although the assumptions have been updated to reflect the extension of renewable energy tax credits. As a result, the 600 MW of wind in 2020 is modeled as benefiting from the PTC. Finally, the Current Preferred Plan Expansion Plan is included in Table 3 below.

Table 3: Current Preferred Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

This Expansion Plan for the Current Preferred Plan matches the total proposed renewable resource additions included in our October 2, 2015 Reply. The updated assumption related to the renewable energy tax credit extension results in a shift in the type – from non-PTC to PTC – and timing of those resources, and an associated cost reduction for the 800 MW of wind added in 2019. Our October proposal included a proposed generic North Dakota CT in 2023, which after further analysis has shifted to a Company-owned CT in Fargo in 2025, although the unit may be placed in-service before 2025. Due to the site-specific resource additions we have selected for our Current Preferred Plan, the model's selection of natural gas capacity additions have adjusted. While a Sherco boiler conversion was considered in our October Reply Comments, it was not selected in our Current Preferred Plan for reasons discussed in Attachment B. Of note, the retirement of the Sherco units result in the need for additional CT capacity and the addition of a combined cycle in 2027.

B. Renewable Energy Standard Compliance Position

Our Current Preferred Plan continues to support and exceed our compliance through 2030 with the Renewable Energy Standard (RES) and objectives across the NSP system that we presented in our January 2015 filing. Minnesota's RES requires the Company to generate or procure 30 percent of retail electric sales from renewable sources by 2020.[3] This scenario assumes the 3,900 MW of renewable energy additions laid out in our Current Preferred Plan and includes: 700 MW of small solar, 1,400 MW of large solar, and 1,800 MW of wind. Table 4 below details our compliance position through the generation of Renewable Energy Credits (RECs) with NSP System RES obligations in 2016 and 2020.

Table 4: Renewable Energy Standard Compliance, Current Preferred Plan

	2016	2020
NSP Calendar Year RECs	11,216,449	17,274,331
NSP RECs Available for Compliance	26,887,161	55,532,748
RECs Needed for Compliance	8,833,247	10,917,122

In our Current Preferred Plan, we expect to generate sufficient RECs to exceed the renewable energy obligations of those states in the NSP system.

C. Solar Energy Standard Compliance Position

The SES requires an additional 1.5 percent of retail sales to come from solar energy resources by 2020. Of the 1.5 percent SES, 10 percent must come from systems with capacity less than 20 kW.

Table 5: Solar Base Case

	2020
S-RECs Needed for SES Compliance	453,483
S-RECs Available to Meet Requirement	4,620,918
Total Compliance Energy	1,396,551

Table 5 above demonstrates that in our Current Preferred Plan, the 1,400 MW of additional utility-scale solar energy in the out-years of the planning period combined with the small solar and community gardens additions take us beyond our SES compliance obligations, and put us on a path toward fulfillment of Minnesota's energy policy vision.

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3 Minn. Stat. § 216B.1691.

Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

A Grid Primer and Summary Report of:

Midcontinent Independent System Operator (MISO) Attachment Y2 Study performed by: MISO (August 28, 2015)

Xcel Energy Transmission Reliability Study performed by: Xcel Energy Transmission Planning in conjunction with Siemens Power Technologies International (January 22, 2016)

Black Start Plan Analysis performed by: Xcel Energy Realtime Transmission Planning

January 29, 2016

This is designed to help prevent key information about our system and the grid from being accessible.

Contains Non-Public Information:

The Company developed this grid primer and summary report in an effort to provide a public report of its technical analyses and conclusions as they relate to the potential retirement of its Sherburne County Generating Plant (Sherco) Units 1 and 2. The reports and analyses themselves contain critical electrical infrastructure information (CEII) and other highly-sensitive information about the Xcel Energy and other regional transmission owner systems, so are entirely not public. We maintain that the partially-redacted study reports are "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). We have also redacted limited portions of this summary report. We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements. We provide a full justification of our non-public treatment of this information in the cover letter accompanying our January 29, 2016 Resource Plan Supplement.

TABLE OF CONTENTS

I. INTRODUCTION

Xcel Energy initiated three technical studies to examine the transmission reliability impacts of its Sherburne County Generating Plant (Sherco) Units 1 and/or 2 if they were to cease operations: (1) a *Midcontinent Independent System Operator (MISO) Attachment Y2 Study*; (2) an *Xcel Energy Transmission Reliability Study*, performed in conjunction with Siemens Power Technologies International (Siemens); and (3) a *Black Start Plan Analysis*. The Company's conclusions from these studies is that: (1) ceasing operation of Sherco Units 1 and 2 would create system conditions that require mitigation; and (2) siting dispatchable, thermal generation at the Sherco site is the most cost-effective solution and provides the greatest level of certainty in terms of cost and reliability to meet the Company's energy and capacity requirements, maintain reliability for its customers, and support the Company's vision of a clean energy future.

The electric "grid" is a large complex machine consisting of generation and transmission facilities that operates across a very large geographic area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast, and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system can impact other portions of the system.

The Sherco Plant is the largest power station in the Midwest, consisting of three units that have a total generating capacity of 2,250 MW. Units 1 and 2 that are a focus in the 2016-2030 Resource Plan are wholly-owned baseload facilities with generating capacity of approximately 700 MW each for a total of approximately 1,400 MW. Both the Company's Sherco Plant and Monticello Nuclear Plant are located in Sherburne County Minnesota, making the location of these large, baseload generating facilities a very important consideration in maintaining system stability and reliability. Together, these plants total nearly 3,000 MW of generating capacity, or approximately 30 percent of the Company's total existing generating capacity.[1]

With the concentration of so much generation in one geographic area, the electrical

[1] Generating capacities are expressed as MISO Unforced Capacity (UCAP) values. Values for the Sherco Plant include both the Xcel Energy and the SMMPA ownership shares of Sherco Unit 3.

performance of the regional transmission system – and the entire mix of resources on the NSP System – is fundamentally designed around these Units. At its core, to preserve system stability and customer reliability the system must balance generation with changing load conditions and fluctuations caused by other disturbances. Large generating units like Sherco Units 1 and 2 afford the capability for the system to "ride through" these frequency disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be compromised.

Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause further disconnections and shedding of load. Sherco Units 1 and 2 provide the spinning mass that assists in maintaining the 60 hertz (Hz) frequency for the region. They are uniquely able to do this because of their size and operating characteristics, which include the ability to quickly increase or decrease their output in response to system conditions. Therefore, potentially ceasing coal operations of one or both Sherco Units 1 and 2 as we have proposed in our Current Preferred Plan must consider more than replacement of the capacity and energy they provide to our customers.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might overload or fail, assuming specific circumstances. We measure these results against North American Electric Reliability Corporation (NERC) requirements.[2] NERC is designated by the Federal Energy Regulatory Commission as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk-power system throughout North America, as called for in the Energy Policy Act of 2005.

NERC defines a reliable bulk-power system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity, and divides reliability into two categories:[3]

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[2] We provide an abbreviated list of NERC Event Categories in Table 13 in Section IV.C.3 of this Summary Report.
[3] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. The bulk-power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization. Also a regional entity MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest and Southern United States, and Manitoba, Canada.[4] MISO is also the Regional Transmission Organization that ensures electric reliability and optimizes supply and demand bids for wholesale electric power in their region. The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

The three studies we initiated examined differing aspects of potentially retiring Sherco Units 1 and 2, as follows:

MISO Attachment Y2 Study. The MISO Tariff requires that any generation retirement be studied and approved by MISO to ensure that it results in no adverse effects to the reliability of the system. Therefore, the focus of this Study was on the impacts to the grid if one or both of Sherco Units 1 and 2 ceased operation. We initiated a Study

[4] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

under Attachment Y2 of the MISO Tariff, which is a non-binding, informational study. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a retirement date-certain is determined.[5]

The MISO Y2 Study concluded that retirement of Sherco Units 1 and 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for the Units to be designated as SSRs. Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.[6]

The Study found that retirement of both units would result in a major reactive power deficiency in the Monticello area that would cause a violation of Monticello's Nuclear Plant Interface Requirements (NPIR) voltage requirements that would be a violation of Monticello's Nuclear Plant Operating Agreement.[7] The plant would not be allowed to operate if the voltage falls below its NPIR minimum threshold. The Study also identified a number of other reliability issues, including thermal overloads of 115 kV and 345 kV transmission lines and some smaller scale voltage deficiencies.

Xcel Energy Transmission Reliability Study. We retained Siemens to study the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated replacement of one or both Units at alternate locations on the NSP System. Our Study used the same system models as MISO used for its Y2 Study, but differed in that the Y2 Study did not examine replacement of all or a portion of Unit 1 and 2 generation. Our Reliability Study also set out to examine the potential impacts from the cumulative effect of additional larger generation unit retirements on the NSP System by also studying the shutdowns of the Monticello Nuclear Plant due to its proximate location to Sherco, and one Prairie Island Unit in combination with Sherco Units 1 and 2. We decided however to pause this work, in light of the increased interest in the future of our nuclear

[5] Per Section 38.2.7 of the MISO Open Access Transmission, Energy, and Operating Reserve Markets tariff.
[6] MISO has proposed tariff changes to the Attachment Y notification process that could make such Notice unnecessary. If a generating unit is being replaced with an equal- or larger-sized (MW) unit, an Attachment Y notice would not be required; only an Interconnection request for the new unit utilizing the existing interconnection rights would be required. An SSR study under Attachment Y of MISO's tariff would only be required if the new/replacement generating unit is smaller (MW) than the unit being retired.
[7] The Monticello Nuclear Plant, along with all nuclear plants in the United States have NPIR voltage requirements that are required to support FERC/NERC Regulation NUC-001. NUC-001 requires coordination between nuclear plant operators and transmission entities for the purpose of ensuring safe nuclear plant operation and shutdown.

units. As we discuss in Section VII of our January 29, 2016 Resource Plan Supplement, we intend to initiate a more broad and in-depth study of the effects of a potential shutdown of our nuclear units on our transmission system in 2016.

Our Reliability Study involved a full thermal analysis, full voltage analysis, and transient stability analysis, and confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Black Start Plan Analysis. A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Sherco Units 1 and 2 are currently the primary Target Units, or first generating units to be repowered as part of our Black Start Plan. This analysis examined the viability and costs associated with changing the current system restoration path from Sherco Units 1 and 2.

Our Black Start Plan analysis concluded that without the current Sherco Unit 1 and 2 restoration path from our Initial Unit(s), we would need to rely on different restoration paths to multiple Target Units.[8] We will need additional facilities on the alternative restoration paths and altering our path causes restoration of our system and customer load to take longer. The expediency of the restoration path is particularly important in winter/cold weather, because a delay of as little as one hour could mean that we may have to begin draining our boiler systems or taking additional measures at our steam generating plants before they freeze and are damaged. If this is necessary, restarting those plants could take several days, which could impact restoration of our customers.

It is important to note that the assumptions used in these studies are based on expected conditions at the time they were initiated in early 2015. The system is dynamic and expected conditions can change when new generation comes online, new transmission lines are constructed, or existing lines are reconfigured.

[8] The Initial Unit is the first generating unit that sets restoration in motion. Target Units are the generating Units on the restoration path that was started by the Initial Unit.

We believe a combination of EPA's Clean Power Plan along with aging generation assets will significantly change the generation mix in the United States over the next 15 years. Not only have we started to perform studies to understand the potential impact of significant generation changes, the industry is also beginning to examine the potential impacts of a changing generation mix. Entities such as NERC and MISO are beginning to study the potential cumulative impacts of significant generation changes across the country.[9]

We have many years ahead of us to try to simulate and understand the cumulative effect of a different mix of generating units. We know what we have today works well, and to the extent replacement generation is located in similar electrical locations, we are confident the grid will continue to perform well.

II. CURRENT SYSTEM/GRID

A. Overview

The "grid" is a large complex machine consisting of existing generation and transmission facilities that operates across a very large area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico.

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

[9] *See* NERC Potential Reliability Impacts of EPA's Proposed Clean Power Plan (Phase I) at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf and MISO Analysis of EPA's Final Clean Power Plan Study Scope (November 2015) at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20151111/20151111%20PAC%20Item%2003e%20Clean%20Power%20Plan%20Final%20Rule%20Analysis%20Scope.pdf

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our bulk transmission system is anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco (coal) and Monticello (nuclear) in the northwest and A. S. King (coal) and Prairie Island (nuclear) in the east and southeast. Together these plants provide over 4,020 MW of capacity and over 29,000 GWh of energy to our customers, which represents 46 percent of the NSP System generating capacity and 65 percent of the system energy. This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake. The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

Over time, we expect that there will be more and more development of microgrids and other new technologies such as batteries. Rather than competing with the existing grid, these new technologies will be complementary, in that each system can support and help the other. For example, to the extent microgrids have challenges, the grid can help provide reliability to those areas – and as microgrids develop over time, there will be more and more integration of the capabilities they can provide into grid operations.

B. Key Elements Ensure Reliable Service

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate dispatchable generation to both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time.

C. Role of Sherco Units 1 and 2

Sherco Units 1 and 2, located in Becker, Minnesota play an important role in the reliable electrical service we provide to our customers. Together, they produce approximately 1,400 MW of capacity and associated energy, and are tied to the transmission grid through five 345 kV and two 115 kV lines.

As we have discussed, the ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. Sherco Units 1 and 2 are no different. In fact, the Upper Midwest system, and the NSP System, has been designed around Sherco Units 1 and 2, and relies on the unique aspects of these Units to not only generate capacity and energy for our customers, but also to provide numerous essential system operational services.

Potentially ceasing coal operations of one or both of these Units must consider more than replacement of their energy output. The Units' technical characteristics include:

- *Power Deliverability.* The existing transmission system has been developed to be able to receive the approximately 1,400 MW of power injected from Sherco Units 1 and 2 and to deliver it to various area substations to meet the electrical power demands of customers. This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.
- *Dynamic Stability.* The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and

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[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Units 1 and 2 have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current.* Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[11] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.

- *Black Start Capability.* In the event of a major regional grid outage, Sherco Units 1 and 2 are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Our current plan requires Initial Unit(s) of approximately 110 MW and up to 300 MW to get the restoration started. Sherco Units 1 and 2, because of their ability to operate at lower outputs, along with their reactive capabilities, are considered eligible Target Units, which are

[11] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

the next units used in the restoration. Sherco Unit 3 is not a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, nuclear units are not viable Target Units, because they cannot vary their output and can only come online after the system is fully stable. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power.

- *Voltage Support.* The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. The Sherco 1 and 2 Units, as large synchronous power sources, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation.* System regulation essentially means the ability of the system to respond instantly to changes in usage, i.e. keeping the generators and loads exactly matched at all times. Sherco Units 1 and 2 have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are sudden large changes to the generation/load balance, as when a generating unit drops offline or a large industrial load (like a smelter) comes online, the frequency drops if there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system.

III. TECHNICAL STUDIES OVERVIEW

As we have discussed, the grid is a complex machine that is integrated over very large portions of the country. The bulk and load serving NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment).

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While studies are essential and provide important insights, our decades of operating and studying the existing system provides valuable insights and perspective in siting considerations for replacing Sherco Unit 1 and 2 generation.

We have stated previously that our initial assessment was that completely replacing the baseload energy from Sherco Units 1 and 2 with renewable energy facilities was likely infeasible from a reliability perspective. Our Studies support the conclusion that the addition of dispatchable, thermal generation at the Sherco site will ensure ongoing reliability of the NSP System for our customers in the most cost-effective manner. Having sufficient dispatchable generation on the system also supports the addition of the significant levels of renewable generation we propose with this Resource Plan.

We are confident that generation injections in locations where those electrical injections occur today will result in a high level of reliability and good performance from our transmission system. With that said, we have proposed to replace a portion of Sherco Units 1 and 2 energy and capacity with a natural gas combined cycle (CC) at the Sherco site. We believe this proposal is superior to alternatives, will provide necessary voltage support to the Monticello Nuclear Plant and surrounding area, and is cost-effective for our customers.

We note that the MISO Y2 Study and our Reliability Study identify transmission upgrades necessary to resolve the respective issues the studies identified. In addition to these transmission upgrades, there are additional (interconnection) transmission costs involved to connect generation to the grid. Therefore, to get a full picture of the costs, interconnection costs must to be added to the transmission upgrade costs.

A. Studies Performed

As outlined previously, we initiated three studies to understand the technical implications and to identify any mitigating measures that must be undertaken, as follows:

- *MISO Y2 Study*,
- *Xcel Energy Transmission Reliability Study*, and
- *Black Start Study*.

Our Studies used the best information available at the time they were initiated to develop the models used to conduct the analyses; MISO performed its Y2 Study in accordance with their Business Practice Manuals.[12] However, all studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. Therefore, there are inherent limitations in any study effort.

B. MISO Attachment Y2 Study

1. Overview

As we discussed in our October 2, 2015 Reply Comments, we initiated a MISO Attachment Y2 Study to examine the reliability impacts from the potential retirement of one or both Sherco Units 1 and 2. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a generation owner determines a retirement date-certain. The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, which apply NERC requirements, and include monitoring and identifying the steady state branch/voltage violations and the transient stability violations on transmission facilities due to the unavailability of the generating resources.

The Company's request was for MISO to analyze retirement of Sherco Units 1 and 2 under two retirement scenarios: (1) retire Sherco Unit 1 and Sherco Unit 2 on May 31, 2021; and (2) retire Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024. Because Sherco Units 1, 2, and 3 (in addition to Monticello) are the largest reactive power resources in the Twin Cities area, MISO specifically assessed the voltage implications under certain power transfer scenarios if all of these plants were out of service. Finally, due to the electrical proximity between the Monticello Nuclear Plant and Sherco, MISO assessed the voltages at Monticello's 115 kV and 345 kV busses to ensure they remained within the very specific and narrow range specified in Monticello's NPIR.

2. Study Results

The MISO Y2 Study concluded that ceasing operations at Sherco Units 1 and 2 would create system conditions that violate NERC requirements that would require transmission upgrades and the need for the Units to be designated as SSRs.

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[12] *See* MISO Business Practice Manual BPM-020 at:
https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Assuming a future Attachment Y study would have similar results, MISO would require that the Company mitigate identified violations to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.

At a high level, the MISO Y2 Study identified several voltage violations due to a substantial reactive power deficiency in the Monticello area that is a major concern and needs to be addressed to maintain voltages at Monticello Nuclear Plant within its permissible range. The Monticello Nuclear Plant cannot operate if its voltage is outside the permissible range. If only one Sherco Unit retires and the other Unit remains in service, the analysis identified a smaller reactive power deficiency that would need to be addressed, and some other relatively minor reliability issues that can be addressed by minor equipment installations such as capacitors.

The MISO Y2 Study also identified thermal violations (transmission lines above their rated capability) created when replacement generation was dispatched from others areas of the MISO system. For example, a rebuild of a 345 kV line to 3,000 Amperes was an identified action that would be needed to alleviate some identified thermal violations. With regard to system stability, the transient stability assessment showed acceptable behavior without Sherco Units 1 and 2.

The specific Study conclusions that require mitigation are as follows:

- Several voltage violations due to a reactive power deficiency in the area that violate Monticello's NPIR voltage requirements, would be a violation of Monticello's Nuclear Plant Operating Agreement, and would require the plant to cease operation until the voltage is within the NPIR range,
- A 25 MVAR capacitor bank would need to be installed in 2017 at WMU-Priam 115 kV bus to alleviate local voltage issues. (*Note*: this is existing MISO MTEP Project 4380, so will not result in incremental cost to the Company),
- A capacitor bank(s) would be needed at the 115 kV bus of a generating station to maintain the voltage above their minimum voltage requirements,
- The rebuild of a 345 kV line to 3,000 Amperes to alleviate a portion of the identified thermal violations,
- A 115 kV line may also need to be rebuilt to alleviate other thermal issues per the SSR criteria, and
- Voltages at Monticello's 115 kV and 345 kV buses are lower than the plant's voltage requirements.

We note that the CC generating unit we have proposed for the Sherco site would fully resolve these issues.

3. *Mitigation of Identified Issues*

The CC generating unit we have proposed for the Sherco site is our preferred option for mitigating the violations identified in the MISO Y2 Study. However, in the alternative, MISO identified potential ways to mitigate the identified impacts, which we estimate would cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, plus significant ongoing operating and maintenance costs to mitigate. We outline these measures in Table 1 below, and also discuss the Synchronous Condenser, which at approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, is the most significant of the mitigating measures.

Table 1: MISO Potential Mitigation Measures and Xcel Energy Estimated Cost ($Millions – 2015)

MISO Identified Potential Mitigation Measure	Xcel Energy Potential Mitigation Measure and Estimated Cost
Reductions and runbacks to existing generators	None
Transfer of certain feeder loads	None
Tripping of certain transmission lines	None
Install reactive capacity on system to maintain voltages at Monticello Nuclear Plant within permissible range as per the Monticello NPIR	Convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install Proposed Project including a 25 MVAR capacitor bank to be installed at substation in 2017 *(already planned)*	No incremental cost to Company
An MTEP project addresses the 115kV system voltage issues resulting from events *(already planned)*	No incremental cost to Company
Increase capacity of a 115 kV line	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install capacitor banks at generator station 115 kV bus.	Install capacitor bank(s) & upgrade substation – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Rebuild of 345 kV line to 3000 Amperes is needed to alleviate some identified thermal violations	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Synchronous Condenser – As we have described, large generators play a very important role on the system, one of which is providing necessary reactive power to the grid. If reactive power cannot be supplied promptly and in sufficient quantity, maintaining voltage is challenging, which is the case with Monticello's NPIR. Therefore, if no replacement generation is installed at Sherco, we would need to install other equipment that can both generate and absorb reactive power as needed to adjust the grid's voltage. Sherco would be a good location for this other equipment because reactive power can only be practically transmitted over relatively short distances.

There are currently three available options to address this issue: (1) a Synchronous Condenser (SC); (2) a Static Var Compensator (SVC); or (3) a Static synchronous compensator (Statcom). Considering the three alternatives, we believe the best option for the NSP System is to convert Sherco Unit 1 or Unit 2 to an SC. Installation and operation of an SC is identical to large electric motors and generators. It is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. Its principal advantage is the ease with which the amount of correction can be adjusted. However, importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. As we have described, there are significant system stability benefits associated with the inertia provided by large rotating masses.

As a point of reference, an SVC is a set of electrical devices for providing fast-acting reactive power. Unlike an SC, which is a rotating electrical machine, an SVC has no significant moving parts (other than internal switchgear). The main advantage of SVCs over simple mechanically-switched compensation schemes is their near-instantaneous response to changes in the system voltage. Similarly, a Statcom is a regulating device that can either provide or absorb reactive power. It is inherently modular and has better characteristics than an SVC. In contrast to an SVC, its maximum reactive output current will not be affected by the voltage magnitude, whereas the SVC's reactive output is proportional to the square of the voltage magnitude, which makes the provided reactive power decrease rapidly when voltage decreases, thus reducing its stability. In addition, the speed of response of a Statcom is faster than that of an SVC and its harmonic emission is lower. Statcoms typically exhibit higher losses and are generally more expensive than SVCs, so are not in widespread use.

Both SVCs and Statcoms are generally less expensive than SCs, however, neither offers the significant stability benefits that come from having large, rotating mass around our system – and both introduce harmonics into the grid. In general, harmonics cause power quality problems, and result in increased heating in equipment and conductors, misfiring in variable speed drives, and torque pulsations in motors, which would potentially affect both our equipment and that of our customers. Additionally, there are other electronic devices on the system, such as the D.C. terminal in the western Twin Cities that has electronic equipment that can be negatively impacted by harmonics. For these reasons, we have determined the SC is the best solution for the NSP System.

4. *Summary*

We note that these results are based on assumptions and the MISO system as it was known in March 2015. We believe it is reasonable to conclude that the MISO Y2 Study results could be viewed as optimistic, since other generators assumed to be running at the time of this study will likely be different than when MISO performs their official Attachment Y analysis, which is currently required in the 26-week period preceding an actual planned Unit retirement.[13]

We are confident, however, that regardless of the status of other generators in the MISO system, the natural gas CC we have proposed to construct at the Sherco site in 2026 is the best solution to mitigate any technical issues associated with retiring Sherco Units 1 and 2.[14] As we have discussed, a large generator plays a very important role on the system, in terms of providing necessary reactive power and maintaining its voltage, frequency and overall stability. For the reasons we have discussed, by placing a large generator at the same injection point on the transmission system, we have absolute confidence that the system will function as well as it does today.

Placing a large generating unit at Sherco will handle the inevitable disturbances the grid successfully deals with every day, which range from ever-changing electric use (i.e., as people/businesses turn on and off electrical equipment), periodic changes to power transfers as electric markets dispatch generation every five minutes, to periodic outages (planned or unplanned), to adverse weather, and other impacts caused by humans, animals, trees, etc.

We discuss the MISO Y2 Study approach, assumptions and inputs in Section IV. below.

[13] As noted previously, MISO is contemplating changes to its Attachment Y requirements.
[14] The MISO Y2 Study identified minor issues related to retirement of the first Unit, which we believe can be resolved without the need for significant upgrades.

C. Xcel Energy Transmission Reliability Study

In early 2015, we engaged Siemens Power Technologies International to gain technical insights as to the local and regional transmission impacts of ceasing coal operations at Sherco Units 1 and 2. The study consisted of two components: (1) analyze alternative locations for replacement generation for Sherco Units 1 and 2, and (2) identify deficiencies in ensuring ongoing reliable energy delivery to our Upper Midwest customers by performing a full technical analysis of the impacts of retiring significant baseload generation from our system and determine potential long-term solutions.

We conducted our Reliability Study in phases: (1) Retirement of one of the Sherco Units 1 and 2; and (2) Retirement of both Sherco Units 1 and 2. The Study included the following analysis for both local and regional transmission facility impacts and disturbances with one or both Sherco Units 1 and 2 out of service:

- *Full thermal analysis.* Thermal analysis evaluates the steady-state flows (greater than 30 seconds) on the transmission system following a disturbance and identifies transmission facilities that are outside their allowable thermal ratings. The thermal analysis also calculates system losses.
- *Full voltage analysis.* Voltage analysis evaluates the steady-state voltages (greater than 30 seconds) on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable voltage limits.
- *Transient stability.* A transient stability analysis evaluates whether the power system electrically "stays together" and the impact on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable stability limits. Specifically, we looked at the ability of the grid to maintain electrical connection following disturbances.

Our Reliability Study used the same MISO MTEP14 models as the MISO Y2 Study, adjusted to reflect the 2020 timeframe, and applied the same planning criteria. However, because the MISO Y2 and the Reliability Studies have different base input assumptions, the two studies investigate different perspectives on the issue of retiring one or two Units at Sherco. Additionally, our Reliability Study differs from the MISO Y2 Study in that the MISO Y2 Study analyzed the impacts of turning off one or both Sherco Units 1 and 2 assuming no replacement generation. Its purpose was to determine how the system would behave in the absence of these generators. Our Reliability Study also analyzed impacts on the transmission system and estimated transmission upgrade costs related to ceasing coal operations at Sherco Unit 1 and 2 *and replacing the generation* at alternate locations as follows: (1) Metro – a location near the Twin Cities; (2) Southwest – a location in southwest Minnesota; and (3) Northwest – a location in eastern North Dakota.

Our Reliability Study's conclusions were consistent with the MISO Y2 Study conclusions, in that they also identified NERC violations that would need to be mitigated if Sherco Unit 1 and 2 are retired. Specifically, we concluded:

1) Siting replacement generating units outside of Sherco is technically feasible but would require transmission system upgrades.
2) The required transmission system upgrades for replacement generation outside of Sherco is dependent on other generation that is included in the study.
3) The further the replacement generation was located from the Twin Cities load center, the greater the transmission losses.

Importantly, our Reliability Study concluded that replacement with a large generating unit that provides similar benefits to the NSP System as Sherco Units 1 and 2 will cost-effectively ensure voltage, frequency, and reliable service for our customers. Additionally, the Study in combination with other identified costs supports that replacement at the current Sherco site is superior and the most economical of the alternatives studied. Finally, our Reliability Study supports the conclusion that locating thermal replacement generation at Sherco provides the most cost certainty with regard to required transmission upgrades, since the Sherco site can utilize existing transmission facilities and interconnection rights – and the grid is constructed such to expect a large generation injection at that location.

It is important to note that our Reliability Study was initiated in early 2015. Since that time, significant amounts of generation have entered the MISO interconnection queue, so the estimated transmission mitigation costs we outline are very likely optimistic, because the generating resources that are in the queue will come online and will "use up" transmission capacity that our Study assumed would be available in the future.

1. Siting Replacement Generating Units Outside of Sherco is Technically Feasible but Would Require Transmission System Upgrades

In this section, we outline the transmission mitigation costs of locating replacement generation at studied locations other than Sherco. The Reliability Study showed that transmission mitigation costs (not including interconnection costs) increase the further away you move the generation from the Twin Cities load center.

Table 2: Estimated Costs – One 750 MW Combined Cycle Unit

($millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS...			
Metro			
Northwest			
Southwest			
			...TRADE SECRET ENDS]

Table 3: Estimated Costs – Two 750 MW Combined Cycle Units

($ millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS...			
Southwest Metro			
Northwest Metro			
Northwest Southwest			
			...TRADE SECRET ENDS]

The indicated Generator Interconnection costs in Tables 2 and 3 above are planning level estimates for the electrical facilities necessary to connect the generating plant to the Point of Interconnection (POI) and include a 345 kV substation that will accommodate a CC unit with two simple cycle turbines and one steam turbine and the 345 kV line which will connect the generator to the MISO POI. The costs vary between generator locations due to the assumed lengths of the transmission line. The generation interconnection costs also include the expected cost to expand the POI substation to accommodate the line from the generator, costs for metering and relaying and other interconnection facilities required by the MISO generation interconnection process. The basis for the costs is historical facility studies performed for other Xcel Energy generator interconnections.

2. The Required Transmission System Upgrades for Replacement Generation Outside of Sherco is Dependent on Other Generation Included in the Study

Greater amounts of generation sited at locations other than Sherco result in the need for more significant transmission upgrades (and costs) to support delivery and interconnection of the generation, as shown in Table 3 above.

3. The Further the Replacement Generation was Located From the Twin Cities Load Center, the Greater the Transmission Losses

The Reliability Study results indicate that the further from the Twin Cities load center that the replacement generation is located, the higher the losses. Tables 4 and 5 below show transmission system losses for peak load and shoulder load conditions for the alternate replacement generation location.

Table 4: Total System Losses by Replacement Location – at Peak Load
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	1,739		Base Scenario	1,738	
Southwest	1,743	4	SW Metro	1,736	-2
Northwest	1,753	14	NW+Metro	1,743	5
Metro	1,725	-14	NW+SW	1,768	29

Note: Point of peak load is during 2020 Summer

Table 5: Total System Losses by Replacement Location – Shoulder Conditions
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	2,207		Base Scenario	2,199	
Southwest	2,221	13	SW+Metro	2,196	-3
Northwest	2,272	65	NW+Metro	2,256	57
Metro	2,180	-27	NW+SW	2,300	102

Note: Shoulder conditions is during 2020 Summer

These tables demonstrate that losses increase the farther away generation is located from the Twin Cities load center.

4. Summary

Our Reliability Study analyzed three alternate locations for siting replacement generation and concluded that siting replacement generation at locations other than Sherco will result in transmission upgrade costs that would not be needed if replacement generation is sited at Sherco. The number and cost of any required transmission upgrades is dependent on the location of the replacement generation, the amount of transmission capacity available from that location, and the amount of "other" generation that will be competing with the replacement generation for transmission capacity.

Additionally, because significant generation has been added to the MISO generation interconnection queue since we started our Reliability Study in early 2015, the costs we have estimated for alternate locations are likely low and less certain because of how the MISO system will evolve as a result. Finally, the further the replacement generation is sited from the Twin Cities load center, the higher the amount of losses the generation experiences – and while not specifically evaluated in our Study, we believe siting replacement generation in wind rich areas such as southwest Minnesota will "use up" transmission capacity that can be used for the installation of additional wind or other renewable generation.

D. Black Start Analysis

As explained in our March 16, 2015 Supplement, Sherco Units 1 and 2 play a significant role on our system and in the entire Upper Midwest. One of the key roles these Units play is in restarting the system in the event of a catastrophic loss of power to all or a significant part of a geographic area. Normally, the electric power used within a generating plant is provided from the station's own generators. If all of the plant's main generators are shutdown, station power is provided by drawing power from the transmission grid, which can be used to start the plant. However, during a wide-area outage, power from the grid will not be available. In the absence of grid power, a so-called "black start" needs to be performed to "bootstrap," or self-start the power grid into operation without the use of external resources.

We are required by NERC to maintain a plan to restart the system, which must be coordinated with neighboring utilities and is subject to acceptance by MISO. In this section, we discuss the considerations that go into black start planning, and our conclusion that other restoration paths, while less efficient, are viable with various equipment upgrades.

1. *Overview*

Black Start planning involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. This process sets up "islands" where part of the transmission and distribution systems in a geographic area begin serving at least part of the load in that area. Once we determine an island is stable, we can synchronize and reconnect/restore more generators and load, essentially expanding the island and restoring our interconnections with other utilities until the system is fully recovered. The longer the system is down, the harder it is to restore, so we work to determine the most efficient path(s) possible.[15]

We generally plan restoration assuming that the event that caused the outage caused no damage to the system. However, because this is a possibility, we must also plan alternate restoration paths that we can take in the event a portion of the system is damaged as part of the catastrophic event. We also must incorporate differing procedures based on the weather extremes in our geographic footprint. For example, any large generating unit that uses steam will take approximately one hour to wind down and fully stop operating. If ambient temperatures are cold, the water that remains in the Unit's pipes and boiler can freeze. Therefore, if we expect restoration of that Unit to take three or more hours, we may need to begin draining the pipes and boilers. If this occurs, our restoration of that generating unit will likely be delayed to the following day, after the unit goes through operational procedures that prepares it for a cold restart.

Sherco Unit 3 is the largest generating unit in the region and during a restoration event, we need it to provide the generating output necessary to restore customer load and the spinning reserves required for the NSP Island.[16] In the circumstance that a generator fails, Sherco Unit 3 has the capacity and the capability to ramp-up generation quickly to pick up the customer load that was lost by the failed generator. This becomes essential as the island grows, incorporating the neighboring utilities. However, Sherco Unit 3 is too large to be a Target Unit, so can only be started after we have at least one additional generator over-and-above the Initial Unit(s).

Our current plan gets from the Initial Unit(s) to Sherco Units 1 and 2 within a couple of hours. Because of their proximate location to Sherco Unit 3, the balance of the restoration plan is set in motion quickly to fully restore the system. As a steam unit, Sherco Unit 3 is impacted by the freeze potential we explained above if it takes longer than approximately four hours to power it up in the winter months. Therefore, getting

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[15] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

[16] In this case, the spinning reserves are the amount of additional generation that is on stand-by in the event that another generator within the island fails. To help ensure consistent availability and reliability of electricity during the restoration process, utilities keep generation capacity on reserve that can be accessed quickly if there is a disruption to the power supply. For example, if another generator or a major transmission line within the NSP/GRE/MP Island goes down, then NSP will access its reserve capacity at Sherco Unit 3 to compensate for that loss.

Sherco Unit 3 up and running quickly not only allows the Company to restore load faster and begin reaching out to neighboring utilities sooner – it also eliminates the concern of broader restoration delays associated with preventing the Unit from freezing.

2. *Planning Considerations*

Only certain types and sizes of generation are eligible to be considered Initial Units or Target Units. As noted previously, the Initial Unit(s) is the first generating unit that sets restoration in motion, and needs to be at least 110 MW and no more than 300 MW. It needs to be big enough to restore a larger Target Unit, but small enough to be able to start with an independent fuel source, such as fuel oil. Target Units are the generating units on the restoration path that are started by the Initial Unit(s). Eligible Target Units include coal, natural gas, hydro, and fuel oil – all of which are controllable and capable of both providing and absorbing reactive power. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. Nuclear units are also not eligible because they cannot vary their output, and can only come online after the balance of the system is fully stable.

When choosing a potential Target Unit as part of a black start study, we consider the following items (other than fuel source):

- Multiple generating units at the site
- Low minimum operating limits
- Ramp rate of the units
- How fast a unit can come on-line once it receives station power
- Unit's ability to act as a stabilizing unit in the island
- Amount of switching required in order to energize the unit

Special care is needed when energizing transmission lines during a system restoration due to the especially light loads present on the system. When lines are energized with little or no real power load, the charging current produces reactive power. We provide an example of how much reactive power may be needed when energizing an overhead transmission line in Table 6 below.

Table 6: Reactive Power Requirement for Energizing Overhead Transmission Lines

Transmission Voltage (kV)	MVAR per mile of line
69	0.011
115	0.033
230	0.125
345	0.164
500	0.770

Underground transmission lines produce even more reactive power that must be absorbed. The reactive power needs of an underground cable is *ten times* that of an overhead transmission line.

The same concern occurs when energizing transformers. The generation that is online must be able to absorb the reactive power injected into the system due to the energization of the transformer.

Table 7: Reactive Power Requirement for Energizing Transformers

Transformer Size (MVA)	MVAR Requirement
28	2.25
47	3.25
70	5.7
187	15
336	27-30
448	36
672	50.25

Before a line or transformer is energized, there must be sufficient generation MVAR capacity online to absorb the capacitive reactance produced by that line/transformer. If not balanced properly, it is easy to overwhelm the generator by collapsing its magnetic field, causing the generator to trip off-line, and potentially re-collapse the system.

When we begin to start-up motors and pumps at the next generating plant, the Initial Unit(s) must be capable of providing that reactive component back to the system in order to start the motors. Table 8 below outlines the amount of reactive power that is needed to start various sized motors at a typical power plant.

Table 8: Reactive Power Requirement for Starting Typical-Sized Generating Unit Motors

	Motor Start		Motor Running	
Motor HP	MW Load	MVAR Load	MW Load	MVAR Load
350	0.36	1.78	0.33	0.16
700	0.73	3.55	0.65	0.32
1500	1.55	7.61	1.4	0.68
2000	2.07	10.15	1.87	0.90
3000	3.11	15.23	2.8	1.35
6000	6.22	30.46	5.6	2.71

Starting large Target Units on our system requires around 30-40 MVAR of reactive power just to start the unit, which is substantial. The restoration path from the Initial Unit(s) to the Target Unit will inject an additional 75-110 MVAR of reactive power onto the system as transmission lines and transformers are energized, which the Initial Unit must absorb until the voltage reactors in our substations are energized.

The amount of MVARs needed for the restoration path will vary depending the on the path. Our current Black Start Plan requires an Initial Unit(s) of approximately 110 MW to 300 MW to restore our Target Unit – setting restoration in motion. Sherco Unit 3 is too large to be a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, as noted previously, nuclear units are not viable Target Units, nor are renewable generating units.

During this time, we must also be energizing transmission lines and transformers to bring customer load onto the system. We must balance the load and generation carefully, as without sufficient load, damage to our or customer equipment can occur from an overload of reactive power; if we energize lines and restore load too quickly, we can trip relays and will have to begin the process again. All substations on the current restoration path have emergency generators for maintaining full operating capability of switches, breakers, and relays at those substations. The emergency generators provide the AC power required to operate transformer pumps and fans as well as the transformer Load Tap Changers (LTCs). The emergency generators also maintain the battery chargers and ensure we maintain full battery capabilities. The substation batteries provide the DC power necessary for protective relaying, the motor operated disconnects, breaker trip coils, and communication equipment.

Generating units that interconnect with other utilities must also have a "sync scope," which is a device that measures frequency, voltage, and phase angle (Volts/VARs) to ensure the two islands (one on each side of the interconnection) are perfectly in sync before interconnecting. If they are not perfectly in sync, both islands could go back down and equipment could sustain damage. This becomes important when we start to reconnect our system with our neighboring systems, or when we bring Minnesota and Wisconsin or North Dakota and South Dakota back together.

3. *Summary*

Each of our current non-renewable generating plants plays a unique role in the black start process. In addition to the key roles currently played by Sherco Units 1 and 2, our **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant plays a key role in restoring the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** portion of our system. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities to other generating units and result in a longer restoration period. As we have discussed, restoration time is of greatest concern in winter/cold months.

The study determined that the existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site were workable for future restoration plans, provided additional emergency generations were added to the system. There is still a delay of several hours in getting from the Initial Unit(s) to Sherco Unit 3, since additional time will be needed to bring either **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** up to a stable minimal load level, before getting to Sherco.

The existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant requires more switching to be part of the restoration plan and has more underground cables in the area that would add a substantial level of complexity to the switching procedures. It is not advisable to utilize **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** as a Target Unit if **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** are available as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** units. In order to utilize the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant, at least 13 new emergency generators would be needed, which would also not be cost-effective or practical from an operational perspective. In comparison, the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would only require a combined five new emergency generators to be installed.

We outline the estimated costs of altering the current Sherco Units 1 and 2 restoration path in Table 9 below. We note that if generation is not replaced at Sherco, at least two of the new restoration paths would need to be used in order to ensure a viable path to Sherco Unit 3. For context, we also include the numbers of operating steps involved for each of the alternative paths, with greater numbers increasing the complexity and extending restoration time.

Table 9: Alternate Restoration Path – Estimated Cost and Operational Steps

Restoration Path	Operational Steps (Transmission)	Estimated Additional Equipment Cost
Current ME	22	
Current MW	16	
New Metro West 345 kV line	25	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro East 345/115 kV	32	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Existing Paths with new Metro West 345 kV line	18	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro West 115 kV	24	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Note: as discussed below, additional costs may be involved with the alternative 115 kV paths.

Our current restoration path relies on the 345 kV transmission system. Some of the above alternatives rely on the 115 kV system. When considering whether or not to use a 115 kV path over a 345 kV path, we must consider the active and reactive power required to energize the line. The higher voltage (345 kV) lines have a higher reactive power requirement for energization, but the lower voltage (115 kV) lines have higher resistance, which results in more line losses, which requires the generator(s) to provide more power (MW) to energize the equivalent 115 kV path.

We provide as Table 10 below, an example of two lines from our system that demonstrates these differences.

Table 10: 115 kV Compared to 345 kV Resistance and Reactive Power

Line voltage	Line Resistance	Reactive Power MVAR/mile
Blue Lake – Black Dog 115 kV	0.009531	0.033
Blue Lake – Black Dog 345 kV	0.000578	0.164

In blackstart planning, we try to balance the role of active and reactive power in the generator, so that there is enough reactive power to energize the next piece of equipment – but not so much so to lose too much active power to line losses, which reduces the numbers of customers we can restore initially.

We also need to maintain control of the system voltage as the restoration paths are energized. The 115 kV path will have a lower VAR requirement, which can lead to lower bus voltages as more equipment is energized. In this case, capacitor banks may need to be energized to boost the voltage. Conversely, the 345 kV path will have a higher VAR requirement than the 115 kV path, which can lead to higher bus voltages and the need to energize existing voltage reactors in order to lower the bus voltages.

Our current Black Start Plan and the NSP System have been designed around the 345 kV system and the understanding that during light loads, the bus voltages may be higher at one end of the transmission line than the other. We therefore have reactors strategically installed throughout the system to help control these voltages. We also have capacitor banks on the 345 kV system for high load periods, where the bus voltages may become depressed. However, while the proposed 115 kV restoration paths currently have some capacitor banks installed, more may be needed, depending on where the new generation is sited and which restoration path is chosen.

Our proposal to construct a natural gas CC unit at the Sherco site would provide for our current and most efficient Black Start Plan to remain in place. The proposed Unit would be big enough to start Sherco Unit 3 without incurring restoration delays, and the additional equipment and/or facilities costs and operational complexities in other parts of the system.

E. Conclusion

While our **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** generation sites are good potential Target units for the restoration plan, there are costs associated with system upgrades as well as a delay in getting

Sherco Unit 3 started. The best solution from a restoration perspective would be to install black start eligible replacement generation onsite at Sherco.

IV. STUDY ASSUMPTIONS, INPUTS, and ALTERNATIVES

A. MISO Y2 Study

MISO Attachment Y2 studies are performed at the request of the generator owner considering retirement of a generating unit(s), and are performed in accordance with the MISO Business Practice Manuals. Their purpose is to determine how the system behaves in the absence of whatever generating unit(s) is being requested to be shut down. MISO runs scenarios with and without the generating units in-service to determine the impacts to the regional transmission system and to identify any potential issues. The identified issues are shared with an adhoc study group made up of neighboring transmission owners and other entities to determine if the issues are real, and what potential solutions are needed to mitigate all of the system deficiencies. MISO does not look at replacement generation alternatives unless they proposed as solutions by members of the adhoc group.

1. *Assumptions*

We provide a summary of the MISO Y2 Study assumptions and inputs below. The study assumptions are detailed beginning on page 8 of the NON-PUBLIC MISO *System Support Resource Attachment Y2 Study Final Report, Xcel Energy, The Sherburne County Generating Plan ("Sherco") Units 1 & 2*, dated August 28, 2015.

Unit Power Output. Each Sherco Units 1 and 2 are rated at 730 MW total output power. Station service load is 47.5 MW for each unit, making the net output per Unit 682.5 MW.[17]

Retirement Scenarios. The Company's March 11, 2015 Attachment Y2 Study request sought study of two retirement scenarios for Sherco Units 1 and 2 as follows:

(1) Both Sherco Units 1 and 2 on May 31, 2021, and
(2) Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024.

Study Models. Studies were performed using the following power flow models:

Scenario 1:

- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)

[17] 2015-2016 UCAP Unit Ratings: Sherco Unit 1 – 696.1 MW; Sherco Unit 2 685.8 MW.

- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak) Scenario 2:
- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)
- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak)
- 2024 Shoulder (MTEP14_2024 Shoulder)

For the model, two sub-scenarios were created which represent the "before" and "after" generator retirements for each retirement scenario. The most relevant 2014 Security Constrained Economic Dispatch (SCED) input data from MTEP14 series was used and updated to reflect conditions in MTEP15 series models.

Model Assumptions - Generation. Units for which an Attachment Y had been completed during the relevant period were modeled as offline. Additionally, Attachment Y Units whose suspensions end before 2020 were modeled in-service.

Model Assumptions – Transmission. Significant transmission projects in service prior to the potential retirement dates were as follows:

- MTEP Project 3831 Great Northern Transmission Line (June 2020). To be added to MTEP14 2024SSH model only, MTEP15 models will have it already.
- MTEP Project 7910 Mud Lake – Brainerd 5L upgrade. Minnesota Power confirmed expected I/S date to be in 2019.
- MTEP Project 7913 Little Falls – Langola Tap – St. Stephen (115 kV) upgrade. Minnesota Power confirmed expected in-service date to be in 2019.
- MTEP Project 3127 N La Crosse – N Madison – Cardinal – Eden – Hickory Creek 345 kV. To be added to MTEP15 2020SUM and MTEP15 2020SSH only, later models already have them.

Additionally, Minnesota Power (MP) provided topology updates to MTEP14-2024SSH and a correction to all cases for its Silver Bay Generation and Iron Range-Forbes 230kV Line summer rating (summer cases only). Finally, each Units station service load was disconnected in the "after" as part of the retirement of the corresponding Unit(s), and the Xcel Energy (XEL) area slack bus was changed due to the potential retirement of Sherco Unit 2.

2. *Criteria and Methodology*

PTI PSS/E was used to perform AC contingency analysis. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to determine if there were any criteria violations due to the Unit(s) change of status.

The *Steady State Thermal* and *Steady State Voltage* Planning Criteria for each Transmission Owner (XEL, Great River Energy (GRE), MP, American Transmission Company (ATC), Dairyland Power Cooperative (DPC), Southern Minnesota Municipal Power Agency (SMMPA), and Ottertail Power (OTP)) were applied.

MISO Transmission Planning Business Process Manuals – SSR Criteria. As specified in the MISO BPM-020-R12, (Section 6.2 beginning on page 133)[18] the System Support Resource criteria for determining if an identified facility is impacted by the suspension of the units will be:

- Under system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" suspension scenario is equal to or greater than:
  a) 5 percent of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" suspension scenario, or
  b) 3 percent of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" suspension scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" suspension voltage calculation.
- Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, or load shedding were considered if applicable.
- Angle/voltage stability studies will be performed if necessary.

3. *Summary of Retirement Scenario Cases*

Tables 11, 12 and 13 below provide summaries of the Case results, as they relate to NERC Event Categories. We note that Case 1 is Sherco Units 1 and 2 out of service

[18] MISO Business Practice Manual BPM-020 can be found at https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

and Case 2 is Sherco Unit 2 out of service. In order to make the results more easily understandable, we have included a brief definition of the NERC Event Categories in the Table 14 immediately following our summary of the Case results.

Table 11: Scenario 1 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		84/84 Thermal (MP) 2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 2/3 Voltage (*addressed within GRE service area*)	
P2		2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 3/21 Voltage (*resolved by MTEP 9064*)	1/1 Thermal (MP) 2/2 Voltage (*addressed by transferring feeder load onto adjacent sources*)
P3		1/1 Thermal (XEL) 84/84 Thermal (MP) 97/142 Voltage (XEL) 119/907 Voltage (MP) 99/110 Voltage (XEL)	
P4		3/21 Voltage (*resolved by MTEP 9064*)	
P5		99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 1/3 Voltage (*resolved by Coal Creek generation reduction*)	1/1 Voltage (GRE – *resolved by MTEP 4380*)
P6	4 Voltage (XEL)	97/142 Voltage (XEL) 99/110 Voltage (XEL)	
P7		99/110 Voltage (XEL) 6/11 Voltage (*resolved by switching on local capacitor banks*)	

Table 12: Scenario 2 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		9/13 Voltage (XEL)	
P2		9/13 Voltage (XEL) 2/2 Voltage (GRE – *resolved by MTEP 4380*)	1/1 Thermal (MP)
P3		9/13 Voltage (XEL) 14/549 Voltage (MP) 6/11 Voltage (MP) 59/59 Thermal (MP)	
P4			
P5		2/2 Voltage (GRE – *resolved by MTEP 4380*)	
P6	3/3 Voltage (XEL)		
P7			

Table 13: Shared Cases (Scenarios 1 and 2) Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1	2/2 Voltage (GRE)		
P2			
P3		5/1 Thermal (XEL) 2/2 Thermal (MP) 8/10 Voltage (XEL) 4/7 Voltage (MP)	
P4			
P5			
P6		8/10 Voltage (XEL)	
P7			

Table 14: Abbreviated List of NERC Event Category Definitions[19]

P1	Single Contingency – Loss of one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Bus Section fault * Internal Breaker fault (non-Bus-tie-Breaker) * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Transmission circuit * Transformer * Shunt Device * Single pole of a DC line
P4	Multiple Contingency – (Fault plus stuck breaker) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section * Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Transformer * Shunt Device * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

[19] For a full description of NERC's event categories, *please see*: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

4. *Special Voltage Stability Study – Monticello Nuclear*

As noted previously, due to the electrical proximity between the Monticello Nuclear generating plan and Sherco, the voltages at Monticello's 115 kV and 345 kV buses received special attention. This special study was to determine whether Monticello's voltage will remain within the plant's NPIR limits at all times, and whether the region around Monticello would be at risk of voltage collapse under certain power transfer scenarios.

Model Preparation. The voltage results of the steady state power flow showed a significant number of voltage violations in the 2021 shoulder case compared to the number of voltage violations in the 2021 summer case in the Twin Cities area, which can be attributed to the number of online units in each case. Only few units in the Twin Cities area are online in the shoulder case, however all the units in the Twin Cities are online in the summer case. The presence of these units supports the voltage stability in the summer case compared to the shoulder case.[20] For this reason, MISO determined the 'Source' and the 'Sink' to implement the power transfer needed for the voltage stability study based on the 2021 shoulder case. All the online units within the Twin Cities area were used as the 'Sink' subsystem (their output was reduced) and all the units outside the Twin Cities are the 'Source' subsystem.

Contingencies. The voltage stability studies selected the events observed to cause the highest voltage drop at Monticello combined with the loss of Sherco Unit 3 to implement NERC P3 contingencies.

Methodology. MISO used the PSS-E PV Analysis tool. For the base case, all taps and switched shunts were allowed for automatic adjustments and Area interchange control was disabled. For the contingency case, all taps and switched shunts were locked and Area interchange control was disabled. The branch loading check (thermal violations check) was disabled to study only the impact of the power transfer on the voltage, and the Machine active power limits were honored.

Verification of the Voltage Collapse Conditions. To verify that power flow solution blows-up due to true voltage collapse conditions and not due to some numerical issues, numerous switched shunt actions were verified right before reaching the blow-up status. All online generators within the Twin Cities reached their Qmax limit, which proved that the case blow-up as the power transfer reached the knee of the P-V curve as shown.

[20] The status of each unit in that area was determined automatically during the SCED process.

Transient Stability. Considering the size of the two Sherco Units and due to their proximity from the two nuclear plants (Monticello and Prairie Island) that have special frequency requirements, a transient stability assessment was needed. This assessment was done to study the impact of the retirement of Sherco Units 1 and 2 in 2021. A similar study must be conducted if the Company decides to retire only one of the Sherco Units 1 and 2.

MISO used the dynamic model MTEP14-2019 Summer Shoulder with specific assumptions including Sherco unit 1 and unit 2 kept offline and all of the applicable generation and transmission assumptions listed earlier. As per MTEP14 Transient Stability Assessment, the MISO West Sub-region is more stressed during high transfers in shoulder periods.[21] After applying all the above changes, SCED was performed on the case. Ten disturbances selected from the MTEP14 study in addition to three disturbances provided by GRE were each simulated for 20 seconds. PSS-E version 32 was used in simulating these disturbances. Again, the Transmission Owner Planning Criteria and Monticello NPIR were considered; the rotor angle, bus voltage, and bus frequency channels in XEL, MP, GRE, and MH were selected.

5. *Limitations*

The MISO Y2 study is a "first come, first served" study where only generators that have already requested to retire are considered when performing the study. MISO does not attempt to predict which generators they believe will retire in the future. With the Clean Power Plan, it is very likely additional generators not included in the MISO Y2 Study performed for Sherco Unit 1 and 2 scenarios will be retired, which could impact Sherco Unit 1 and 2 retirement.

B. Xcel Energy Transmission Reliability Study

1. *Sherco 1 Study Replacement Scenarios*

We initiated our Reliability Study to further investigate the transmission impacts associated with replacement generation for one or two Sherco units being located at various locations on the NSP System. We identified three potential locations that include both greenfield and brownfield conditions. Our considerations in choosing the locations include proximity to existing transmission facilities, generation facilities, and natural gas pipelines – and other factors, such as potential land availability needed to accommodate new generation. The alternative locations are as follows:

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[21] The MTEP15 dynamic model was not yet ready.

- Metro
- Southwest
- Northwest

2. *Sherco 1 and 2 Study Replacement Scenarios*

We considered nine scenarios for Sherco Units 1 and 2 replacement:

1. CAPCON 700 MW, Metro 600 MW[22]
2. CAPCON 700 MW, Northwest 700 MW
3. CAPCON 700 MW, Southwest 700 MW
4. Northwest 700 MW, Metro 600 MW
5. Northwest 700 MW, Southwest 700 MW
6. Northwest 1,400 MW
7. Southwest 700 MW, Metro 600 MW
8. Southwest 1,400 MW
9. Metro 1,200 MW

Linear power flow methods (DCCC) were used to perform contingency analysis on each of the nine scenarios for the summer and shoulder peak system conditions. Based on these thermal results potential mitigation was identified and estimated.

Four scenarios were selected for further analysis based internal stakeholder input.

1. Southwest 750 MW, Metro 750 MW
2. Northwest 750 MW, Metro 750 MW
3. Northwest 750 MW, Southwest 750 MW
4. Sherburne County 1,500 MW (Stability Only)

3. *Study Methodology*

The replacement scenarios were evaluated for the study year 2020. Summer peak and shoulder peak cases were developed based on the MISO MTEP14, 2019 summer peak and summer shoulder cases. These cases were updated from 2019 to 2020 by adding in the MISO MTEP14 Appendix A projects with an in-service date before June 1, 2020. In addition to transmission projects, all generator projects located in the MISO DPP study cycle through the DPP 2014 February benchmark cases that were

[22] CAPCON is the generating resources being added to the NSP System as a result of the Competitive Acquisition proceeding in Docket No. E002/CN-12-1240. These resource include: Mankato Energy Center II, Aurora Solar, and Black Dog 6.

located in the region were added to the cases. The CC generation was dispatched based on a merit order in the shoulder peak cases.

a. Steady State Analysis

Summer peak and shoulder cases were evaluated for steady-state thermal and voltage issues using PSSE version 33 and PSSMUST version 10.2 Contingency criteria was based on the MTEP14 contingencies files.

- NERC Category A with system intact (no contingencies)
- NERC Category B contingencies
  - Single element outages, at buses with a nominal voltage of 100 kV and above, in the following areas: WEC (area 295), XEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MEC (area 635), WAPA (area 652), MDU (area 661), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698)
  - multiple-element outages initiated by a fault with normal clearing such as multi-terminal lines, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.
- NERC Category C
  - NERC Category C events, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.

Monitored elements for each of the areas are described in the Table 15 below.

Table 15: Monitored System Elements

Owner/ Area	Monitored Facilities	Thermal Limits		Voltage Limits	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
ATCLLC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.07/1.05/0.93
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.96/0.95	1.05/0.96/0.95
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04/0.99/0.97/0.96/0.95	1.15/1.1/0.94/0.9
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.0	1.1/0.95
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.1/0.92
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
Monticello	345 kV	100% of Rate A	100% of Rate B	1.0492/0.9914	1.0492/0.9914
Monticello	115 kV	100% of Rate A	100% of Rate B	1.05/1.0087	1.05/1.0087
Prairie Island	345 kV	100% of Rate A	100% of Rate B	1.05/0.9911	1.05/0.9911
Prairie Island	161 kV	100% of Rate A	100% of Rate B	1.05/0.9969	1.05/0.9969

A branch is considered thermally constrained if the following conditions are met.

1. The branch is loaded above its applicable normal or emergency rating, and
2. A replacement scenario generator has a larger than 5% DF on the overloaded facility under system intact or post contingent, or
3. The impact of the replacement scenario is greater than 10% of the applicable rating of the overloaded facility

A bus is considered a voltage constraint if both of the following conditions are met.

1. The bus voltage is outside of applicable normal or emergency limits, and
2. The change in bus voltage is greater than 0.01 per unit.

b. System Loss Analysis

Real power losses for the study were based on a comparison of total system losses from the benchmark base cases and the replacement scenario cases.

c. Reactive Power Analysis

Reactive power production for the study was studied by comparing the amount of reactive power produced in the Xcel Energy area in the benchmark base case compared to the replacement scenario cases.

4. *Transient Stability*

Transient stability was performed using PSSE version 32.2. Transient stability analysis was performed using the MTEP14 stability package. Disturbances were simulated on the benchmark case and the study cases to identify any significant impacts.

a. Disturbance Criteria

The stability simulations as part of this study took into account both regional and local contingencies. For local contingencies generic clearing times were used and the fault admittances for single line to ground faults were estimated by assuming the Thevenin impedance of the positive, negative, and zero sequence networks at the point of the fault are equal.

b. Performance Criteria

Simulation results were evaluated using the MRO System Performance Table in the MRO System Performance Standard TPL-503-MRO-01. Transient voltages must be within the default limits of 0.70-1.20 per unit with the exception of specific buses, areas or companies that have different requirements. All machine rotor angle oscillations must be positively damped with a minimum damping factor of 5% for disturbances with a fault, or 10% for line trips without a fault.

Transient apparent impedance swings on all lines were monitored after fault clearing using the mrely1 user written model. The mrely1 model uses a generic three-zone mho characteristic. Apparent impedance transient swings into the inner two zones are unacceptable for NERC Category B disturbances. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC

Category C disturbances, unless a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

5. *Mitigation Cost Assumptions*

Unit cost tables were developed for the overhead transmission lines, substation, transformers, and any reactive power instillations that were needed for the study effort. These costs were based on new construction and in 2015 dollars.

6. *Limitations*

The Reliability Study, when it was initiated in early 2015, included a number of projects from the MISO interconnection queue that were assumed to be going into service at the time the study was performed. Because of this, any changes to the MISO Queue could have an impact on the conclusions of the our Reliability Study – with the likely outcome of increasing the identified estimated interconnection costs for projects analyzed.

C. Black Start Analysis

1. *Assumptions and Inputs*

The primary purpose of the study was to investigate the impacts of retiring Sherco Units 1 and 2, on the NSP Power System Restoration Plan. The study looked at future blackout scenarios where Sherco Units 1 and 2 are not available for restoration efforts. The intent was to identify potential new Target Units and the associated restoration paths for those units. The Study also identified potential challenges with the various scenarios and what potential upgrades would be required to make those viable options for future restoration plans. The Study assumed that the natural gas pipeline supplies for potential new Target Units is adequate to start and run the plants for the restoration plan.

The Black Start Study utilized the same study models that were created for the Xcel Energy Transmission Reliability Study, modified for the blackout scenario base cases, from which multiple Target Units and associated restoration paths were studied. Due to the proximity from where the proposed replacement generation in the model was sited to the primary Twin Cities load center, we eliminated the Northwest generation and the Southwest generation locations – only studying the Metro location and other existing plant locations.

2. *Alternatives Examined*

We analyzed four new potential restoration paths: (1) a 345kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**, (2) a 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** with underground cable, (3) another 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** using overhead lines, and then (4) a combination 345/115 kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. After the generation was started at each of the new Target Units, the restoration paths were energized to Sherco.

3. *Study Methodology*

To demonstrate generator capability is adequate to perform its black start functions, the Initial and Target Units must stay within real and reactive limitations based on that unit's most recent D-curve, or operating limits.[23] Unit loading must be dispatched so that the contingent loss of one of the units will not cause the other online units to exceed their real and reactive power capabilities or their governor response capability.

The Initial Unit(s) requires that the terminal voltage of the generators must be 13.1 kV (95%), if the loading on that generator exceeds 10 MW. A temporary reduction to 12.8 kV (93%) is allowed for unit output less than 10 MW. Due to these restrictions and the current tap settings on the generator step-up transformers (GSU), there are additional voltage constraints for the 115 kV bus.

For the Initial and Target Units to be considered capable of performing their functions within the our Black Start Plan, they must be able to energize at least one restoration path between the black start substation, and the new Target Unit. The Initial Unit(s) must be able to start the new Target Unit and then continue the restoration path to the Sherco substation and be able to complete the Sherco Unit 3 load start-up sequence without causing violations to the above criteria.

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[23] In addition to producing capacity and energy to meet customer load requirements, generating units help control voltage on the grid by producing and absorbing reactive power (MVAR); *producing* MVAR helps *increase* the voltage, and *absorbing* MVAR helps *decrease* the voltage. When a generator is producing or absorbing reactive power, it cannot produce its maximum MW output because its operating capability is partially "used up" from producing or absorbing reactive power. Therefore, a generating unit's D-curve shows the operating limits for a generating unit in terms of the relationship between the active power (MW) it is producing and the reactive power it is either producing or absorbing – and how they are balanced within the unit's maximum operating limits.

To effectively analyze the restoration paths, we created scripts to simulate the major switching steps outlined for each switching step along the restoration path. For each major step in the restoration path development, we monitored bus voltages at key transmission substations and the Initial Units' real and reactive power output. Both the steady-state and immediate post-switching (time 0+) results were displayed for each step, as outlined in Table 16 below.

Table 16: Steady-State and Immediate Post-Switching Results

	Switching Limits		Steady State Limits	
	Low Voltage	High Voltage	Low Voltage	High Voltage
All buses	0.90 pu	1.05 pu	0.95 pu	1.05 pu

We did not actively monitor transmission equipment loadings because the amount of load energized to support each restoration path did not exceed the lowest rating of any one piece of series connected equipment.

4. *General Findings*

The Study determined that **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would not be a good Target Unit due to the difficulty in switching to get there for the operators, as well as the number of emergency generators that would need to be added to the system. The overhead path, while longer and requiring an additional generator to be installed, was a better option than the underground path. The reactive power requirements for the underground path were a challenge and could require an additional Initial Unit(s).

The Metro East 345/115 kV path and the Metro West 345 kV paths were the preferred paths to the alternate Target Units. However the process of bringing the Target Unit online and up to minimum load will delay the restart of Sherco Unit 3, and the restoration of off-site station power to both Monticello and Prairie Island. Importantly, the existing paths to Sherco Units 1 and 2 or the new proposed onsite CC unit allows restoration of offsite station power to both nuclear plants and start-up procedures for Sherco Unit 3 in the most efficient timeframe.

System Support Resource Attachment Y2 Study
Final Report

Xcel Energy

The Sherburne County Generating Plant ("Sherco") Units 1 & 2

August 28, 2015

Redacted

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Sherco 1 Replacement Power Study

Prepared for

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Attachment E
Estimated Rate Impacts

In order to show the impacts of our plan on customer rates and bills, we have included an estimated rate impact analysis of our Updated 2015 and Current Preferred Plan below that includes the breakdown of anticipated increases by customer class. The estimated customer impacts are shown for the five-year period from 2016-2020 at the Minnesota customer class levels. In this Attachment, we present the results of that analysis and discuss the methodology we used to calculate the revenue requirements associated with our Updated 2015 and Current Preferred Plans.

A. Rate Forecast Methodology

To calculate the rate impacts of the Updated 2015 and Current Preferred Plans, we started with the 2016 Budget forecast of total revenue requirements for 2016-2020, developed in July 2015. This is the forecast that formed the basis for the 2016 MN Electric Rate Case (Docket No. E002/GR-15-826) filed in November 2015. [1]

The assumption differences between the Rate Case, the Updated 2015 Plan, and the Current Preferred Plan are as follows:

1. *Rate Case:* Our rate case model includes the following resource additions:
   - 287 MW of solar Power Purchase Agreements (PPA) in 2017, made up of the 100 MW Aurora distributed solar project (Docket No. E002/M-15-330) and 187 MW from our Solar Request for Proposals (Docket No. E002/M-14-162)
   - Updated Community Solar Gardens forecast we reflected in our March 2015 Supplement, totaling over 200 MW by 2020
   - Rooftop solar additions of 9 MW per year through 2020, reflecting Solar Rewards and Made in Minnesota projects
   - 200 MW Courtenay wind project, expected to achieve commercial operation by end of 2016
   - 200 MW Odell wind PPA, expected to achieve commercial operation in 2016

[1] The Company filed an electric rate case application for a 2016-2018 multi-year rate plan in November, 2015. The information contained in that filing includes specific assumptions and adjustments for ratemaking, and will therefore differ from the estimated rate impact information provided in this filing.

- 600 MW of non-Production Tax Credit (PTC) PPA wind, reflecting the proposal in our Updated 2015 plan, before the extension of the PTC
- 345 MW Calpine Corporation Mankato Energy Center natural gas combined cycle project, expected in-service no later than 2019
- 232 MW Xcel Energy Black Dog natural gas combustion turbine project, expected to achieve commercial operation no later than 2019
- Sherco Units 1 and 2 operational through 2030

These changes are summarized in Table 1 below.

Table 1: 2016 Rate Case Resource Additions

	Rate Case				
	2016	2017	2018	2019	2020
Solar PPA MW	0	287	0	0	0
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	0	0	0
PPA Wind w/ PTCs MW	200	0	0	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	600
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

2. *Updated 2015 Plan*

The Updated 2015 Plan reflects the same resources shown in the rate case above, with the exceptions of the 600 MW of non-PTC PPA wind in 2020 switches to PTC wind in the Updated 2015 Plan, to reflect the extension of the renewable energy tax credits.

The changes from the Rate Case forecast to the Updated 2015 Plan are shown in Table 2 below.

Table 2: Changes from 2016 Rate Case to Updated 2015 Plan

	2016	2017	2018	2019	2020
PPA Wind w/ PTCs MW	-	-	-	-	+600
PPA Wind wo/ PTCs MW	-	-	-	-	-600

3. Current Preferred Plan

The resource additions in our Current Preferred Plan reflect all the changes described above, as well as the resource adjustments described below and shown in Table 3 below:

- Ceasing operations of Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023
- 200 MW of owned solar, added in 2018 and in 2020
- 200 MW of PPA solar, added in 2018 and in 2020
- 400 MW of owned PTC wind in 2018
- 400 MW of PPA wind with PTC in 2018

The changes from the Updated 2015 Plan to the Current Preferred Plan are shown in Table 3 below.

Table 3: Changes from Updated 2015 Plan to Current Preferred Plan

	2016	2017	2018	2019	2020
Owned Solar MW	-	-	+100	-	+100
Solar PPA MW	-	-	+100	-	+100
Owned Wind w/ PTCs MW	-	-	+400	-	-
PPA Wind w/ PTCs MW	-	-	+400	-	-

Table 4 below summarizes all the resources included in our Revenue Requirements analysis of the Current Preferred Plan costs.

Table 4: Current Preferred Plan Resources

	Current Preferred Plan				
	2016	2017	2018	2019	2020
Owned Solar MW	-	-	100	0	100
Solar PPA MW	0	287	100	0	100
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	400	0	0
Owned Wind wo/ PTCs MW	0	0	0	0	0
PPA Wind w/ PTCs MW	200	0	400	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	0
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

B. Estimated Rate Impacts by Class per Year

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future.

To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

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

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[2]
- Return on Equity (ROE) requested in Docket No. E002/GR-15-826 of 10.00 percent,
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated typical and precedential regulatory adjustments made in rate cases, such as Advertising, Association Dues, Corporate Aviation, Customer Deposits, Foundation Administration, Incentive Compensation, Investor Relations, the Monticello Extended Power Uprate (EPU) prudence decision from Docket No. E002/CI-13-754, Nobles Amounts over the Certificate of Need, the Prairie Island EPU Amortization, Removal of Non-Asset Trading, and the Sherco Life Extension,

We added the following adjustments appropriate to the Updated 2015 Plan scenario and to the Current Preferred Plan.

Updated 2015 Plan scenario:

- The generation resources described in Table 2 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel

[2] Data as of August, 2015.

clause revenue.

Current Preferred Plan scenario:

- The generation resources described in Table 4 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel clause revenue.
- We estimated rate base, operating expenses, and tax credits related to the owned wind and solar resources and added them to the revenue requirements model.
- We estimated book and tax depreciation expenses, associated balances, and associated property taxes related to an earlier retirement of Sherco Units 1 and 2. These were added to the revenue requirements model.
- We estimated changes to variable O&M at coal, gas combined cycle, and gas combustion turbine plants due to the different fuel dispatch assumptions associated with the generation resource assumptions and adjusted the revenue requirements model.

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

- The internal forecast for 2019-2020 is not prepared at the level of detail necessary for support of a rate case,
- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,
- We have made no determination of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and
- All factors of the Cost of Capital, including debt rates, return on equity, and debt-equity ratios, are subject to change through a rate case.

C. Determining Class Rate Impacts

After the Minnesota jurisdiction projected total revenue requirements for the period are developed, the costs are allocated to customer class based on the approved CCOSS allocation methods from the Company's last rate case order (Docket No.

E002/GR-13-868). Below, we provide detail on the Commission approved methods for allocating all production-related costs.

1. *Allocation of Production Related Costs*

a. Capital-Related Production Costs

When allocating capital-related production costs, the Company uses the plant stratification approach approved by the Commission in the Company's last five rate cases.

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

We show the Commission-approved plant stratification analysis that we applied to capital-related production costs for each plant type in Table 5 below:

Table 5: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$792	$792 / $792	100.0%	0.0%
Fossil	$2,022	$792 / $2,022	39.2%	60.8%
Nuclear	$4,146	$792 / $4,146	19.1%	80.9%
Combined Cycle	$1,037	$792 / $1,037	76.3%	23.7%
Wind	$14,894	$792 / $14,894	5.3%	94.7%
Solar	$8,182	$792 / $8,182	9.7%	90.3%

After production capital costs for each type of generation plant are split into capacity-related and energy related components based on the percentages shown in Table 5 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator. The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour. The approved E8760 allocator from the last rate case order is shown in Table 6 below:

Table 6: Approved E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.24%	3.33%	67.01%	0.42%

The capital costs that have been classified as being capacity or demand-related are allocated to customer class using the Commission-approved D10S capacity allocator. The D10S allocator is simply each class's load that is coincident with the NSP System peak load. The Commission approved D10S class allocator percentages are shown in Table 7 below:

Table 7: Approved D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	34.86%	3.72%	61.42%	0.00%

b. Fuel and Purchased Energy Expenses

These costs are allocated to class using the Commission approved E8760 energy allocator shown in Table 6 above.

c. Production O&M Expense

When allocating Other Production O&M expenses, the Company used the Commission ordered "Location" method. This method starts by identifying those production O&M expenses that vary directly with energy output. Using this criteria, the only expenses that vary directly with output are expenses for chemicals and water use. These costs are allocated to class using the E8760 allocator shown in Table 6. The remaining O&M costs are split into capacity and energy-related components based on the type of production plant associated with the costs. The stratification percentages shown in Table 5 were used to separate costs. Energy-related costs are allocated to class using the E8760 allocator, while capacity-related costs are allocated using the D10S allocator.

2. *Calculation of Class Rate Impacts of the Updated 2015 Plan*

After all costs had been allocated and revenue requirements by class were calculated, we then determined the estimated bill impacts by class relative to the current rate level. To do this, we calculated the current rate level using the compliance ordered revenues by class with riders included from Docket E002/GR-13-868. We used this calculation to estimate monthly billing units by customer class and resulting typical bills. The CCOSS allocation based estimates of relative percent class increases for the period were then applied to current typical bills to estimate the average dollar per month increase by customer class (see Table 8 below).

Using the above methodology, the incremental costs in the last year of the period (2020) for the Preferred Plan would be expected to increase the average Residential rate by about 4.5 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $20.48 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.0 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.37 cents per kWh above the 2015 level.

Table 8: Updated 2015 Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1		2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)		12.654¢	13.934	14.372	14.663	15.285	15.775	N/A
Cumul Increase (¢/kWh)			1.280	1.718	2.009	2.632	3.122	N/A
Cumulative Increase (%)			10.12%	13.58%	15.88%	20.80%	24.67%	4.51%
$ Impact/Month, @	656 kWh		$8.40	$11.27	$13.18	$17.26	$20.48	N/A
Sm Non-Dmd (avg rate, ¢/kWh)		11.970¢	12.934	13.248	13.402	13.769	14.013	N/A
Cumul Increase (¢/kWh)			0.963	1.277	1.431	1.799	2.042	N/A
Cumulative Increase (%)			8.05%	10.67%	11.96%	15.03%	17.06%	3.20%
$ Impact/Month, @	952 kWh		$9.17	$12.16	$13.62	$17.12	$19.44	N/A
Demand (avg rate, ¢/kWh)		8.649¢	9.219	9.435	9.559	9.834	10.023	N/A
Cumul Increase (¢/kWh)			0.570	0.786	0.911	1.185	1.374	N/A
Cumulative Increase (%)			6.59%	9.09%	10.53%	13.70%	15.89%	2.99%
$ Impact/Month, @	38,865 kWh		$221.52	$305.49	$354.00	$460.52	$534.16	N/A
Street Ltg (avg rate, ¢/kWh)		15.137¢	17.100	18.340	19.081	19.928	20.810	N/A
Cumul Increase (¢/kWh)			1.964	3.204	3.945	4.791	5.673	N/A
Cumulative Increase (%)			12.97%	21.17%	26.06%	31.65%	37.48%	6.57%
$ Impact/Month, @	60 kWh		$1.18	$1.92	$2.37	$2.87	$3.40	N/A

1/ Average 2015 Rates are Based on the Outcome of Docket No. E002/Gr-13-868.

3. *Calculation of Class Rate Impacts with the Current Preferred Plan*

Table 9 below shows the estimated bill impacts by class relative to the current rate level for the Current Preferred. The incremental costs in the last year of the period (2020) for the Current Preferred Plan would be expected to increase the average Residential rate by about 4.7 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $21.39 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.25 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.5 cents per kWh above the 2015 level.

Table 9: Current Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	12.654¢	13.945	14.384	14.778	15.397	15.914	N/A
Cumul Increase (¢/kWh)		1.292	1.731	2.124	2.744	3.260	N/A
Cumulative Increase (%)		10.21%	13.68%	16.79%	21.68%	25.77%	4.69%
$ Impact/Month, @ 656 kWh		$8.47	$11.35	$13.93	$18.00	$21.39	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	11.970¢	12.945	13.261	13.515	13.879	14.147	N/A
Cumul Increase (¢/kWh)		0.975	1.290	1.545	1.908	2.177	N/A
Cumulative Increase (%)		8.14%	10.78%	12.91%	15.94%	18.18%	3.40%
$ Impact/Month, @ 952 kWh		$9.28	$12.28	$14.71	$18.17	$20.72	N/A
Demand (avg rate, ¢/kWh)	8.649¢	9.228	9.446	9.666	9.937	10.149	N/A
Cumul Increase (¢/kWh)		0.580	0.797	1.018	1.288	1.501	N/A
Cumulative Increase (%)		6.70%	9.22%	11.77%	14.90%	17.35%	3.25%
$ Impact/Month, @ 38,865 kWh		$225.35	$309.77	$395.57	$500.67	$583.22	N/A
Street Ltg (avg rate, ¢/kWh)	15.137¢	17.105	18.345	19.159	20.004	20.890	N/A
Cumul Increase (¢/kWh)		1.968	3.209	4.022	4.867	5.753	N/A
Cumulative Increase (%)		13.00%	21.20%	26.57%	32.16%	38.01%	6.65%
$ Impact/Month, @ 60 kWh		$1.18	$1.93	$2.41	$2.92	$3.45	N/A

Attachment F
Demand Response, Grid Efficiency, and Distributed Energy Resources as Alternative Resources

The Commission's January 6, 2016 Order required an analysis of the potential for demand response (DR), improved system or grid efficiencies, and distributed energy resources (DER) to replace all or part of the energy and capacity that would otherwise be provided by new gas-fired resources. Below we provide our view of the future viability of DR and DER, including supply-side, demand-side and grid efficiencies as replacement for large generators.

We have also included a Strategist simulation where all possible alternatives, including incremental demand response, distributed generation, grid modernization, utility scale renewables, and thermal units are simultaneously considered and optimized. In various Stakeholder sessions, the Company has referred to such a process as a "Grand Optimization."

As discussed in greater detail below, conducting an analysis that considers all possible alternatives is difficult given the solution option capacity constraints of the Strategist software and current desktop computer processing capabilities. However, the Company has attempted to conduct such an exercise to the greatest extent possible reflecting the above limitations. Ultimately, our Strategist modelling found that the Company's Current Preferred Plan provides a balanced approach that allows us to add significant amounts of renewable resources while also considering impacts on customer costs, procurement, construction and operations.

A. DER as Replacement of Central Station Generation

We believe there are three fundamental and sequential questions related to technological viability, economics and policy that must be addressed in order to assess whether DERs are a viable replacement for central station generation in the planning horizon considered in this resource plan.

1) **Technological Viability** - Do technologies currently exist to meet the required reliability, safety and operational standards at the scale necessary to effectively replace large central station generation?
2) **Economics** - If replacement is technologically viable, how does the cost of DER options compare to the alternatives over the near and long-term?

3) **Policy** - Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We address each of these questions below.

1) Do technologies currently exist to meet the required reliability and operational standards at the scale necessary to effectively replace large central station generation?

As we consider the retirement of Sherco Units 1 and 2, it is important to understand the services and functions that will need to be replaced, particularly those beyond energy and capacity. As noted in our March 16, 2015 Supplement, the Units' size, location and operating characteristics make them unique in the NSPM system and provide important services related to system stability, grid support, and black start capabilities. This is in addition to the replacement capacity and energy required to reliably meet system demand. For context, Sherco Units 1 and 2 are approximately 750 MW each for a combined 1,500 MW of generation.

Given the role of Sherco Units 1 and 2 in the system, a comparable replacement portfolio of distributed resources must be able to:

- Supply the necessary long-term capacity and energy when and where it is needed, in accordance with established safety, security and reliability standards;
- Balance generation with changing load conditions and fluctuations to maintain proper voltage and frequency for the region; and
- Stabilize the grid in the event of a wide-area outage.

Other technical issues and system requirements may emerge upon further study. For example, as discussed in our response to Clean Energy Organizations' Information Request No. 29, advanced inverters may provide some benefits for managing high penetrations of renewable resources, but inverter-connected resources at high levels of penetration generally do not provide the fault current necessary for utility protective relays to operate. As noted in our March Supplement, we have contracted with an independent third party to study the technical impacts of our proposal.

While we recognize the future potential of distributed technologies, it is our understanding that no precedent exists to confidently prove that a distributed portfolio comprised of today's distributed technologies could consistently satisfy all three of these conditions. While it may be possible to design a theoretical portfolio that addresses these requirements, committing to such a plan in practice introduces significant uncertainty and risks, particularly to reliability. Until more operational and performance information is available to better understand what capabilities these technologies do and do not have under a full range of operating conditions and in the context of a large-scale shift away from centralized resources, we recommend continued presence of large-scale, centralized generation in our fleet.

That said, we see the potential for distributed resources to take on a growing role in coming years and are committed to leveraging them as they become technically viable, cost-competitive, and have an established and acceptable operational record. Over time, it is possible that DER technology could advance to the point that distributed resources could become viable alternatives to centralized generation, but such a decision must be based on well-established capabilities, instead of projections.

Below we provide an overview of the likely core components of a hypothetical distributed resource portfolio consisting of DR, DER, and grid efficiencies. As noted above, it is untested and unknown if and to what extent these resources may work together to replace new large-scale, centralized generation.

- *Supply-side Resources* – These resources are necessary to provide the energy and capacity necessary to meet customers' needs.
    - <u>Distributed Generation</u>. Distributed generation would need to be deployed at an unprecedented scale, strategically dispersed and centrally managed to maintain reliable service.
    - <u>Energy Storage</u>. Storage is a critical complement to DG that addresses the intermittency of renewable DG and allows DG to be dispatchable. Battery storage may also provide other system services, such as voltage and frequency regulation, black start capabilities and spinning and non-spinning reserve, though more research is needed to test how those services can be dispatched and "stacked."

- *Demand-side Resources* – These resources have the potential to reduce and/or shift customer demand, thus deferring or avoiding the need for supply-side investments. Demand-side resources, by definition, rely on actions on the customer's side of the meter, which introduces questions of dispatchability and dependability.

- Demand Response. Existing demand response programs could be expanded to reduce peak demand and reduce the need for additional peaking capacity.
- Energy Efficiency. Aggressive energy efficiency could lower customer demand and energy, which could reduce the need for generation.
- Rate Design. With the enabling metering technology, rates could be redesigned to encourage customers to shift energy use more to off-peak, thus reducing the need for additional peaking capacity. Examples include time-of-use rates and demand charges.

- *Grid Efficiencies* – Through technological advances, the grid can be operated to reduce losses and potentially provide capacity benefits.

  - Voltage control. Voltage control, as enabled by an Advanced Distribution Management System (ADMS), Field Area Network (FAN), and other distribution system technologies, can provide energy or capacity benefits. Voltage can be controlled to reduce energy use by maintaining voltage at the lowest acceptable level (often referred to as Distribution Voltage Optimization). An alternative control scheme is to use the system as a stand-by resource or spinning reserve. This is done by maintaining voltage in the typical range (as we do today), and lowering the voltage only when a capacity shortage occurs. Such a reduction can have a significant initial impact, but is expected to taper off over time to a lower plateau. A hybrid scheme may be possible where the system is operated in the conservation mode normally, but if a capacity need is identified, the control reverts to a "Virtual Spinning Reserve" mode.

It is important to acknowledge the pivotal role that grid modernization investments have in enabling DER to play an increased role in the future. For example, communications and control software and technologies such as ADMS, FAN, and Distributed Energy Resources Management System (DERMS), are vital for the control, management and optimization of these resources, making them necessary prerequisites for treating DERs as reliable system resources. For example, the ADMS will enable increased hosting capacity, which is the amount of distributed energy that can be hosted on the distribution system, by allowing, in conjunction with other controls, active mitigation of potentially problematic voltage and load situations.

2) If replacement is technologically viable, how does the cost of DR and DER options compare to the alternatives over the near and long-term?

As discussed above, we believe technology has not sufficiently matured to enable DERs as alternatives to new large-scale generation additions. As is common with technologies still climbing the maturity or commercialization curve, many of the distributed resource technologies that would be needed are not cost-competitive with established technologies. As discussed below, the DER and incremental DR alternatives were not selected in our Grand Optimization due to their higher cost.

However, our existing DR programs continue to be an important part of our resource portfolio, as demonstrated by the increase in our DR forecast. The Company has a long history of success with DR. Currently, we have exceeded 930 MW in the Upper Midwest since we began offering load management programs for customers in the 1980s. While we remain committed to providing customer options, we must continue to be vigilant in adjusting the portfolio in order to be compliant with the rules set by federal regulation and MISO. Further, we must take the opportunity to develop and test customer programs using new technology prior to depending upon them as a resource on our system or in the MISO market.

We have acknowledged that it is likely there will be some attrition over the planning period, wherein customers begin to choose new opportunities with lower demand reduction potential. This may at times be a trade-off between further participation and the ability to self-control, which could reduce our portfolio in the short-term.

Given the modeling result, we have not adjusted our moderate demand response forecast. However, we continue to review new customer choices for DR including dynamic pricing options (time-of-use, peak pricing, etc.), new technologies (smart thermostats), and updated rates to encourage participation. We have also begun investing in a Demand Response Management System to help facilitate new opportunities as they arise due to changing technology.

While the cost declines observed for solar DG and storage over the past few years are encouraging, it is unclear and perhaps unlikely that these cost declines can overcome the economies of scale inherent in larger-scale alternatives. Similarly, while distributed resources may provide other benefits over time, such as deferred or avoided transmission and distribution investments, it is premature to assign a definitive timeline and value to those benefits.

3) Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We recognize the growing interest among our regulators, stakeholders and customers In transitioning to a 21st century electric system and are advancing these interests in several different ways. We agree that it is a worthwhile goal to make plans to move away from coal and other carbon-emitting resources in favor of carbon-free alternatives, as demonstrated by our proposal in this transformational Resource Plan. These proposals are responsive to state energy policy goals, which seek to dramatically lower the state's contribution to climate change, maximize energy efficiency and conservation, and promote renewable energy, among others. The question is in how best to meet those policy goals, while also satisfying the basic requirements of safe, reliable, secure and affordable energy.

With the technological and economic challenges currently facing DERs, we believe we are not yet at the point where DERs can fulfill or have an advantage in satisfying those basic requirements at the scale and speed implicit in this question. We are taking steps to reduce the challenges and prepare for the future grid, such as through our grid modernization efforts and solar plus storage demonstration project proposal, but it is still too early to confidently choose DERs as a reasonable and complete alternative to new central station generation additions.

B. Strategist Analysis

The first step in beginning the optimization was to define the available alternatives to be considered. To narrow the scope of the exercise, the alternatives were reduced to the following representative options:

- *Incremental Demand Response Option* - The DR option was constructed by extrapolating results from the Brattle DR Potential Study[1] to future years. The Brattle study did not contemplate or produce results directly related to this use, and extrapolating the results of the study is inherently an estimate or proxy. To adequately project costs and availability of DR resources many years out would require a new analysis, and could likely produce very different results. Nevertheless, the proxy DR resource was developed as a new optional resource that is incremental to the "Base" DR included in all cases. The incremental capacity and costs were derived by taking the difference between the "High"

[1] Appendix O of our Initial Filing.

and "Base" DR scenarios included in our initial filing. Costs for the new program were then escalated at inflation to determine the costs for an incremental program starting at various years. The incremental DR capacity made available is greater than two new combustion turbines.

- *Incremental Distributed Generation Option* – The alternative reflects current information on distributed small solar projects with representative pricing at $120/MWh with no escalation. Flat pricing assuming technology and project development improvements are expected to offset any inflation.
- *Incremental Grid Modernization* – Costs and operational attributes for grid modernization are not clear enough at this time to develop a reasonable optimization alternative for inclusion in the modeling. We discussed grid modernization qualitatively above.
- *Incremental Renewables* – The same expansion alternatives with vintages and tax benefits that were used in the main scenarios were also included in the Grand Optimization. However, tranches with identical tax benefits were limited to certain specified years to reduce the computational requirements of the model. As an example, 30% ITC solar was limited to be installed in 2021, and full PTC wind was limited to 2018, rather than being available in all years. Late wind with no PTC benefit and late solar with 10% ITC benefit were also offered as options after the expiration of the PTC and ITC benefits.
- *Thermal Alternatives* – The generic thermal CT and CC units were made available in all years. Generic not site specific alternatives were used.

The Grand Optimization tests many resource options for cost-effectiveness including DR, distributed generation, wind generation with and without PTC benefits, and solar generation with 30% or 10% ITC benefits, along with the thermal generation options. Because of the number of resource options available to choose from in each year, the cumulative number of possible combinations is enormous. If there were no limits placed on the Strategist model's logic, the model would need to evaluate every resource option added an arbitrarily large number of times every year to ensure every possible resource combination was evaluated. The size of the problem quickly becomes too large for the software.

Strategist automatically begins to disregard combinations when the problem gets too large, a process called "truncation." Strategist truncates the excess combinations (in the Company's version there are 2,500 combinations retained) based on accumulated cost to the year it needs to truncate. Thus, a plan might get truncated in 2020 if it was not one of the lowest cost 2,500 plans in 2020, even though later in the simulation it might have ultimately ended up being lower-cost had it been allowed to continue in the process. There must be a balance between limiting the number of options per year while ensuring every option has equal chance for its benefits and costs to be included in the final results of the optimization.

There are multiple ways to solve the truncation problem. One way is to prescreen options before putting them into the Strategist model based on relative costs. The Company has done this in evaluating thermal generation technologies. Some thermal generation technologies have been prescreened based on having a cost advantage for similar benefits. An example of a prescreened option is how the Company compared the cost of a 2x1 combined cycle versus a 1x1 combined cycle (CC). The Company determined that over a typical range of capacity factors, the installed cost of a 2x1 CC on a $/kW basis is significantly more favorable than the cost of a 1x1 CC, while providing very similar energy benefits. By prescreening and removing the 1x1 CC option from Strategist, the scale of the problem is reduced.

The Company has not prescreened DR, DG, wind, or solar resource options in the Grand Optimization as these options and the timing of their additions is the main focus of the analysis.

Solving an optimization of this size also requires a "trial and error" iterative approach. Initially, the model is allowed to select any type of resource, but only in smaller quantities. As iterative results indicate what types of technologies are consistently selected at particular times, a small number of these consistently-selected alternatives can be switched from being part of the optimization to being locked in. When the model no longer has to consider them as alternatives, it reduces the problem size. In the next run, the model is allowed to consider additional alternatives beyond those locked in to the plan. If more are taken, then those additional resources are also locked in. By iteratively offering and then locking in resources, a stable point can be determined when the model has just as much of a particular resource as it desires; that is, no additional resources are selected even when available. This iterative approach is essentially the same process that the Company has followed in determining its proposals in March and October 2015.

The Grand Optimization was analyzed in two steps. The first step is a capacity-need only optimization, with the second step including the system energy benefits of non-capacity (or "superfluous") resources in a resource-need optimization. Both steps find the lowest PVSC based on the assumptions and meet the required reserve margin; however, a capacity-need optimization allows the Strategist Model to add resource options only if there is a capacity need to meet the required reserve margin. By contrast, a resource-need optimization allows the Strategist Model to add resource options even if there is not a capacity need to meet the required reserve margin. An example to explain the distinction between the two optimizations is to consider a wind resource option with production tax credit benefits - the wind alternative contributes relatively little to firm capacity, and a very large amount of wind would be required to offset the need for even one CT. However, the low-cost energy could very well be below the marginal system energy costs, resulting in significant economic value if added as a resource. The wind would most likely not be selected in a capacity-need optimization, but could very likely be selected in the resource-need optimization.

1. *Capacity-Need Optimization Process and Results*

The Company started the capacity-need optimization from the results of the Company's Current Preferred Plan. In this Plan, which adds 1,800 MW of wind and 1,000 MW of solar and retires Sherco Units 1 and 2 in 2026 and 2023 respectively, there is one combined cycle unit added and nine combustion turbine units added from 2018 to 2030. An optimized capacity-view with wind, solar, DR, and DG options should add a similar amount of firm capacity. An iterative process as described above was followed, and the PVSC from each iteration was compared to the prior iteration to ensure that the optimization was getting more efficient. The least-cost solution of the capacity-need optimization is displayed below in Table 1. It is important to note that no "real-world" constraints were placed on the number or type of options that could be added in a given year, and no attempt was made to smooth the rate impact of the additions. In actuality, the results of this exercise need to be tempered with considerations of system operational limitations, contracting, negotiating and construction logistics (especially wind equipment transport and limited tall crane availability for turbine erection), large step increases in customer costs, etc. Since there is no capacity need until 2024, after a Sherco unit is retired, all the resource additions are in 2024 or later. The capacity-need optimization adds 800 MW of late wind, 3600 MW of late solar, four CTs, and one CC from 2024 to 2030. The DR and DG alternatives were not selected due to the higher cost of those resources.

Table 1: Capacity-Need Expansion Plan

28_C: Capacity-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	800	1,800	800	-	200	3,887
Wind	350	200	200	-	-	-	-	-	-	-	-	-	400	400	-	-	1,550
PPA CT	-	-	-	-	-	-	-	-	-	230	460	230	-	-	-	-	920
PPA CC	-	-	-	-	345	-	-	-	-	-	778	-	-	-	-	-	1,123
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2. *Resource-Need Optimization*

The number of possible combinations in the resource-need optimization is much greater than the possible combinations in the capacity-need optimization. The resource-need optimization considers increments of wind, solar, and DR options above the number required to meet the reserve margin and internally adds them to the system to evaluate cost effectiveness. Since Strategist quickly exceeds its maximum number of combinations with these incremental superfluous resources, the Company had to extensively use an iterative process.

As we discussed earlier, the iterative process uses the results of a prior incremental test to determine if in the next run a resource should be locked in place or removed. The Company took the PVSC results of each run to verify that the solution to the optimization was becoming more efficient with each iteration.

The resource-need optimization used the results of the capacity-need optimization as well as the Company's Current Preferred Plan to help set the initial constraints. As an example, since the PTC wind and 30% ITC solar are similar or lower cost than corresponding non-PTC late wind and 10% ITC late solar additions of the capacity-need optimization, the resource-need optimization would be expected to add no less renewable energy than the capacity-need optimization.

Using run results and the iterative process, the least-cost plan consisted of PTC wind, combustion turbines, and late solar as the best options. The least-cost solution of the resource-need optimization is displayed below in Table 2. The resource-need optimization adds 5,200 MW of PTC wind, 2,600 MW of late solar, and seven combustion turbines. Again, the DR and DG alternatives were not selected due to the higher cost of those resources. As with the capacity-need results, no "real-world" constraints were set on the options by year and the same considerations would apply to convert theoretical results such as this into an actual plan.

Table 2: Resource-Need Expansion Plan

28_B: Resource-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	1,400	1,000	-	200	2,887
Wind	350	200	200	-	5,200	-	-	-	-	-	-	-	-	-	-	-	5,950
PPA CT	-	-	-	-	-	-	-	-	-	-	690	690	230	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	345
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

In summary, the capacity-need and resource-need optimizations indicate that the Company's Current Preferred Plan is consistent and prudent. Applying a more rateable approach to renewables, while still incorporating large amounts of PTC-eligible wind and tax incented solar makes sense for customers. Our Current Preferred Plan represents a balance of the Resource-Need and Capacity-Need Expansion Plans. Adding 5,200 MW of wind in 2018 based on the results of the Resource-Need Optimization is not a viable option from a rate-impact, contracting, construction or operations perspective. Likewise, waiting until 2026 to add additional renewables based on the Capacity-Need Optimization fails to account for the energy and environmental benefits of adding competitive fixed price renewable energy resources to our system in the near-term. Our plan balances the advantages of adding significant amount of renewables–1,200 MW by 2020–but in a manner that also considers the impacts on customer costs.

Attachment G
Socioeconomic Study Summary

The Company has worked with the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth to prepare an analysis of the economic impacts on the state of Minnesota, including Sherburne County, of alternative retirement and replacement scenarios for the Sherburne County generating Units 1 and 2 (Sherco). This study was initiated in response to the Commission's request in our Sherco Life Cycle Management (LCM) proceeding.[1] This study – Economic Impacts of Sherco Plant Alternatives – is included with this filing as Attachment F1 and looked at impacts on employment, gross domestic product (GDP), and disposable personal income on those locations impacted by a change in operating expenditures, capital expenditures, and electricity rates. The scenarios, explained in more detail below, included various Sherco unit retirement dates and the replacement of the two Sherco units with one combined cycle (CC) at the Sherco site and one CC located in Dakota County.

While this study did not model a scenario that directly reflects our Current Preferred Plan (ceasing coal generation at Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023), those dates do fall within the range of scenarios analyzed, with retirement dates ranging from Sherco 1 and 2 in 2020 to Sherco 1 in 2031 and Sherco 2 in 2025. Retirement of either of the Sherco units generates initial positive economic impacts in Sherburne County as a result of decommissioning activities and the construction of a combined cycle at the Sherco site and is then followed by negative economic impacts. The pattern of positive impacts followed by negative impacts is due to shifting the retirement to a date earlier than the economic end of life. The long-term economic effect on Sherburne County after this initial activity is negative under most scenarios due to lost operating and maintenance activity. The construction of replacement generation for one Sherco unit retirement, sited in Dakota County in the scenarios examined for this study, generates positive economic impacts in Dakota County during the construction phase and the succeeding years as a result of ongoing operations. The effect of Sherco unit retirements is a shift in employment from Sherburne County to Dakota County, or the location in which replacement generation is constructed. The timing of those impacts varies in relation to the timing of

[1] *In the Matter of Xcel Energy's Sherco Life Cycle Management Study/2014 Integrated Resource Plan*, Docket No. E002/RP-13-868.

generator retirement and replacement. Construction of replacement generation within Minnesota helps to offset some of the negative economic impacts in the State of Minnesota associated with lost generation.

A. Methodology

The research analysis method used for this study was the Regional Economic Models, Incorporated's (REMI) input-output, general equilibrium, econometric, and economic geography model, using state and national economic and demographic data, as well as data from the Company including capital expenditures, operating expenditures, and revenue requirements for each scenario. The study covered a period from 2015 through 2040, looking at near-term, mid-term, and long-term impacts of alternative retirement and replacement scenarios for Sherco Units 1 and 2. This study period was selected in order to capture the economic activity in the near-term related to decommissioning and the construction of replacement generation, as well as the longer-term impacts of operations and employment at the replacement facilities.

While the specific location of replacement generation for the Sherco units is unknown, Dakota County was selected because it is within Minnesota and the study's purpose was to examine impacts on the State of Minnesota. In addition, it allows for the transfer of economic impacts, such as jobs from Sherco to another location, to be quantified. Therefore, economic impacts were analyzed in this report for Sherburne County, Dakota County, and the rest of Minnesota.

The study examined four scenarios and a baseline scenario, detailed in Table 1 below. We include for comparison the Current Preferred Plan scenario, to illustrate the similarity of the retirement dates and replacement plans between our plan and the scenarios studied. These scenarios correspond to the Updated 2015 Plan and alternative retirement scenarios that were presented in the March 16, 2015 Supplement. The results of the retirement scenarios included in the study are reported as the change in economic impacts relative to the baseline scenario. Replacement generation options included in the study were modeled based on combinations of comparatively-sized gas-fired CC generators, located at the site of our Black Dog plant in Dakota County and at the existing Sherco site.

Table 1: Scenarios Analyzed in the Socioeconomic Study

Scenario	Unit 1 Retirement Date	Unit 2 Retirement Date	Unit 1 Replacement	Unit 2 Replacement
Baseline/ Updated 2015 Plan	2031	2031	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2031 SHC2 2025	2031	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2025 SHC2 2025	2025	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2020 SHC2 2020	2020	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2023 SHC2 2020	2023	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
Current Preferred Plan*	2026	2023	Combined Cycle at Sherco	Combustion Turbine in Fargo

**Not analyzed in this study, but included for comparison.*

B. Results

Overall, the study found that all early retirement scenarios, when compared to the Baseline, result in comparatively slower growth within the Minnesota economy. This impact, however, represents a relatively small percentage of the overall Minnesota economy, as the state's total Gross Domestic Product (GDP) for 2014 was $316 billion. The impact on statewide GDP, shown in Table 2 below, was between $16 million and $90 million, representing a less than one percent impact. None of the scenarios reviewed has a recessionary impact on the state.

Table 2: Sherco Retirement Impacts on the Minnesota Economy, 2015-2040 Averages

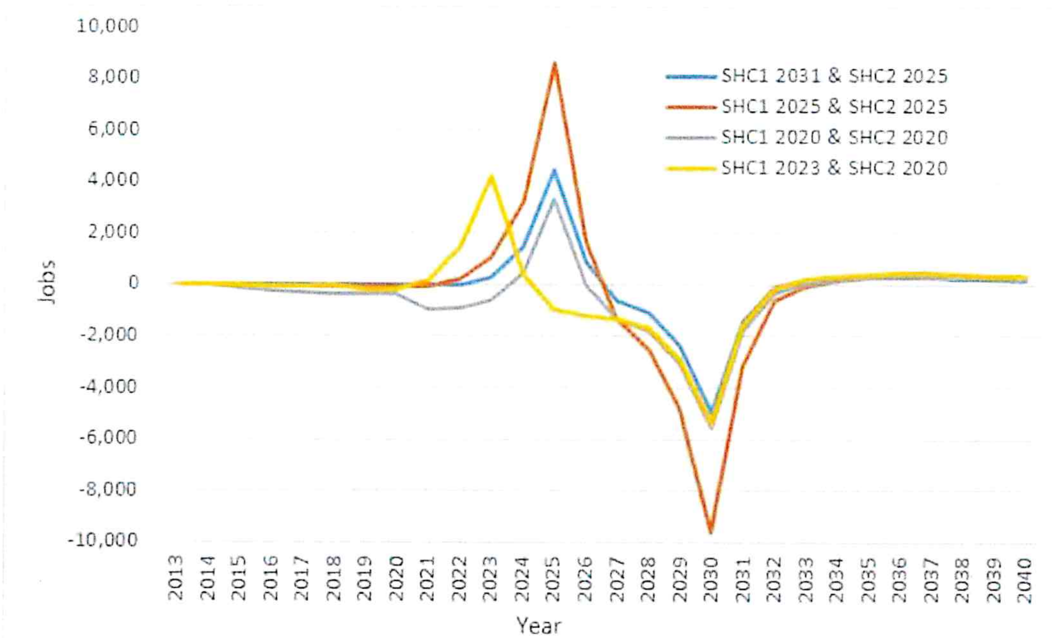
Metric	Units	2015–2040			
		SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1] Fixed (2014) dollars.

All scenarios will result in increased revenue requirements associated with the capital cost of replacement generation. The increase in revenue requirements will result in increased electricity rates for residential, commercial, and industrial utility customers, which will in turn have a negative economic impact on the state overall. The extent of the economic impacts is affected by factors that include the retirement cost of existing units, the source of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The study showed the impacts of the various retirement scenarios on private employment, shown in Figure 1 below, as compared to the baseline. This illustrates how the timing of the impacts on employment shifts relative to the retirement dates. In each scenario, there is a near-term increase in employment relative to the baseline due to decommissioning and the construction of replacement generation. The subsequent dip in employment below the baseline is due to the retirement of the Sherco units.

Figure 1: Sherco Retirement Impact on Minnesota Private Employment



C. Summary

While the Socioeconomic Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 retirement dates fall within the range of scenarios analyzed. Results show that all early retirement scenarios, when compared to a baseline, result in moderately slower growth in the Minnesota economy. The closure of Units 1 and 2 showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, construction of replacement generation within Minnesota creates positive impacts where the replacement is constructed and helps to offset some of the negative economic impacts in the state associated with early retirement. The path charted by our Current Preferred Plan provides certainty for stakeholders, as well as an 8 to 10 year transition period. With our proposal for on-site replacement generation, we demonstrate our commitment to promoting economic development in Central Minnesota.

NORTHERN STATES POWER

ECONOMIC IMPACTS OF SHERCO PLANT ALTERNATIVES

Research by:

Business Research Division
Leeds School of Business
University of Colorado Boulder

Reviewed by:

Bureau of Business and Economic Research
Labovitz School of Business and Economics
University of Minnesota Duluth

October 15, 2015

A report prepared for Northern States Power.

Leeds School of Business
UNIVERSITY OF COLORADO BOULDER
BUSINESS RESEARCH DIVISION

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DEFINITIONS

Employment: Includes the number of full-time and part-time jobs (headcount) by business physical location.

Deflators: Measure of price changes within an industry.

Gross Domestic Product: Total value of final goods and services produced each year within a country or region.

Leakage: Economic activity that occurs outside the area of study but is driven by activity within the study area.

Metropolitan Statistical Area: Geographic areas with 50,000 or more population.[1]

Multiplier: Change in total economic activity driven by a change in direct economic activity.

Output: Total production value of goods and services, including intermediate goods purchased and value added.

Personal Income: Includes all sources of income, including employee compensation, proprietors' income, rental income, capital income, and transfer payments.

[1]For more information, visit: http://www.whitehouse.gov/sites/default/files/omb/assets/fedreg_2010/06282010_metro_standards-Complete.pdf, retrieved July 13, 2014.

EXECUTIVE SUMMARY

This document presents the results of an analysis prepared by the Leeds School of Business to quantify the economic impacts on the state of Minnesota of alternative retirement dates for the Northern States Power Company (NSP) coal-fired Sherco 1 and Sherco 2 generating units. The purpose of an economic impact study is to identify the impacts on employment, gross domestic product, disposable personal income, and other economic metrics for those locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates.

The study area was the state of Minnesota. Impacts on Sherburne County and Dakota County are reported separately from all other counties in the state. Sherburne County is reported separately because the Sherco generating units are both located there, and this separation allows the local effect of an early Sherco retirement to be identified. Dakota County is reported separately because it may be a viable location for the construction of the generation needed to replace the retired Sherco generation. While the location of replacement generation is currently unknown, the purpose of the study was to examine impacts on the state of Minnesota. Therefore, it was important to select a location for replacement generation within the state in order to maintain the focus on Minnesota economic impacts.

The study period was the years 2015 through 2040. This period was selected to capture the near-term economic activity related to decommissioning Sherco and constructing replacement generation, as well as the effects of a change in electricity rates. An abbreviated description of the four retirement scenarios is provided below. A detailed description of the scenarios is provided in the Scenarios section of the report.

The study examined four retirement scenarios and a baseline scenario. The baseline scenario included operating Sherco 1 and Sherco 2 through 2031, then replacing them with the combined cycle generators. Four retirement scenarios were included, and the study results are reported as the change in economic impacts of these scenarios relative to the baseline scenario. The replacement generation that was modeled was based on combinations of comparatively sized gas-fired combined cycle generators located at the Black Dog site in Dakota County and at the Sherco site.

- SHC1 2031 & SHC2 2025: Sherco 1 and Sherco 2 will stop operation in 2031 and 2025, respectively. Sherco 2 will be replaced with a combined cycle generator constructed at Black Dog, and Sherco 1 will be replaced with a combined cycle generator constructed at the Sherco site.
- SHC1 2025 & SHC2 2025: Sherco units 1 and 2 will stop operation in 2025 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2020 & SHC2 2020: Sherco units 1 and 2 will retire in 2020 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2023 & SHC2 2020: Sherco 2 will retire in 2020 and be replaced with a combined cycle generator constructed at the Black Dog site. Sherco 1 will retire in 2023 and be replaced with a combined cycle generator constructed at the Sherco site.

The research team used the REMI model for the analysis. The model used by Leeds was provided by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The 1.6.8 model includes historical data through 2012. NSP provided data that included capital expenditures, operating expenditures, revenue requirements, and taxes for each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

The study findings show that the continued operation of and investments in Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators, will have the greatest ongoing positive economic contribution to the Minnesota economy. The retirement and replacement scenarios have varying degrees of impact on the Sherburne County and Dakota County economies. Retiring either of the Sherco units generates positive economic activity in Sherburne County during the decommissioning phase, but produce a negative economic cost during the succeeding years under most scenarios due to lost operating and maintenance activity. The construction of replacement generation in Dakota County generates positive economic activity during the construction phase and during the succeeding years given the change in local operations. There will be an increase in revenue requirements for all retirement scenarios due to the capital-related costs of replacement generation. These higher costs will increase electricity rates for residential, commercial, and industrial utility customers and will have a negative economic impact on Sherburne County, Dakota County, and the rest of Minnesota. The extent of the economic impacts is affected by factors that include the retirement costs of existing units, the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

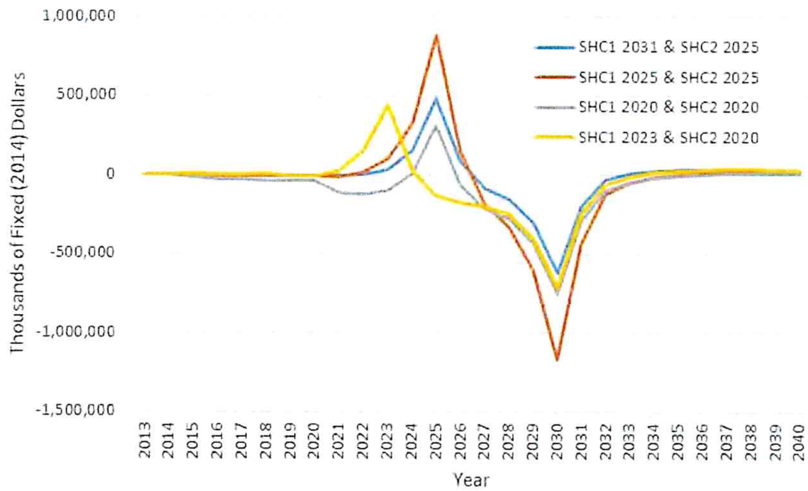
Comparing the four alternative scenarios to the baseline scenario, the time series of economic impacts on Minnesota GDP is illustrated in Figure 1. The figure shows the near-term benefits accrued during the decommissioning and construction phase, followed by a negative impact due to higher revenue requirements over the remainder of the study period. The smallest negative economic impact results from the retirement and replacement of generators in 2025 and 2031. The greatest negative economic impact relative to the baseline results from the earlier retirement of both Sherco 1 and Sherco 2 in 2020 and the replacement in 2026 and 2031.

The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades. The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.

Since all scenarios involve generator retirement and replacement, the spikes and dips in economic activity are largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring units in 2020 instead of 2031, for instance, increases economic activity in the 2020s, but decreases economic activity in the 2030s. Since all of the alternative scenarios retire and replace Sherco

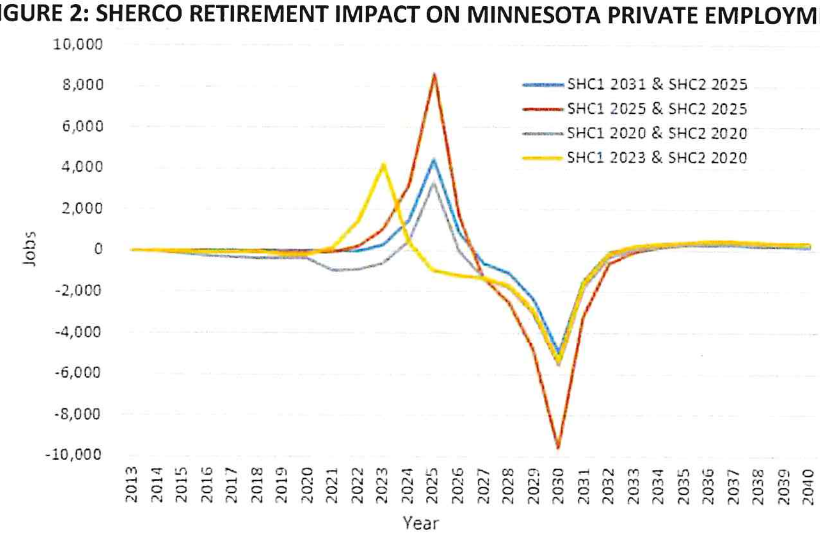
1 and Sherco 2 sooner than the baseline scenario, then all of the alternative scenarios also shift economic activity earlier.

FIGURE 1: SHERCO RETIREMENT IMPACT ON MINNESOTA GDP



A similar pattern is shown for Minnesota private employment, which is shown in Figure 2. Likewise, the near-term activity related to the decommissioning of existing generation and the constructing of replacement generation increases jobs. While employment continues to increase in Minnesota under all scenarios over the study period, early retirement of the Sherco generators results in a decrease in Minnesota employment compared to the baseline scenario.

FIGURE 2: SHERCO RETIREMENT IMPACT ON MINNESOTA PRIVATE EMPLOYMENT



In addition to the differences between near-term and long-term effects shown above, there are also location specific impacts for Sherburne County, Dakota County, and the rest of Minnesota. Compared to the baseline scenario, most retirement scenarios show negative impacts on Sherburne County given that this location will experience decreasing generation operations over time. Dakota County benefits from early retirement of the first Sherco generator because the construction and new operating activity at the Black Dog site will be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. However, while the near-term benefits of constructing the replacement generation in Dakota County may be large, these employment benefits decline rapidly and are not large over the entire study period. Locally, the impact of early retirement is a shift in employment from Sherburne County to Dakota County; statewide, employment continues to grow but at a slower rate.

A summary of all economic metrics for each retirement scenario is shown in Table 1 for the state of Minnesota. Each of the retirement and replacement scenarios place Minnesota on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, total statewide employment is lower, on average, by 75 jobs to 570 jobs as compared to the baseline; GDP is lower by $16 million to $90 million, and real disposable personal income is lower by $14 million to $83 million. In percentage terms, the change from the baseline scenario is less than one-tenth of 1%.

While the economic impacts of the retirement and replacement scenarios may appear large in absolute values, the percentage change of the impacts is relatively small in light of the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

TABLE 1: SHERCO RETIREMENT IMPACTS ON THE MINNESOTA ECONOMY, AVERAGE 2015–2040

		Average 2015–2040			
Metric	**Units**	**SHC1 2031/ SHC2 2025**	**SHC1 2025/ SHC2 2025**	**SHC1 2020/ SHC2 2020**	**SHC1 2023/ SHC2 2020**
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 2 for Sherburne County. Most of the retirement and replacement scenarios place Sherburne County on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 5 and -140 jobs as compared to the baseline; the changes in GDP range between -$4 million and -$19 million, and the changes in real disposable personal income range between -$2 million and -$11 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 2: SHERCO RETIREMENT IMPACTS ON SHERBURNE COUNTY, AVERAGE 2015–2040

Metric	Units	SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
		Average 2015–2040			
Total Employment	Jobs	-31	-22	-140	5
	Percent Change	*-0.07%*	*-0.05%*	*-0.34%*	*0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-6,863	-18,871	13,737
	Percent Change	*-0.11%*	*-0.18%*	*-0.48%*	*0.35%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-2,920	-10,584	2,668
	Percent Change	*-0.05%*	*-0.06%*	*-0.22%*	*0.06%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 3 for Dakota County. Most of the retirement and replacement scenarios place Dakota County on a slightly faster economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 18 and -12 jobs as compared to the baseline; the changes in GDP range between -$445,000 and -$6 million, and the changes in real disposable personal income range between -$714,000 and -$7 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 3: SHERCO RETIREMENT IMPACTS ON DAKOTA COUNTY, AVERAGE 2015–2040

Metric	Units	SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
		Average 2015–2040			
Total Employment	Jobs	18	0	-12	7
	Percent Change	*0.01%*	*0.00%*	*0.00%*	*0.00%*
Gross Domestic Product	Dollars (Thousands)[1]	-445	-3,757	-5,751	-3,430
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-714	-4,508	-6,641	-5,182
	Percent Change	*0.00%*	*-0.02%*	*-0.02%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

STUDY METHODOLOGY

The Business Research Division at the University of Colorado Boulder was hired by Northern States Power to conduct economic impact analyses on retirement scenarios for the Sherco generating units in Sherburne County, Minnesota. This analysis examines the economic impacts of various early retirements of Sherco 1 and Sherco 2. Economic impact studies detail the direct spending that a company or activity has on the area of study, as well as the indirect impact, which is the ripple effect that direct spending has on other businesses in the community. This term is also referred to as the *multiplier effect*, wherein companies utilize the local supply chain. A multiplier is a numeric way of describing the full effects of money changing hands within an economy. For instance, when NSP purchases natural gas, this affects the mining and transportation industries. This is the indirect impact. Additionally, spending by employees has an inherent effect on local communities as they purchase groceries, clothes, and gas; pay rent or a mortgage; get haircuts, etc. This is understood as the induced impact.

The research team used the REMI model for the analysis. Appendix 1 provides an overview of the REMI model. The REMI model is a dynamic forecasting and policy analysis model that incorporates econometric, input-output, and computable general equilibrium techniques. The model was created by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota, with 2012 data as the last historical year within the model.

NSP defined the scenarios to be examined in this study. These are described in detail in the Scenarios section. A baseline scenario was provided by NSP which included operating Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators. The research team developed economic scenarios that included spending and rate changes brought about by four different Sherco retirement and replacement scenarios. The result is a simulated forecast of the economy under scenarios where utility rates and spending on operating and capital expenditures change. Last, the report compares the simulations to the baseline scenario to quantify the economic impacts on the Minnesota economy and on Sherburne County and Dakota County.

The research team collected data on NSP estimates related to ongoing operating and maintenance expenditures, capital expenditures, and revenue requirements. The timing of operating and capital expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

Data were provided in nominal dollars, quantified in the year of expected impact. The impacts are presented in fixed, 2014 dollars, and discounted by the model using industry price deflators.

Costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for each economic region modeled, which included Sherburne County, Dakota County and the rest of Minnesota. This reduces subjectivity and error associated with asking NSP the source and composition of labor, capital, and intermediate inputs to production by community. The local purchasing coefficients within REMI change over time based on changing demand.

ECONOMIC MODEL AND THE MINNESOTA ECONOMY

The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The model used for this study excludes the government spending response to changes in GDP. The REMI model includes an input-output table, industry spending patterns, and local purchasing coefficients.

When working with statewide models, the research team calibrates demographics using state demography forecasts for age, gender, and race. However, given the detailed economic regions, which included Sherburne County, Dakota County, and rest of Minnesota, no further model calibration was applied given the detailed data available for these economic regions.

Sherburne County and Dakota County are part of the Minneapolis-St. Paul-Bloomington Metropolitan Statistical Area. Data from the Bureau of Labor Statistics' Quarterly Census of Employment and Wages show the area recorded 1.8 million total nonfarm covered employees in 2014; Sherburne County represented 1.4%, or 25,835 of the total, and Dakota County represented 10%, or 180,324 of the total. Data from the Bureau of Economic Analysis shows Minnesota GDP of $316 billion in 2014. Real GDP in the state grew at a rate of 1.4% year-over-year. Per capita personal income for the state in 2014 was $48,711. Per capita personal income in 2013, which is the most current data available, was $50,687 in Dakota County and $36,358 in Sherburne County.

The REMI standard regional control places Sherburne County, Dakota County, and the rest of Minnesota on a growth trajectory throughout the analysis horizon, with faster rates of growth in the short term and slowing growth over the entire study period (Figure 3). Similar to recent years, Sherburne County is projected to grow employment at a faster rate than Dakota County and the rest of the state.

FIGURE 3: EMPLOYMENT FORECAST, 2015–2040

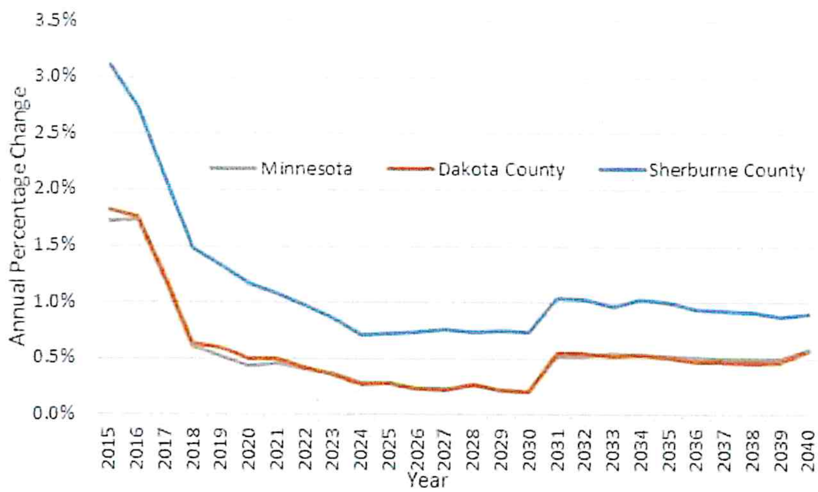
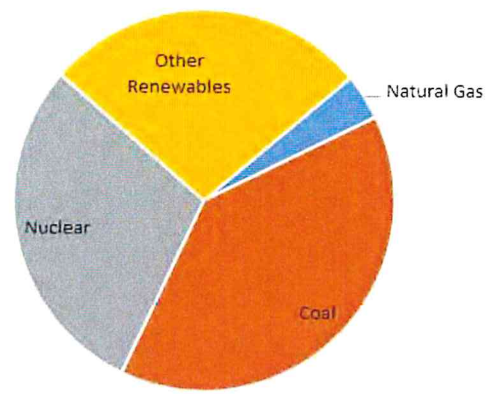


TABLE 4: PROJECTED COMPOUND ANNUAL GROWTH RATES, 2015–2040

COUNTY	EMPLOYMENT	GDP	PERSONAL INCOME
Sherburne County	1.1%	2.4%	3.0%
Dakota County	0.5%	2.1%	2.5%
Rest of Minnesota	0.5%	2.1%	2.3%

As a side point, Minnesota ranked 33rd in the nation in total energy production and 18th for total energy consumed per capita in 2012. As shown in Figure 4, approximately 46% of energy generated in the state came from coal-fired power plants, and an additional 21% was produced by nuclear power plants. Minnesota ranked 7th in wind-generated electricity and is also a top producer of ethanol, with more than 20 corn-based ethanol production plants.

FIGURE 4: MINNESOTA ELECTRICITY GENERATION, GIGAWATT HOURS, 2012



Source: Energy Information Administration.

SCENARIOS

Sherco Generating Units 1 and 2 were built in the 1970s, and a third unit was built in the 1980s. Since installation, these units have been operating for 38, 37, and 27 years, respectively, as of 2014. The 2,400 MW station burns an estimated 30,000 tons of Montana and Wyoming coal daily. In addition to normal operating maintenance, investments have been made to improve the ability of wet scrubbers in Units 1 and 2 to capture sulfur dioxide and ash, as well as in technology to reduce particulates. Modifications and upgrades have been completed to achieve over 90% reduction of sulfur dioxide (SO_2) to meet Best Achievable Retrofit Technology (BART) criteria.

The five scenarios include one baseline scenario where Sherco 1 and Sherco 2 are operated through the Xcel Energy 2016–2030 Upper Midwest Resource Planning period and four retirement scenarios. These scenarios correspond to the Preferred Plan and Preferred Plan Sherco retirement scenarios provided in the March 16, 2015 Supplement. The only change in these scenarios was to replace the first two combined cycle units represented by generic combined cycle units with location specific combined cycle units. This change was required to quantify the economic impacts of Sherco retirements on the local and the state economy.

Baseline

This is the "Preferred Plan" (Resource Plan Scenario 10, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 1 and Sherco 2 continue operation through the end of the Resource Planning period (2030). On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement. These units stop generating January 1, 2031 and remain in standby operating condition until they are retired June 1, 2031. This delay occurs in order to retain accreditation for the Midcontinent Independent System Operator (MISO) capacity year. No Selective Catalytic Reduction (SCR) technology is installed on Sherco 1 and Sherco 2. The replacement combined cycle generators are installed in 2031.

SHC1 2031 & SHC2 2025

This is the "Preferred Plan with Retire 1 Unit 2025" (Resource Plan Scenario 10B, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating January 1, 2031, and remain in standby operating condition until it is retired June 1, 2031. No SCR will be added to Sherco 1. A replacement combined cycle generator will be constructed at the Sherco site and begin operation upon the retirement of Sherco 1 in 2031. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2025 & SHC2 2025

This is the "Preferred Plan with Retire 2 Units 2025" (Resource Plan Scenario 10G, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2020 & SHC2 2020

This is the "Preferred Plan with Retire 2 Units 2020" (Resource Plan Scenario 10E, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 1 and Sherco 2 will stop generating at the end of the year 2020. Both units will remain in standby operating condition until they are retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2026. An additional replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1 or to Sherco 2. On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement.

SHC1 2023 & SHC2 2020

This is the "Preferred Plan with Retire 1 Unit 2020, 1 Unit 2023" (Resource Plan Scenario 10F, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2020. This unit will remain in standby operating condition until it is retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2024. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2023. This unit will remain in operating status and be retired June 1, 2024. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

DATA AND ASSUMPTIONS

NSP provided the research team with capital expenditures, operating expenditures, and revenue requirements for each scenario. The timing of operating and capital expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario. For modeling purposes, cost assumptions were provided in nominal dollars. For comparison purposes, NSP converted inputs from nominal to real dollars using internal deflators. Costs in real dollars are presented in the following section.

Real costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for inputs given that three subregions are specified for this study. This reduces subjectivity and error associated with obtaining the source and composition of labor, capital, and intermediate inputs to production by community from NSP. The local purchasing coefficients within REMI change over time based on changing demand.

Capital Expenditures

The lowest capital cost scenario is the SHC1 2020 & SHC2 2020 in which NSP continues to operate Sherco units 1 and 2 until 2020 and then replaces them with combined cycle units at the Black Dog site and the Sherco site. This scenario, as shown in Table 5, has an estimated capital cost of $1.6 billion between 2015 and 2040, which includes on-going capital needs to repair and replace individual components to reliably continue operation of both units until 2020.

Alternatively, the baseline scenario is the highest capital cost scenario, estimated at nearly $1.9 billion as both Sherco units 1 and 2 in Sherburne County are retired in 2031 and are replaced with combined cycle generating units in Dakota County and Sherburne County (Table 5 and Table 6).

TABLE 5: CAPITAL EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$1,860.8	$0.0	0.0%
SHC1 2031 & SHC2 2025	$1,814.6	-$46.2	-2.5%
SHC1 2025 & SHC2 2025	$1,812.7	-$48.1	-2.6%
SHC1 2020 & SHC2 2020	$1,631.1	-$229.7	-12.3%
SHC1 2023 & SHC2 2020	$1,689.7	-$171.1	-9.2%

TABLE 6: CHANGE IN CAPITAL EXPENDITURES BY LOCATION (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$63.0	$16.8	-$46.2
SHC1 2025 & SHC2 2025	-$65.0	$16.8	-$48.1
SHC1 2020 & SHC2 2020	-$246.5	$16.8	-$229.7
SHC1 2023 & SHC2 2020	-$194.6	$23.5	-171.1

Operating and Maintenance

In addition to the consideration of capital expenditures, fixed and variable operating and maintenance costs vary by scenario. At $982 million, the baseline scenario has the highest operating and maintenance costs—3.5% to 25.8% higher than the alternative scenarios (Table 7). The various retirement and replacement scenarios reduce total fixed and variable operating costs.

TABLE 7: OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Fixed Operating and Maintenance (Millions)	Total Variable Operating and Maintenance (Millions)	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$923.0	$59.1	$982.0	$0.0	0.0%
SHC1 2031 & SHC2 2025	$897.6	$49.9	$947.5	-$34.5	-3.5%
SHC1 2025 & SHC2 2025	$855.3	$39.3	$894.6	-$87.4	-8.9%
SHC1 2020 & SHC2 2020	$663.1	$65.2	$728.3	-$253.7	-25.8%
SHC1 2023 & SHC2 2020	$715.2	$43.7	$758.9	-$223.1	-22.7%

Total fixed and variable operating costs would increase in Dakota County under the alternative scenarios, while costs would decrease in Sherburne County (Table 8).

TABLE 8: CHANGE IN OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$64.5	$30.0	-$34.5
SHC1 2025 & SHC2 2025	-$117.1	$29.7	-$87.4
SHC1 2020 & SHC2 2020	-$310.5	$56.8	-$253.7
SHC1 2023 & SHC2 2020	-$264.8	$41.6	-$223.1

Property Taxes

Property taxes were a separate consideration given the location of the alternative scenarios. While other taxes, such as income taxes and sales taxes, are important considerations, property taxes are particularly important because of the localized impact of the revenue stream. The tax impact was not explicitly modeled in this study. However, a reduction in activity at Sherco would result in a reduction in property taxes in Sherburne County, and an increase in activity at Black Dog would result in an increase in property taxes in Dakota County.

Revenue Requirements

Based on the level of operation and capital expenditures detailed in this report, NSP estimated the increase in revenue requirements included in electricity rates for electric customers for the four early retirement scenarios compared to the baseline scenario. This effectively isolates the revenue requirements and the electricity rate impact for the alternative scenarios and holds economic growth and electricity demand constant.[2] Revenue requirements are not equal to the sum of operation and capital expenditures because capital expenditures are recovered over the life of the asset. Therefore, revenue requirements occur over the life of the asset and include both a return of and return on capital. The revenue requirements estimate the additional electric revenues that would be recovered from customers for each scenario, despite the location of the supply chain for operating and capital purchases. At $1.1 billion, the change in revenue requirements is largest for the SHC1 2020 & SHC2 2020 Scenario between 2015 and 2040 (Table 9). Changes in revenue requirements were applied to residential, commercial, and industrial customers in Minnesota.

TABLE 9: CHANGE IN REVENUE REQUIREMENTS FOR MINNESOTA CUSTOMERS (NOMINAL), 2015–2040

Scenario	Dollar Change (Millions)	Percentage Change
Baseline	$0.0	0.0%
SHC1 2031 & SHC2 2025	$146.6	0.1%
SHC1 2025 & SHC2 2025	$806.4	0.7%
SHC1 2020 & SHC2 2020	$1,111.9	0.9%
SHC1 2023 & SHC2 2020	$826.9	0.7%

RESULTS

Continued operation of and investments in Sherco units 1 and 2 will have an ongoing positive economic contribution to the Minnesota economy. Scenarios involving early retirement and replacement of one or both of the units would also have near-term economic benefits, but the economic benefits of the baseline scenario are comparatively larger than the early retirement scenarios. The extent of the economic impacts is affected by factors that include the retirement costs of existing generating units,

[2]Electricity costs were entered as fuel cost variables: "Electricity (Commercial Sectors) Fuel Cost (amount)" for nonresidential sectors, and "Consumer Price (amount) for the residential sector."

the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The retirement and replacement scenarios have varying degrees of impact on the Dakota County and Sherburne County economies. Retiring Sherco units in Sherburne County generates positive economic activity during the decommissioning phase but instills a negative economic cost during the other years due to lost operating and maintenance activity and to higher revenue requirements placed on residential and business utility customers. The construction and new operating activity at the Black Dog site in Dakota County would be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. While these benefits accrue to Dakota County, it essentially shifts economic benefits from Sherburne County to Dakota County, and the overall impact on the Minnesota economy is marginally negative compared to the baseline scenario. The economic impacts of the retirement and replacement scenarios may appear large in absolute values, but the percentage change of the impacts is relatively small compared to the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

To quantify the economic contribution of the baseline scenario, the projected capital expenditures and operating expenditures from 2015 through 2040 were removed from the Minnesota economy. The resulting decrease in economic activity is the economic contribution of projected operations. This analysis excludes the revenue requirements associated with current operations of Sherco 1 and 2 since those revenue requirements are imbedded in the overall system revenue requirements for the company. The alternative scenarios were modeled using the changes in spending compared to baseline scenario on capital expenditures, operating expenditures, taxes, and revenue requirements. The revenue requirements for the alternative scenarios were supplied for the overall system, and it was possible to model the impact of *change* in revenue requirements for the retirement scenarios because the only system changes between the baseline scenario and the retirement scenarios include the retirement and replacement effects. Everything else in the system was left unchanged.

The following is a net analysis, examining the benefits as well as the costs. The growing demand for energy and plant energy output is controlled by comparing the economic impacts of the retirement scenarios to the baseline scenario. This section reports the impacts in fixed (2014) dollars and the following paragraphs summarize the economic impacts by scenario.

Baseline Scenario Economic Contribution

In terms of economic contributions to the state of Minnesota, the baseline scenario, which includes continued long-term operation of Sherco units 1 and 2 until retirement and replacement in 2031, yields 980 jobs on average over the 26-year time horizon (Table 10). The baseline scenario would yield a contribution to total GDP of $2.8 billion in fixed 2014 dollars over the forecast horizon from 2015–2040, excluding the revenue requirements to customers.[3,4] Despite the Sherburne County location of Sherco units 1 and 2, the economic benefits of capital and operating expenditures extend beyond Sherburne County as direct and indirect goods and services are purchased from vendors throughout the state and as employee disposable income is spent in the larger Minnesota economy. Detailed results are available in Appendices 2,3, and 4.

TABLE 10: ECONOMIC CONTRIBUTION OF SHERCO 1 AND 2, AVERAGE 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	527	228	224	980
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	465	215	205	885
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	65,815	25,391	16,065	107,273
	Percent Change	*1.7%*	*0.1%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	40,606	15,168	14,369	70,141
	Percent Change	*0.9%*	*0.1%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars. Note: The baseline scenario is the total economic impact (excluding rate impact); other scenarios are in comparison to the baseline scenario.

SHC1 2031 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2025 and its replacement with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2031 and its replacement with a combined cycle generator at Sherco. This early retirement scenario has the second-highest capital expenditures and operating costs, and the second-lowest revenue requirements. This scenario records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on

[3] Revenue requirements for each scenario are calculated for the entire NSP system rather than just for Sherco 1 and 2.

[4] Total contributions to GDP are summed over the entire period while averages are shown in Table 10 (26 years times $107,273K equals $2.8 billion).

consumers (both residential and commercial/industrial) as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, while they are slightly larger in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. Compared to the baseline scenario, over the 26-year horizon, Sherburne County employment is lower by an average of 31 jobs per year, Dakota County is higher by an average of 18 jobs per year, and the rest of Minnesota is lower by an average of 62 jobs per year, as shown in Table 11.

TABLE 11: SHC1 2031 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

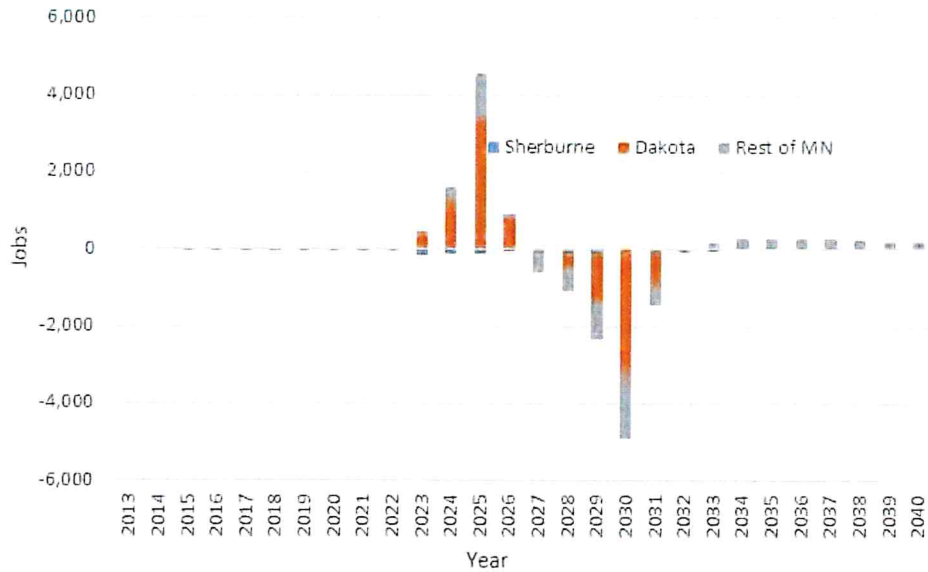
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-31	18	-62	-75
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-27	16	-46	-57
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-445	-11,479	-16,021
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-714	-10,602	-13,719
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 5.)

As shown in Figure 5, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the Sherco unit shutdown and decommissioning phase.

FIGURE 5: SHC1 2031 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT



Total capital spending and operating and maintenance costs for this early retirement scenario are less than those for the baseline scenario. Revenue requirements are greater than in the baseline scenario, and this increase is greater than the decrease in total operating costs. The economic impacts are tempered, however, due the size of these impacts relative to the large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. As shown in Table 11, slower growth in GDP of $16 million and 75 fewer jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2025 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco units 1 and 2 in 2025, replaced with combined cycle generators at Sherco and Black Dog. This scenario has the third-highest fixed capital costs, operating costs, and revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are recorded in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 12, over the 26-year horizon, Sherburne County employment is lower by an average of 22 jobs, Dakota County is flat, and the rest of Minnesota is lower by 237 jobs compared to the baseline scenario.

TABLE 12: SHC1 2025 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVE. 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-22	0.2	-237	-258
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-22	0	-187	-209
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-6,863	-3,757	-42,640	-53,257
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,920	-4,508	-40,494	-47,919
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 6.)

Visible in Figure 6, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the reconstruction of Sherco 1.

FIGURE 6: SHC1 2025 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT

Despite the decrease in total capital spending and decrease in operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. Slower growth in GDP of $53 million and 258 fewer jobs represent less than one-tenth of a percent change in economic growth statewide (Table 12). The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2020 & SHC2 2020 Economic Impacts

This scenario includes placing Sherco 1 and 2 in standby mode in 2020, replaced with new combined cycle generators at Black Dog in 2026 and at Sherco in 2031. This scenario has the lowest fixed capital costs and operating costs and the highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County averages modest employment losses despite gaining a generating facility—mostly due to the delayed replacement facility in Dakota County. Sherburne County loses some operating activity and the rest of Minnesota incurs higher utility costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are incurred in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 13, over the 26-year horizon, Sherburne County employment is lower by an average of 140 jobs, Dakota County is lower by an average of 12 jobs, and the rest of Minnesota is lower by 418 jobs compared to the baseline scenario.

TABLE 13: SHC1 2020 & SHC2 2020 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

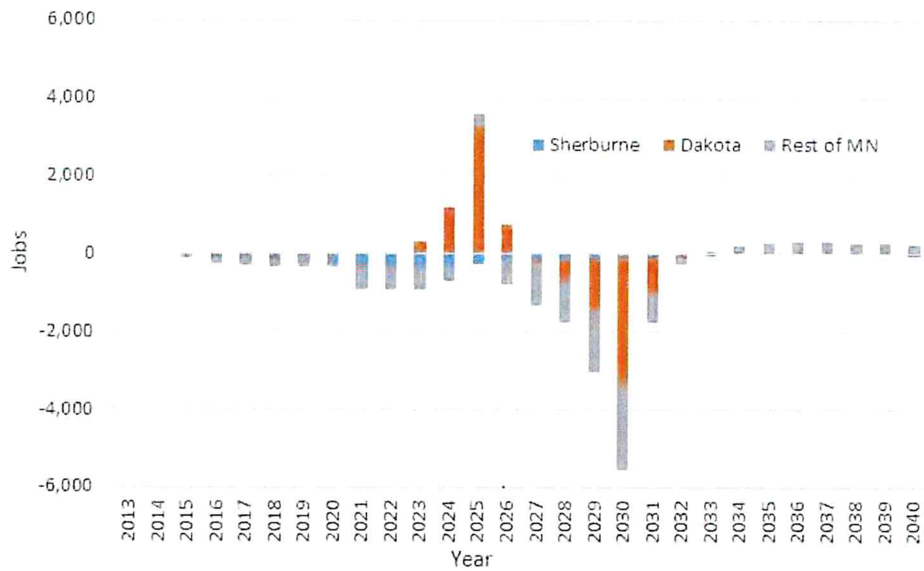
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs	-140	-12	-418	-570
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-121	-10	-334	-465
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-18,871	-5,751	-65,339	-89,966
	Percent Change	*-0.5%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-10,584	-6,641	-66,262	-83,485
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 7.)

As Figure 7 shows, Dakota County records the greatest employment impact. This is due to the new construction and operations within the county. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 7: SHC1 2020 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $90 million and 570 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2023 & SHC2 2020 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2020, replaced with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2023, replaced with a combined cycle generator at Sherco. This alternative scenario has the second-lowest fixed capital costs and operating costs, and the second-highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota Counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs.

The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County and Sherburne County record a net increase in economic activity, while the rest of Minnesota incurs higher utility costs. However, these deviations are relatively small compared to the overall Minnesota economy. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 14, over the 26-year horizon, Sherburne County employment is higher by an average of 5 jobs, Dakota County is higher by an average of 7 jobs, and the rest of Minnesota is lower by 313 jobs compared to the baseline projection.

TABLE 14: SHC1 2020 & SHC2 2023 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

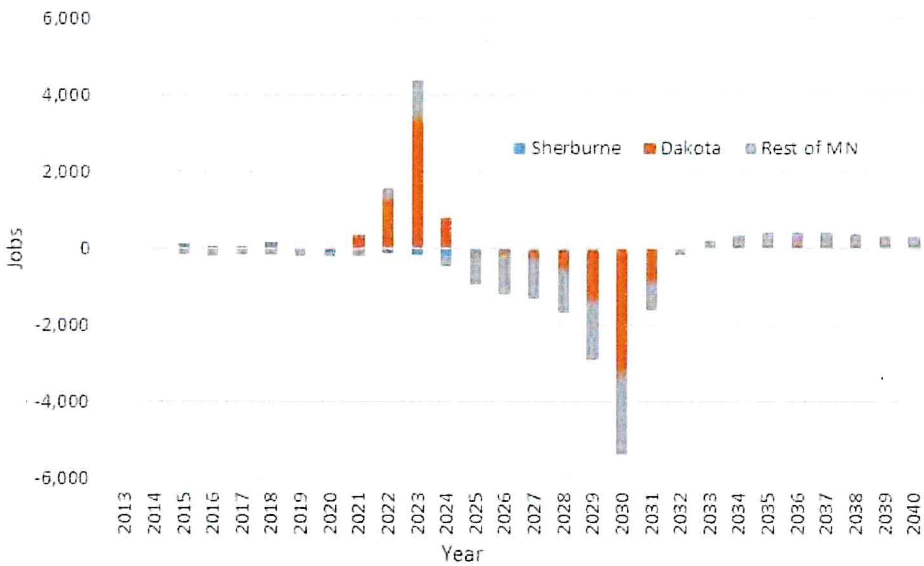
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	2	8	-248	-239
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	13,737	-3,430	-60,123	-49,813
	Percent Change	*0.4%*	*0.0%*	*0.0%*	*0.0%*
Personal Income	Dollars (Thousands)[1]	2,668	-5,182	-49,930	-52,443
	Percent Change	*0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spikes and dips in economic activity are largely due to timing. Retiring Sherco 1 in 2023 instead of 2031, and retiring Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 8.)

As Figure 8 indicates, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 8: SHC1 2023 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending and operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $50 million and 300 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

CONCLUSION

This paper provides an analysis of the economic impact of early retirement and replacement of the coal-fired Sherco 1 and Sherco 2 units with an equivalent MW amount of combined cycle gas-fired generation capacity. This report finds the costs associated with an increase in revenue requirements to pay for early retirement and replacement are modestly greater than the economic benefits associated with the change in capital investments and operating costs.

This analysis uses data on operations, maintenance, capital expenditures, and revenue requirements provided by NSP on the current Sherco 1 and 2 units and on four retirement scenarios.

Overall, the study found the following:

- Current Sherco operations have an impact that extends beyond Sherburne County as NSP purchases goods and services from vendors throughout Minnesota and as income earners spend disposable personal income throughout the state.
- Some of the construction and operating benefits do not impact the Minnesota economy as goods and services are sourced from out of state while the increase in revenue requirements (costs) are placed on all Minnesota NSP customers (residential, commercial, and industrial).
- The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades.
- The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.
- All early Sherco retirement scenarios will result in higher revenue requirements of $147 million–$1.7 billion, or 0.1%–0.9% for NSP's Minnesota electricity customers, partially due to fuel costs. This negative economic impact is greater than the economic benefits associated with the construction of replacement generation and changes in operations.
- Continued operation of and investments in Sherco units 1 and 2 through 2031 will have the greatest ongoing positive impact to the Minnesota economy.
- Compared to the baseline scenario, all early Sherco retirement scenarios result in comparatively slower growth within the Minnesota economy in terms of:
    - Employment (-75 to -570 jobs on average)
    - GDP (-$16 million to -$90 million on average), and

  - Real disposable personal income (-$14 million to -$83 million).

  Note: These changes represent a relatively small percentage of the overall Minnesota economy, Sherburne County economy, and Dakota County economy, and none of the scenarios are recessionary.

- The statewide economic losses compared to the baseline scenario increase as the retirement of Sherco units are moved to earlier dates because of the need for earlier capital expenditures and increased costs to rate payers.
  - Scenario SHC1 2020 & SHC2 2020 results in the greatest statewide decrease in GDP compared to the baseline scenario.
  - The SHC1 2031 & SHC2 2025 retirement scenario results in the smallest economic loss compared to the baseline scenario.
- As a percentage of local economic activity, Sherburne County experiences the greatest negative impact under most retirement scenarios due to the reduction in local operating activity, while Dakota County records the largest positive impacts due to the construction of replacement generation at the Black Dog site. The study period impacts are generally a decrease in employment in Sherburne County, as well as a shift of employment from Sherburne County to Dakota County. Construction of replacement generation on the Sherco site buffers some of the negative economic impacts associated with lost generation.

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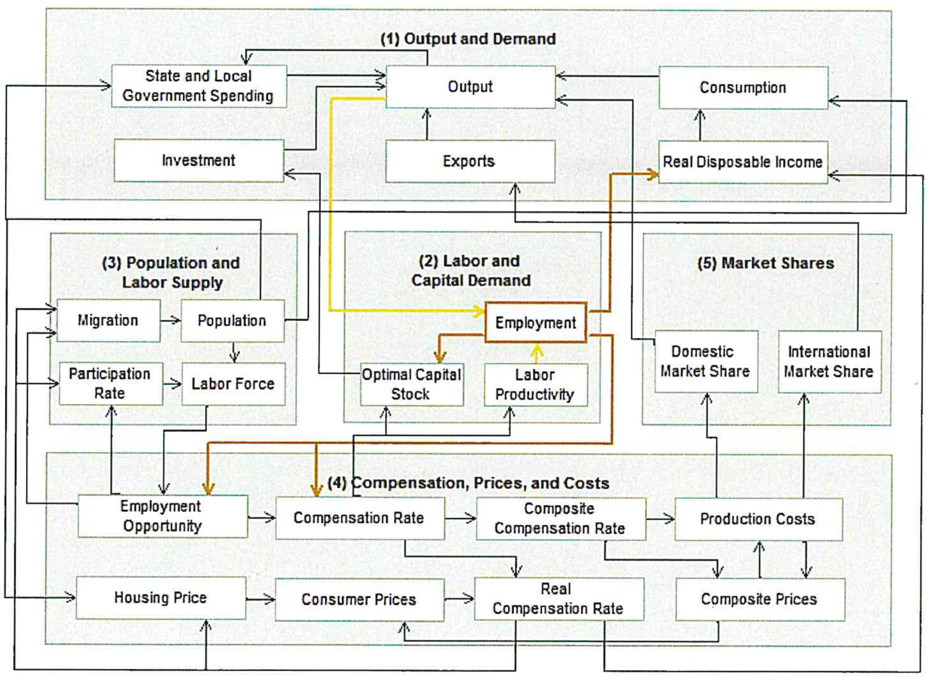
APPENDIX 1: OVERVIEW OF REMI POLICY INSIGHT

This summary was provided by REMI, Inc.

Policy Insight is a structural economic forecasting and policy analysis model. It integrates input-output, computable general equilibrium, econometric, and economic geography methodologies. The model is dynamic, with forecasts and simulations generated on an annual basis and behavioral responses to wage, price, and other economic factors.

The REMI model consists of thousands of simultaneous equations with a structure that is relatively straightforward. The exact number of equations used varies depending on the extent of industry, demographic, demand, and other detail in the model. The overall structure of the model can be summarized in five major blocks: (1) Output and Demand, (2) Labor and Capital Demand, (3) Population and Labor Supply, (4) Wages, Prices and Costs, and (5) Market Shares.



Block 1. Output and Demand

This block includes output, demand, consumption, investment, government spending, import, product access, and export concepts. For each industry, demand is determined by the amount of output, consumption, investment and capital demand on that industry. Consumption depends on real disposable income per capita, relative prices, differential income elasticities and population. Input productivity depends on access to inputs because the larger the choice set of inputs, the more likely that the input with the specific characteristics required for the job will be formed. In the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for residential, non-residential, and equipment investment. Government spending changes are determined by changes in the population.

Block 2. Labor and Capital Demand

The Labor and Capital Demand block includes the determination of labor productivity, labor intensity and the optimal capital stocks. Industry-specific labor productivity depends on the availability of workers with differentiated skills for the occupations used in each industry. The occupational labor supply and commuting costs determine firms' access to a specialized labor force.

Labor intensity is determined by the cost of labor relative to the other factor inputs, capital and fuel. Demand for capital is driven by the optimal capital stock equation for both non-residential capital and equipment. Optimal capital stock for each industry depends on the relative cost of labor and capital, and the employment weighted by capital use for each industry. Employment in private industries is determined by the value added and employment per unit of value added in each industry.

Block 3. Population and Labor Supply

The Population and Labor Supply block includes detailed demographic information about the region. Population data is given for age and gender, with birth and survival rates for each group. The size and labor force participation rate of each group determines the labor supply. These participation rates respond to changes in employment relative to the potential labor force and to changes in the real after tax compensation rate. Migration includes retirement, military, international and economic migration. Economic migration is determined by the relative real after tax compensation rate, relative employment opportunity and consumer access to variety.

Block 4. Wages, Prices, and Costs

This block includes delivered prices, production costs, equipment cost, the consumption deflator, consumer prices, the price of housing, and the wage equation. Economic geography concepts account for the productivity and price effects of access to specialized labor, goods and services.
These prices measure the price of the industry output, taking into account the access to production locations. This access is important due to the specialization of production that takes place within each industry, and because transportation and transaction costs of distance are significant. Composite prices for each industry are then calculated based on the production costs of supplying regions, the effective

distance to these regions, and the index of access to the variety of output in the industry relative to the access by other uses of the product.

The cost of production for each industry is determined by cost of labor, capital, fuel and intermediate inputs. Labor costs reflect a productivity adjustment to account for access to specialized labor, as well as underlying compensation rates. Capital costs include costs of non- residential structures and equipment, while fuel costs incorporate electricity, natural gas and residual fuels.

The consumption deflator converts industry prices to prices for consumption commodities. For potential migrants, the consumer price is additionally calculated to include housing prices. Housing price changes from their initial level depend on changes in income and population density.

Compensation changes are due to changes in labor demand and supply conditions and changes in the national compensation rate. Changes in employment opportunities relative to the labor force and occupational demand change determine compensation rates by industry.

Block 5. Market Shares

The Market Shares equations measure the proportion of local and export markets that are captured by each industry. These depend on relative production costs, the estimated price elasticity of demand, and effective distance between the home region and each of the other regions. The change in share of a specific area in any region depends on changes in its delivered price and the quantity it produces compared with the same factors for competitors in that market. The share of local and external markets then drives the exports from and imports to the home economy.

The Labor and Capital Demand block includes labor intensity and productivity as well as demand for labor and capital. Labor force participation rate and migration equations are in the Population and Labor Supply block. The Wages, Prices, and Costs block includes composite prices, determinants of production costs, the consumption price deflator, housing prices, and the wage equations. The proportion of local, inter-regional and export markets captured by each region is included in the Market Shares block.

APPENDIX 2: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON THE MINNESOTA ECONOMY

The following tables exhibit the economic impacts of the baseline scenario on the Minnesota economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 15: ECONOMIC CONTRIBUTION OF BASELINE SCENARIO ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	545	511	631	3,115	241	980
Private Non-Farm Employment	Jobs	515	454	567	2,920	112	885
Gross Domestic Product	Dollars (Thousands)[1]	58,758	56,019	73,325	345,997	18,944	107,273
Real Disposable Personal Income	Dollars (Thousands)[1]	29,475	33,754	45,510	207,539	40,525	70,141

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 16: ECONOMIC CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-23	349	286	-1,286	246	-75
Private Non-Farm Employment	Jobs	-21	348	262	-1,192	269	-57
Gross Domestic Product	Dollars (Thousands)[1]	-2,656	36,698	6,624	-161,786	32,256	-16,021
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,813	17,126	-32,173	-83,661	25,542	-13,719

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 17: ECONOMIC CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-50	895	395	-2,874	245	-258
Private Non-Farm Employment	Jobs	-46	884	332	-2,650	339	-209
Gross Domestic Product	Dollars (Thousands)[1]	-5,747	85,523	-16,608	-360,954	17,216	-53,257
Real Disposable Personal Income	Dollars (Thousands)[1]	-6,365	40,301	-89,229	-211,488	14,438	-47,919

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 18: ECONOMIC CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-293	-545	-681	-1,687	207	-570
Private Non-Farm Employment	Jobs	-276	-472	-554	-1,463	300	-465
Gross Domestic Product	Dollars (Thousands)[1]	-28,154	-72,538	-135,514	-239,782	6,515	-89,966
Real Disposable Personal Income	Dollars (Thousands)[1]	-23,050	-93,037	-171,610	-151,162	4,032	-83,485

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 19: ECONOMIC CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-71	1,252	-1,683	-1,481	361	-300
Private Non-Farm Employment	Jobs	-70	1,231	-1,597	-1,294	423	-239
Gross Domestic Product	Dollars (Thousands)[1]	3,270	128,358	-229,536	-202,810	35,226	-49,813
Real Disposable Personal Income	Dollars (Thousands)[1]	-8,685	42,906	-218,317	-123,437	29,645	-52,443

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

APPENDIX 3: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON SHERBURNE COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Sherburne County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 20: CONTRIBUTION OF BASELINE SCENARIO ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	490	430	422	1,242	136	527
Private Non-Farm Employment	Jobs	461	378	367	1,135	63	465
Gross Domestic Product	Dollars (Thousands)[1]	66,831	58,796	62,471	132,322	18,373	65,815
Real Disposable Personal Income	Dollars (Thousands)[1]	26,949	30,386	32,658	85,887	30,426	40,606

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 21: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	-55	-79	-26	-1	-31
Private Non-Farm Employment	Jobs	0	-54	-72	-18	3	-27
Gross Domestic Product	Dollars (Thousands)[1]	-25	-3,045	-14,301	-4,458	455	-4,097
Real Disposable Personal Income	Dollars (Thousands)[1]	7	-2,180	-5,664	-3,457	-1,052	-2,406

[1]Dollars are fixed (2014) dollars.

TABLE 22: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	392	422	-911	-17	-22
Private Non-Farm Employment	Jobs	0	383	357	-870	12	-22
Gross Domestic Product	Dollars (Thousands)[1]	-58	34,907	22,691	-93,905	324	-6,863
Real Disposable Personal Income	Dollars (Thousands)[1]	-8	18,054	31,922	-54,491	-9,707	-2,920

[1]Dollars are fixed (2014) dollars.

TABLE 23: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-129	-325	-204	-62	-5	-140
Private Non-Farm Employment	Jobs	-124	-302	-172	-38	6	-121
Gross Domestic Product	Dollars (Thousands)[1]	-9,864	-39,616	-37,735	-12,002	981	-18,871
Real Disposable Personal Income	Dollars (Thousands)[1]	-5,567	-18,993	-17,643	-9,094	-3,171	-10,584

[1]Dollars are fixed (2014) dollars.

TABLE 24: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	106	-92	-69	30	44	5
Private Non-Farm Employment	Jobs	95	-100	-67	31	41	2
Gross Domestic Product	Dollars (Thousands)[1]	35,663	7,779	-2,351	12,822	14,728	13,737
Real Disposable Personal Income	Dollars (Thousands)[1]	9,369	39	-3,123	2,171	4,463	2,668

[1]Dollars are fixed (2014) dollars.

APPENDIX 4: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON DAKOTA COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Dakota County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 25: CONTRIBUTION OF BASELINE SCENARIO ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	1	1	78	1,065	36	228
Private Non-Farm Employment	Jobs	1	1	77	1,026	10	215
Gross Domestic Product	Dollars (Thousands)[1]	-535	-422	8,014	121,058	2,954	25,391
Real Disposable Personal Income	Dollars (Thousands)[1]	-84	-251	3,445	62,511	11,543	15,168

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 26: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-3	338	535	-820	39	18
Private Non-Farm Employment	Jobs	-3	333	495	-798	50	16
Gross Domestic Product	Dollars (Thousands)[1]	-286	33,672	51,237	-93,710	5,803	-445
Real Disposable Personal Income	Dollars (Thousands)[1]	-448	15,509	26,996	-44,887	-1,096	-714

[1]Dollars are fixed (2014) dollars.

TABLE 27: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-6	341	489	-873	43	0
Private Non-Farm Employment	Jobs	-5	337	450	-845	56	0
Gross Domestic Product	Dollars (Thousands)[1]	-591	34,087	44,762	-102,846	4,291	-3,757
Real Disposable Personal Income	Dollars (Thousands)[1]	-873	15,510	16,888	-52,685	-2,282	-4,508

[1]Dollars are fixed (2014) dollars.

TABLE 28: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-15	281	460	-845	47	-12
Private Non-Farm Employment	Jobs	-14	280	427	-816	60	-10
Gross Domestic Product	Dollars (Thousands)[1]	-1,592	26,952	40,202	-99,992	3,826	-5,751
Real Disposable Personal Income	Dollars (Thousands)[1]	-1,867	6,144	13,960	-50,546	-2,247	-6,641

[1]Dollars are fixed (2014) dollars.

TABLE 29: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-17	1,208	-393	-828	60	7
Private Non-Farm Employment	Jobs	-16	1,182	-418	-794	75	8
Gross Domestic Product	Dollars (Thousands)[1]	-2,437	118,085	-48,109	-95,211	8,425	-3,430
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,127	53,008	-24,533	-51,351	-2,038	-5,182

[1]Dollars are fixed (2014) dollars.

Attachment H
Preliminary Assessment of CO_2 Markets under the Clean Power Plan

We present this preliminary assessment of potential revenues from carbon dioxide (CO_2) credits in future markets under the Clean Power Plan (CPP), in response to requests by the Department of Commerce and Commissioners during the December 3, 2015 Minnesota Public Utilities Commission hearing.

Although our Current Preferred Plan is not primarily driven by the CPP, we believe this plan will not only achieve, but likely exceed, the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. As a result, the Current Preferred Plan may generate excess reductions in the form of CO_2 allowances (if Minnesota's plan is mass-based) or Emission Rate Credits (if the plan is rate-based), which under the CPP would be tradable to the owners of other CPP-regulated units within the state or in other states. As long as Minnesota's plan allows the Company to monetize the value of these reductions on behalf of our customers, this value could be used to help reduce the rate impact of transitioning our generation portfolio to a much lower-carbon system.

This Attachment estimates the value to our customers of excess CO_2 reductions under two State Plan scenarios. However, we emphasize the preliminary nature of this assessment: both the size and value of the allowances or ERCs we generate, beyond those used for our own compliance, are subject to uncertainty because they depend on State Plan decisions yet to be made and predictions about prices in CO_2 credit markets not yet in existence.

A. CPP Final Rule, State Plans and CO_2 Credit Markets

The CPP final rule sets CO_2 targets, for 2022 and each year thereafter, for each of the states in our Upper Midwest System. The targets are provided in "rate-based" form (pounds of CO_2 per MWh, both specific to coal and gas units and for each state as a whole) and "mass-based" form (total tons of CO_2, by year, on aggregate for all the CPP-regulated units in a state). Only the Minnesota targets affect the Company directly, since we own and operate CPP-regulated units only in Minnesota; however, the costs and benefits of compliance will be shared among customers in all our five states.

The rule allows each state to develop a State Plan to achieve the targets, providing states considerable flexibility in how they do this. It allows EPA to impose a Federal

Plan on any state that fails to submit an approvable plan. Initial State Plan submittals are due in September 2016, with the option to seek an extension to September 2018 to submit a final plan. The Minnesota Pollution Control Agency (MPCA) is the lead agency with responsibility to develop Minnesota's State Plan, in consultation with other agencies and stakeholders. The Company has been an active participant in MPCA's stakeholder group, as well as similar processes in our other states and regional stakeholder processes, discussing State Plan design decisions. We have been working to identify areas of agreement among utilities and other stakeholders.

A key decision in State Plan design is whether to take a rate-based or mass-based approach. A rate-based approach would seek to achieve the pounds of CO_2 per MWh targets, either on a statewide level or using the subcategory rates specific to coal and natural gas combined cycle units, and would allow eligible activities – including renewable energy, energy efficiency, and nuclear uprates – to earn Emission Rate Credits (ERCs) that could be used by regulated units for compliance. A mass-based approach would seek to achieve the total tons of CO_2 targets, requiring all regulated units to surrender CO_2 allowances equivalent to their emissions in a compliance period.

One of the most important flexibility mechanisms in the CPP is the option for states to create CO_2 credit markets – i.e. allow the owners of CPP-regulated units in a state to transact CO_2 allowances or ERCs with other regulated units, or with other entities, within the state or in other states. This would enable regulated unit owners to purchase allowances or ERCs for compliance, if this is more cost-effective than reducing emissions on their own system, or sell allowances or ERCs, if a regulated unit owner is able cost-effectively to reduce emissions such that it holds more allowances or ERCs than it needs for compliance.

EPA views this compliance flexibility as key to containing costs, and appropriate for CO_2, since the climate benefits of reducing emissions are independent of location. EPA does not mandate that State Plans allow trading, but provides much of the necessary infrastructure, including presumptively approvable model trading rules, EPA-administered allowance and ERC tracking systems, accreditation of credit verifiers, etc. EPA also allows trading between State Plan states and states who accept a Federal Plan. However, EPA proposes that regulated units in mass-based states may only trade with those in other mass-based states, and units in rate-based states may only trade with those in other rate-based states.

Minnesota and the other states the Company serves in the Upper Midwest are all actively considering allowing CO_2 credit trading in their CPP State Plans. However, none of our states has yet determined whether their plan will be mass-based or rate-based, and because of EPA's proposed restriction on trading between rate and mass, the geographic scope and liquidity of future CO_2 credit markets is unknown.

B. Scenario Analysis: Potential Value of CO_2 Credits to Our Customers

The Current Preferred Plan includes actions – coal unit retirement, maintenance of nuclear units, renewable energy additions, and ongoing energy efficiency savings – that are projected to reduce CO_2 potentially beyond what the State Plan requires of the Company. These actions may put the Company in the position of being a net allowance or ERC seller, after the Company has surrendered sufficient allowances or ERCs to bring its own units into compliance. This section presents a preliminary analysis of the value to our customers of these actions, under different possible credit prices and State Plan designs.

Uncertainties affecting the size of the Company's allowance budget include whether Minnesota and other states in the region take mass-based or rate-based approaches to compliance, how the State Plan allocates allowances in a mass-based approach, and which actions are eligible for ERC issuance in a rate-based approach. Uncertainties affecting the price obtainable for any allowances or ERCs include whether states allow trading in their plans, how much EPA's proposed restriction on trading between rate and mass limits the geographic scope and liquidity of CO_2 credit markets, and the structure of CO_2 credit markets that may emerge.

1. *Credit Prices*

Estimating the market value of CO_2 reductions requires assuming a price for allowances or ERCs in markets not yet in existence. The Commission's current regulatory cost range under Minn. Stat. § 216H.06 – $9 to $34 per short ton of CO_2 emitted – represents one potential price range for allowances (not ERCs).[1] The Company applies the midpoint of this range, $21.50 per ton, as a base assumption in resource planning, and applies the two ends of the range as sensitivities. The MPCA and Minnesota Department of Commerce recently released a request for comments on

[1] April 28, 2014 Order. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06.* Docket No. E999/CI-07-1199.

the 2016 update of the regulatory cost range, making a preliminary recommendation to retain the range at $9 to $34 per ton.[2]

The Company agreed with the agencies that this range remains reasonable with the information currently available.[3] The Commission's regulatory cost range was first established in 2008, at a time when Congress was contemplating economy-wide, mass-based CO_2 "cap and trade" proposals, and reflected expert predictions of the CO_2 price that might emerge in such markets. While none of these proposals was signed into law, and today power sector CO_2 regulation is proceeding under section 111(d) of the Clean Air Act, as noted above, EPA has provided for market-based compliance mechanisms in both State and Federal Plans. Minnesota and other states in the region appear to be strongly considering this option, so a market-based regulatory cost appears to be a reasonable assumption.

We do not, however, know whether Minnesota's plan will involve allowance or ERC trading, what other states in the region might choose, or how broad or liquid CO_2 credit markets might be. Experience with existing CO_2 markets in the United States and internationally suggests that efficient market design and geographically broader markets lead to lower CO_2 prices, and prices in existing United States CO_2 markets have historically been in the lower end of the Commission's range.[4] However, with CPP State Plans still in such early stages, and actual CPP markets not yet in existence, it seems premature to conclude that prices will be lower than $9 (or higher than $34). For this analysis, we have used the same $9, $21.50, and $34 per ton that we use in Strategist modeling.

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[2] December 3, 2015 Request for Comments. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06.* Docket No. E999/CI-15-708, Docket No. E999/CI-07-1199. The Agencies recommended shifting the date utilities are required to begin applying the range to 2022, which reflects the first year utilities will face a cost to comply with the CPP.
[3] January 14, 2016 *Comments on Updating the Estimated Cost of Future Carbon Dioxide Regulation under Minn. Stat. § 216H.06.* Docket No. E999/CI-15-708.
[4] For example, $12.73 per metric ton ($11.55 per short ton) in the most recent allowance auction in California, and $7.50 per short ton in the most recent allowance auction in the northeastern states Regional Greenhouse Gas Initiative. Prices in prior auctions were lower. See http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm and http://www.rggi.org/market/co2_auctions/results.

The Commission has no corresponding estimate that could be applied as a price per ERC, and there are no existing rate-based CO_2 markets from which to estimate a price of ERCs.[5]

2. *State Plan Decisions Affecting Company's Allowance Budget*

The size of the Company's allowance budget will depend on many decisions yet to be made in Minnesota's State Plan. Strategist modeling provides a forecast of CO_2 emissions from our CPP-regulated units; however, whether and by how much the allowance budget allocated to the Company (under a mass-based plan) exceeds those emissions will depend on how the plan allocates allowances. Similarly, our overall ERC position (under a rate-based plan) will depend on the activities eligible for ERC crediting.

We here provide analysis of a mass-based plan simply because the Commission's regulatory cost range under Minn. Stat. § 216H.06 provides an allowance price in dollars per ton of CO_2, and we have no comparable basis for predicting a price per ERC. We note that the Company has not yet concluded whether a mass- or rate-based plan is better for our customers.

To estimate our allowance position, we compare projected emissions from CPP-regulated units to the allowance budget that would be allocated to the Company under two hypothetical State Plan scenarios. Both begin with the statewide CO_2 budget for existing units from the CPP, and apply a set of allocation assumptions to derive the share of this budget allocated to the Company.

Scenario 1 assumptions:

- Plan covers existing units only, not new units;
- MPCA demonstrates to EPA that the risk of emission leakage[6] is low in Minnesota, and does not implement allowance set-asides to address leakage;

[5] There are existing markets providing prices for Renewable Energy Credits (RECs) of different types and vintages, and there is some overlap between the types of activities that can generate ERCs and those that can generate RECs. However the overlap is partial, and ERCs and RECs will be separate compliance instruments (ERCs for CPP compliance, RECs for compliance with state renewable energy mandates). Currently low REC prices reflect, among other factors, that relatively cost-effective renewable energy has put many utilities in the situation of having ample RECs for compliance with state renewable energy mandates. However, eventual prices for ERCs will be driven by supply and demand in new CPP markets, which will depend on how many states choose rate-based plans. We have not assumed REC prices provide a proxy for ERC prices.

[6] The CPP defines emission leakage as the incentive to shift generation from affected units regulated under section 111(d) of the Clean Air Act to non-affected units (e.g. new units regulated under section 111(b)).

- Plan includes the Clean Energy Incentive Program (CEIP) allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes no other allowance set-asides;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;[7]
- Plan does not limit the years of allowance allocation to a retired unit;
- The Company earns some allowances back from the CEIP set-aside by implementing eligible activities (wind and solar installed, and low-income energy efficiency implemented, after September 2018).[8]

Scenario 2 assumptions:

- Plan covers existing units only, not new units;
- MPCA adopts EPA's proposed allowance set-asides to address leakage: a set-aside for renewable energy at five percent of the state's allowance budget, and an output-based set-aside for existing natural gas combined cycle units;
- Plan includes the CEIP allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes other set-asides, for purposes yet to be determined, totaling an additional 20 percent of the statewide allowance budget;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;
- Plan allocates no allowances to a retired unit after two years, redirecting these allowances to the renewable energy set-aside;[9] and

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[7] We here adopt the default allowance allocation method from EPA's proposed Federal Plan, while noting that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

[8] Xcel Energy, MPCA and others have urged EPA to shift the eligibility date for the CEIP earlier, making new wind and solar installed, and low-income energy efficiency implemented, after initial plan submittal in September 2016 (rather than after final plan submittal in September 2018) eligible for CEIP allowances or ERCs. Since EPA's decision on this issue is not yet known, this analysis assumes CEIP eligibility as currently proposed.

[9] As proposed by EPA in the proposed Federal Plan. Neither this nor any other allowance allocation provision is binding for an approvable State Plan.

- The Company earns some allowances back from the CEIP, renewable energy, and existing natural gas combined cycle allowance set-asides, but is not assumed to earn any allowances back from other set-asides.

3. Results

The difference in the allowances available to monetize on behalf of our customers (after surrendering sufficient allowances to cover our CPP-regulated unit emissions) is significant between the two State Plan scenarios above.

Scenario 1, because it includes no allowance set-asides except the CEIP and does not limit the years of allowance allocation to retired units, results in a larger Company budget and therefore larger compliance buffer. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a remainder of between 1 and 4 million tons per year, totaling about 25 million tons cumulatively over 2022-2030. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-2030 is $540 million ($258 million in net present value terms).

Scenario 2 has significantly more allowance set-asides: for renewable energy (5 percent of the state budget), for existing natural gas combined cycle units, and for other purposes (20 percent of the state budget); in all, set-asides amount to 29-33 percent of the state budget, before accounting for additional allowances redirected from retired units to the renewable energy set-aside. Scenario 2 also discontinues allowance allocation to a retired unit two years after retirement, which significantly reduces the Company's budget. The Company earns some allowances back from the CEIP, renewable energy, and existing NGCC set-asides by implementing those actions, but is assumed to receive no allowances from the other set-asides, which simply redirect allowance value to other entities and purposes. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a deficit in some years and a small remainder in others, and over 2022-2030 a much smaller remainder of 3.5 million tons cumulatively. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-30 is $75 million ($33 million in net present value terms).

At $21.50 per ton, the difference between State Plan scenarios 1 and 2 is an undiscounted value of $465 million over 2022-2030 ($225 million in net present value terms). The value at three different CO_2 allowance prices, corresponding to the Commission's low, midpoint, and high regulatory cost values, is shown below:

Table 1: Value of allowances, in excess of compliance needs, under two State Plan scenarios (hundreds of million dollars, undiscounted, over 2022 to 2030)

Allowance Price	Scenario 1	Scenario 2	Difference
\$9/ton	\$226	\$31	\$194
\$21.50/ton	\$540	\$75	\$465
\$34/ton	\$853	\$119	\$735

The "difference" column in this table essentially represents the value transferred from the Company's customers to other parties, in or out of state, by shifting to a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-retirement.

Since all allowance value is assumed to accrue to the Company's customers, a state plan similar to Scenario 1 would provide around \$540 million to help mitigate the rate impacts of transitioning to a lower-carbon energy system. A state plan similar to Scenario 2 would provide \$465 million less to mitigate customer cost impacts, and would shift much of this value from our customers to other parties.

4. *Rate-Based Compliance*

The actions in our Current Preferred Plan would also generate a large number of ERCs if Minnesota adopts a rate-based State Plan. Actions eligible for ERC issuance ultimately depend on the State Plan, but the eligible actions under the CPP include:

- *Renewable energy*: generation starting January 1, 2022 from new facilities placed in service after January 1, 2013. The Company's new wind and solar placed in service after 2012, including projects earlier approved by the Commission, and projects proposed in the Current Preferred Plan, are eligible;
- *Energy efficiency*: electricity savings starting January 1, 2022, from measures placed in service after January 1, 2013, are eligible;
- *Nuclear uprates*: the 71 MW uprate at our Monticello nuclear generating station is eligible, since it was placed in service after 2012;
- *New Canadian hydro*: if the Company executes a new power purchase agreement with a new or uprated hydro facility in Canada, this would be eligible;

- *Affected units*: ERCs generated by natural gas combined cycle units operating below the subcategory rate specified for that year, as well as combined cycle units generating gas-shift ERCs, are eligible;[10]
- *CEIP*: generation and savings in 2020-21 from renewable energy projects that commence construction, and low-income energy efficiency measures placed in service, after final state plan submittal in 2018, including ERCs from the EPA match of 1:1 for renewable energy and 2:1 for low-income energy efficiency.[11]

Greater uncertainty surrounds the ERC eligibility of actions such as distributed generation, repowering on-site of an existing renewable energy facility built before 2012, combined heat and power, etc.

Based on preliminary estimates of the ERCs generated from our proposed actions, we expect the Company would generate more ERCs than needed to bring our regulated units into compliance. These ERCs are assumed available for sale to the owners of CPP-regulated units in any state that adopts a rate-based plan. We have not attempted to estimate a value of excess ERCs, since we have no basis for predicting an ERC price comparable to the available methods for CO_2 allowance prices; however, as with allowances, the value of any excess ERCs accrues to our customers and could be used to reduce the electricity rate impacts of transitioning the Company's generation portfolio to a lower-carbon system.

C. State Plan Positions

The Company has not yet taken a position whether a rate-based or mass-based State Plan is best for our customers, since that decision is dependent on the specifics of each plan. A mass-based plan has advantages in terms of simplicity of administration and compliance, but – as indicated by the two Scenarios above – poses risks of allowance allocation decisions that could significantly increase costs to our customers. A rate-based plan has lower allocation risks, but is significantly more complex to administer as proposed by EPA. We are currently in the process of identifying, in discussion with the MPCA, other utilities, and other stakeholders, areas of agreement for each plan type.

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[10] Gas-shift ERCs are a special type of ERCs awarded to combined cycle units that operate above their unit-specific 2012 baseline level of operation. Gas-shift ERCs may only be used for compliance by coal units.
[11] As mentioned above, we are not assuming for this analysis that EPA moves the CEIP eligibility dates earlier, nor that MPCA submits its State Plan earlier than the September 2018 deadline.

If MPCA selects a mass-based plan, we believe this plan should:

- Enable interstate trading through a "trading-ready" approach;
- Cover existing affected coal and natural gas combined cycle units only, not new units;[12]
- Demonstrate to EPA that the risk of emission leakage is low in Minnesota, using state Renewable Energy Standard and Conservation Improvement Program mandates, integrated resource plans, etc.;
- Allocate allowances to the owners of affected units on behalf of their customers. Allowance auctions serve no policy objective in a fully regulated state like Minnesota, merely increasing costs to customers without achieving additional CO_2 reductions;
- Allocate allowances to an affected unit that retires after 2012 for the duration of the CPP program. The analysis above illustrates the significant amount of value transferred from our customers to other parties, in and out of state, by redirecting these allowances;
- Not assign a "shelf life" to previously issued allowances;
- Allocate allowances among affected unit owners based on 2010-12 operations;[13]
- Minimize allowance set-asides, which utilities agree are likely to increase costs, except for the Clean Energy Incentive Program (CEIP) set-aside;[14]
- Require that the state allowance budget be used only for purposes of compliance, and that allowances may not be retired for other purposes;
- Include, but explore the ability to improve, the CEIP.

If the State Plan significantly deviates from the above principles, a rate-based plan may be better for our customers. If MPCA selects a rate-based plan, we believe this plan should:

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[12] The Clean Air Act defines existing units as those constructed prior to, and new units as those constructed subsequent to, January 8, 2014 – the date of EPA's release of the proposed New Source Performance Standard under Clean Air Act section 111(b).

[13] For example, allowances could be allocated based on 2010-12 generation (as proposed by EPA in the proposed Federal Plan), 2010-12 emissions, or another basis. EPA leaves the allocation method to states' discretion. The most appropriate method (both whether based on generation or emissions, and whether any allowance set-asides are appropriate) remains under discussion as of this filing. Whatever the method, the plan should incorporate EPA's correction in the final CPP for Sherburne County Unit 3, replacing 2012 data with typical-year generation or emissions.

[14] Whether any targeted set-asides are appropriate likewise remains under discussion as of this filing. In general, utilities agree allowance set-asides should be minimal and used with caution, since each set-aside reduces the budget allocated to utility customers and thus increases their costs.

- Enable interstate trading through a "trading-ready" approach;
- Use the subcategory-specific emission performance rates for fossil fuel-fired steam generating units and stationary combustion turbines;
- Leverage Minnesota's robust renewable energy and energy efficiency policies to streamline EPA's evaluation, monitoring and verification requirements for ERC crediting;
- Make the broadest possible set of zero-carbon actions eligible to earn ERCs, including but not limited to:
    - renewable energy (all types defined as renewable in state statute),
    - renewable energy uprates and repowering,
    - distributed generation,
    - end-use energy efficiency,
    - demand response and demand-side management,
    - nuclear uprates,
    - Canadian hydro,
    - existing natural gas combined cycle operating below the applicable subcategory rate or generating gas-shift ERCs, and
    - transmission and distribution efficiency improvements;
- Not assign a "shelf life" to ERCs;
- Award ERCs to existing (pre-2012) renewable energy facilities that are significantly repowered on the same site after 2012;
- Include, but explore the ability to improve, the CEIP.

CERTIFICATE OF SERVICE

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

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

or

xx by electronic filing.

Docket No. E002/RP-15-21

Dated this 29th day of January 2016

/s/

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SaGonna Thompson
Regulatory Administrator

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Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_Official
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Xcel Energy		Data Request No. 5-1
Docket No.:	PU-19-220	
Response To:	North Dakota Public Service Commission	
Requestor:	Adam Renfrandt	
Date Received:	October 8, 2019	

Question:
For purposes here, the Reference Case refers to the case with the retirement dates noted on page 57, Attachment J1 of Volume 2 Appendices to the "2020-2034 Upper Midwest Integrated Resource Plan". The N.D. Plan refers to the case in section IV, Volume 1, Chapter 4 of the "2020-2034 Upper Midwest Resource Plan".

NDPSC Question No. 1: Provide all output (including PVRR) that results from modeling the following five changes to the Reference Case and each of the eight sensitivities:
1) Remove the "no-going-back" constraint
2) Remove the constraint that adds generic solar starting in 2023 to maintain the minimum 2015 IRP Preferred Plan solar levels
3) Remove all costs, constraints, and objectives for CO2 and other emission externalities
4) Do not account for meeting any renewable energy objective
5) Remove all assumptions behind growth rates and build-outs of renewables (i.e., Community Gardens, Small Solar – RDF Projects, Solar*Rewards, Wind, etc.), and select all generators, including demand response, based on cost, assuming no pre-determined goals otherwise
6) Remove Sherco CC and MEC Ownership, and add back in MEC PPA to expiration. Add Sherco CC and MEC PPA extension as generic additions.
7) Add back Sherco and King Units through the end of useful life as defined in the N.D. approved depreciation schedules without reduced levels of dispatch
8) Add back incremental demand response, and add based on cost

Now add the following to the Case Above:

1) Assume Sherco 1 and 2 retires in 2026 and 2023, respectively.
Along with the output, provide the yearly capacity factors for King, the Sherco units, and the nuclear plants. Also, provide tables similar to Table 3-2 and Table 3-3 on pages 58 and 63 of the Resource Plan, respectively. Provide the generic units that

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were added by year and sorted from least cost to most cost. Break out PVRR by cost elements by year, or reference the location within the files provided.

Response:
Attachment A provides the results of the additional Strategist modeling conducted in response to DR 5-1 through 5-4. Attachment A provides a summary of the present value of revenue requirements (PVRR) for each scenario as well as the expansion plans for each case similar to Tables 3-2 and 3-3. The detailed output files for each scenario are also attached.

In order to conduct the requested analysis, we removed all constraints from the model, including the removal of:

- Any "forced in" expansion units, including the "no going back" constraint,
- CO2 costs and the 80 percent reduction by 2030constraint, and
- Additions of Community Solar Gardens, Solar*Reward, or Distributed Solar.

There is no constraint in the modeling for any renewable energy objectives and only existing DR is included. In addition, the updated analysis models the Mankato Energy Center as PPA.

The accelerated shutdown of Sherco 1 and 2 was one element of our last resource plan, which also include significant additions of renewables, operation of the nuclear fleet through current licenses, additions of natural gas generation, and energy efficiency. Our last resource plan included significant analysis of the costs and reliability impacts of the accelerated shutdown of Sherco 1 and 2.

We plan to retire Sherco 1 and Sherco 2 in 2026 and 2023, respectively, and therefore our initial filing only includes the planned retirement dates. However, the current depreciation lives in North Dakota run through 2034. In order to run scenarios that assume Sherco 1 and Sherco 2 operate through the current North Dakota depreciation lives, our energy supply group developed cost projects for both the operation and maintenance and ongoing capital expenditures necessary to run the units through 2034. The Sherco CC provide important reliability benefits once Sherco 1 and 2 retire. For the scenarios that assume Sherco 1 and 2 operate through 2034, the construction of the CC at the Sherco was delayed until 2034.

The retirement dates for the units for each scenario are summarized below:

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Scenario	Base Case Retirement Years	Change Case Retirement Years
DR 5-1 Impact of operating Sherco 1 and 2 through 2034	Sherco 1 - 2026 Sherco 2 – 2023 Sherco 3 – 2040 King – 2037	Sherco 1 - 2034 Sherco 2 – 2034 Sherco 3 – 2040 King – 2037
DR 5-2 Impact of no early retirement of coal.	Sherco 1 - 2026 Sherco 2 – 2023 Sherco 3 – 2030 King – 2028	Sherco 1 - 2026 Sherco 2 – 2023 Sherco 3 – 2037 King – 2037
DR 5-3– Impact of no extension of Monticello	Sherco 1 - 2034 Sherco 2 – 2034 Sherco 3 – 2040 King – 2037 Monticello - 2040	Sherco 1 - 2034 Sherco 2 – 2034 Sherco 3 – 2040 King – 2037 Monticello - 2030
DR 5-4 Impact of no nuclear extension	Sherco 1 - 2034 Sherco 2 – 2034 Sherco 3 – 2040 King – 2037 Monticello – 2040 Prairie Island 1 - 2043 Prairie Island 2 - 2044	Sherco 1 - 2034 Sherco 2 – 2034 Sherco 3 – 2040 King – 2037 Monticello – 2030 Prairie Island 1 - 2033 Prairie Island 2 - 2034

We note that this analysis does not consider costs or risks related to future environmental regulation. In addition to the base assumptions, we have included sensitives for high gas prices and low gas prices. Low gas prices increase the benefits or reduce the costs of early coal shutdown, while high gas prices increase the benefits of nuclear extension. We continue to conclude that our preferred plan appropriately balances costs and future risks and uncertainty while transitioning to a cleaner generation fleet.

Please note, the Strategist files CD is marked as "Not Public," as it contains not public information consistent with the Company's July 2, 2019 Application for Trade Secret Protection and the October 22, 2019 Order granting trade secret protection.

Preparer:	Jon Landrum
Title:	Manager, Resource Planning
Department:	Resource Planning
Telephone:	303.571.2765
Date:	January 20, 2020

Case No. PU-19-220
NDPSC DR No. 5-1
Attachment A - Page 1 of 1

SHERCO CC FLOAT WITH SH12

	DR 5-1	DR 5-2	DR 5-3	DR 5-4
	Early Retire SH12	Early Retire All Coal	Extend Monti isolated	Extend Monti and PI isolated
Case 1	SH1-2026, SH2 - 2023, SH3 - 2040, K - 2037	SH1-2026, SH2 - 2023, SH3 - 2030, K - 2028	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037, extend Monti	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037, extend Monti & PI
Case 2	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037	SH1-2034, SH2 - 2034, SH3 - 2040, K - 2037
Case 1	36,558	36,724	36,658	36,500
Case 2	36,541	36,541	36,541	36,541
PVRR Savings (Costs) Case 2-Case 1:	(17)	(183)	(117)	41
PVRR Savings (Costs) as % of base	-0.046%	-0.498%	-0.318%	0.113%
Case 1	35,282	35,407	35,513	35,506
Case 2	35,342	35,342	35,342	35,342
PVRR Savings (Costs) Case 2-Case 1:	60	(65)	(171)	(164)
PVRR Savings (Costs) as % of base	0.170%	-0.184%	-0.482%	-0.463%
Case 1	37,742	38,360	37,098	36,258
Case 2	37,386	37,386	37,386	37,386
PVRR Savings (Costs) Case 2-Case 1:	(355)	(973)	288	1,128
PVRR Savings (Costs) as % of base	-0.942%	-2.538%	0.778%	3.112%

I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table IV-9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low-price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

**Coal prices are delivered prices, while gas and market prices are hub prices.*

Strategist Modeling Assumptions and Outputs

I. Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown in Table 1 below were calculated by taking a weighted average of NSP jurisdictions from the April 2018 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0 percent.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

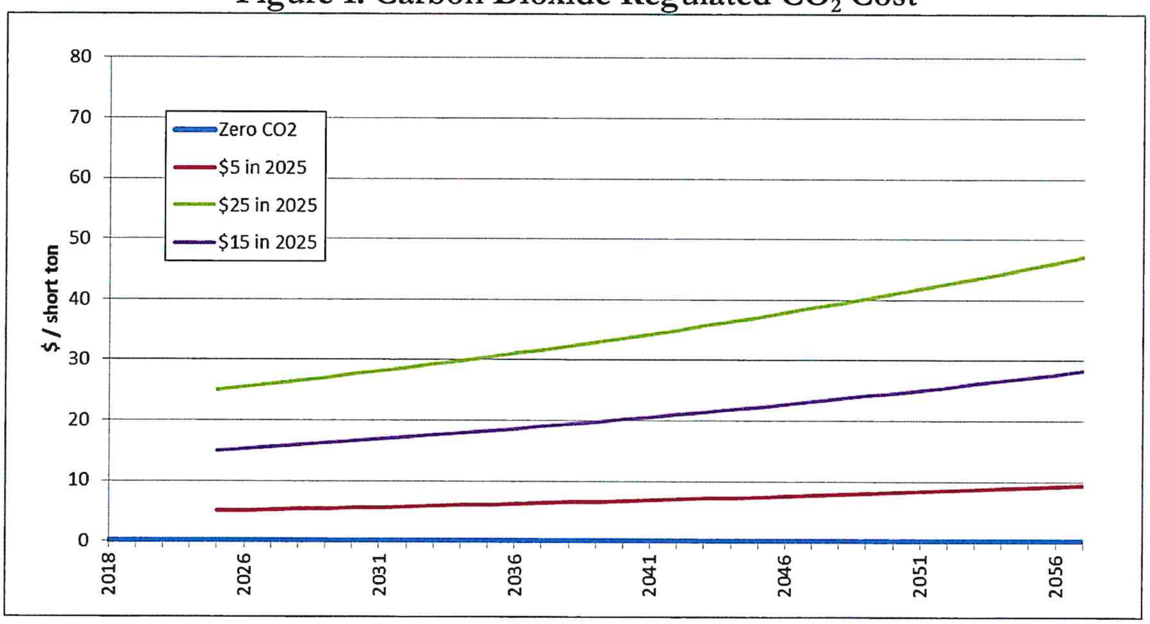
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	8.40%
Effective RM Based on Non-coincident Peak	2.98%

4. Regulated CO_2 Costs

Figure 1 below shows the annual Regulated CO_2 Costs used in the analysis. The base assumption is $15 per short ton starting in 2022, which is the average of $5 per short ton and $25 per short ton. The range of Regulated CO_2 Costs is drawn from the Minnesota Public Utilities Commission's ORDER ESTABLISHING 2018 AND 2019 ESTIMATE OF FUTURE CARBON DIOXIDE REGULATION COSTS issued June 11, 2018 in Docket No. E999/CI-07-1199. All prices escalate at general inflation.

Figure 1: Carbon Dioxide Regulated CO_2 Cost



5. Externality Costs

The values of the criteria pollutants PM2.5, NOx and SO2 are derived from the "Low" and "High" (Base Case) values for each of the three locations, pursuant to the Commission's ORDER UPDATING ENVIRONMENTAL COST VALUES issued January 3, 2018 in Docket No. E-999/CI-14-643 (Order Point 2, pages 57-58). The values of the criteria pollutants CO and Pb are derived from the "Low" and "High" (Base Case) values for each of the three locations. All prices are escalated to 2018 real $.

For plants located within 200 miles of Minnesota, it was decided that the NOx, PM2.5 and SO2 values would be selected based on the appropriate category Urban/Metro Fringe/Rural for each plant in question.

Table 3: Externality Costs

MPUC Externality Costs				
$2018 per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

The CO_2 values are derived from the above-referenced Orders. In the Base Case, the CO_2 values until 2025 are based on the "High" (externalities) Environmental Cost Values for CO_2. The Base Case CO_2 values from 2025 onwards are based on the "High" end of the range determined in the June 11th Order (see page 12 of the Order). All prices are escalated to 2018 real $ and escalate at general inflation (set at 2 percent per year) thereafter.

Table 4: Carbon Dioxide Externality Costs

MPUC CO_2 Externality Costs		
$ per short ton		
Year	Low	High
2018	9.09	42.76
2019	9.49	44.58
2020	9.90	46.45
2021	10.32	48.39
2022	10.77	50.38
2023	11.22	52.43
2024	11.69	54.55
2025	12.16	56.72
2026	12.67	58.97
2027	13.17	61.29
2028	13.70	63.67
2029	14.24	66.12
2030	14.80	68.64
2031	15.37	71.24
2032	15.97	73.91
2033	16.57	76.67
2034	17.21	79.50
2035	17.85	82.41
2036	18.52	85.41
2037	19.20	88.50
2038	19.91	91.68
2039	20.62	94.96
2040	21.38	98.32
2041	22.14	101.78
2042	22.94	105.34
2043	23.74	109.00
2044	24.58	112.76
2045	25.43	116.63
2046	26.33	120.61
2047	27.23	124.71
2048	28.17	128.92
2049	29.12	133.24
2050	30.12	137.69
2051	31.14	142.26
2052	32.18	146.97
2053	33.26	151.80
2054	34.36	156.76
2055	35.50	161.87
2056	36.66	167.11
2057	37.86	172.51

6. Demand and Energy Forecast

The Fall 2018 Load Forecast developed by the Xcel Energy Load Forecasting group is used. The forecast is shown with no DG solar reduction, as solar was modeled as a resource.

Table 5: Fall 2018 Demand and Energy Forecast

Demand (MW)					Energy (GWh)				
Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments	Year	Model Output	W/ Hist DSM, Building Code Adj	w DSM/Eff Adjustments	Final w EV Adjustments
2018	10,415	9,241	9,151	9,152	2018	50,447	44,348	43,909	43,914
2019	10,424	9,313	9,131	9,136	2019	50,530	44,649	43,772	43,798
2020	10,499	9,399	9,146	9,156	2020	50,847	45,129	43,800	43,865
2021	10,559	9,497	9,173	9,191	2021	50,746	45,223	43,449	43,560
2022	10,621	9,623	9,226	9,251	2022	50,844	45,598	43,375	43,529
2023	10,684	9,719	9,251	9,285	2023	50,991	45,857	43,186	43,394
2024	10,755	9,831	9,291	9,329	2024	51,326	46,318	43,189	43,425
2025	10,842	9,949	9,338	9,376	2025	51,333	46,589	43,021	43,257
2026	10,939	10,101	9,418	9,456	2026	51,483	47,061	43,044	43,281
2027	11,038	10,287	9,533	9,571	2027	51,699	47,722	43,256	43,493
2028	11,140	10,494	9,669	9,706	2028	52,079	48,780	43,852	44,089
2029	11,232	10,634	9,737	9,775	2029	52,105	49,097	43,735	43,972
2030	11,320	10,795	9,827	9,864	2030	52,279	49,704	43,893	44,130
2031	11,418	10,940	9,899	9,937	2031	52,516	50,195	43,935	44,172
2032	11,518	11,065	10,044	10,082	2032	52,895	50,712	44,424	44,661
2033	11,619	11,204	10,201	10,239	2033	52,931	50,918	44,639	44,875
2034	11,717	11,333	10,331	10,369	2034	53,112	51,274	44,995	45,232
2035	11,813	11,443	10,441	10,478	2035	53,346	51,577	45,298	45,534
2036	11,912	11,568	10,566	10,604	2036	53,746	52,103	45,806	46,042
2037	12,006	11,675	10,672	10,710	2037	53,750	52,169	45,890	46,126
2038	12,100	11,769	10,766	10,804	2038	53,911	52,329	46,050	46,287
2039	12,197	11,867	10,864	10,902	2039	54,165	52,584	46,305	46,541
2040	12,301	11,970	10,968	11,005	2040	54,589	53,007	46,709	46,946
2041	12,396	12,065	11,063	11,101	2041	54,599	53,018	46,739	46,975
2042	12,488	12,157	11,155	11,192	2042	54,767	53,186	46,907	47,143
2043	12,581	12,250	11,248	11,285	2043	55,031	53,450	47,171	47,407
2044	12,693	12,362	11,360	11,398	2044	55,467	53,884	47,587	47,823
2045	12,765	12,434	11,432	11,469	2045	55,503	53,921	47,642	47,879
2046	12,851	12,520	11,518	11,556	2046	55,700	54,119	47,840	48,076
2047	12,947	12,616	11,614	11,652	2047	55,996	54,415	48,136	48,372
2048	13,035	12,705	11,703	11,741	2048	56,359	55,038	48,740	48,977
2049	13,124	12,794	11,792	11,830	2049	56,435	54,854	48,575	48,811
2050	13,213	12,883	11,881	11,919	2050	56,667	55,085	48,806	49,042
2051	13,302	12,972	11,970	12,008	2051	56,899	55,316	49,037	49,274
2052	13,391	13,062	12,059	12,097	2052	57,288	55,700	49,403	49,640
2053	13,480	13,151	12,148	12,186	2053	57,362	55,779	49,500	49,736
2054	13,595	13,265	12,263	12,301	2054	57,812	56,228	49,949	50,185
2055	13,684	13,355	12,352	12,390	2055	58,043	56,459	50,180	50,417
2056	13,773	13,444	12,441	12,479	2056	58,436	56,847	50,549	50,786
2057	13,862	13,533	12,531	12,568	2057	58,507	56,922	50,643	50,880

7. DSM Forecast

The DSM forecast corresponds to what was used in the 2018v2.0 Load Forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period and is what is embedded in the 2018v2 Load Forecast.

Table 6: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2018	439	114
2019	877	229
2020	1,330	316
2021	1,774	402
2022	2,223	489
2023	2,671	576
2024	3,129	663
2025	3,568	750
2026	4,017	837
2027	4,465	924
2028	4,928	1,011
2029	5,362	1,097
2030	5,811	1,184
2031	6,259	1,271
2032	6,287	1,244
2033	6,279	1,216
2034	6,279	1,216
2035	6,279	1,216
2036	6,297	1,216
2037	6,279	1,216
2038	6,279	1,216
2039	6,279	1,216
2040	6,297	1,216
2041	6,279	1,216
2042	6,279	1,216
2043	6,279	1,216
2044	6,297	1,216
2045	6,279	1,216
2046	6,279	1,216
2047	6,279	1,216
2048	6,297	1,216
2049	6,279	1,216
2050	6,279	1,216
2051	6,279	1,216
2052	6,297	1,216
2053	6,279	1,216
2054	6,279	1,216
2055	6,279	1,216
2056	6,297	1,216
2057	6,279	1,216

8. Demand Response Forecast

The Load Management Forecast used was developed by the Xcel Energy Load Research group, 2018v4 vintage plus 406 MW of incremental generic DR starting in 2023. Table 7 below shows the July demand.

Table 7: 2018 Load Management Forecast

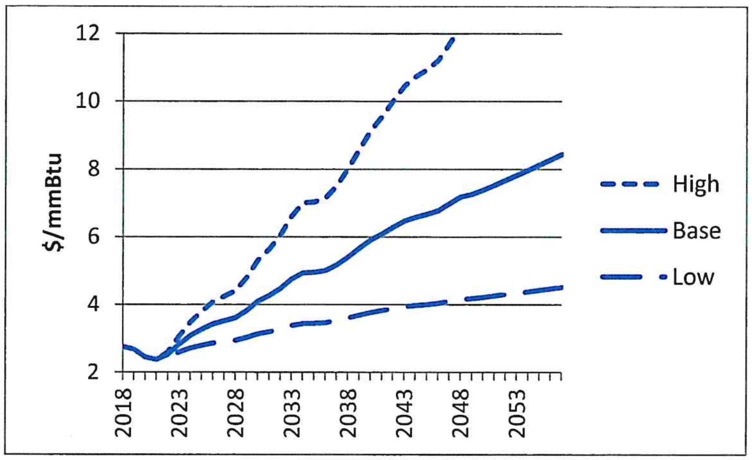
DR Forecast	
Year	**July Demand (MW)**
2018	899
2019	916
2020	932
2021	948
2022	962
2023	1,409
2024	1,413
2025	1,418
2026	1,423
2027	1,418
2028	1,408
2029	1,398
2030	1,388
2031	1,378
2032	1,369
2033	1,360
2034	1,351
2035	1,343
2036	1,335
2037	1,327
2038	1,319
2039	1,312
2040	1,304
2041	1,297
2042	1,291
2043	1,284
2044	1,277
2045	1,271
2046	1,265
2047	1,259
2048	1,252
2049	1,246
2050	1,240
2051	1,233
2052	1,227
2053	1,221
2054	1,214
2055	1,208
2056	1,202
2057	1,196

9. Natural Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Gas Prices as of October 18, 2018 were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2022.

Figure 2: Ventura Natural Gas Price Forecast and Sensitivities



10. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 13 contains gas transportation charges for generic thermal resources.

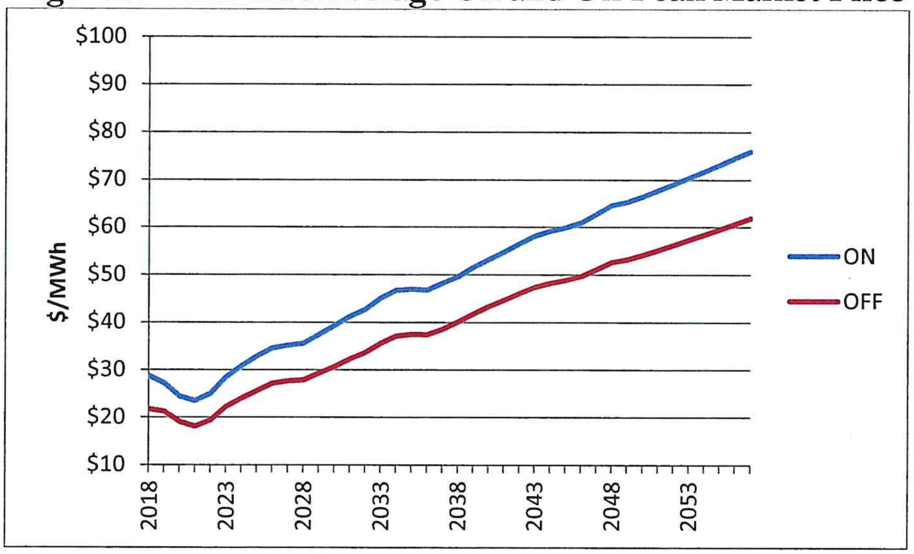
11. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 13 contains gas demand charges for generic thermal resources.

12. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 3 below shows the market prices under zero cost CO_2 assumptions.

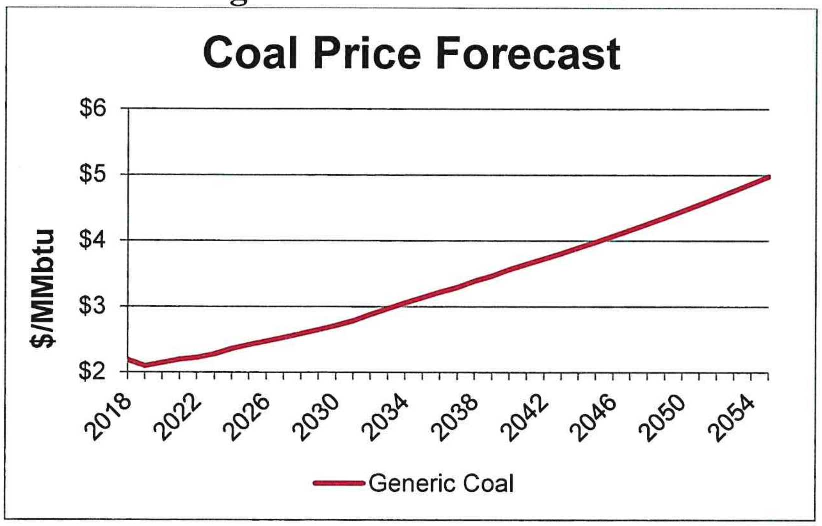
Figure 3: Minn Hub Average On and Off Peak Market Price



13. Coal Price Forecast

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

Figure 4: Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all 12 months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 8: Surplus Capacity Credit

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
$/kW-mo	3.72	3.79	3.87	3.95	4.03	4.11	4.19	4.27	4.36	4.45
	2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
$/kW-mo	4.54	4.63	4.72	4.81	4.91	5.01	5.11	5.21	5.31	5.42
	2038	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**
$/kW-mo	5.53	5.64	5.75	5.87	5.98	6.10	6.23	6.35	6.48	6.61
	2048	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**
$/kW-mo	6.74	6.87	7.01	7.15	7.29	7.44	7.59	7.74	7.90	8.05

15. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind and generic solar have assumed transmission delivery costs. Table 9 below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 9: Transmission Delivery Costs

	$/kw
CC	$ 330
CT	$ 100
Wind	$ 200
Solar	$ 70

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

18. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 182 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh.

21. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

Table 10: Wind Integration Costs

Year	Integration $/MWh		Coal Cycling $/MWh	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	0.00	0.00
2021	0.42	0.42	0.00	0.00
2022	0.43	0.43	0.00	0.00
2023	0.44	0.44	0.00	0.00
2024	0.44	0.44	0.00	0.00
2025	0.45	0.45	0.00	0.00
2026	0.46	0.46	0.00	0.00
2027	0.47	0.47	0.00	0.00
2028	0.48	0.48	0.00	0.00
2029	0.49	0.49	0.00	0.00
2030	0.50	0.50	0.00	0.00
2031	0.51	0.51	0.00	0.00
2032	0.52	0.52	0.00	0.00
2033	0.53	0.53	0.00	0.00
2034	0.54	0.54	0.00	0.00
2035	0.55	0.55	0.00	0.00
2036	0.56	0.56	0.00	0.00
2037	0.57	0.57	0.00	0.00
2038	0.59	0.59	0.00	0.00
2039	0.60	0.60	0.00	0.00
2040	0.61	0.61	0.00	0.00
2041	0.62	0.62	0.00	0.00
2042	0.63	0.63	0.00	0.00
2043	0.65	0.65	0.00	0.00
2044	0.66	0.66	0.00	0.00
2045	0.67	0.67	0.00	0.00
2046	0.69	0.69	0.00	0.00
2047	0.70	0.70	0.00	0.00
2048	0.71	0.71	0.00	0.00
2049	0.73	0.73	0.00	0.00
2050	0.74	0.74	0.00	0.00
2051	0.76	0.76	0.00	0.00
2052	0.77	0.77	0.00	0.00
2053	0.79	0.79	0.00	0.00
2054	0.80	0.80	0.00	0.00
2055	0.82	0.82	0.00	0.00
2056	0.84	0.84	0.00	0.00
2057	0.85	0.85	0.00	0.00

22. Wind Congestion Costs

Wind Congestion Costs were developed internally by Resource Planning using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. From the study, we included a congestion cost of $3.43 per MWh in 2020, escalating at 2 percent thereafter for all new wind projects.

Table 11: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2018	-	-
2019	-	-
2020	-	3.43
2021	-	3.50
2022	-	3.57
2023	-	3.64
2024	-	3.71
2025	-	3.79
2026	-	3.86
2027	-	3.94
2028	-	4.02
2029	-	4.10
2030	-	4.18
2031	-	4.27
2032	-	4.35
2033	-	4.44
2034	-	4.53
2035	-	4.62
2036	-	4.71
2037	-	4.80
2038	-	4.90
2039	-	5.00
2040	-	5.10
2041	-	5.20
2042	-	5.30
2043	-	5.41
2044	-	5.52
2045	-	5.63
2046	-	5.74
2047	-	5.86
2048	-	5.97
2049	-	6.09
2050	-	6.22
2051	-	6.34
2052	-	6.47
2053	-	6.60
2054		6.73
2055		6.86
2056		7.00
2057		7.14

23. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

24. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 12: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVSC Base	All Strategist expansion plans are optimized under the PVSC Base assumption. PVSC Base includes the Regulated CO_2 Costs, Externality Costs, and Surplus Capacity Credit. Optimized expansion plans were also completed using the PVSC Reference assumption and the High Renewables Scenario. All Strategist outputs, except the Markets Off sensitivity, assume the modeling of MISO Energy Market interactions.
PVRR Base	This assumption removes Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit from the PVSC Base assumption. The following sensitivities were also ran using the PVRR assumption as the starting point: Low Gas, High Gas, Low Load, High Load, Markets off no dump, Markets off with dump, 3% Esc costs, 1% esc. costs.

Sensitivities	Sensitivity Description
Markets Off No Dump Credit	This sensitivity removes the modeling of the Company's hourly sales in the MISO Energy Market. No credit was applied for dump energy.
Markets Off With Dump Credit	This sensitivity removes the modeling of the Company's hourly purchases in the MISO Energy Market and allows for a credit of one half of the all hours market price for dump energy.
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2022.
Low CO_2 Externality Costs All Years	This sensitivity removes the Regulated CO_2 Cost and models the Low Externality Price of CO_2 for the modeling period.
Low CO2 Externality Costs through 2024	This sensitivity uses the Low Externality Price of CO2 through 2024, then the low Regulated CO_2 Cost thereafter.
High CO_2 Externality Costs All Years	This sensitivity models the High Externality Price of CO_2 for the full modeling period.
Low Load	This sensitivity uses a minus one standard deviation from the base demand and energy forecast.
High Load	This sensitivity uses a plus one standard deviation from the base demand and energy forecast.
No CO2	This sensitivity assumes there are no Externality or Regulatory costs associated with CO2.

25. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

26. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

27. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2017 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

28. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

<u>Thermal</u>

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles

g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

<u>Renewable</u>

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Tables 13-14 below show the assumptions for the generic thermal and renewable resources.

Table 13: Thermal Generic Information (Costs in 2018 Dollars)

Resource	Sherco CC	Generic CC	Generic CT	Generic CT	Generic CT
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	916	916	374	232	374
Summer Peak Capacity with Ducts (MW)	870	870	NA	NA	NA
Summer Peak Capacity without Ducts (MW)	643	643	331	228	331
Capital Cost ($/kW)	$914	$951	$446	$495	$445
Electric Transmission Delivery ($/kW)	NA	$301	NA	NA	$100
Ongoing Capital Expenditures ($/kW-yr)	$6.77	$6.77	$4.77	$3.85	$3.85
Gas Demand ($/kW-yr) 2018$	$32.56	$21.14	NA	NA	$2.07
Fixed O&M Cost ($000/yr) 2018$	$2,605	$3,105	$422	$736	$668
Variable O&M Cost ($/MWh)	$1.42	$1.42	$4.90	$4.90	$4.90
Levelized $/kw-mo (All Fixed Costs) $2018	$12.04	$12.71	$4.62	$5.13	$5.58
Heat Rate with Duct Firing (btu/kWh)	6,494	6,818	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	6,331	6,647	9,042	9,791	9,042
Heat Rate 75% Loading (btu/kWh)	6,464	6,787	9,474	10,234	9,474
Heat Rate 50% Loading (btu/kWh)	6,876	7,220	10,833	12,006	10,833
Heat Rate 25% Loading (btu/kWh)	7,831	8,222	11,279	12,835	11,279
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2

Table 14: Renewable Generic ECC Costs - $/MWh

GENERIC WIND		
Year	PTC	ECC ($/MWH)
2023	60%	33.06
2024	40%	37.72
2025	0%	46.48
2026	0%	46.76
2027	0%	47.07
2028	0%	47.39
2029	0%	47.74
2030	0%	48.11
2031	0%	48.55
2032	0%	49.00
2033	0%	49.49
2034	0%	50.00
2035	0%	50.53
2036	0%	51.09
2037	0%	51.68
2038	0%	52.30
2039	0%	52.95
2040	0%	53.63
2041	0%	54.34
2042	0%	55.08
2043	0%	55.86
2044	0%	56.67
2045	0%	57.53
2046	0%	58.41
2047	0%	59.34
2048	0%	60.32
2049	0%	61.33
2050	0%	62.39
2051	0%	63.64
2052	0%	64.91
2053	0%	66.21
2054	0%	67.53
2055	0%	68.88
2056	0%	70.26
2057	0%	71.66

GENERIC SOLAR		
Year	ITC	ECC ($/MWH)
2023	30%	43.45
2024	30%	43.75
2025	10%	44.05
2026	10%	44.34
2027	10%	44.64
2028	10%	44.93
2029	10%	45.22
2030	10%	45.50
2031	10%	46.04
2032	10%	46.58
2033	10%	47.12
2034	10%	47.66
2035	10%	48.21
2036	10%	48.77
2037	10%	49.32
2038	10%	49.88
2039	10%	50.44
2040	10%	51.01
2041	10%	51.52
2042	10%	52.02
2043	10%	52.53
2044	10%	53.04
2045	10%	53.55
2046	10%	54.06
2047	10%	54.57
2048	10%	55.08
2049	10%	55.58
2050	10%	56.09
2051	10%	57.21
2052	10%	58.36
2053	10%	59.52
2054	10%	60.71
2055	10%	61.93
2056	10%	63.17
2057	10%	64.43

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVSC Base and PVRR Base annual costs and savings for the proposed repowering of Jeffers & CWN PPA are shown below in Figure 5.

The PVSC and PVRR for the proposed ownership of Jeffers & CWN PPA are shown below in Figure 6.

Figure 5: Annual PVSC and PVRR Net Costs (Savings) in $millions

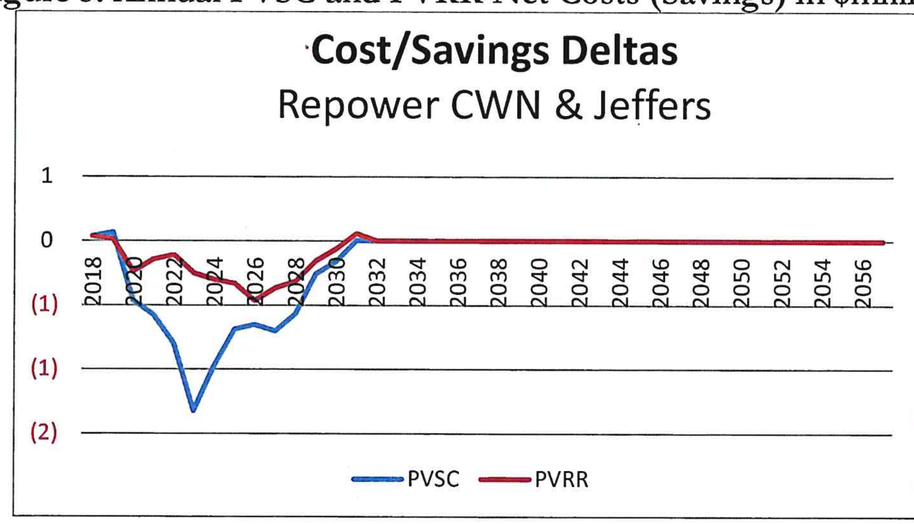


Figure 6: Annual PVSC and PVRR Net Costs (Savings) in $millions