DIRECT TESTIMONY AND SCHEDULES
PHILIP JOSEPH "P.J." MARTIN

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of Northern States Power Company,
a Minnesota corporation d/b/a Xcel Energy
Jurisdictional Cost Allocation Matters

Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708,
PU-13-742, PU-13-743, PU-13-194, PU-13-195
Exhibit ___ (PJM-1)

Resource Planning

July 15, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company-Minnesota (NSPM or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC, SERC, and other markets across the U.S. My statement of qualifications is provided as Exhibit ___(PJM-1), Schedule 1.

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

A. My testimony explains and supports the Company's resource planning analysis as set forth in our Application for Consideration of a Resource Treatment Framework (RTF) to Address Jurisdictional Cost Allocation

Issues (RTF Application) filed on December 31, 2016 with the North Dakota Public Service Commission (Commission) and the Minnesota Public Utilities Commission (MPUC). It also provides updated information relating to resource planning activity that has occurred since the submission of the RTF Application.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- Section II provides a brief overview of the RTF Application, to provide context for the rest of the testimony.
- Section III provides a history of NSP's Integrated System.
- Section IV provides an overview of the challenges, from a resource planning point of view, that led to the RTF, and identifies the "Disputed Resources."
- Section V explains that upcoming, major changes in the NSP System making this the right time to implement the RTF.
- Section VI briefly describes the concepts and proposals presented in the Company's RTF as potential solutions.
- Section VII outlines the resource planning analyses performed in support of the RTF proposals.
- Section VIII sets forth my conclusions and recommendations.

II. OVERVIEW OF THE RTF APPLICATION

Q. AT A GENERAL LEVEL, WHAT IS THE PURPOSE OF THE RTF APPLICATION?

A. Company Witnesses Mr. Aakash H. Chandarana and Mr. Richard "Rick" D. Starkweather address this question in their Direct Testimonies. At a high level, the Company is proposing to address past and anticipated future resource disagreements by recommending a more separate future between North Dakota and the remainder of the NSP System.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSALS IN THE RTF APPLICATION.

A. The RTF Application presented the following "Framework":

1. All currently anticipated and past resource selection and other disagreements will be permanently addressed and the Legacy System established.

2. All NSPM states will continue to be served by the Legacy System and all of our customers will enjoy the benefits and bear the burdens of the Legacy System.

3. With respect to future new resource additions, the Company will be able to assess and propose resources for North Dakota and the remainder of the NSP System separately.

    a. When a resource need arises in North Dakota, that need will be met by a resource sized for, dedicated to serve only, and fully recovered in North Dakota.

    b. When a resource need arises in, or new resources are otherwise planned for, the remainder of the NSP System, those resources will be sized for, dedicated to serve only, and fully recovered in the remainder of the NSP System. Consequently, our North Dakota jurisdiction will not obtain the benefits or pay the costs associated with new NSP System resource additions.

    c. Xcel Energy may propose particular future resources to be utilized concurrently by North Dakota and the remainder of the NSP System should circumstances warrant, and will propose cost-sharing arrangements at that time.

4. Over time, the generation portfolio serving North Dakota and the remainder of the NSP System will materially separate as units of the NSP System retire or expire.

5. South Dakota may elect to join North Dakota under this framework or remain part of the NSP System consistent with its own outlooks.

My testimony discusses some aspects of this Framework. Company Witness Mr. Starkweather discusses the Framework in more detail in his Direct Testimony.

Q. CAN YOU PROVIDE A FURTHER EXPLANATION OF STEP ONE OF THE FRAMEWORK?

A. There are a number of generation resources serving the NSP System for which the Company is either not fully recovering its costs or is recovering its costs subject to refund. These are sometimes referred to as the "Disputed Resources" and include past resource selection disagreements. I'll address them in more detail below. Additionally, the Company also anticipates likely future resource disagreements regarding its proposed 1,550 MW Wind Portfolio, the Mankato Energy Center Expansion PPA (MEC II), recovery of the North Dakota undepreciated portion of Sherco Units 1 and 2, and the Company's biomass optimization plan.

Q. THE THIRD PART OF THE FRAMEWORK CONTEMPLATES THAT SOME NEW STRUCTURE WOULD BE DEVELOPED UNDER WHICH MINNESOTA AND NORTH DAKOTA CAN BE SERVED SEPARATELY. WHAT STRUCTURES ARE PRESENTED IN THE RTF APPLICATION?

A. The RTF Application presents four structures for consideration: Regulatory Alignment, Proxy Pricing, Pseudo Separation, and Legal Separation. The RTF Application focuses on Pseudo Separation and Legal Separation, because those two structures are the ones the Company has been exploring in the most detail. In their Direct Testimony, Company witnesses Mr.

Chandarana and Mr. Starkweather describe these structures and their pros and cons.

Q. HOW DOES YOUR TESTIMONY RELATE TO THESE STRUCTURES?

A. One of the purposes of the RTF Application, and the Company's direct case of which my Direct Testimony is a part, is to provide information about these structures that the Commission might find helpful in analyzing options. My testimony is intended to provide detailed supporting information relating to the resource planning issues implicated by these options.

III. THE INTEGRATED NSP SYSTEM

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

A. This section is meant to provide the Commission with background information and context about the Company's integrated system and how the Company undertakes resource planning.

Q. PLEASE DESCRIBE THE NSP SYSTEM.

A. NSPM is a wholly-owned operating subsidiary of Xcel Energy Inc. which owns and operates, in conjunction with its affiliate Northern States Power Company – Wisconsin (NSPW), an integrated system of generation and transmission assets that serves approximately 1.6 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin (the NSP System). The NSP System developed over many years: as the electric power needs of its customers grew and evolved, the Company undertook various large-scale investments to serve them.

Q. WHY DO YOU REFER TO THE NSP SYSTEM AS "INTEGRATED"?

A. Each resource in the NSP System—whether generation or transmission—was developed in consideration of the whole, balancing the need for system reliability, fuel diversity and hedges against supply and cost volatility.

Q. PLEASE DESCRIBE THE DEVELOPMENT OF NSP'S INTEGRATED SYSTEM.

A. The history of NSP's generation and transmission assets is a long and complex story, spanning decades. Schedule 5 of the RTF Application provides a detailed overview; we also provide context in our June 2016 Compliance Filing, both of which are provided as Schedules to the Direct Testimony of Company Witness Mr. Chandarana. I'll provide a very condensed version here, for context.

Q. PLEASE START BY DESCRIBING KEY PARTS OF NSP'S INTEGRATED SYSTEM THAT WERE DEVELOPED OVER THE DECADES.

A. From the 1940s to the 1960s, NSP mainly constructed coal-fired generators around the Twin Cities, including Black Dog, Riverside, High Bridge, and the King plant in Bayport. These plants were tied together with high-voltage transmission.

By the late 1950s, load was increasing very rapidly. In response, in the 1960s the Company built the 345kV transmission loop around the Twin Cities, and built 345kV transmission lines between the Twin Cities and St. Louis, Chicago, and Omaha, as well as a 500kV transmission line from Winnipeg to the Twin Cities. These lines provided greater reliability, enhanced economies of scale, and enhanced diversity of supply, because they allowed power to be imported from other regions, such as the importation of hydroelectric power from Manitoba.

These transmission lines also allowed the development of large central station generators that were built in the 1960s and 1970s, such as the Allen S. King plant, the Monticello and Prairie Island nuclear plants, and Sherco 1 and 2. The Sherco site was expanded in the 1980s with Sherco 3. The Company also added a significant amount of natural gas generation to its system in the 1980s and 1990s. Since the mid-1990s, the Company has added several thousand megawatts of renewable energy generation.

Q. ARE THERE ADVANTAGES TO THE INTEGRATED GENERATION PORTFOLIO THAT RESULTED FROM THIS HISTORICAL PROCESS?

A. Yes. One advantage is economies of scale. Simply put, the development of large generation facilities generally provided lower per-unit costs and drove efficiencies. Because of the large size of the integrated system, the Company has the scale to respond to capacity needs by building additional, large, generation facilities.

A second advantage is reliability—if there is a problem at one generation location, other locations can fill the need. These advantages were not possible without an integrated system that includes both a variety of generation assets and sufficient transmission infrastructure.

Q. DID THE INTEGRATED GENERATION PORTFOLIO THAT RESULTED FROM THIS HISTORICAL PROCESS HEDGE RISK?

A. Yes. The price of fuel used in producing energy, such as coal and natural gas, is subject to significant fluctuations over time, depending on macroeconomic forces. Because of the integrated nature of NSP's System, if the price of one type of fuel increases relative to another, more power can be drawn from other sources. This pooling of resources hedges the risk of becoming over-dependent on a single or very limited number of fuel sources. For example, if there were to be a significant spike in the price of natural gas, the diversity of the NSP portfolio provides access to coal and other non-gas-fired resources that would provide a more economical solution to serve load. We are seeing this today with historically low gas prices pushing our coal production down.

Q. AS THIS INTEGRATED SYSTEM WAS BEING DEVELOPED, HOW DID THE COMPANY'S NORTH DAKOTA SERVICE TERRITORY FIT IN?

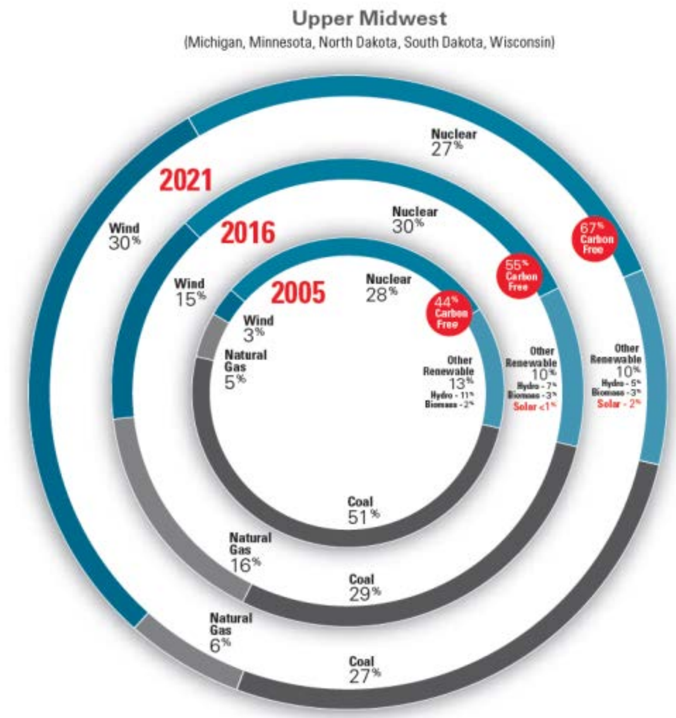
A. The Company's North Dakota service territory is physically isolated from the rest of the Company's service area in South Dakota, Minnesota, and Wisconsin. In addition, the Company's three main markets in North Dakota—Fargo, Grand Forks, and Minot—are physically separate from each other. For these reasons, historically the bulk of the Company's North Dakota load was served by the Stanton Station facility through agreement with what is now Great River Energy (GRE).

Q. DID THE MARKET STRUCTURE IN THE ELECTRICITY INDUSTRY CHANGE STARTING IN THE 1990S?

A. Yes. The 1992 Energy Policy Act called for the creation of competitive wholesale electric markets, and in 1996, under the auspices of that Act, FERC issued Order Nos. 888 and 889. These Orders required utilities to separate the generation function from the transmission function and set the stage for regional transmission organizations. A few years later, the Midcontinent Independent System Operator (MISO) was created, and by 2005 MISO began centralized dispatch of all generation across its upper-Midwest footprint. The competitive market structure that resulted from these changes (and all the other related activity too detailed to discuss here) provided a new set of options for power generation. It was no longer necessary to have an integrated utility system built around large central stations; instead energy can be provided, especially for smaller load pockets, in a wide variety of ways.

Q. PLEASE DESCRIBE THE GENERATION SOURCES COMPRISING THE INTEGRATED NSP SYSTEM AS IT EXISTS NOW.

A. The NSP System includes many sources of electricity generation. Currently, our system energy mix includes approximately 29 percent coal, 30 percent nuclear, 15 percent wind, 16 percent natural gas, 7 percent hydro, 3 percent biomass, and less than 1 percent solar, as set forth in the diagram below.



[Source: 2016 Corporate Responsibility Report]

Schedules 3 and 4 to the RTF Application, which are attached to the Direct Testimony of Company Witness Mr. Chandarana, provide a detailed list of each of the generation sources, ranging from our large coal and nuclear resources down to very small wind and solar power purchase agreements. These Schedules also identify the retirement or termination date for each of the generation sources.

Q. HAS THE COMPANY CONTINUED TO PLAN FOR ITS NSP SYSTEM IN AN INTEGRATED MANNER?

A. Yes. The investments necessary for electric service are capital-intensive. Generally, integrated system planning is the best way to achieve economies of scale. In addition, integrated system planning allowed the states we serve to share in the costs of resources, and provided diversity and hedge benefits.

Q. ARE THE BENEFITS OF INTEGRATED SYSTEM PLANNING STILL IMPORTANT?

A. Very much so. On behalf of all customers, we have taken advantage of the geographic, supply, and resource diversity that the five-state NSP System provides, with all states sharing in the costs and benefits of this system. While maintaining an integrated system at times requires necessary compromises between the various customer groups and jurisdictions we serve, the size and scope of the integrated NSP System continues, we believe, to benefit all of our customers. These advantages remain true and important even in the market-oriented competitive landscape that developed over the last 20 years.

Q. HOW DOES THE COMPANY PLAN FOR RESOURCES GIVEN THE INTEGRATED NATURE OF ITS SYSTEM?

A. We plan our resource investments based on a long-term planning horizon. We do not make resource selection decisions based only on meeting our peak load obligation from a capacity standpoint; we also consider our energy needs throughout the planning horizon, and try to build a generation portfolio that best serves all of our service area, on a reliable and cost-effective basis. Central to this analysis is assessing the Company's System as an integrated whole.

Q. HOW DOES INTEGRATION INFLUENCE THE COMPANY'S RESOURCE PLANNING?

A. Planning for, and managing, the integrated NSP System is highly complex and requires us to balance the needs and priorities of all of the jurisdictions we serve. We strive to consider the goals of each jurisdiction when planning. We also are obligated to meet the regulatory requirements applicable in each jurisdiction, which as a practical matter, means that whichever state has the most stringent requirements sets the bar for our compliance. To be clear, North Dakota generally has the least stringent compliance requirements; if North Dakota law imposed more onerous requirements, the Company would incorporate those requirements in its planning.

But because of the integrated nature of the NSP System (and the inherent advantages of integration) to date it has been neither possible nor logical to separately analyze each state's energy needs on a stand-alone basis. Instead, we develop a single resource plan for our entire system. Not only is this a sound way of planning, but we are required to file a comprehensive resource plan in some of the jurisdictions where we serve. Our most recent Upper Midwest Resource Plan (often referred to as the Integrated Resource Plan or IRP), filed with the Commission and MPUC on January 2, 2015, provides a very detailed description of the considerations that we balance as we undertake resource planning. The MPUC approved our IRP, as supplemented, in an Order dated January 11, 2017.[1] The Company files its IRP in North Dakota for informational purposes; consistent with past practice, the Commission did not act on the Company's IRP.

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[1] *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, Docket No. E-002/RP-15-21, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Jan. 11, 2017.

Q. HAS THE COMPANY FOLLOWED A SET OF GUIDING ASSUMPTIONS AS IT DEVELOPED THE NSP SYSTEM?

A. Yes. As my testimony above illustrates, our resource planning has been informed by the following concepts for many years:

- Planning should be done on an integrated basis, because this captures economies of scale, ensures that risk and cost are spread over the widest possible group, and allows diversity of energy supply, which assists with system reliability and price control.
- Planning should respect the sovereign nature of each of the states where we serve, and ensure that regulators understand the costs and risks associated with their decisions.
- Planning should ensure that the Company has an opportunity to fully recover its cost of service in each state served by the NSP System.

Q. IS IT STILL POSSIBLE TO CONDUCT RESOURCE PLANNING BASED ON THESE ASSUMPTIONS?

A. We still believe that planning on an integrated basis presents the best outcomes for the Company and all of the customers irrespective of service area. That said, it appears this integrated approach may no longer be possible. The purpose of the RTF Application is to initiate a dialogue about how to proceed if that is, in fact, the case. The Direct Testimony of Company witness Mr. Chandarana provides additional discussion.

IV. CHALLENGES OF THE FUTURE

Q. HAS THE COMPANY ENCOUNTERED DIFFICULTIES WITH RESPECT TO INTEGRATED RESOURCE PLANNING?

A. Yes. While the Company strives to achieve the guiding principles I stated above, these principles can only function when all participants are aligned in equitably sharing both the benefits and costs of the NSP System on a proportional basis. In the last decade, the Company has not been able to appropriately balance the Commission and the MPUC's outlooks relating to resource planning and related issues. These differences have resulted in (a) unresolved issues with resources that the Company has already presented to the Commission and the MPUC; (b) mismatched rate recovery; and (c) uncertainty around any future resource selection. These differences are described in detail in our RTF Application and 2016 Compliance Filing provided as Schedules to the Direct Testimony of Company Witness Mr. Chandarana.

Q. PLEASE PROVIDE AN EXAMPLE OF THESE DIFFERENCES.

A. An obvious difference is the laws regarding externality costs in North Dakota and Minnesota. North Dakota uses the Present Value of Revenue Requirement (PVRR) to analyze costs when planning resources. Minnesota uses the present value of societal cost (PVSC) to analyze costs. The cost of a particular project or plan may be quite different when looked at from a PVRR perspective as compared to a PVSC perspective and, thus, lead to different outcomes.

Q. WHAT IS THE EFFECT ON THE COMPANY OF THESE JURISDICTIONAL DIFFERENCES?

A. Simply put, the uncertainty caused by the divergence between the North Dakota and Minnesota regulatory environments makes it difficult to plan in several respects. This is especially the case because resource planning is an iterative process, where the selection of one resource at a particular time will influence the selection of the next incremental resource.

First, it is hard for the Company to determine what projects to support. As I have explained herein, resource planning is already a very complex process and it requires discretion and sound judgment. When there is disagreement about what projects will be approved by one jurisdiction or another, resource planning becomes even more difficult. The vast majority of the Company's service area is in Minnesota; so naturally, the Company must approach resource decisions accordingly.

Second, the Company is concerned with our ability to comply with our regulatory and legal obligations in all of the states we serve and the costs associated with potentially having to duplicate work if obligations in other states become more prescriptive. As the Company develops and refines its procedures and systems for regulatory compliance, those procedures and systems are necessarily based primarily on compliance with Minnesota's obligations which are more robust than the other states that comprise the NSP System.

Third, Xcel Energy, like any other large company, has to plan its business strategies and finances. Because the vast majority of its revenue is derived from providing service in Minnesota, the Company's business plan is based substantially on expectations concerning service in Minnesota. Accordingly, when divergent state priorities drive inconsistent regulatory outcomes, business planning takes on added complexity.

Fourth, and perhaps most importantly, the Company faces increasing risk that it will not have a reasonable opportunity to recover its costs in all NSP System jurisdictions. If regulators consistently reject the Company's proposed resource investments, we will be unable to fully recover the costs of these investments unless we have some agreed upon mechanism to reallocate unrecovered costs.. This inability to recover costs erodes the fundamental concept of integration that underpins the NSP System. The Company simply cannot operate in an environment where it cannot recover costs.

Q. HAS THE COMPANY IDENTIFIED SPECIFIC RESOURCES THAT SHOULD BE ADDRESSED AS PART OF THIS RTF PROCEEDING?

A. Yes. The Company has identified certain resources that were supported in Minnesota and disputed in North Dakota—we call them the Disputed Resources. In the Company's view, it is necessary to resolve the disputes about these resources in order to successfully implement any proposal to restructure the Company's service between Minnesota and North Dakota. The Disputed Resources are listed on Schedule 3 to the RTF Application. For ease of reference, the Disputed Resources can be summarized as follows:

- Certain CBED and smaller solar resources;
- Six biomass PPAs currently serving the NSP System;

- The two PPAs that emerged from the 187 MW solar portfolio additions;
- The Company's PPA for the capacity and energy of the Mankato Energy Center expansion (MEC II) project.

In addition to the Disputed Resources, we foresee that the North Dakota amortization of Sherco Units 1 & 2 depreciation expense associated with their retirement in 2026 and 2023, respectively, may present future cost recovery issues. Finally, in light of these resource issues and the timing of resource implementation, we believe the resolution of the Disputed Resources will necessarily include the Company's proposed addition of 1,550 MW of wind generation, as set forth in Case No. PU-17-120 (the 2017 Wind ADP). The Company views the Wind Portfolio as demonstrative of the advantages of a large integrated System that can be leveraged to add resources that can reduce overall cost to our customers. It is the Company's view that accepting the Commission's prior determinations regarding the Disputed Resources could result in advantageous resources such as the Wind Portfolio being allocated away from our North Dakota jurisdiction. I note that the Company recently submitted an Application for an Advanced Determination of Prudence for several changes to its biomass portfolio; because my analysis assumes the Company's proposal for the resolution of the disputed resources, the impacts of these PPA changes are mooted here.

V. ANTICIPATED CHANGES IN THE NSP SYSTEM

Q. IS 2017 A LOGICAL TIME TO CONSIDER CHANGES IN THE STRUCTURE OF NSP'S INTEGRATED SYSTEM?

A. Yes. We have significant resource expirations in the next decade, while at the same time we do not currently foresee a need for additional capacity before the mid-2020s. This presents a window of opportunity to implement a RTF structure that permits greater flexibility and customer responsiveness before future resource selections must be made.

Q. WHAT ARE THE RESOURCE RETIREMENTS THAT THE COMPANY ANTICIPATES IN THE NEXT TEN YEARS?

A. As the Commission is aware, the timing of resource retirements and PPA expirations is discussed in great detail in the Company's recent IRP (including supplements).

In summary, the most important upcoming reductions in energy resources in the next ten years are:

- 2023: Blue Lake Units 1-4 (natural gas combustion turbines (CTs)) will cease operation (157 MW);
- 2023: Sherco 2 (688 MW) will be retired;
- 2025: Manitoba Hydro contracts will expire (850 MW);
- 2027: Cottage Grove Combined Cycle Energy Center contract will expire (231 MW);
- 2026 Sherco Unit 1 (695 MW) will be retired; and
- 2026: Mankato Energy Center Combined Cycle (MEC I) contract will expire (282 MW).

Collectively, these retirements total over 2,900 MW, or approximately 30 percent of the Company's accredited generation resources.

Q. LOOKING OVER A LONGER HORIZON, WHAT ARE SOME ANTICIPATED FUTURE CHANGES IN THE NSP SYSTEM?

A. In the 2030s, more than 2500 MW, UCAP, of additional system resources are also scheduled to retire, including:

- 2030: Monticello Nuclear Generating Plant (600 MW UCAP);
- 2033: Prairie Island Nuclear Generating Plant Unit 1 (509 MW UCAP);
- 2034: Prairie Island Nuclear Generating Plant Unit 2 (504 MW UCAP);
- 2037: Allen S. King Plant (500 MW UCAP); and
- 2040: Sherco Unit 3 (524 MW UCAP (NSP's portion)).

But the schedule of these retirements is not certain. In the Company's recent IRP proceeding, the MPUC directed the Company to file its next resource plan on February 1, 2019, and to describe in that filing our plans and possible scenarios for the cost-effective and orderly retirement of our aging baseload fleet. The MPUC also required the Company to evaluate, in addition to generation resource options and alternatives, combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could, in the aggregate, meet post-retirement energy and capacity needs as well as contribute to grid support.

Q. WHAT ARE THE COMPANY'S NEEDS WITH REGARD TO MAKING SIGNIFICANT CAPACITY ADDITIONS?

A. Based on the Company's current load profile and forecast, the Company does not anticipate the need to add additional capacity until Sherco unit retirements and significant PPA expirations create a capacity need.

Further, as Mr. Chandarana discusses, NSP's integrated system may be fundamentally changing; the nature of that change could redefine what is needed as baseload capacity.

Q. WHAT OTHER CHANGES DO YOU ANTICIPATE WILL AFFECT THE COMPANY'S RESOURCE PLANNING OVER THE NEXT TEN OR TWENTY YEARS?

A. We anticipate that Minnesota stakeholders will continue to state a preference for increasing levels of renewables in the years ahead, furthering Minnesota's carbon reduction goals. Conversely, we know that North Dakota stakeholders are unlikely to agree with Minnesota's preference to give greater weight to the PVSC perspective, rather than the PVRR perspective, when analyzing the costs of resource options. In addition, newer technologies continue to impact system demand and the types of resources available to meet that demand. The Commissions' perspectives with regard to these changes may contribute to future misalignment.

Of course, there are many other unpredictable issues that may also affect resource planning: environmental regulations are in a state of potential flux; tax laws may change; storage solutions may begin to emerge, demand may fluctuate more than expected; and fuel costs may change unpredictably. There will always be a need for course corrections as such unpredictable issues arise. For the purposes of this proceeding, we are focusing on the issues that we can anticipate with reasonable certainty.

Q. WHY DOES THE COMBINATION OF THESE MAJOR RETIREMENTS WITH A LENGTHY GAP BEFORE CAPACITY IS NEEDED PRESENT A USEFUL PLANNING WINDOW FOR THE RTF APPLICATION?

A. Although long lead times are needed to plan for large future resource additions, the existing gap in anticipated capacity needs makes now the right time to identify a long-term solution for the problems outlined above. It allows us to implement solutions for each jurisdiction when the need to add resources eventually arises. Moreover, we intend to outline the scenarios for retirement of our baseload fleet in our next IRP (scheduled for 2019). As such, the Company believes it would be wise to address structural issues now, before that next IRP is due to be filed.

VI. OPTIONS PRESENTED IN THE RTF

Q. DOES THE PROPOSED RTF CONSIDER FUTURE RESOURCE INVESTMENT ON A WHOLLY-INTEGRATED BASIS?

A. No. Through the work we have done in completing our resource planning analysis, discussed in detail in Section VII below, we are proposing a future where resources would no longer be selected on the basis of a wholly-integrated NSP System. The RTF presents a Framework that would allow Minnesota and North Dakota to gradually become more independent of one another with respect to future resource selection. We believe this Framework will provide our jurisdictions with greater flexibility and customization around energy resource planning selection, consistent with their size and priorities.

Q. PLEASE BREAK DOWN THE STEPS NECESSARY TO IMPLEMENT THE COMPANY'S PROPOSED FRAMEWORK.

A. First, there must be some resolution of how to handle the Disputed Resources and anticipated known future disagreements. That will allow us to define the "Legacy System," *i.e.*, the entire NSP System currently in place at the present time, as a starting point. The Framework contemplates that the Legacy System will serve Minnesota, North Dakota, and the other NSPM states, and so it is necessary to determine what resources the Legacy System will be comprised of.

Second, the Framework contemplates that new resource additions will be separated so that resources solely needed by North Dakota will be dedicated to North Dakota, and resources needed by the other jurisdictions will be dedicated to the remainder of the NSP System. The Company has concluded that two structures support this outcome: Pseudo Separation and Legal Separation. Whatever separation mechanism is determined to be the best fit, the effect of the separation will be that as units of the NSP System retire or expire, the generation portfolio serving North Dakota will gradually separate from the generation portfolio serving the remainder of the NSP System.

Q. WHAT ARE PSEUDO SEPARATION AND LEGAL SEPARATION?

A. Pseudo Separation refers to separating the generation portfolio serving North Dakota from the generation portfolio serving the remainder of the NSP System, without changing the corporate structure of NSPM, by assigning the benefits and burdens of a resource to the jurisdiction(s) that supports it and developing separate resources for the non-approving jurisdiction(s) should such resources be needed.

Legal Separation refers to creating a separate operating company to serve our North Dakota customers.

These proposed structures are discussed in greater detail in the Direct Testimony of Company witnesses Mr. Chandarana and Mr. Starkweather. My resource planning analysis is equally applicable to either structure as both assume separate service to our North Dakota customers.

Q. HOW WOULD PSEUDO SEPARATION WORK FOR PURPOSES OF RESOURCE PLANNING?

A. We would establish separate Loads and Resources tables the North Dakota jurisdiction and the remainder of the NSP System to reflect the specific generation mix in which a particular jurisdiction has chosen to participate. We would then plan for the North Dakota jurisdiction's and the remainder of the NSP System's load serving needs and energy policy priorities separately. Over time, this would result in different resource mixes serving different jurisdictions. I also note that certain new L&R assumptions would have to be made to conform the North Dakota jurisdictions to MISO's resource adequacy requirements.

Pseudo Separation would require developing and implementing complex cost allocation and accounting processes. Schedule 6 to the RTF Application provides a detailed description of our proposed processes. This topic is discussed in greater detail in the Direct Testimony of Company witness Ms. Karen L. Everson.

Q. HOW WOULD THE LEGAL SEPARATION STRUCTURE ADDRESS THE COMPANY'S CURRENT RESOURCE PLANNING CHALLENGES?

A. In Legal Separation, we would serve our customers in North Dakota through a separate operating company that would continue to be part of the Xcel Energy Inc. corporate family. The separate operating company would allow us to address the resources needs of specific jurisdictions on a truly individual basis.

Further, Legal Separation also creates greater opportunities for the Company to more fully participate in investments in North Dakota that are valued by North Dakota policy makers, such as development of gas generation, without requiring the agreement of other NSPM states or imposing the risk of unrecoverable costs on NSPM.

Q. HOW WOULD LEGAL SEPARATION BE IMPLEMENTED?

A. We would establish a new operating company to serve only our North Dakota customers. For ease of reference, we refer to the hypothetical new company as NSP Dakota, or NSPD.

Once NSPD is established, it would be the regulated entity in North Dakota. Just as with our other operating companies, its rate base, operating expenses, and fuel costs would form the basis of its rates. We envision that rather than being allocated a share of the costs of the Legacy System, NSPD would transition to a unit-specific supply agreement with the NSP System to take service from the Legacy System. That contractual relationship could evolve into NSPD joining the current NSPM and NSPW Interchange Agreement should circumstances warrant that additional step. The relationship between NSPD, NSPM, and NSPW is discussed further by Company Witness Mr. Starkweather.

VII. RESOURCE PLANNING ANALYSES

A. Introduction

Q. WHAT IS THE PURPOSE OF THE COMPANY'S RESOURCE PLANNING ANALYSIS SET FORTH IN THE RTF APPLICATION?

A. To analyze the options discussed in the RTF Application, it is necessary to understand the impact of those options from a resource planning perspective. Accordingly, we undertook an analysis to look into the costs and benefits of system integration. Our analysis also assessed cost mitigation strategies so that an implemented RTF could result in reasonable impact to all our customers.

Q. WHAT TOOLS DID THE COMPANY USE IN CONDUCTING ITS RESOURCE PLANNING ANALYSIS?

A. We utilized our Strategist resource planning tool to facilitate our resource planning analysis.

Q. HOW ACCURATE IS STRATEGIST AS A RESOURCE PLANNING TOOL?

A. While Strategist is an industry standard resource planning tool, it is a modeling tool and therefore only as good as the assumptions that underlie the model. The assumptions we used for the analyses set forth in the RTF Application are attached thereto as Schedule 7. We have updated the assumptions to reflect changes since December 2016, particularly the continued reductions in the cost of wind generation and lower natural gas price forecasts. Those updated assumptions are provided as Exhibit ___(PJM-1), Schedule 2.

We believe that we have used reasonable assumptions to conduct our analysis, but we stress that these are only assumptions. Further, it is necessary to recognize that the impacts of the RTF could be permanent – or at least last for decades, during which the NSP System will evolve, along with technologies, legal requirements, and the industry as a whole. It is not fully possible to predict all the forms this evolution will take, nor all the potential impacts on our customers. Therefore, while we believe that our resource planning analysis supports our recommendation, it is intended to validate our more qualitative assessment of the need for and reasonableness of our proposed RTF rather than to determine optimal resource choices as in a resource plan or resource selection proceeding.

Q. PLEASE DESCRIBE THE STEPS INVOLVED IN YOUR RESOURCE PLANNING ANALYSIS.

A. The steps in our resource planning analysis are as follows:

1. *Evaluate an Equitable Legacy System through allocation of Disputed Resources*: As I described above, it is necessary to resolve the Disputed Resources in order to establish the Legacy System. So our first step was to identify and validate a potentially equitable allocation of the Disputed Resources and other pending issues, such as depreciation for Sherco 1 and 2 and the 2017 Wind ADP.
2. *Establish a Baseline Future NSP System*: Next, to evaluate options for the future of the NSP System, we established a "status quo" baseline of future resource planning. Our resource planning analysis begins with the presently known future of the NSP System, consistent with the outcome of our most current IRP proceeding (referred to as the IRP Plan). However, most of the

assumptions that were developed for the IRP proceeding are over two years old, as we first submitted the IRP in early January of 2015. Consequently, we also present a view of the IRP with updated modeling assumptions (referred to as the July 2017 Updated IRP Plan). The July 2017 Updated IRP Plan establishes a baseline from which to continue to analyze our RTF.

3. *Determine the Impact of the North Dakota Load on the NSP System*: We then assessed the impact of the North Dakota load on the NSP System to understand the effect of the potential loss of the North Dakota load on the remainder of the NSP System and the effect to North Dakota of exiting the integrated system. With this information, we sought to identify a timeframe when we could equitably begin to establish a separate North Dakota-based generation portfolio.

4. *Assess Continued Service to North Dakota from the Legacy System*: We also examined the reasonableness of continuing to serve North Dakota from the Legacy System. As I discussed earlier, the various principles we have established for managing the NSP System recognize the history and value of the Legacy System; therefore, to develop the RTF we needed to determine an equitable way of continuing to serve North Dakota from the Legacy System. We identified two potential generation portfolios that could serve North Dakota: a high capital cost option (adding a combined cycle plant) and a low capital cost option (adding combustion turbines). These potential portfolios act as comparison points that guide our analysis as to the impacts and validity of our proposed path to continue serving North Dakota with the Legacy System after the point of separation.

5. *Evaluate a North Dakota Separation Scenario*: We then analyzed a scenario under which North Dakota would largely leave the Legacy System (an exit scenario) after the 2025 equitable exit date established by our analysis. While

we are not proposing an exit scenario, we recognize that either or both this Commission and the MPUC may prefer an exit scenario if the baseload resources presently existing on the NSP System should be retired more quickly than presently contemplated, as such an exit scenario could better allocate the costs and liabilities of an accelerated transformation of the NSP System. We also believe that informing the record with an exit scenario is important. As I stated above, should an exit scenario occur, we are proposing that our North Dakota customers continue to be served by our nuclear portfolio to provide baseload generation and fuel diversity to North Dakota and for reasons of equity. Therefore, our analysis of these scenarios contemplates continued service in North Dakota by our nuclear fleet.

I discuss each of these steps in depth in the subsections below.

Q. HOW DOES YOUR RESOURCE PLANNING ANALYSIS APPLY TO BOTH THE LEGAL SEPARATION AND PSEUDO SEPARATION STRUCTURES DISCUSSED IN THE COMPANY'S RTF APPLICATION?

A. Our resource planning analysis is equally applicable to both the Pseudo Separation and Legal Separation structures, as the cost of particular generation portfolios would likely be equivalent under both structures. The main difference between the two would be that under the Pseudo Separation structure, the costs of different service options would be allocated through state-based ratemaking allocations, whereas under a Legal Separation structure, the costs of different service options would be allocated contractually between the new NSPD and the remainder of the NSP System.

Q. ON WHAT BASIS DID THE COMPANY CONDUCT ITS REVENUE REQUIREMENT ANALYSIS?

A. We conducted our analysis on a PVSC basis (with externalities), a PVRR basis (without externalities), and a PVRRcc basis. PVRRcc means PVRR but with the addition of a capacity credit. The concept of the capacity credit is described in more detail in the Company's response to Commission Data Request No. 2-1, which is attached as Exhibit ___(PJM-1), Schedule 3.

The Strategist outputs using these three approaches are attached as Schedule 7 to the RTF Application. Updated versions are attached as Exhibit ___(PJM-1), Schedule 4.

Q. GENERALLY SPEAKING, HAVE YOU UPDATED THE INFORMATION SUPPORTING THE RESOURCE PLANNING ANALYSIS PROVIDED IN THE RTF APPLICATION?

A. Yes. We updated modeling assumptions to reflect more current information particularly with natural gas price forecasts as well as to accurately reflect characteristics and size of our proposed 1,550 MW wind portfolio. Schedule 2 provides a summary of all the assumptions used in the analysis.

It should also be noted that the most recent analysis assumes a "markets on" view whereas the analysis that was provided in the December 2016 filing was based on a "markets off" view. As the "markets on" view is a more realistic representation of how our loads and resources actually interact with the MISO market, we felt that adopting the "markets on" assumption for this analysis was appropriate and consistent with North Dakota preferences.

As I discuss the steps in the resource planning analysis, I'll summarize the work shown in the RTF Application and explain where and how we updated it with the most recent assumptions and data.

B. Step 1 – Allocation of Disputed Resources

Q. HOW DID YOU ANALYZE A POTENTIALLY EQUITABLE ALLOCATION OF THE DISPUTED RESOURCES?

A. We studied what would happen if the North Dakota share of the Disputed Resources, except for MEC II, was allocated away from North Dakota and instead was allocated to the remainder of the NSP System. We further assumed that the proposed 1,550 MW of new wind generation was allocated to the remainder of the NSP System. Company Witness Mr. Chandarana discusses why the Company believes this could be an equitable outcome.

To test whether that division would be equitable, we compared the costs of that division to the costs of the status quo under our current allocation methods. The modeling period for this comparison is from now through 2040, so this comparison shows long-term savings and costs. The results are shown in Table 1 in the RTF Application, which is reproduced below:

Table 1: Costs of the Reallocation of Disputed Resources Compared to Shared 1500 MW Wind

PVRR, $M	MN/SD/NSPW	ND
Shared Legacy, Jur Future, Share 1500MW wind	48,435	2,430
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	48,404	2,467
PVRR Delta, $M	**MN/SD/NSPW**	**ND**
Shared Legacy, Jur Future, Share 1500MW wind	-	-
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and wind	(32)	37

This Table indicates that reallocating the North Dakota share of the Disputed Resources, plus the wind generation resources, to the remainder of the NSP System would result in approximately $32 million savings on a PVRR basis to the NSP System states and approximately $37 million in additional costs on a PVRR basis to North Dakota.

Q. HAVE YOU UPDATED THIS ANALYSIS TO REFLECT CURRENT ASSUMPTIONS AND THE DETAILS OF THE 2017 WIND ADP FILING?

A. Yes, we updated the analysis to reflect current estimates regarding our 1,550 MW Wind Portfolio as well as other assumptions.

Table 2: Costs of the Reallocation of Disputed Resources Compared to Shared 1,550 MW Wind

PVRR, $M	MN/SD/NSPW	ND
Shared Legacy, Jur Future, Share 1550MW Wind	45,556	2,312
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and Wind	45,565	2,312
PVRR Delta, $M	**MN/SD/NSPW**	**ND**
Shared Legacy, Jur Future, Share 1550MW Wind	-	-
Shared Legacy, Jur Future, Jur Reallocated Disputed Resources and Wind	9	0

Q. WHAT IS DRIVING THE DIFFERENCES IN OUTCOMES OF THIS ANALYSIS WITH UPDATED ASSUMPTIONS?

A. The differences are driven primarily by changes in gas and power price assumptions as well as the “markets on” vs “markets off” approach. As mentioned previously, the most recent analysis assumes a “markets on” view whereas the analysis that was provided in the December 2016 application was based on a “markets off” view. The “markets on” assumption provides a more realistic simulation of actual MISO interaction so should provide a more accurate representation of costs.

Q. WHAT DOES THE UPDATE SUGGEST?

A. The updated data in Table 2, above, suggests that North Dakota will not be subject to incremental long-term costs over the duration of the modeling period while the rest of the NSP System states will only see about $9 million in additional costs on a PVRR basis. The immediate cost impacts are provided in the calculations performed in the Direct Testimony of Company witness Mr. Charles R. Burdick. Because of the negligible impacts to both North Dakota and the remainder of the NSP System, we believe this analysis demonstrates that our proposed division of the Disputed Resources is reasonable and equitable.

Q. IS THIS THE ONLY POSSIBLE WAY TO ALLOCATE THE DISPUTED RESOURCES AND RESOLVE THE ISSUES WITH SHERCO 1 & 2 AND THE 2017 WIND ADP?

A. No. We are willing to consider other proposals.

C. Step 2 – Establish a Baseline Future of the NSP System

Q. WHY DID YOU, IN THE NEXT STEP, ESTABLISH A BASELINE FUTURE OF THE NSP SYSTEM?

A. By establishing a baseline, we can measure the potential effects of future changes in the NSP System. It is not possible to consider options unless you know what you are comparing against.

Q. HOW WAS YOUR BASELINE ESTABLISHED?

A. In our RTF Application, we describe a process in which we started with the Reference Case from our most recent 2015 IRP and the outcome of the IRP (the IRP Plan); updated the Reference Case and the IRP Plan to account for updated information and assumptions; calculated the system-wide costs under the original and updated Reference Case and the IRP Plan; and calculated the incremental costs to North Dakota under each.

Q. WHAT DID THAT EXERCISE SHOW?

A. Using the outdated modeling assumptions from the MPUC-approved IRP, the IRP Plan was more expensive than the Reference Case on a PVRR basis, but less expensive on a PVSC basis. But, using updated modeling assumptions, especially renewable pricing and the increased amount of production tax credit (PTC)-eligible wind production, the results changed: the updated IRP Plan was less expensive on both a PVRR and a PVSC basis. These findings validated our judgments underlying the proposed RTF: the MPUC—relying on the older modeling assumptions—approved a resource plan that was least cost when externalities and potential future regulatory costs were accounted for and not least cost when they were not, demonstrating that the resource planning outlooks of North Dakota and Minnesota generate inconsistent results.

Q. HAVE YOU UPDATED THIS STEP OF THE ANALYSIS?

A. Yes. To make sure that the Commission has the most accurate possible information regarding the baseline established in this step of the analysis, we have re-run this step using the most current assumptions.

Q. DID YOU UPDATE THE IRP PLAN BASED ON CURRENT ASSUMPTIONS?

A. Yes. The updated IRP Plan includes our proposed 1,550 MW of wind, a new sales forecast, updates to gas pricing assumptions and some other updates. Compared to the Updated plan provided in the December 2016 filing, the newest expansion plan generally includes more large solar, less small solar, a similar amount of wind, more CT replacements and less CC replacement. It is shown in Table 3 below.

Table 3: July 2017 Updated Expansion Plan

Updated Expansion Plan	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Small Solar	0	24	297	170	72	17	14	11	11	11	11	11	11	12	12	12	13	13	14	15	16	765
Large Solar	-	262	-	-	-	-	-	400	200	300	200	150	-	400	-	-	-	-	-	-	-	1,912
Wind	350	400	-	-	1,157	400	-	-	-	-	-	-	-	100	200	-	-	-	-	-	-	2,607
PPA CT	-	-	-	-	-	-	-	-	-	-	230	460	460	230	-	-	920	-	-	-	230	2,529
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	-	778	-	778	778	2,680
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	-	-	-	-	-	230
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	-	-	-	-	-	786

Q. CAN YOU PROVIDE A BREAKDOWN OF ALL OF THE DIFFERENT PLANS AND NAMING CONVENTIONS USED?

A. Yes. The Chart 1 below attempts to lay out all of the different plans that have been referenced in the RTF analysis along with a brief description and vintage to better clarify.

Chart 1: Plan Names, Descriptions and Vintages

Plan Name	Brief Description	Vintage
IRP Reference Case	Sherco 1 and 2 run to 2030, 400 MW of wind by 2020, 287 MW of solar (187 MW portfolio plus Aurora), CTs for additional capacity needs with "markets off" assumption	January 2015
IRP Plan	Closure of Sherco 2 in 2023, Sherco 1 in 2026, 1,200 MW of wind by 2020, 800 MW of solar, Sherco CC, CTs for additional capacity needs with "markets off" assumption	October 2015
Original December 2016 Filing Updated Reference Case	Updated the IRP Reference Case with Fall 2016 assumptions with "markets off" assumption	December 2016
Original December 2016 Filing Updated IRP Plan	Updated the IRP Plan with Fall 2016 assumptions and 1,500 MW of wind by 2020 with "markets off" assumption	December 2016
Current Filing July 2017 Updated Reference Case	Updated the IRP Reference Case with Spring 2017 assumptions with "markets on" assumption	July 2017
Current Filing July 2017 Updated IRP Plan	Updated the IRP Reference Case with Spring 2017 assumptions and	July 2017

Q. DID YOU UPDATE THE ANALYSIS OF THE SYSTEM-WIDE IMPACT OF THE VARIOUS PLANS?

A. Yes. The results of that analysis are shown in the Table 4 below, which provides the system-wide impact of our IRP Reference Case, our Updated Reference Case, our IRP plan, and our Updated IRP Plan on a PVSC and PVRR basis.

Table 4: Cost of Resource Plan to NSP System

Total System, $M*	BASE CASE PVSC	BASE CASE PVRR
IRP Reference Case	45,955	40,847
IRP Plan	45,788	41,824
Updated Reference Case	45,026	39,917
Updated Plan	43,564	39,771
Delta, IRP Assum	(166)	977
Delta, Current Assum	(1,462)	(145)

* NPV Calculations in this table are through 2040

The system-wide costs, over time, are shown on a PVRR and PVSC basis in the following Figure 1 and Figure 2:

Figure 1

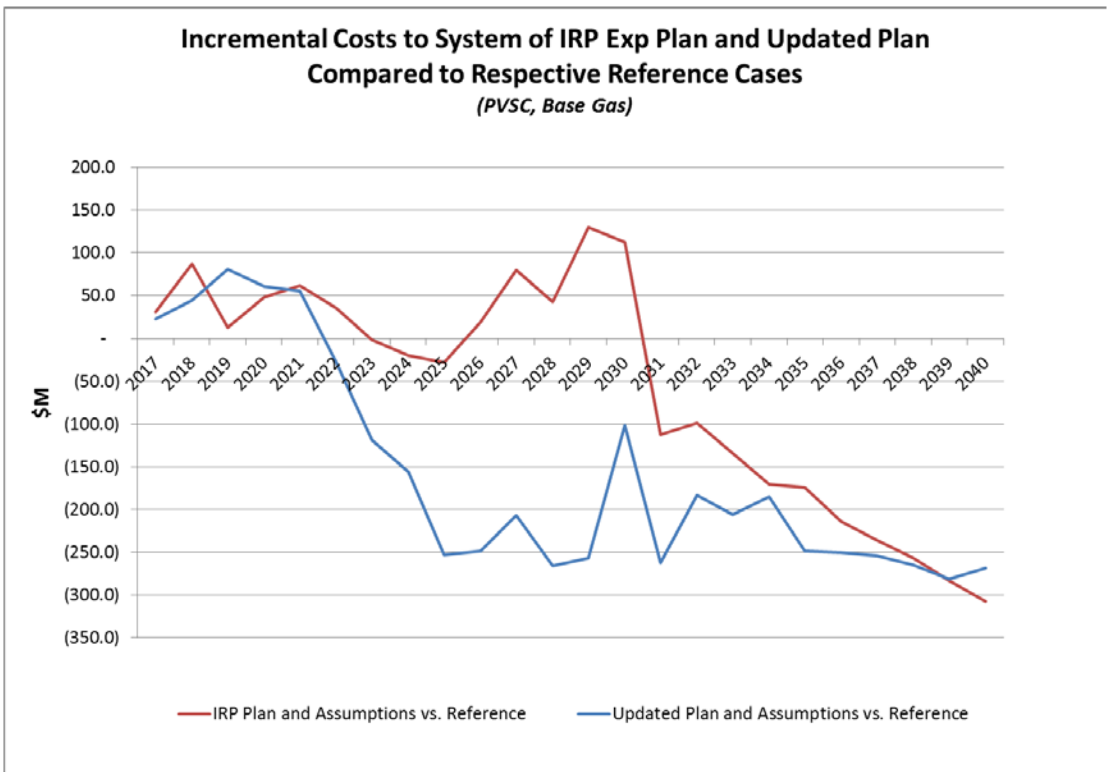
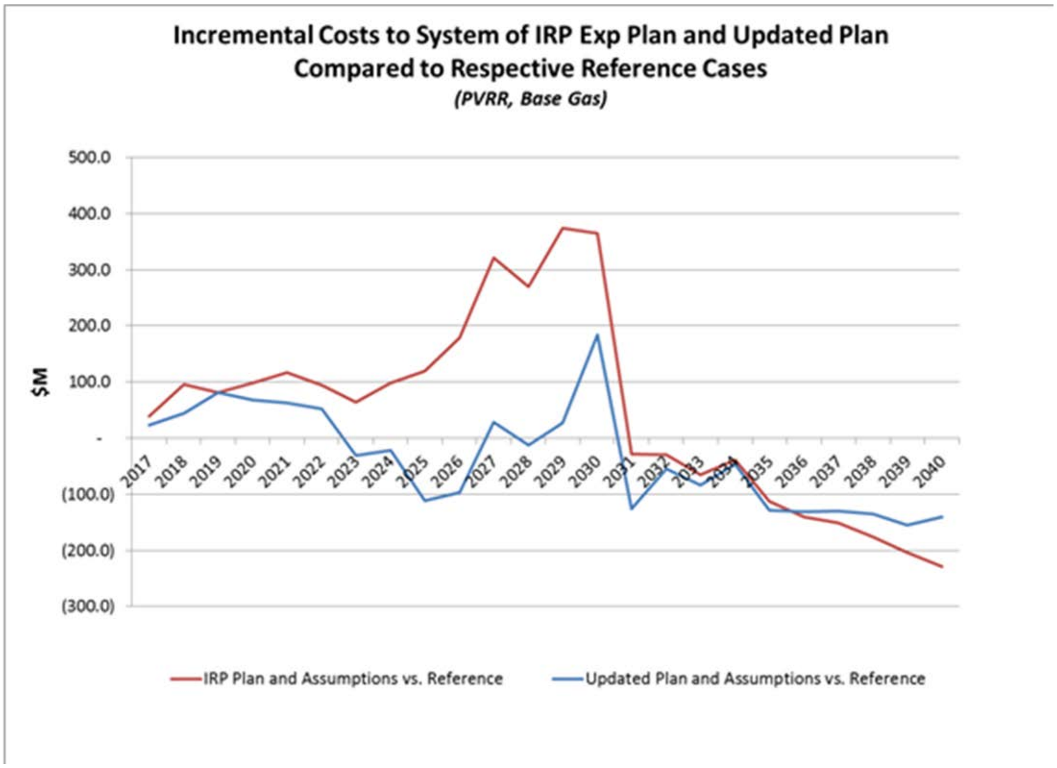


Figure 2



Q. WHAT IS THE COST IMPACT TO NORTH DAKOTA BASED ON THE UPDATED ASSUMPTIONS?

A. The cost impact is set forth in Table 5 below:

Table 5: Cost of Resource Plan to North Dakota

	BASE CASE	
ND Jur, $M*	**PVSC**	**PVRR**
IRP Reference Case	2,441	2,243
IRP Plan	2,413	2,272
Updated Reference Case	2,346	2,064
Updated Plan	2,256	2,047
Delta, IRP Assum	(28)	29
Delta, Current Assum	(90)	(17)

* NPV Calculations in this table are through 2040

The cost impact to North Dakota, over time, of the IRP Plan and the Updated Plan compared to each respective Reference Case are shown on a PVRR and PVSC basis in the following Figure 3 and Figure 4:

Figure 3

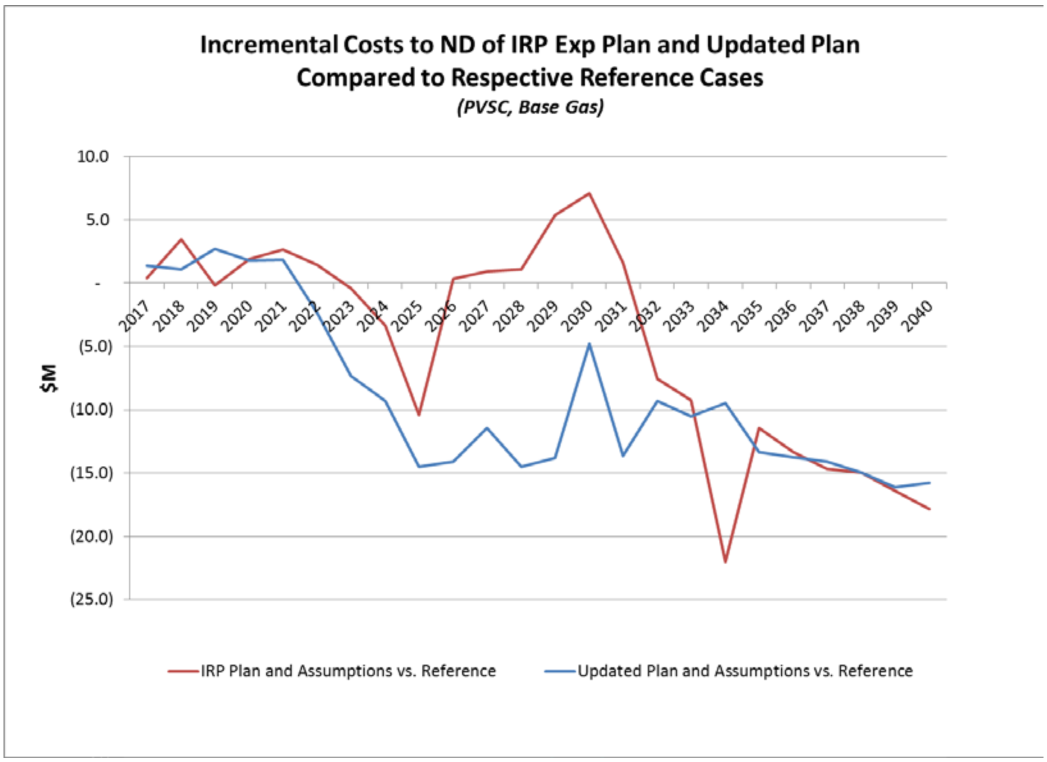
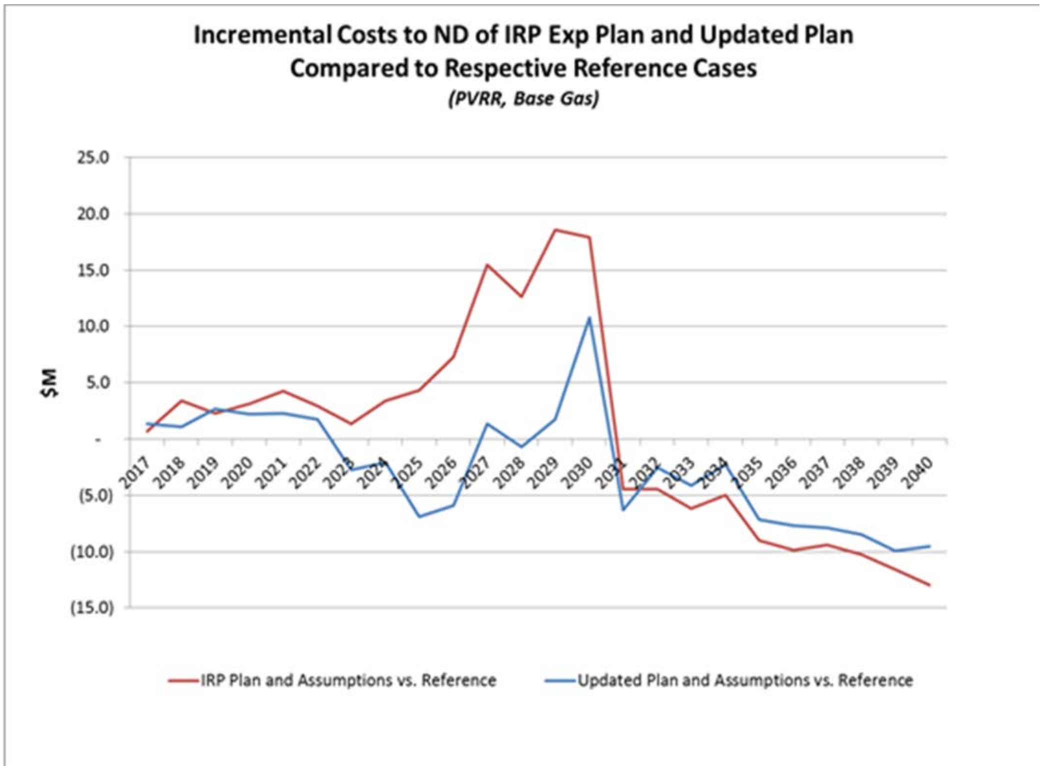


Figure 4



Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THIS UPDATED BASELINE ANALYSIS?

A. These refreshed model results are consistent with the analysis that was presented in the December 2016 RTF filing. As we noted in the previous filing, the MPUC-approved IRP Plan is more expensive than the IRP Reference Case on a PVRR basis, while on a PVSC basis, the IRP Plan is somewhat less expensive than the IRP Reference Case over the life of the plan. This is shown in the IRP Assumptions Delta line in the preceding tables. However, when we update both the IRP Reference Case and the IRP Plan with our most recent assumptions, particularly the 1,550 MW wind impacts and lower natural gas price forecasts, the model results show that the July 2017 Updated IRP Plan is less expensive than the July 2017 Updated Reference Case on both a PVSC and PVRR basis. While the assumptions have changed slightly from what was provided in the original RTF filing, these results still align with the analysis provided in December 2016.

Q. WHAT FIGURE DO YOU USE AS THE BASELINE FOR THE REST OF THE RESOURCE PLANNING ANALYSIS?

A. We view the July 2017 Updated IRP Plan as our baseline scenario because it reflects our most recent assumptions and expansion plans. Further, it represents a plan that is more attractive than previous IRP and Reference plans on both a PVSC and PVRR basis which is preferable to all jurisdictions.

D. Step 3 – The Impact of the North Dakota Load

Q. AFTER ESTABLISHING A BASELINE, WHAT WAS THE NEXT STEP IN YOUR RESOURCE PLANNING ANALYSIS?

A. We next performed an examination of the impact of the North Dakota load on the NSP System.

Q. WHY DID YOU PERFORM THIS EXAMINATION?

A. We undertook this analysis to determine the magnitude of the NSP System costs carried by our North Dakota customers and what the impact would be to the remainder of the NSP System should it lose the North Dakota customer base. Additionally, we performed this analysis to better understand the impacts of timing – specifically, how would the NSP System be impacted from a cost perspective should it lose the North Dakota load before and after the shutdown of Sherco Unit 2 at the end of 2023 and after the shutdown of Sherco Unit 1 at the end of 2026. Further, we modeled the assumption of continued service to North Dakota from the Legacy System to quantitatively validate the assumptions that underlie our proposed RTF.

Q. WHICH YEAR DID YOU CHOOSE AS THE EARLIEST DATE TO PERFORM THE ANALYSIS OF THE IMPACT OF THE NORTH DAKOTA LOAD ON THE NSP SYSTEM?

A. We chose 2023 because it is the earliest reasonable date by which we can permit and install new generation resources in North Dakota.

Q. DID YOU ANALYZE THE IMPACT OF THE LOSS OF NORTH DAKOTA LOAD ON THE REMAINDER OF THE NSP SYSTEM?

A. Yes. This analysis is shown in Table 6 and Figures 5 and 6 from the RTF Application. These tables and figures, set forth below, identified the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC, PVRR, and rate impact basis, including the impact of continued sharing of the Legacy System by all NSP System customers.

Table 6: Impact of Loss of ND Load on Remainder of NSP System

	BASE CASE		LOW GAS		HIGH GAS	
MN/SD/NSPW, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	52,493	48,302	49,213	45,106	57,477	53,201
Shared Legacy, Jur Future	52,350	48,348	49,182	45,203	57,296	53,164
Loss of ND Load, 2023	52,614	48,462	49,399	45,344	57,477	53,240
Loss of ND Load, 2025	52,496	48,365	49,282	45,248	57,360	53,141
Loss of ND Load, 2027	52,439	48,314	49,228	45,197	57,307	53,090

	BASE CASE		LOW GAS		HIGH GAS	
Delta, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	(144)	45	(31)	97	(181)	(37)
Loss of ND Load, 2023	121	160	186	238	(0)	40
Loss of ND Load, 2025	2	63	68	142	(117)	(59)
Loss of ND Load, 2027	(54)	12	15	91	(171)	(111)

Figure 5

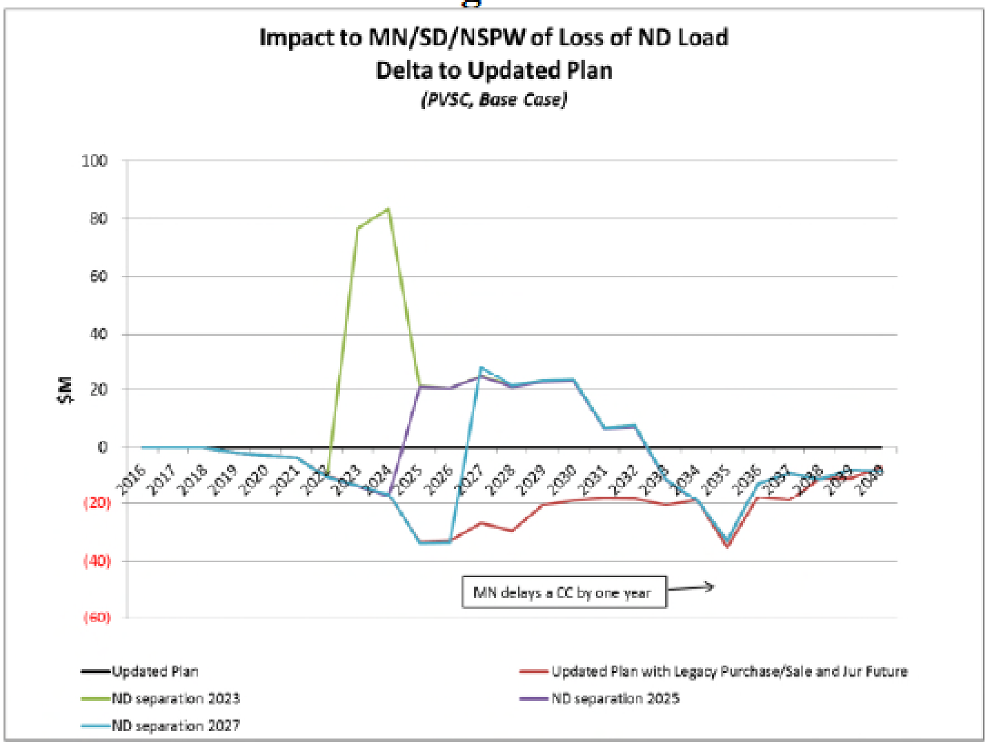
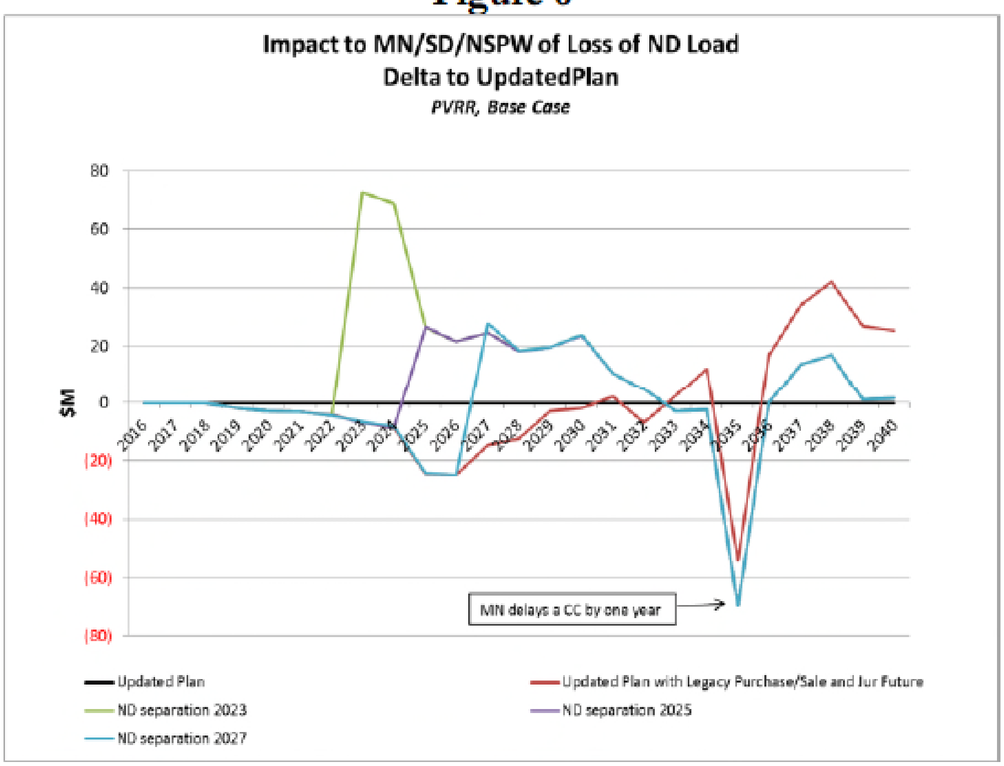


Figure 6



Q. DID YOU UPDATE THIS ANALYSIS REGARDING THE IMPACT OF THE NORTH DAKOTA LOAD?

A. Yes. Table 7, below, shows the impact of the loss of the North Dakota Load on the remainder of the NSP System, updated based on the most recent assumptions and data:

Table 7: Impact of Loss of ND Load on Remainder of NSP System

	BASE GAS		LOW GAS		HIGH GAS	
MN/SD/NSPW, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	50,251	45,406	48,129	43,366	53,230	48,316
Shared Legacy, Jur Future	50,396	45,503	48,154	43,346	53,384	48,424
Loss of ND Load, 2023	50,322	45,588	48,281	43,633	53,219	48,411
Loss of ND Load, 2025	50,264	45,509	48,216	43,546	53,168	48,338
Loss of ND Load, 2027	50,256	45,481	48,199	43,506	53,166	48,318

	BASE GAS		LOW GAS		HIGH GAS	
Delta, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	145	98	25	(20)	154	108
Loss of ND Load, 2023	71	183	153	267	(11)	95
Loss of ND Load, 2025	13	103	87	180	(62)	23
Loss of ND Load, 2027	5	75	70	140	(64)	2

Updated Figures 7 and 8, below, identify the impact of the loss of North Dakota load on the remainder of the NSP System in 2023, 2025, and 2027 on a PVSC and PVRR basis; updated based on the most recent assumptions and data.

Figure 7

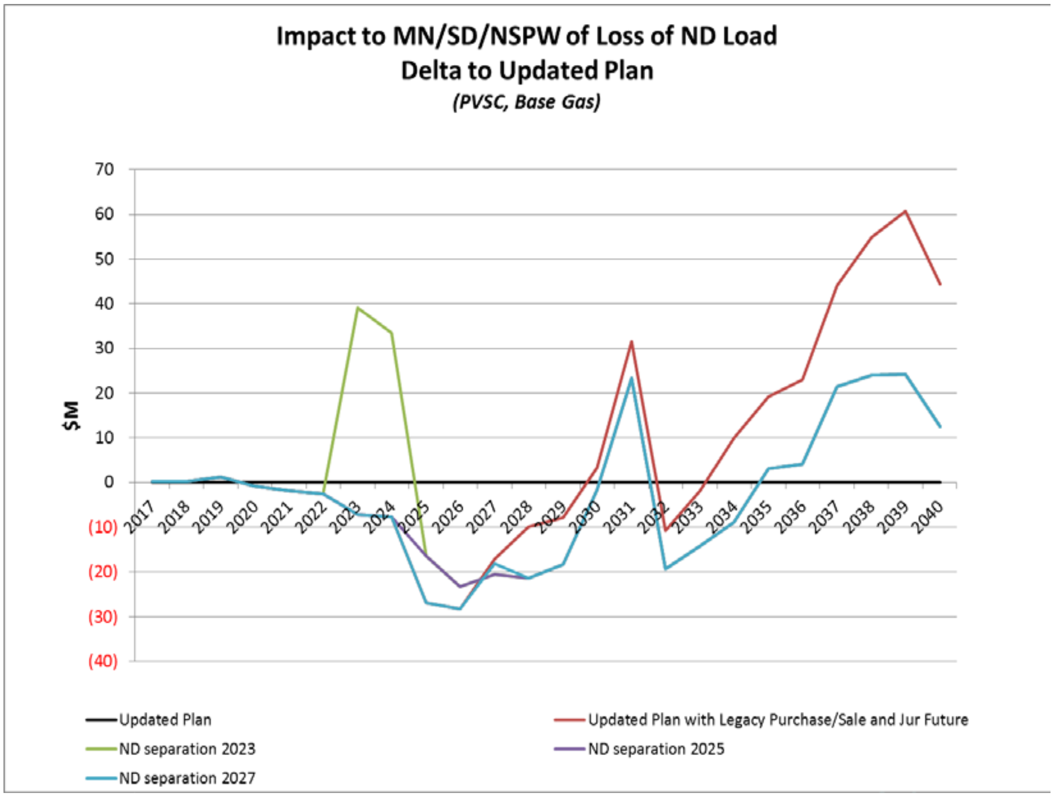
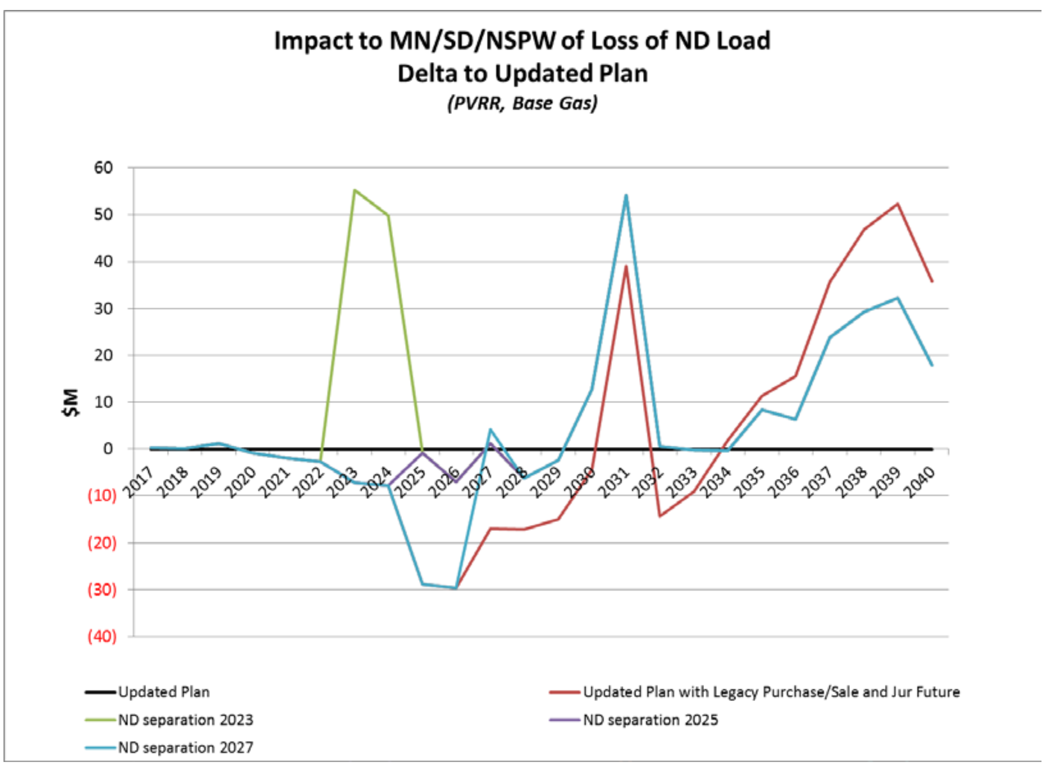


Figure 8



Q. WHAT DO THESE TABLES AND FIGURES DEMONSTRATE WITH RESPECT TO THE IMPACT OF LOSS OF THE NORTH DAKOTA LOAD?

A. They show that the longer the separation of the North Dakota load from the NSP System is deferred, the lesser the cost impact to the remainder of the NSP System. We can also infer that the inverse is true: the earlier the North Dakota load separates from the NSP System, the earlier the cost shifts occur to the remainder of the System. However, the true impact to our North Dakota customers from separating from the NSP System cannot be fully modeled without assumptions about the generation portfolio that would serve North Dakota as a stand-alone system.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM ANALYZING THE LOSS OF THE NORTH DAKOTA LOAD?

A. We draw several conclusions from this analysis. First, continued service from the Legacy System is reasonable and materially mitigates the impacts to the remainder of the NSP System from the loss of our North Dakota load. Second, under the most recent assumptions, either 2025 or 2027 appear to be equitable dates for the NSP System to lose the North Dakota load, should that be the preferred outcome of the Commissions. This is because the cost impacts of a 2025 or 2027 date similarly balance savings to North Dakota and potential negative impacts to the remainder of the NSP System triggered by the loss of the North Dakota load. Third, to ensure that the NSP System is not overburdened with costs resulting from separation, our North Dakota customers should continue to be served by the Legacy System from the implementation of our RTF, expected to be in 2020, until at least 2025 under any circumstances.

Q. IS THE YEAR 2025 THEREFORE SIGNIFICANT IN YOUR RESOURCE PLANNING ANALYSIS?

A. Yes. The remainder of the updated resource planning analysis, discussed below, utilizes a 2025 date as the appropriate measuring point for North Dakota service scenarios. While a 2027 separation better mitigates cost impacts for the remainder of the NSP system, from a capacity planning standpoint, 2025 is a reasonable date as that is when the NSP System is expected to first have a capacity need which will formally enable separation on future resource additions to occur. But as I noted earlier, our proposal is to continue to serve North Dakota from the legacy system.

E. Step 4 – Continued Service to North Dakota

Q. WHAT WAS THE NEXT STEP IN YOUR RESOURCE PLANNING ANALYSIS?

A. After establishing key baseline information in the analyses I discuss above, we then sought to validate the reasonableness of continued service to North Dakota from the NSP System beginning in 2025.

Q. PLEASE EXPLAIN HOW YOU PERFORMED THE VALIDATION ANALYSIS?

A. We undertook our validation analysis by developing two potential generation portfolio scenarios that we believe would identify the low-end and the high-end costs of serving North Dakota separately, and would also allow assessment of the potential volatility of these scenarios when compared to the Legacy System. Recognizing the myriad of different service options that may be available, we believe that these scenarios provide reasonable "bookends" to quantitatively validate the concepts that underlie our proposed RTF.

Q. ON WHAT BASIS DID YOU CONDUCT YOUR VALIDATION ANALYSIS?

A. Because this analysis is focused on serving North Dakota, we present our figures here on a PVRR basis only.

Q. PLEASE DESCRIBE THE FIRST GENERATION PORTFOLIO YOU DEVELOPED.

A. The first generation portfolio we developed was based on full service to our North Dakota customers from only combustion turbines (the CT Scenario). Under this scenario, we assumed that a combustion turbine fleet would be installed in 2025, consistent with our analysis above, and that our North Dakota customers would be served from the Legacy System until then.

Because the CT Scenario adds only combustion turbines to serve our North Dakota load, the majority of the energy is supplied by the markets. The resource additions are in 2025 (230 MW), 2031 (115 MW), and 2041 (115 MW). For the alternative where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, resource needs requiring resource additions have combustion turbines being added in 2031, 2035, 2041, and 2051, and are all sized at 115 MW.

Q. WHY DID YOU DEVELOP THE CT SCENARIO?

A. We developed this scenario to analyze the costs of least-cost capacity resources with low capacity factors which therefore require material reliance on energy markets to serve our North Dakota load. We feel this scenario represents the low-end cost of serving North Dakota separately as the portfolio consists of less expensive capacity costs in the form of a combustion turbine to provide a higher heat rate hedge which allows North

Dakota to limit market price exposure in high price LMP hours, but otherwise rely on lower priced market energy.

Q. PLEASE DESCRIBE THE SECOND GENERATION PORTFOLIO YOU DEVELOPED.

A. The second generation portfolio we developed was based on full service to our North Dakota customers from combined cycle plants (CC Scenario). Under this scenario, we assumed that the combined cycle fleet would be installed in 2025 and that our North Dakota customers would be served from the Legacy System until then.

In this scenario, a single 389 MW combined cycle plant was added in 2025 to serve our North Dakota load. A combined cycle plant was not an option for the scenario where North Dakota continues to be served by the Legacy System, with jurisdictional planning for future resources, as the incremental load-serving need was not large enough to justify a combined cycle plant. Resource needs are therefore met by combustion turbines in the Legacy System, as I described above.

Q. WHY DID YOU DEVELOP THE CC SCENARIO?

A. We developed this scenario to analyze the costs of serving our North Dakota customers with a higher capacity factor and lower heat rate resource which has higher initial capital costs, but reduces dependency on energy markets. We feel this scenario represents the high-end cost of serving North Dakota separately as the portfolio consists of more expensive CC capacity, however, given the lower heat rate and higher production levels associated with the CC, North Dakota is expected to be less dependent on market energy.

Q. HOW DID YOU USE THE CC AND CT SCENARIOS?

A. We used the CC and CT Scenarios, which represent extremes on both ends of potential service options, to provide comparison points for continued service to North Dakota by the Legacy System.

Q. DID YOU PERFORM AN ADDITIONAL VALIDATION ANALYSES?

A. Recognizing that the CT Scenario and CC Scenario both use only a single fuel (gas), and rely on market purchases for some or most of the energy needs of our North Dakota customers, we also performed an analysis for high and low gas sensitivities. Additionally, for the purposes of validating our RTF, we performed this analysis on the CT and CC Scenarios without the assumption that North Dakota would continue to be supported by the Company's nuclear fleet.

Q. WHAT WERE THE RESULTANT COSTS OF SERVICE TO NORTH DAKOTA BASED ON THE ANALYSES YOU CONDUCTED?

A. Table 7, from the RTF Application, (inserted below) identifies the costs of service to North Dakota from the CT Scenario, Legacy System, and CC Scenario on a PVSC and PVRR basis under our base case and high and low gas sensitivities, as well as the differential between these scenarios and our Updated Plan.

Table 7: Cost of North Dakota Service Scenarios

	BASE CASE		LOW GAS		HIGH GAS	
ND, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT, No Nuclear	2,958	2,477	2,522	2,120	3,382	3,005
Loss of ND Load, 2025 CC, No Nuclear	2,786	2,512	2,485	2,218	3,218	2,948

	BASE CASE		LOW GAS		HIGH GAS	
Delta, $M	PVSC	PVRR	PVSC	PVRR	PVSC	PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT, No Nuclear	247	(90)	1	(264)	389	159
Loss of ND Load, 2025 CC, No Nuclear	75	(55)	(36)	(166)	225	102

Figure 7, from the RTF Application, below, represents the PVRR view of these scenarios compared to our Updated Plan graphically for our base case.

Figure 7

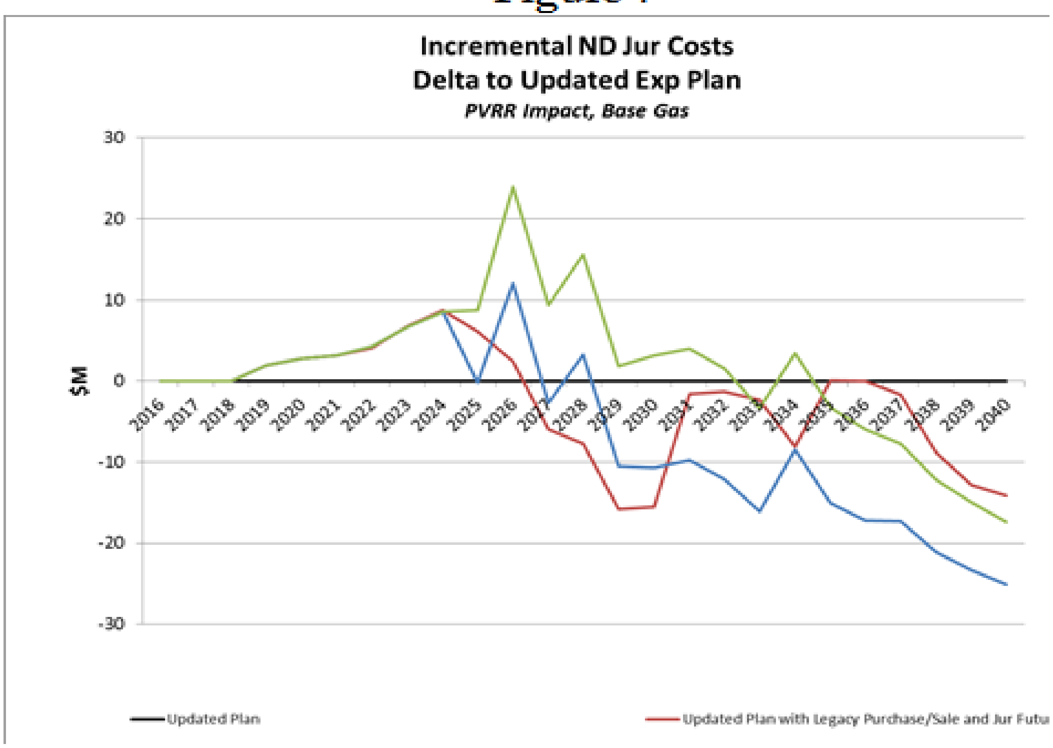
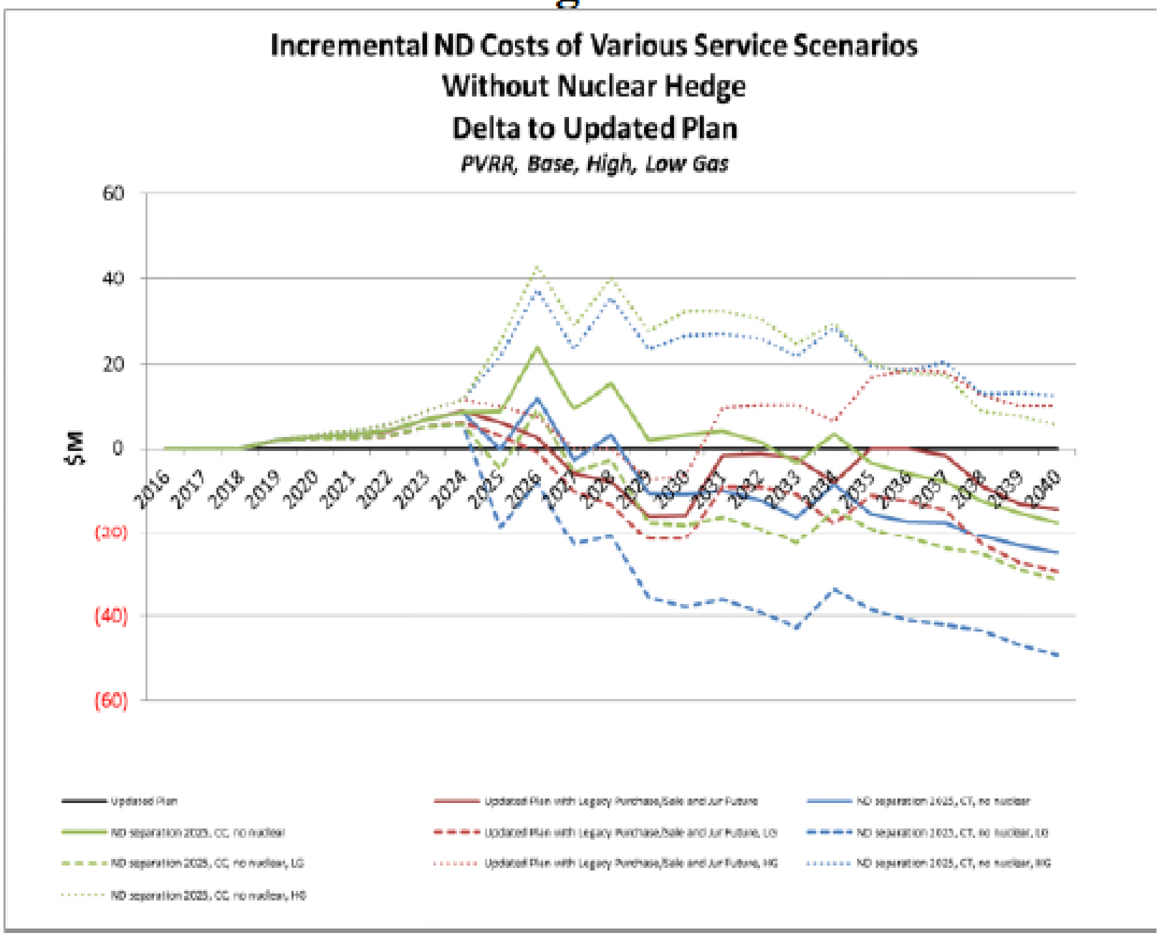


Figure 8, from the RTF Application, below, represents the PVRR view of the base case, high gas, and low gas scenarios compared to our Updated Plan graphically.

Figure 8



Q. HAVE YOU UPDATED THESE ANALYSES TO REFLECT CURRENT ASSUMPTIONS?

A. Yes. Updated Table 6, below, shows the costs of service to North Dakota from the CT Scenario, Legacy System, and CC Scenario on a PVSC and PVRR basis under our base case and high and low gas sensitivities, as well as the differential between these scenarios and our Updated Plan, updated based on the most recent assumptions and data:

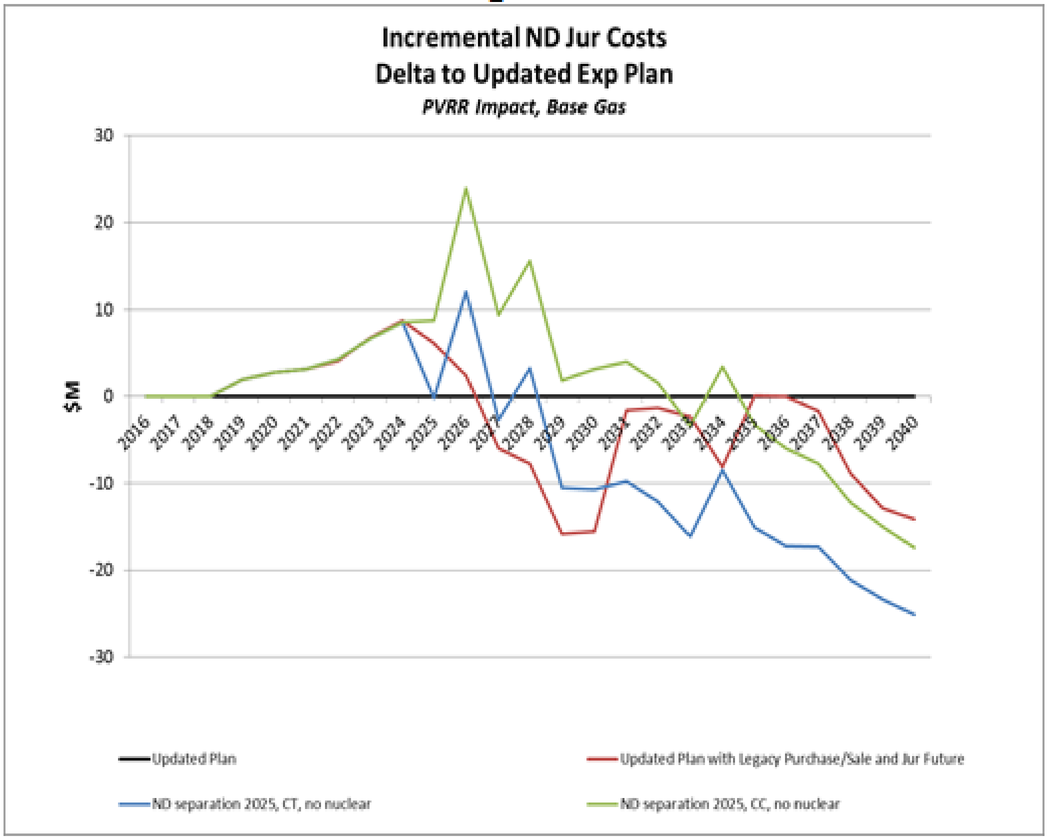
Table 6: Cost of North Dakota Service Scenarios

	BASE GAS		LOW GAS		HIGH GAS	
ND, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	2,756	2,474	2,632	2,356	2,930	2,642
Shared Legacy, Jur Future	2,649	2,364	2,585	2,305	2,732	2,443
Loss of ND Load, 2025, CT, No Nuclear	2,325	2,262	2,288	2,227	2,376	2,312
Loss of ND Load, 2025, CC, No Nuclear	2,398	2,335	2,202	2,141	2,667	2,603

	BASE GAS		LOW GAS		HIGH GAS	
Delta, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	(107)	(110)	(47)	(51)	(197)	(198)
Loss of ND Load, 2025, CT, No Nuclear	(431)	(212)	(344)	(130)	(554)	(330)
Loss of ND Load, 2025, CC, No Nuclear	(358)	(139)	(430)	(216)	(262)	(38)

Updated Figures 7 and 8, (inserted below), show the PVRR view of the base case, high gas, and low gas scenarios compared to our Updated Plan graphically, updated based on the most recent assumptions and data.

Figure 7


Incremental ND Jur Costs
Delta to Updated Exp Plan
PVRR Impact, Base Gas
$M
30
20
10
0
-10
-20
-30
2016
2017
2018
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2020
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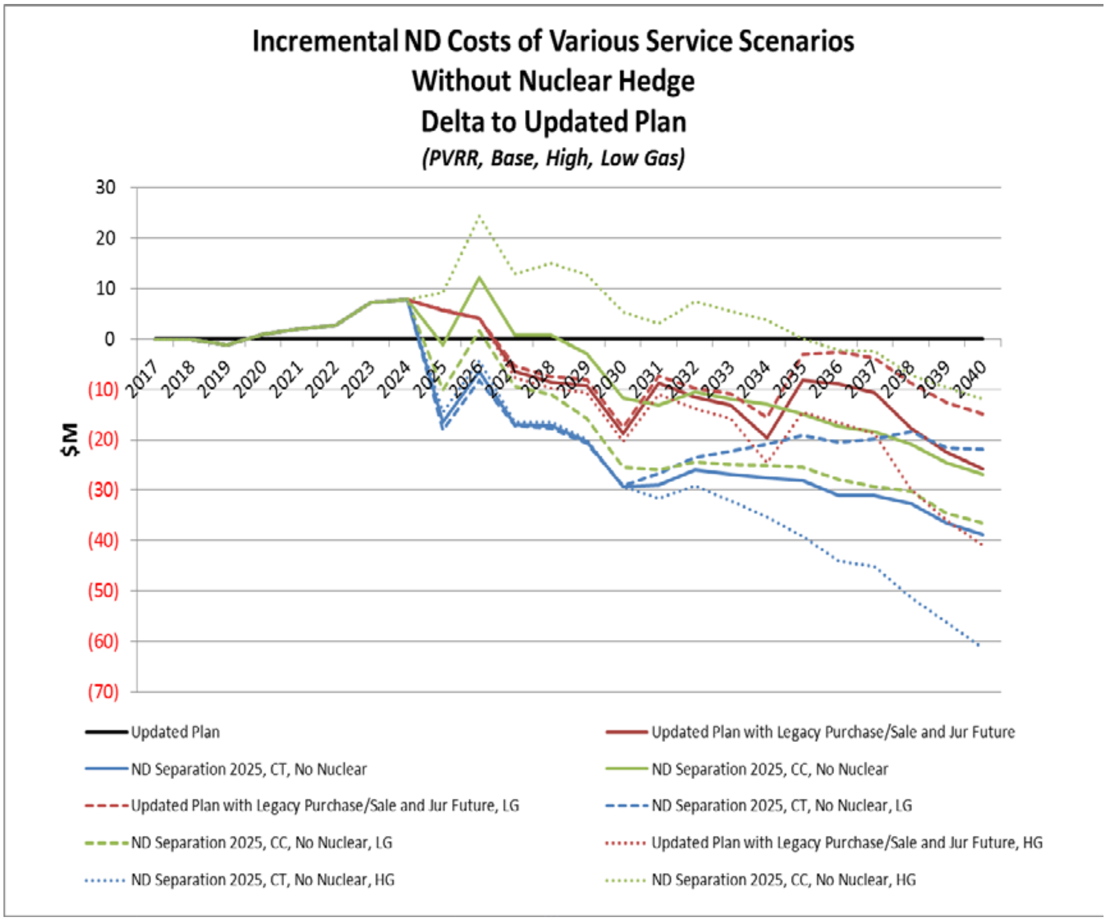
2040
Updated Plan
Updated Plan with Legacy Purchase/Sale and Jur Future
ND separation 2025, CT, no nuclear
ND separation 2025, CC, no nuclear

Figure 8



Q. PLEASE EXPLAIN THE DATA PROVIDED IN THE ABOVE TABLES AND FIGURES AS IT RELATES TO THE CT SCENARIO.

A. Using our base case assumptions, the CT Scenario is the lowest cost. As shown in Figure 8, the capital costs of installing combustion turbines results in less rate impact when compared to our Updated Plan than either continued service from the Legacy System or in the CC Scenario. However, as also shown in Figure 8, the CT Scenario is the most volatile and risky, as it had the largest range of possibilities when assessing the spread between the high and low gas scenarios.

Q. BASED ON YOUR ANALYSIS, DO YOU BELIEVE THAT SERVICE FROM ONLY COMBUSTION TURBINES IS EFFECTIVE?

A. The exposure to the energy markets based on the assumed ten percent capacity factor of the combustion turbines and the impact on energy markets from gas prices leads us to conclude that service from only combustion turbines may not be prudent if North Dakota prefers more certainty with regard to energy costs and less exposure to market priced energy. The risk of the CT only service is the greatest as evidenced by the relatively large spread between the high to low gas scenarios when compared to the CC or Legacy System options.

Q. WHAT DO THE ABOVE TABLES AND FIGURES SUGGEST ABOUT CONTINUED SERVICE TO NORTH DAKOTA FROM THE LEGACY SYSTEM?

A. The Legacy System performed reasonably well in our base case and in a high and low gas scenario, especially through the 2020s. While not the cheapest scenario under our base case, continued service from the Legacy System reduces the need for capital investment in 2025. Additionally, through the 2020s, service by the Legacy System was least volatile, demonstrating the hedge value of the Legacy System. Of note, the Legacy System scenario under our base case assumptions outperformed the CC Scenario under our low gas sensitivity through 2030, which further demonstrates the value of the fuel diversity of the Legacy System.

Q. HOW DID THE CC SCENARIO PERFORM?

A. The CC Scenario was the most expensive in the early years but also a reasonable service option when compared to our Updated Plan in a base case scenario. The performance of the CC Scenario was impacted by the "lumpiness" of the costs of constructing these types of generators: the analysis shows that there would have to be significant capital investments in the early years of this scenario but then capacity and energy would be sufficient for many years. And while the CC Scenario is more volatile than the Legacy System, it was less volatile than the CT Scenario when comparing the base case to the high and low gas sensitivities.

Q. HOW DO THESE UPDATED GAS SCENARIO IMPACTS COMPARE TO WHAT WAS PROVIDED IN THE INITIAL RTF APPLICATION?

A. The most noticeable change is that the cost deltas for all of the scenarios are more favorable to North Dakota primarily because of the decrease in the natural gas and market energy price forecasts from the Fall of 2016 to the Spring of 2017. In the original chart provided in the RTF filing, forward gas prices were higher which created more risk and larger spreads between the high and low gas sensitivities. In addition, the high gas sensitivities in the original filing in December 2016 also showed significant cost deltas when compared to the Updated IRP Plan. Now, with the lower gas pricing forecasts, the risk has shrunk somewhat for all scenarios and the cost deltas for separation scenarios are more favorable relative to the Updated IRP plan.

Q. IS IT SAFE TO ASSUME THAT THE SPRING 2017 NATURAL GAS AND ENERGY MARKET PRICE FORECASTS ARE RELIABLE?

A. All forecasts are point in time estimates based on the best information available at the time and subject to change. The Spring 2017 forecasts were created at the tail end of a relatively mild winter when natural gas storage was at fairly high levels and prices were at relatively low levels. Looking back at prices over the past decade, however, natural gas has experienced significant volatility. Therefore, while gas pricing could remain at low levels for the foreseeable future, there is always a risk that prices could increase above current expectations in which case large exposure to the commodity will not be preferred.

Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THE REASONABLENESS OF CONTINUED SERVICE TO NORTH DAKOTA FROM THE NSP SYSTEM BEGINNING IN 2025?

A. We conclude that continued service to North Dakota from the Legacy System is reasonable as it is less expensive than service under our Updated Plan over its life under base case assumptions, and is the least volatile of the scenarios should gas prices materially change (either to serve the CC Scenario with gas or the impact to the market energy providing ninety percent of the energy in the CT Scenario). Consequently, we believe that this analysis quantitatively validates the qualitative assessments that led to our proposed RTF.

F. Step 5 – Evaluating North Dakota Separation Scenarios

Q. WHAT WAS THE LAST STEP IN YOUR RESOURCE PLANNING ANALYSIS?

A. The last step involved analyzing North Dakota separation scenarios to provide context for this Commission and the MPUC. Also, in the event that the Commission and the MPUC do not want to take service from the entire Legacy System past 2025, this step illustrates how the evolution of the Legacy System could be accelerated.

Q. HOW DID YOU CONDUCT THIS ANALYSIS?

A. To mitigate some of the volatility identified in the CT Scenario and CC Scenario discussed above, and to retain the equity of the incurred liabilities for the use of the Legacy System proposed as part of our RTF, we paired our nuclear fleet to the CT Scenario and CC Scenario for our analysis of separation scenarios (CT Scenario + Nuclear and CC Scenario + Nuclear, respectively).

Q. HOW DOES THIS ANALYSIS MITIGATE THE VOLATILITY IDENTIFIED IN THE CT SCENARIO AND CC SCENARIO?

A. From a resource planning standpoint, we would expect that the addition of approximately twenty percent of capacity needs being met by a high capacity alternative fuel source such as nuclear would materially mitigate the volatility of the CC Scenario and CT Scenario and also offset earlier capital investment needs, which could lead to better overall cost performance. Our analysis bears this out.

Q. WHAT WERE THE RESULTS OF THE NORTH DAKOTA SERVICE SCENARIOS WITH THE ADDITION OF NUCLEAR?

A. Table 8, from the RTF Application, below, identifies the PVSC and PVRR performance of the CT Scenario + Nuclear, the CC Scenario + Nuclear, and continued service from the Legacy System as well as a comparison to our Updated Plan.

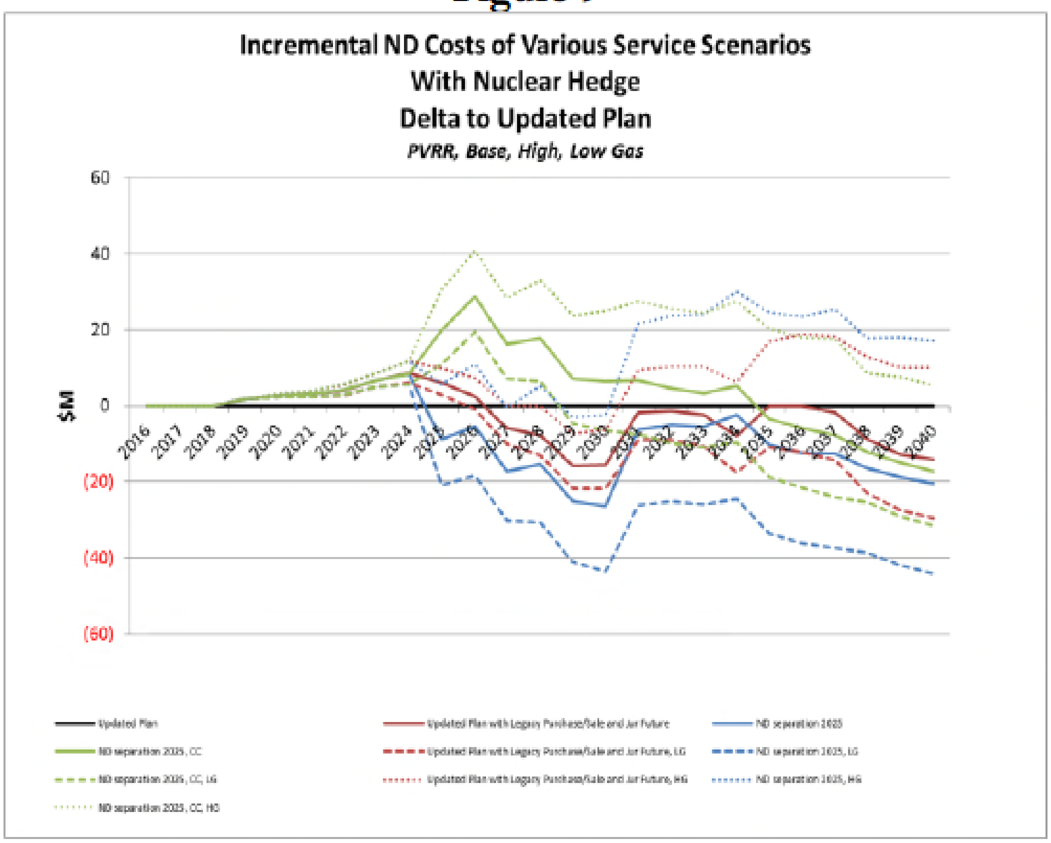
Table 8: ND Service Scenarios with Nuclear Hedge

ND Jur, $M	BASE GAS PVSC	BASE GAS PVRR	LOW GAS PVSC	LOW GAS PVRR	HIGH GAS PVSC	HIGH GAS PVRR
Updated Plan	2,711	2,567	2,521	2,384	2,993	2,846
Shared Legacy, Jur Future	2,899	2,515	2,575	2,245	3,243	2,903
Loss of ND Load, 2025, CT	2,884	2,456	2,491	2,130	3,307	2,944
Loss of ND Load, 2025 CC	2,780	2,534	2,507	2,265	3,182	2,937

Delta, $M	BASE GAS PVSC	BASE GAS PVRR	LOW GAS PVSC	LOW GAS PVRR	HIGH GAS PVSC	HIGH GAS PVRR
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	188	(52)	54	(139)	251	57
Loss of ND Load, 2025, CT	173	(111)	(30)	(254)	314	98
Loss of ND Load, 2025 CC	69	(33)	(14)	(119)	189	92

Figure 9, from the RTF Application, below, provides a graphic representation of our modeling outputs.

Figure 9



Q. DID YOU UPDATE THESE ANALYSES?

A. Yes. Table 7, below, identifies the PVSC and PVRR performance of the CT Scenario + Nuclear, the CC Scenario + Nuclear, and continued service from the Legacy System as well as a comparison to our Updated Plan, all based on the most recently updated assumptions and data.

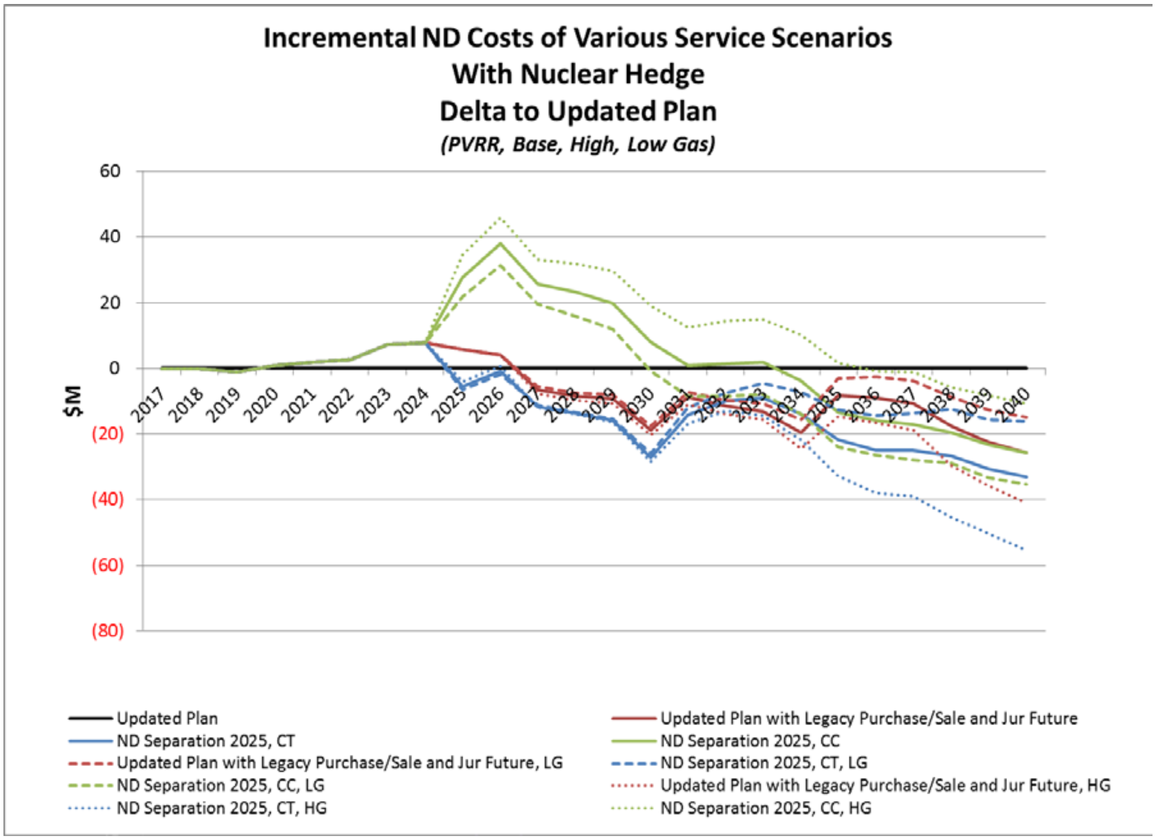
Table 7: ND Service Scenarios with Nuclear Hedge

	BASE GAS		LOW GAS		HIGH GAS	
ND, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	2,756	2,474	2,632	2,356	2,930	2,642
Shared Legacy, Jur Future	2,649	2,364	2,585	2,305	2,732	2,443
Loss of ND Load, 2025, CT	2,385	2,319	2,350	2,286	2,433	2,366
Loss of ND Load, 2025, CC	2,498	2,432	2,318	2,255	2,747	2,678

	BASE GAS		LOW GAS		HIGH GAS	
Delta, $M	**PVSC**	**PVRR**	**PVSC**	**PVRR**	**PVSC**	**PVRR**
Updated Plan	-	-	-	-	-	-
Shared Legacy, Jur Future	(107)	(110)	(47)	(51)	(197)	(198)
Loss of ND Load, 2025, CT	(371)	(155)	(282)	(71)	(496)	(276)
Loss of ND Load, 2025, CC	(259)	(42)	(314)	(102)	(183)	37

Figure 9, below, provides a graphic representation of these modeling outputs.

Figure 9



Q. WHAT INFORMATION CAN BE GLEANED FROM COMPARISON OF THE ANALYSES IDENTIFYING THE COSTS OF SERVICE TO NORTH DAKOTA WITHOUT NUCLEAR AND THOSE WHICH ADD THE NUCLEAR HEDGE?

A. Comparing outputs of the above tables, we can see that the CT Scenario performs similarly when paired to our nuclear portfolio than without it from a PVRR cost delta perspective. From a volatility perspective, pairing the CT with the nuclear portfolio provides an alternatively fueled market hedge that reduces the range of outcomes and risk. The CC Scenario also performed better over its life when tied to our nuclear portfolio due to the offset of capital investment provided by carrying forward our nuclear portfolio, as well as the fuel hedge provided by alternative, baseload fuel sources. Additionally, on a PVRR basis, the Legacy System performed in the midpoint, with the least volatility, when compared to the other two scenarios.

Q. WHAT DO YOU CONCLUDE GIVEN THE ABOVE RESULTS?

A. I conclude that continued service to North Dakota from the Legacy System continues to be the most prudent path forward under any RTF structure. However, should the Commissions choose to separate North Dakota from the Legacy System sooner than current anticipated baseload retirement dates, continued service from our nuclear fleet is a key component of doing so, as it would provide material fuel hedge value and offset initial capital investments to help smooth a transition to stand-alone service for our North Dakota customers.

VIII. CONCLUSION

Q. OVERALL, WHAT CONCLUSIONS CAN BE DRAWN FROM YOUR RESOURCE PLANNING ANALYSIS?

A. Based on our resource planning analysis, continued service to North Dakota from the Legacy System would be a reasonably equitable outcome. However, should it be determined that a more complete separation should be undertaken, then doing so no sooner than 2025 with continued service to our North Dakota customers from our nuclear fleet is a reasonable time and way to do so. Last, our resource planning analysis confirmed that our proposal to address the Disputed Resources provides negligible impacts to both North Dakota and the remainder of the NSP System.

Q. PLEASE SUMMARIZE THE KEY FINDINGS RESULTING FROM THE COMPANY'S RESOURCE PLANNING ANALYSIS.

A. Our resource planning analysis yields the following key findings:

- **Fair Treatment of Disputed Resources** – Step 1 of our resource planning analysis shows that reallocating the Disputed Resources (except MEC II) over the remainder of the NSP System while also allocating all of our wind additions to the remainder of the NSP System results in an equitable outcome for both our North Dakota customers and our customers being served by the remainder of the NSP System.
- **Reduced Costs of Our Updated Plan** – Step 2 demonstrates that the most recent July 2017 Updated IRP Plan is less costly than the July 2017 Updated Reference Case from both a PVRR and PVSC basis for both the NSP System and North Dakota.
- **Impacts and Timing of Dissolving the Legacy System** – Step 3 demonstrates that continued service from the Legacy System is reasonable and mitigates cost shifting to the remainder of the NSP System, and that no sooner than 2025 is a reasonably equitable time for North Dakota to separate.
- **Costs and Risks of Replacement Generation Options** – Step 4 demonstrates that if North Dakota separates in 2025 and chooses to self-supply generation resources, a combined cycle resource demonstrates a high expected portfolio capacity cost and lower energy risk profile (less exposure to market purchases) while combustion turbine resources demonstrates a lower expected portfolio capacity cost with a higher energy risk profile (more

exposure to market prices). Importantly, this validates the reasonableness of continued service from the Legacy System.

- **Benefits of Legacy System and Nuclear** – Step 5 demonstrates how continued service from the diversity of resources in the Legacy System, particularly our nuclear fleet, would help provide a lower risk profile for North Dakota in terms of replacement generation options with a mid-range cost impact.

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

A. Yes, it does.

Philip Joseph "P.J." Martin
Director, Resource Planning and Bidding
NSPM

Philip Joseph "P.J." Martin is the Director, Resource Planning and Bidding for Northern States Power Company – Minnesota. He is responsible for the direction of electric resource planning for the NSP System, which provides electric service to customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

Martin joined Xcel Energy in August 2015 as Director, Strategic Asset Planning where he focused primarily on business planning for the four operating companies at Xcel Energy Inc. In October 2016, he was promoted to his current role.

Prior to joining Xcel Energy, Martin was a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, he engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. He also supported long-term planning and risk management efforts for these customers in MISO, PJM, SERC, and other markets across the United States.

Martin received his B.A. in international relations from Dartmouth College and his Master of Business Administration degree with a concentration in finance from East Carolina University.

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 6.62 percent. This is the after-tax weighted average cost of capital from the 2016-2030 Upper Midwest Resource Plan.

The rates shown in Table 1 were calculated by taking a weighted average of Minnesota (85 percent) and Wisconsin (15 percent) information from the January 2014 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before tax Elec. WACC	After tax Elec. WACC
L-T Debt	45.24%	5.12%	2.33%	1.37%
Common Equity	52.56%	9.89%	5.24%	5.24%
S-T Debt	2.20%	0.64%	0.01%	0.01%
Total			7.58%	6.62%

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling. The inflation rates are developed using long-term forecasts from Global Insight. The labor and non-labor inflation rates are from the February 2016 Corporate Assumptions Memo. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015.

- Variable O&M inflation – 50% labor inflation and 50% non-labor inflation – 2.88%.
- Fixed O&M inflation – 75% labor inflation and 25% non-labor inflation – 3.07%.
- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.8 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.8\%) - 1 = 2.41\%.$$

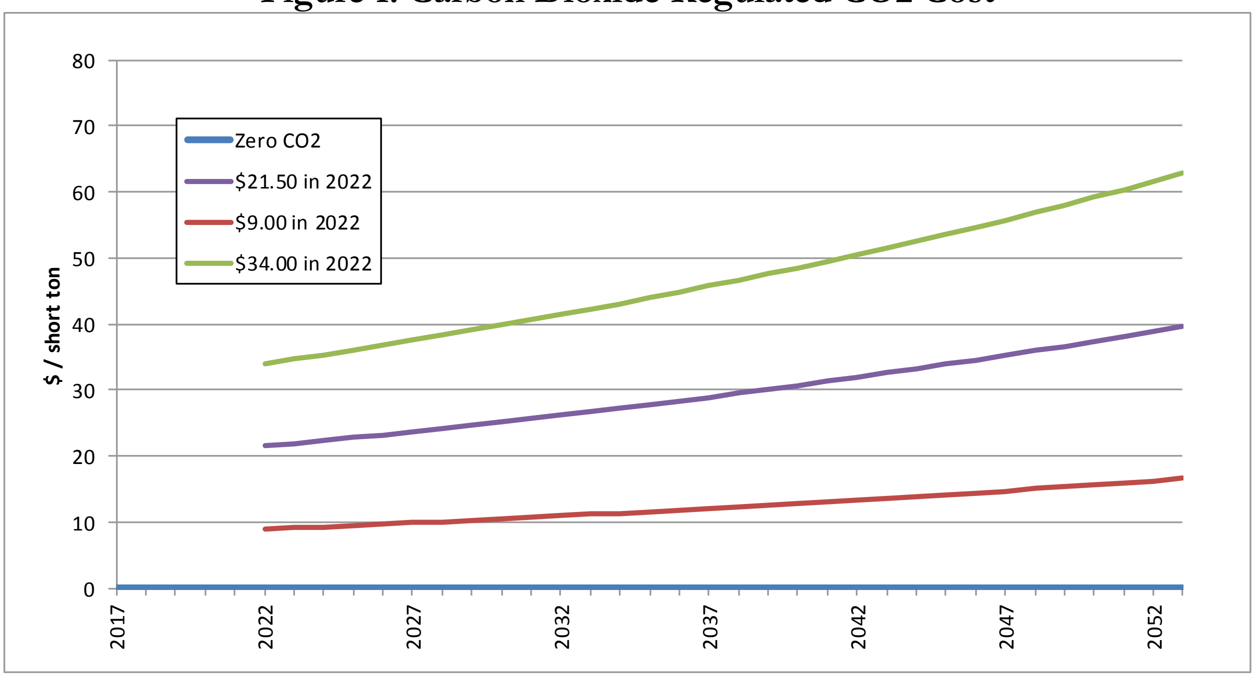
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.80%
Effective RM Based on Non-coincident Peak	2.41%

4. Regulated CO_2 Costs

Figure 1 shows the annual Regulated CO_2 Costs used in the analysis. The base assumption is $21.50 per short ton starting in 2022 which is the average of $9 per short ton and $34 per short ton. The range of Regulated CO_2 Costs is drawn from the Minnesota Public Utilities Commission's Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E999/CI-07-1199 issued August 5, 2016. All prices escalate at general inflation.

Figure 1: Carbon Dioxide Regulated CO2 Cost



5. Externality Costs

Externality Costs are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued June 16, 2016 (Docket Nos. E999/CI-93-583 and E999/CI-00-1636) and are shown in Table 3 below. Prices are shown in 2016 dollars and escalate at general inflation. Sulfur dioxide assumed zero cost due to a large surplus of allowances, a weak sales market, and zero externality cost per Commission policy.

Table 3: Externality Costs

MPUC Updated Externality Prices				
2016 $ per short ton				
	Urban	**Metro Fringe**	**Rural**	**<200mi**
NOx	$1,466	$399	$153	$153
PM10	$9,627	$4,326	$1,282	$1,282
CO	$3	$2	$1	$1
Pb	$5,808	$2,990	$671	$671

6. Demand and Energy Forecast

The Spring 2017 Load Forecast developed by the Xcel Energy Load Forecasting group is used.

Table 4: Spring 2017 Demand and Energy Forecast

Demand (MW)				Energy (GWh)			
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments	Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2017	10,435	9,293	9,202	2017	50,828	44,965	44,526
2018	10,485	9,401	9,221	2018	50,739	45,279	44,400
2019	10,559	9,535	9,263	2019	51,173	45,957	44,639
2020	10,646	9,652	9,309	2020	51,485	46,477	44,705
2021	10,726	9,773	9,358	2021	51,715	46,904	44,688
2022	10,815	9,931	9,444	2022	51,912	47,391	44,726
2023	10,911	10,004	9,314	2023	52,217	47,861	44,747
2024	11,013	10,169	9,392	2024	52,566	48,387	44,813
2025	11,123	10,330	9,466	2025	52,831	48,988	44,976
2026	11,239	10,504	9,553	2026	52,984	49,493	45,032
2027	11,343	10,710	9,672	2027	53,258	50,214	45,304
2028	11,445	10,879	9,754	2028	53,630	51,036	45,662
2029	11,558	10,993	9,781	2029	53,930	51,447	45,639
2030	11,673	11,152	9,853	2030	54,118	51,923	45,666
2031	11,779	11,280	10,008	2031	54,414	52,356	46,090
2032	11,883	11,391	10,146	2032	54,778	52,788	46,493
2033	12,005	11,530	10,312	2033	55,080	53,191	46,905
2034	12,127	11,653	10,435	2034	55,263	53,416	47,130
2035	12,234	11,751	10,534	2035	55,551	53,715	47,429
2036	12,335	11,858	10,640	2036	55,903	54,151	47,846
2037	12,450	11,949	10,732	2037	56,184	54,393	48,106
2038	12,570	12,045	10,828	2038	56,363	54,530	48,244
2039	12,679	12,129	10,911	2039	56,675	54,798	48,512
2040	12,784	12,206	10,989	2040	57,059	55,135	48,830
2041	12,900	12,293	11,075	2041	57,371	55,399	49,113
2042	13,020	12,381	11,164	2042	57,560	55,537	49,251
2043	13,124	12,451	11,234	2043	57,877	55,800	49,514
2044	13,237	12,530	11,313	2044	58,241	56,112	49,807
2045	13,326	12,586	11,368	2045	58,563	56,384	50,098
2046	13,438	12,664	11,447	2046	58,748	56,521	50,235
2047	13,540	12,733	11,515	2047	59,117	56,836	50,550
2048	13,644	12,803	11,585	2048	59,590	57,254	50,950
2049	13,748	12,873	11,655	2049	59,729	57,347	51,061
2050	13,851	12,943	11,726	2050	60,036	57,602	51,316
2051	13,955	13,013	11,796	2051	60,342	57,857	51,567
2052	14,059	13,083	11,866	2052	60,818	58,278	51,969
2053	14,163	13,153	11,936	2053	60,955	58,368	52,078

7. DSM Forecast

The DSM forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

Table 5: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2017	439	113
2018	879	227
2019	1,318	342
2020	1,772	429
2021	2,216	516
2022	2,665	603
2023	3,114	690
2024	3,573	777
2025	4,012	864
2026	4,461	951
2027	4,910	1,038
2028	5,375	1,125
2029	5,808	1,212
2030	6,257	1,299
2031	6,266	1,272
2032	6,294	1,245
2033	6,286	1,217
2034	6,286	1,217
2035	6,286	1,217
2036	6,305	1,217
2037	6,286	1,217
2038	6,286	1,217
2039	6,286	1,217
2040	6,305	1,217
2041	6,286	1,217
2042	6,286	1,217
2043	6,286	1,217
2044	6,305	1,217
2045	6,286	1,217
2046	6,286	1,217
2047	6,286	1,217
2048	6,305	1,217
2049	6,286	1,217
2050	6,286	1,217
2051	6,290	1,217
2052	6,308	1,217
2053	6,290	1,217

8. Demand Response Forecast

The 2017 Load Management Forecast developed by the Xcel Energy Load Research group is used. The table below shows the July demand.

Table 6: 2017 Load Management Forecast

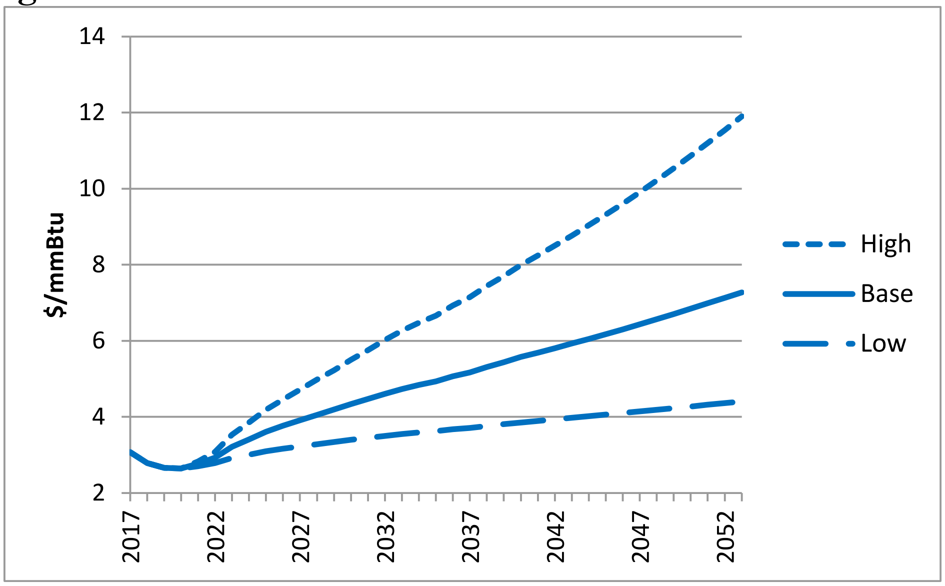
July Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024
LMF	853	864	880	896	911	926	933	940
July Demand (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
LMF	947	948	944	940	936	932	928	924
July Demand (MW)	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
LMF	920	916	913	909	905	901	898	894
July Demand (MW)	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
LMF	891	887	884	880	877	873	870	866
July Demand (MW)	**2049**	**2050**	**2051**	**2052**	**2053**			
LMF	863	860	856	853	849			

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 February 28, 2017 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 2021.

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 12 contains gas transportation charges for generic thermal resources.

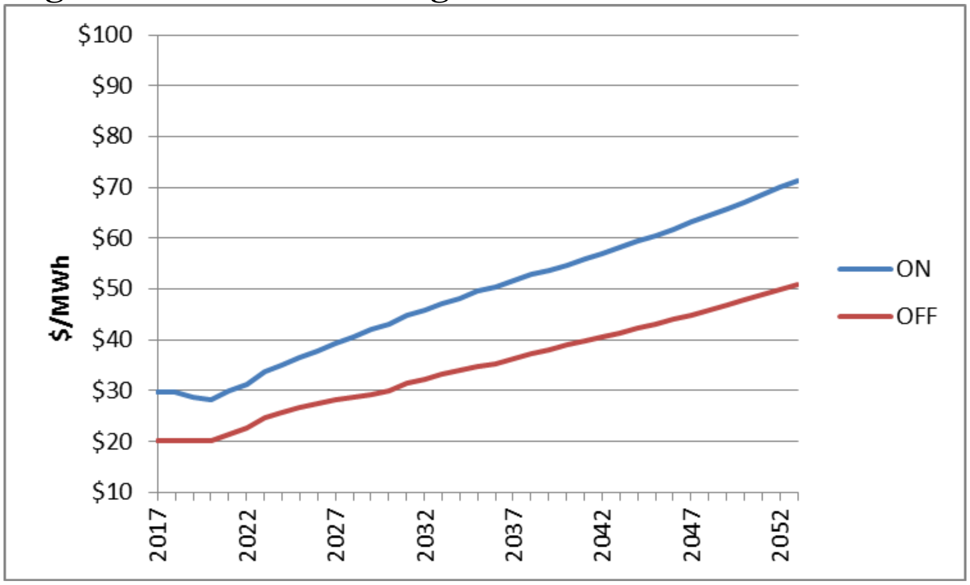
11. Natural Gas Demand Charges

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 12 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.

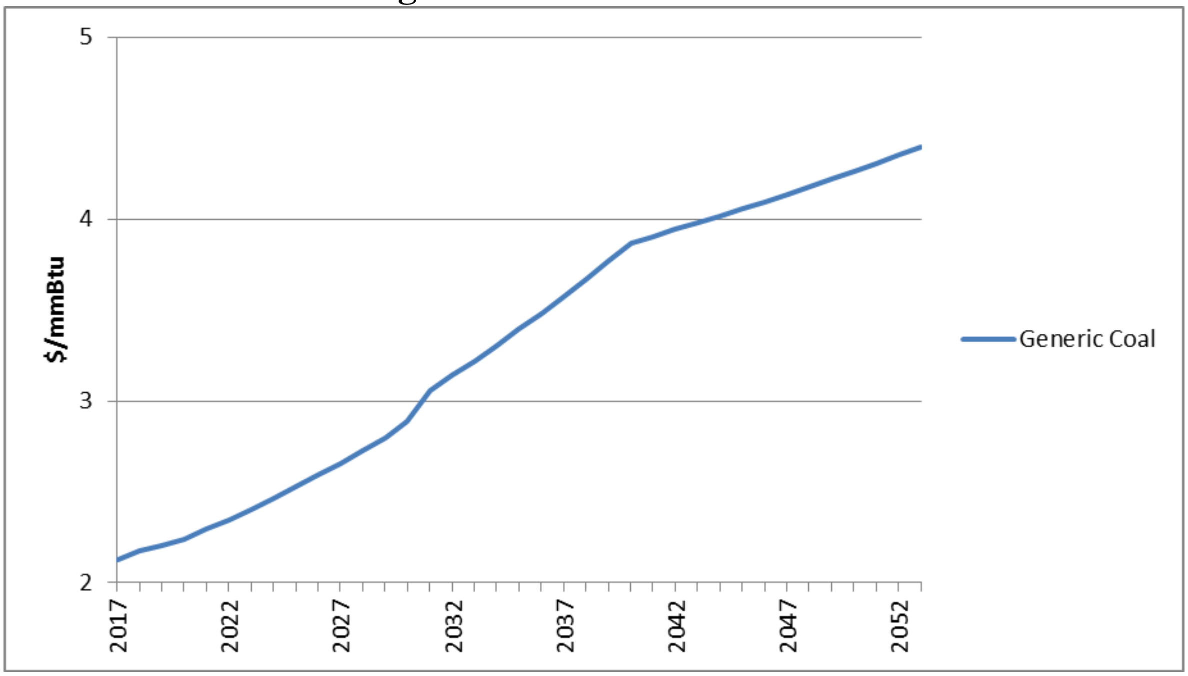
Figure 3: Minn Hub Average On and Off Peak Market Price



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 twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 7: Surplus Capacity Credit

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
$/kW-mo	4.84	4.94	5.03	5.14	5.24	5.34	5.45	5.56	5.67	5.78

	2027	2028	2029	2030	2031	2032	2033	2034	2035
$/kW-mo	5.90	6.02	6.14	6.26	6.39	6.51	6.64	6.78	6.91

	2036	2037	2038	2039	2040	2041	2042	2043	2044
$/kW-mo	7.05	7.19	7.33	7.48	7.63	7.78	7.94	8.10	8.26

	2045	2046	2047	2048	2049	2050	2051	2052	2053
$/kW-mo	8.43	8.59	8.77	8.94	9.12	9.30	9.49	9.68	9.87

15. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind and generic solar have assumed transmission delivery costs. The table 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 8: Transmission Delivery Costs

	$/kw
CC	$ 429
CT	$ 158
Solar	$ 70
Wind	$ 96

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. This value is the MISO proposed solar capacity credit for the 2016/2017 planning year.

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 94 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

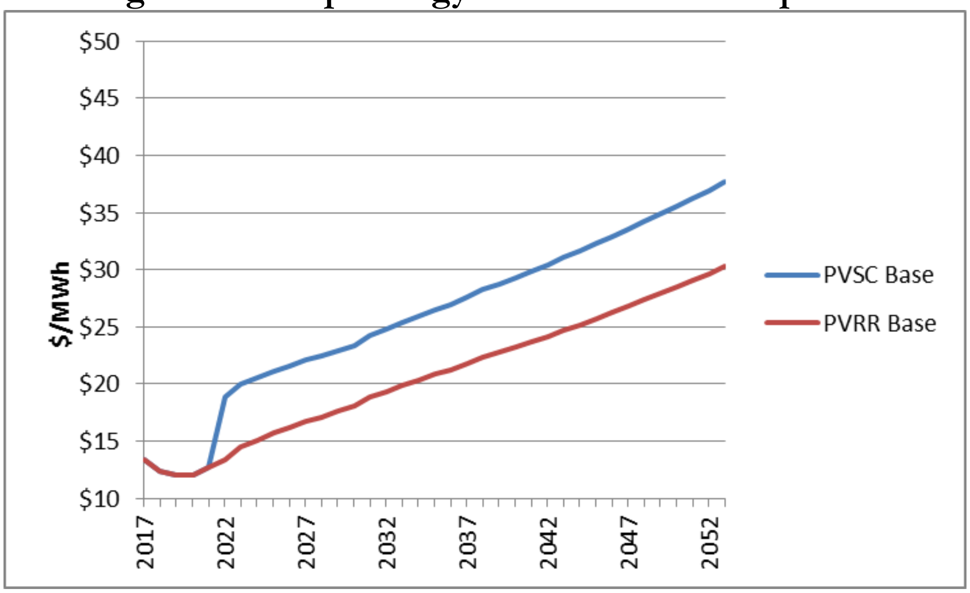
20. Emergency Energy Costs

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 in 2014 escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 mmBtu/MWh. Emergency energy occurs only in rare instances.

21. Dump Energy Credit

Dump energy occurs whenever generation cannot be reduced enough to balance with load, a situation that occurs when hourly modeled non-dispatchable renewable generation resources combined with minimum turn-down capabilities of must-run thermal units exceeds the Company's hourly load. Under base assumptions, it is assumed the dump energy can be sold into the MISO market for one-half of the all-hours average market price. The Dump Energy Credit is not used in sensitivities that model the Company's interactions with the MISO market on an hourly basis.

Figure 5: Dump Energy Credit Base Assumptions



22. 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

The complete Wind Integration Study is included in Appendix M of the 2015 Upper Midwest Resource Plan. The results of the study as used in Strategist are shown below. The Coal Cycling Costs are zero after 2040 because the last coal unit on the Company's system in the modeling retires in 2040.

Table 9: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2016	0.41	0.42	0.75	1.26
2017	0.42	0.43	0.77	1.28
2018	0.43	0.44	0.78	1.31
2019	0.44	0.45	0.80	1.33
2020	0.44	0.46	0.82	1.36
2021	0.45	0.46	0.83	1.39
2022	0.46	0.47	0.85	1.41
2023	0.47	0.48	0.87	1.44
2024	0.48	0.49	0.88	1.47
2025	0.49	0.50	0.90	1.50
2026	0.50	0.51	0.92	1.53
2027	0.51	0.52	0.94	1.56
2028	0.52	0.53	0.96	1.59
2029	0.53	0.54	0.98	1.62
2030	0.54	0.55	1.00	1.66
2031	0.55	0.56	1.01	1.69
2032	0.56	0.58	1.04	1.72
2033	0.58	0.59	1.06	1.76
2034	0.59	0.60	1.08	1.79
2035	0.60	0.61	1.10	1.83
2036	0.61	0.62	1.12	1.87
2037	0.62	0.63	1.14	1.90
2038	0.64	0.65	1.17	1.94
2039	0.65	0.66	1.19	1.98
2040	0.66	0.67	1.21	2.02
2041	0.67	0.69	-	-
2042	0.69	0.70	-	-
2043	0.70	0.71	-	-
2044	0.72	0.73	-	-
2045	0.73	0.74	-	-
2046	0.74	0.76	-	-
2047	0.76	0.77	-	-
2048	0.77	0.79	-	-
2049	0.79	0.80	-	-
2050	0.81	0.82	-	-
2051	0.82	0.83	-	-
2052	0.84	0.85	-	-
2053	0.86	0.87	-	-

23. Wind Congestion Costs

Wind Congestion Costs were developed by Xcel Energy Transmission Planning group from PROMOD LMP simulations for years 2020 and 2025 using the MTEP 16 database. Based on those simulations, we included congestion cost of $2.71 per MWh in 2020, escalating at 2% thereafter, for all new wind including the 1,550MW proposed wind portfolio.

Table 10: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2017	-	-
2018	-	-
2019	-	2.66
2020	-	2.71
2021	-	2.77
2022	-	2.82
2023	-	2.88
2024	-	2.93
2025	-	2.99
2026	-	3.05
2027	-	3.11
2028	-	3.18
2029	-	3.24
2030	-	3.31
2031	-	3.37
2032	-	3.44
2033	-	3.51
2034	-	3.58
2035	-	3.65
2036	-	3.72
2037	-	3.80
2038	-	3.87
2039	-	3.95
2040	-	4.03
2041	-	4.11
2042	-	4.19
2043	-	4.28
2044	-	4.36
2045	-	4.45
2046	-	4.54
2047	-	4.63
2048	-	4.72
2049	-	4.81
2050	-	4.91
2051	-	5.01
2052	-	5.11
2053	-	5.21

24. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

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 2014-2016 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 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 12-13 below show the assumptions for the generic thermal and renewable resources.

Table 12: Thermal Generic Information (Costs in 2016 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,758	5,487	963	1,212	626	1,572	4,731
Electric Transmission Delivery ($/kw)	NA	NA	429	NA	158	NA	NA
Gas Demand ($/kw-yr)	0	0	8.96	11.98	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,973	25,546	7,813	4,299	614	886	5,382
Variable O&M Cost ($/MWh)	2.92	11.00	3.20	1.82	2.36	1.88	4.88
Ongoing Capital Expenditures ($/kw-yr)	9.96	24.31	4.50	4.97	6.11	1.93	14.67
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 13: Renewable Generic ECC Costs - $/MWh

Year	PTC Wind	Non-PTC Wind	30% ITC Solar	10% ITC Solar
2019	14			
2020	14		44	
2021	14		45	
2022	15		45	
2023	15		46	
2024	15		47	
2025	16	31	48	56
2026	16	31	49	57
2027	16	32	50	58
2028	17	32	51	60
2029	17	33	52	61
2030	17	34	53	62
2031	18	34	54	63
2032	18	35	55	64
2033	18	36	56	66
2034	19	37	58	67
2035	19	37	59	68
2036	19	38	60	70
2037	20	39	61	71
2038	20	40	62	73
2039	21	40	64	74
2040	21	41	65	76
2041	21	42	66	77
2042	22	43	67	79
2043	22	44	69	80
2044		45	70	82
2045		45		83
2046		46		85
2047		47		87
2048		48		89
2049		49		90

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Xcel Energy

Docket No.:	PU-12-813, PU-13-194, PU-13-195, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743	Data Request No.	2-1
Response To:	North Dakota Public Service Commission Commission Advocacy Staff		
Requestor:	PA Consulting Group		
Date Received:	May 10, 2017		

Question:
Referencing the Company's 2016-2030 Resource Plan filing, Appendix J:
On Page 15 the Company discusses the "surplus capacity credit". Please explain the credit and how it was developed, and provide examples as to when and how it is applied.

Response:
In IRP proceedings, the issue of "how", "if", and "at what level" excess generation capacity should be valued is an appropriate subject of discussion. Some level of excess capacity above required reserve margins has economic value for several reasons as discussed below. Recognizing that reasonable minds can differ regarding the value of excess capacity, we have presented both a view valuing excess capacity and a view providing no value to excess capacity in the resource planning analysis presented in our December 31, 2016 Application in this Case and will continue to do so on an ongoing basis.

In the simplest case, having a surplus capacity margin in a future year results in excess capacity that could potentially be sold by the utility (predicated on finding a willing counterparty) and readily monetized. The quantity and price at which the parties could transact would depend on the then-current marketplace and the other alternatives available to the counterparty, but the excess capacity would certainly have intrinsic non-zero economic value, whether realized or not.

Having excess capacity in a given year also carries forward and can offset a requirement to procure capacity in a later year. As a numerical example, if a utility has a 100 MW surplus in a given year, and then experiences 75 MW of load growth the subsequent year, it would have had to procure that 75 MW if not for the carried forward surplus from the previous year. This deferral of capacity procurement also has non-zero economic value.

In a market-based approach to capacity valuation, there must always be a non-zero value for capacity for transactions to occur. To estimate what the expected "market value" would be, one must take a long-term view of what would result in overall stability of the market whereby all participants are adequately compensated for having sufficient capacity installed (or contracted) to meet their reliability objectives. At the point where the overall market requires new capacity installed (the system grows beyond the level of current installed capacity and load-side management opportunities), the market must provide enough revenue to support construction. In this case, the market price would be the annual carrying costs of lowest-cost new construction. Granted, a market will experience certain years of surplus and carryover where no incremental capacity is needed, but given that a system-wide capacity deficit is not an option due to regulatory and reliability concerns, the overall long-term market price must be at or above the cost of new entrants for sustainability.

Lastly, carrying excess capacity above the minimum requirements reduces shortage risk on the system. Assuming there is a real cost associated with failing to ensure reliability, any measure that reduces this risk must have some level of non-zero economic value proportionate to the risk mitigation it provides.

For all of the above scenarios, the expected value of surplus capacity converges to the cost to construct the lowest-cost new capacity resource. For the Company's resource planning analyses, the comparable value is the economic carrying cost (ECC) representation of the costs for a new large generic combustion turbine, which is the lowest cost capacity alternative modeled.

The remaining question is how much surplus capacity has economic value. In purely economic terms, essentially all capacity would have value, but for system planning and modeling purposes this must be tempered. In the case of the risk mitigation example, even though all capacity reduces risk somewhat, the first tier of excess provides the most mitigation, with each subsequent tier providing less mitigation. At some point, the amount of risk reduction provided converges asymptotically to zero. In the market-based approach, at some point when the overall market is satisfied, the value of the excess will also converge to zero.

For planning and modeling, one does not want to reward infinite levels of capacity and create portfolios that are much longer than would ever be realistically expected or deemed prudent. However, in addition to the economic reasons for recognizing the intrinsic value of excess capacity, providing credit for surplus to some level also leads to better modeling results by helping offset the "lumpiness" of the expansion plans due to the size differences of the resources offered.

A simple explanation is the comparison between combustion turbine and combined cycle units. Each alternative has a different relationship of construction costs vs. operating costs. The combustion turbine has lower construction costs (on a per-MW basis) but higher operating costs while the combined cycle is the opposite (higher construction costs and lower operating costs). Ideally we would want planning models to accurately determine the value of this tradeoff and select the resource options that match the system's needs, both for capacity and energy. If the system primarily needs capacity, select the CT; if the system has a significant energy need, select the CC.

However, the size difference of the alternatives complicates this analysis. The generic combined cycle plant is 778 MW while the combustion turbine is 230 MW (nameplate). Thus, if the capacity need in a given year is 200 MW, selecting the combined cycle plant will result in procuring much more capacity than the minimum required, and the model will be prejudiced against selecting it and incurring the carrying costs of the excess for several years. In the Company's resource planning analyses, with the capacity credit valued as the fixed costs of a CT, the combined cycle plant will still incur a penalty for the size difference, but the penalty is reduced to only the incremental cost difference (in $/MW) between combined cycle technology and combustion turbine technology, i.e. reflective of the technologies themselves, not simply the size difference. The result is a more accurate representation of what the system actually needs.

The Company has allowed up to 500 MW of surplus capacity above minimum needs to receive credit. This is close to the size differential between the generic CT and combined cycle, and is also a reasonable tradeoff between allowing zero and an infinite amount of surplus capacity to receive credit.

In each year that there is a surplus capacity position (above firm requirements plus reserves) the excess amount is credited at the surplus capacity credit value. This is incorporated into the optimization algorithm so that modestly long portfolios have a chance to compete and be considered for selection.

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Department:	Resource Planning
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Date:	May 24, 2017

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	51,900	42,680	2,790	2,673	2,762	2,806	2,926	3,169	3,203	3,214	3,302	3,301	3,405	3,470	3,526	3,450	3,728	3,640	3,785	3,859
Updated Plan	50,251	41,307	2,811	2,717	2,840	2,866	2,980	3,144	3,092	3,068	3,064	3,067	3,210	3,219	3,283	3,354	3,480	3,466	3,590	3,684
Updated Plan with Legacy Purchase/Sale and Jur Future	50,396	41,333	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,037	3,039	3,193	3,209	3,275	3,357	3,511	3,456	3,588	3,694
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	50,458	41,394	2,819	2,725	2,849	2,873	2,986	3,149	3,091	3,066	3,043	3,043	3,196	3,212	3,277	3,359	3,512	3,457	3,589	3,695
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	50,449	41,385	2,811	2,717	2,840	2,866	2,980	3,144	3,093	3,069	3,047	3,050	3,205	3,222	3,288	3,360	3,511	3,456	3,588	3,695
ND separation 2023	50,322	41,317	2,811	2,717	2,842	2,865	2,978	3,141	3,131	3,101	3,048	3,044	3,190	3,198	3,265	3,352	3,503	3,447	3,576	3,675
ND separation 2025, CT	50,264	41,259	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,048	3,044	3,190	3,198	3,265	3,352	3,503	3,447	3,576	3,675
ND separation 2025, CC	50,264	41,259	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,048	3,044	3,190	3,198	3,265	3,352	3,503	3,447	3,576	3,675
ND separation 2025, CT, no nuclear	50,335	41,330	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,068	3,069	3,205	3,212	3,278	3,372	3,516	3,452	3,582	3,684
ND separation 2025, CC, no nuclear	50,335	41,330	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,068	3,069	3,205	3,212	3,278	3,372	3,516	3,452	3,582	3,684
ND separation 2027	50,256	41,252	2,811	2,717	2,842	2,865	2,978	3,141	3,085	3,060	3,037	3,039	3,192	3,198	3,265	3,352	3,503	3,447	3,576	3,675

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	1,649	1,373	(21)	(43)	(78)	(59)	(54)	25	111	147	238	234	195	250	243	96	248	173	195	175
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	145	26	0	0	1	(1)	(2)	(3)	(7)	(8)	(27)	(28)	(17)	(10)	(8)	3	32	(11)	(2)	10
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	207	87	8	8	9	7	6	5	(1)	(2)	(21)	(24)	(14)	(7)	(6)	5	33	(10)	(1)	11
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	198	77	(0)	0	0	0	(0)	1	1	1	(17)	(17)	(5)	3	5	6	31	(10)	(1)	11
ND separation 2023	71	10	0	0	1	(1)	(2)	(3)	39	33	(17)	(23)	(21)	(21)	(18)	(2)	23	(19)	(14)	(9)
ND separation 2025, CT	13	(48)	0	0	1	(1)	(2)	(3)	(7)	(8)	(17)	(23)	(21)	(21)	(18)	(2)	23	(19)	(14)	(9)
ND separation 2025, CC	13	(48)	0	0	1	(1)	(2)	(3)	(7)	(8)	(17)	(23)	(21)	(21)	(18)	(2)	23	(19)	(14)	(9)
ND separation 2025, CT, no nuclear	84	22	0	0	1	(1)	(2)	(3)	(7)	(8)	4	2	(5)	(7)	(5)	18	37	(14)	(7)	0
ND separation 2025, CC, no nuclear	84	22	0	0	1	(1)	(2)	(3)	(7)	(8)	4	2	(5)	(7)	(5)	18	37	(14)	(7)	0
ND separation 2027	5	(56)	0	0	1	(1)	(2)	(3)	(7)	(8)	(27)	(28)	(18)	(21)	(18)	(2)	23	(19)	(14)	(9)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,862	2,346	153	145	148	149	156	174	177	178	183	183	189	192	196	191	206	201	209	213
Updated Plan	2,756	2,256	155	146	151	151	157	172	169	169	168	169	177	178	182	186	192	191	198	203
Updated Plan with Legacy Purchase/Sale and Jur Future	2,649	2,211	154	146	150	152	159	174	176	177	174	173	171	170	173	167	183	180	186	184
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,597	2,162	147	138	142	144	151	167	170	171	168	169	168	167	171	183	184	178	184	183
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,597	2,160	155	146	151	151	157	171	168	168	164	161	158	157	160	164	184	180	185	183
ND separation 2023	2,319	1,963	154	146	150	152	159	174	136	143	146	145	147	147	149	140	155	159	162	159
ND separation 2025, CT	2,385	2,027	154	146	150	152	159	174	176	177	144	149	150	150	152	143	158	161	165	162
ND separation 2025, CC	2,498	2,165	154	146	150	152	159	174	176	177	177	188	188	186	188	178	173	173	175	172
ND separation 2025, CT, no nuclear	2,325	1,972	154	146	150	152	159	174	176	177	132	142	144	145	147	140	143	145	146	148
ND separation 2025, CC, no nuclear	2,398	2,066	154	146	150	152	159	174	176	177	148	161	162	163	164	157	159	160	161	162
ND separation 2027	2,454	2,096	154	146	150	152	159	174	176	177	174	173	164	173	174	164	161	161	164	161

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	106	90	(1)	(1)	(3)	(2)	(2)	3	8	10	15	14	12	15	14	5	14	10	11	10
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(107)	(45)	(0)	(0)	(1)	1	2	3	7	8	6	4	(6)	(8)	(9)	(18)	(9)	(11)	(12)	(19)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(160)	(95)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	(0)	(9)	(10)	(11)	(2)	(8)	(13)	(14)	(20)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(160)	(96)	0	(0)	(0)	(0)	0	(1)	(1)	(1)	(5)	(7)	(19)	(21)	(21)	(21)	(9)	(11)	(13)	(20)
ND separation 2023	(437)	(293)	(0)	(0)	(1)	1	2	3	(33)	(25)	(22)	(23)	(30)	(31)	(33)	(46)	(37)	(33)	(36)	(44)
ND separation 2025, CT	(371)	(230)	(0)	(0)	(1)	1	2	3	7	8	(24)	(20)	(27)	(28)	(30)	(43)	(34)	(30)	(33)	(41)
ND separation 2025, CC	(259)	(91)	(0)	(0)	(1)	1	2	3	7	8	9	19	11	9	6	(8)	(19)	(19)	(23)	(31)
ND separation 2025, CT, no nuclear	(431)	(284)	(0)	(0)	(1)	1	2	3	7	8	(36)	(26)	(33)	(32)	(35)	(46)	(50)	(47)	(51)	(55)
ND separation 2025, CC, no nuclear	(358)	(190)	(0)	(0)	(1)	1	2	3	7	8	(21)	(8)	(15)	(14)	(18)	(28)	(34)	(31)	(37)	(41)
ND separation 2027	(302)	(160)	(0)	(0)	(1)	1	2	3	7	8	6	4	(13)	(5)	(7)	(21)	(31)	(31)	(34)	(42)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
4,022	4,143	4,201	4,222	4,343	4,443	4,502	4,643	4,742	4,864	4,973	5,172	5,298	5,528	5,682	5,788	5,918	6,089	6,223
3,787	3,906	3,962	3,973	4,078	4,191	4,232	4,343	4,451	4,566	4,901	5,054	5,167	5,386	5,590	5,719	5,853	6,020	6,181
3,807	3,929	4,006	4,028	4,139	4,235	4,281	4,395	4,482	4,617	4,968	5,126	5,240	5,471	5,686	5,798	5,948	6,097	6,270
3,807	3,930	4,007	4,029	4,139	4,236	4,281	4,395	4,482	4,617	4,968	5,126	5,240	5,471	5,686	5,798	5,948	6,097	6,270
3,808	3,931	4,008	4,030	4,141	4,238	4,284	4,398	4,486	4,620	4,968	5,125	5,240	5,470	5,685	5,797	5,947	6,096	6,269
3,790	3,910	3,983	3,997	4,102	4,203	4,236	4,369	4,462	4,580	4,856	5,092	5,226	5,456	5,667	5,774	5,923	6,076	6,224
3,790	3,910	3,983	3,997	4,102	4,203	4,236	4,369	4,462	4,580	4,856	5,092	5,226	5,456	5,667	5,774	5,923	6,076	6,224
3,790	3,910	3,983	3,997	4,102	4,203	4,236	4,369	4,462	4,580	4,856	5,092	5,226	5,456	5,667	5,774	5,923	6,076	6,224
3,792	3,912	3,985	3,998	4,103	4,204	4,237	4,370	4,463	4,581	4,856	5,092	5,226	5,456	5,668	5,774	5,923	6,076	6,224
3,792	3,912	3,985	3,998	4,103	4,204	4,237	4,370	4,463	4,581	4,856	5,092	5,226	5,456	5,668	5,774	5,923	6,076	6,224
3,790	3,910	3,983	3,997	4,102	4,203	4,236	4,369	4,462	4,580	4,856	5,092	5,226	5,456	5,667	5,774	5,923	6,076	6,224

235	237	239	249	265	252	271	300	291	298	72	117	131	141	93	69	65	70	42
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	23	44	55	61	44	49	52	31	51	67	71	73	85	96	79	95	77	89
20	24	45	56	61	45	50	52	31	51	67	71	73	85	96	79	95	77	89
21	24	46	57	63	47	52	55	35	54	67	70	72	84	96	79	94	77	88
3	4	21	24	24	13	4	26	11	14	(45)	37	58	70	78	56	69	56	43
3	4	21	24	24	13	4	26	11	14	(45)	37	58	70	78	56	69	56	43
3	4	21	24	24	13	4	26	11	14	(45)	37	58	70	78	56	69	56	43
5	5	23	25	25	14	5	27	12	15	(45)	37	58	70	78	56	70	56	43
5	5	23	25	25	14	5	27	12	15	(45)	37	58	70	78	56	70	56	43
3	4	21	24	24	13	4	26	11	14	(45)	37	58	70	78	56	69	56	43

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
222	229	233	235	242	248	251	259	265	272	278	290	297	310	319	325	332	342	349
209	215	219	220	225	232	234	240	246	253	272	281	289	303	315	323	330	340	349
201	207	209	202	204	207	223	230	232	235	241	245	250	254	253	255	287	297	301
199	205	208	201	202	227	225	227	230	233	239	243	249	252	251	253	286	295	299
200	206	208	200	201	204	220	226	228	232	241	245	251	254	253	255	288	297	301
153	154	157	159	161	164	188	194	196	198	199	202	204	208	210	213	216	220	216
156	157	160	162	163	165	190	195	197	199	201	203	206	209	211	214	218	221	224
164	166	168	169	170	173	175	177	180	183	185	188	191	195	198	201	205	209	213
150	151	154	156	157	159	184	191	193	195	198	200	203	207	209	212	215	219	222
163	165	166	168	169	171	174	176	179	182	185	188	191	195	198	201	205	209	212
156	157	159	162	163	165	189	194	196	198	200	203	205	209	211	214	217	221	224

14	14	14	15	17	16	17	19	19	19	6	8	8	7	4	2	2	2	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(7)	(8)	(10)	(17)	(22)	(25)	(11)	(11)	(15)	(18)	(31)	(37)	(39)	(49)	(62)	(68)	(43)	(43)	(49)
(9)	(10)	(11)	(19)	(23)	(5)	(9)	(13)	(17)	(20)	(33)	(38)	(40)	(51)	(64)	(70)	(45)	(45)	(50)
(9)	(10)	(11)	(19)	(24)	(28)	(14)	(14)	(18)	(22)	(32)	(36)	(38)	(49)	(62)	(68)	(43)	(43)	(48)
(55)	(61)	(62)	(60)	(65)	(68)	(46)	(46)	(51)	(55)	(73)	(80)	(84)	(95)	(105)	(109)	(114)	(120)	(133)
(53)	(58)	(59)	(58)	(62)	(67)	(44)	(45)	(49)	(54)	(72)	(79)	(83)	(94)	(104)	(108)	(113)	(119)	(125)
(44)	(49)	(51)	(50)	(55)	(59)	(59)	(63)	(67)	(70)	(87)	(93)	(97)	(108)	(117)	(121)	(125)	(131)	(137)
(59)	(64)	(65)	(63)	(68)	(72)	(49)	(50)	(54)	(58)	(74)	(81)	(85)	(96)	(106)	(111)	(115)	(121)	(127)
(46)	(51)	(53)	(52)	(56)	(61)	(60)	(64)	(68)	(71)	(87)	(94)	(98)	(108)	(117)	(121)	(126)	(131)	(137)
(53)	(58)	(60)	(58)	(63)	(67)	(45)	(46)	(51)	(55)	(72)	(79)	(83)	(94)	(104)	(108)	(113)	(119)	(125)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	45,664	37,853	2,690	2,582	2,664	2,705	2,820	2,783	2,789	2,797	2,835	2,820	2,909	2,969	3,005	2,897	3,243	3,165	3,243	3,247
Updated Plan	45,406	37,725	2,712	2,625	2,743	2,771	2,881	2,833	2,760	2,778	2,731	2,729	2,936	2,958	3,030	3,070	3,124	3,112	3,163	3,203
Updated Plan with Legacy Purchase/Sale and Jur Future	45,503	37,719	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,702	2,699	2,919	2,941	3,015	3,065	3,163	3,098	3,154	3,205
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	45,565	37,780	2,719	2,633	2,752	2,778	2,887	2,838	2,760	2,776	2,708	2,703	2,922	2,943	3,017	3,067	3,164	3,099	3,155	3,206
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	45,556	37,770	2,712	2,625	2,743	2,771	2,881	2,834	2,761	2,779	2,712	2,711	2,931	2,953	3,028	3,069	3,162	3,099	3,155	3,205
ND separation 2023	45,588	37,844	2,712	2,625	2,744	2,770	2,879	2,831	2,816	2,827	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CT	45,509	37,765	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CC	45,509	37,765	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CT, no nuclear	45,577	37,832	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,749	2,746	2,952	2,965	3,040	3,101	3,191	3,118	3,170	3,212
ND separation 2025, CC, no nuclear	45,577	37,832	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,749	2,746	2,952	2,965	3,040	3,101	3,191	3,118	3,170	3,212
ND separation 2027	45,481	37,737	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,702	2,699	2,940	2,951	3,028	3,083	3,178	3,113	3,163	3,203

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	258	129	(21)	(44)	(79)	(66)	(61)	(50)	28	19	104	91	(27)	11	(26)	(173)	119	52	79	44
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	98	(5)	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	(17)	(17)	(15)	(4)	39	(14)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	159	56	8	8	9	7	6	5	(1)	(2)	(23)	(26)	(14)	(15)	(13)	(3)	40	(13)	(8)	3
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	150	45	0	0	0	0	(0)	1	1	1	(19)	(18)	(5)	(4)	(2)	(1)	39	(14)	(9)	2
ND separation 2023	183	120	0	0	1	(1)	(2)	(3)	55	50	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CT	103	40	0	0	1	(1)	(2)	(3)	(7)	(8)	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CC	103	40	0	0	1	(1)	(2)	(3)	(7)	(8)	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CT, no nuclear	171	108	0	0	1	(1)	(2)	(3)	(7)	(8)	18	17	15	7	10	31	67	5	6	8
ND separation 2025, CC, no nuclear	171	108	0	0	1	(1)	(2)	(3)	(7)	(8)	18	17	15	7	10	31	67	5	6	8
ND separation 2027	75	13	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	4	(6)	(2)	13	54	1	(0)	(0)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,500	2,064	148	139	143	143	149	152	152	154	156	155	160	163	165	158	178	173	177	177
Updated Plan	2,474	2,047	149	140	145	146	152	153	150	152	149	149	161	162	167	169	172	171	173	175
Updated Plan with Legacy Purchase/Sale and Jur Future	2,364	1,999	149	140	144	146	153	156	157	159	154	153	155	154	158	150	163	159	160	155
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,312	1,950	141	132	136	139	146	148	150	153	149	149	152	151	156	166	164	157	158	154
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,312	1,949	149	140	145	146	152	153	149	150	144	141	142	141	145	147	163	159	160	155
ND separation 2023	2,276	1,920	149	140	144	146	153	156	136	143	146	144	146	146	148	139	155	158	161	158
ND separation 2025, CT	2,319	1,960	149	140	144	146	153	156	157	159	143	148	149	149	151	142	158	161	164	161
ND separation 2025, CC	2,432	2,099	149	140	144	146	153	156	157	159	176	187	187	186	187	177	172	172	175	171
ND separation 2025, CT, no nuclear	2,262	1,909	149	140	144	146	153	156	157	159	132	142	144	145	147	140	143	145	146	148
ND separation 2025, CC, no nuclear	2,335	2,003	149	140	144	146	153	156	157	159	148	161	162	163	164	157	159	160	161	162
ND separation 2027	2,366	2,008	149	140	144	146	153	156	157	159	154	153	163	172	173	163	160	160	164	161

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	26	17	(1)	(1)	(3)	(2)	(2)	(2)	3	2	7	6	(1)	1	(2)	(11)	6	3	4	2
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(110)	(48)	(0)	(0)	(1)	1	2	3	7	8	6	4	(7)	(9)	(9)	(19)	(9)	(12)	(13)	(20)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(162)	(97)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(9)	(11)	(11)	(3)	(8)	(14)	(15)	(21)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(162)	(98)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(19)	(21)	(22)	(22)	(8)	(12)	(13)	(20)
ND separation 2023	(198)	(127)	(0)	(0)	(1)	1	2	3	(14)	(9)	(3)	(4)	(15)	(17)	(19)	(30)	(17)	(13)	(12)	(17)
ND separation 2025, CT	(155)	(87)	(0)	(0)	(1)	1	2	3	7	8	(6)	(1)	(12)	(14)	(16)	(27)	(14)	(10)	(9)	(14)
ND separation 2025, CC	(42)	52	(0)	(0)	(1)	1	2	3	7	8	28	38	26	23	20	8	1	1	2	(4)
ND separation 2025, CT, no nuclear	(212)	(138)	(0)	(0)	(1)	1	2	3	7	8	(17)	(7)	(17)	(17)	(20)	(29)	(29)	(26)	(27)	(27)
ND separation 2025, CC, no nuclear	(139)	(44)	(0)	(0)	(1)	1	2	3	7	8	(1)	12	1	1	(3)	(12)	(13)	(10)	(12)	(13)
ND separation 2027	(109)	(39)	(0)	(0)	(1)	1	2	3	7	8	6	4	2	9	6	(6)	(11)	(11)	(10)	(14)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,377	3,458	3,493	3,567	3,673	3,738	3,838	3,948	4,028	4,130	4,216	4,364	4,470	4,692	4,819	4,899	5,006	5,150	5,255
3,255	3,334	3,372	3,440	3,528	3,607	3,695	3,779	3,870	3,964	4,214	4,329	4,407	4,603	4,785	4,889	4,996	5,138	5,246
3,266	3,350	3,408	3,487	3,580	3,642	3,734	3,822	3,892	4,006	4,272	4,391	4,469	4,675	4,868	4,955	5,081	5,207	5,336
3,267	3,351	3,408	3,488	3,581	3,643	3,734	3,822	3,892	4,006	4,272	4,391	4,469	4,675	4,868	4,955	5,081	5,207	5,336
3,267	3,351	3,409	3,489	3,582	3,645	3,737	3,825	3,896	4,009	4,272	4,391	4,469	4,675	4,867	4,954	5,081	5,207	5,336
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,265	3,342	3,397	3,471	3,561	3,626	3,708	3,813	3,889	3,985	4,154	4,363	4,463	4,670	4,861	4,945	5,071	5,197	5,302
3,265	3,342	3,397	3,471	3,561	3,626	3,708	3,813	3,889	3,985	4,154	4,363	4,463	4,670	4,861	4,945	5,071	5,197	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302

121	123	121	126	145	131	143	170	158	166	2	34	63	88	34	10	10	12	9
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	15	36	47	52	36	39	43	22	42	58	62	63	72	83	66	86	69	91
12	16	36	48	53	37	40	44	22	42	58	62	63	72	83	66	86	69	91
12	17	37	49	55	38	42	46	26	45	58	61	62	71	83	65	85	69	90
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
10	8	25	30	33	19	13	34	19	21	(60)	34	56	66	76	56	75	59	56
10	8	25	30	33	19	13	34	19	21	(60)	34	56	66	76	56	75	59	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
185	190	193	197	204	208	213	220	224	230	235	244	250	263	270	274	280	289	294
178	182	185	189	194	198	203	208	213	218	232	239	245	257	269	275	281	289	295
169	173	174	171	171	172	192	197	198	200	201	203	206	208	206	207	238	246	247
168	171	173	169	170	193	193	194	196	198	199	201	204	207	205	205	236	245	246
168	172	173	169	169	170	189	194	194	197	201	203	206	208	207	207	238	247	248
153	154	157	159	161	164	188	194	196	198	199	202	204	208	210	213	216	220	216
156	157	160	162	163	165	190	195	197	199	201	203	206	209	211	214	218	221	224
164	166	168	169	170	173	175	177	180	183	185	188	191	195	198	201	205	209	213
150	151	154	156	157	159	184	191	193	195	198	200	203	207	209	212	215	219	222
163	165	166	168	169	171	174	176	179	182	185	188	191	195	198	201	205	209	212
155	157	159	162	163	165	189	194	196	198	200	203	205	209	211	214	217	221	224

7	8	8	8	10	10	10	12	11	12	3	4	5	5	1	(1)	(1)	(1)	(1)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(8)	(9)	(11)	(18)	(22)	(26)	(11)	(11)	(15)	(19)	(32)	(37)	(39)	(50)	(62)	(68)	(43)	(43)	(48)
(10)	(11)	(12)	(19)	(24)	(5)	(10)	(13)	(17)	(21)	(34)	(38)	(40)	(51)	(64)	(70)	(45)	(45)	(50)
(9)	(10)	(12)	(20)	(25)	(28)	(14)	(14)	(18)	(22)	(32)	(36)	(38)	(49)	(62)	(68)	(43)	(43)	(48)
(25)	(28)	(28)	(29)	(33)	(35)	(15)	(14)	(17)	(21)	(33)	(38)	(40)	(50)	(59)	(62)	(65)	(69)	(79)
(22)	(25)	(25)	(27)	(31)	(33)	(13)	(12)	(16)	(19)	(32)	(37)	(39)	(49)	(57)	(61)	(63)	(68)	(71)
(13)	(16)	(17)	(20)	(23)	(26)	(28)	(31)	(33)	(36)	(47)	(51)	(53)	(62)	(71)	(73)	(76)	(80)	(83)
(28)	(31)	(31)	(33)	(37)	(39)	(19)	(17)	(20)	(23)	(35)	(39)	(41)	(51)	(60)	(63)	(66)	(70)	(73)
(15)	(17)	(18)	(21)	(25)	(27)	(29)	(32)	(34)	(36)	(48)	(51)	(53)	(63)	(71)	(74)	(76)	(80)	(83)
(22)	(25)	(25)	(27)	(31)	(33)	(14)	(14)	(17)	(20)	(32)	(37)	(39)	(49)	(58)	(61)	(64)	(68)	(71)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	45,664	37,853	2,690	2,582	2,664	2,705	2,820	2,783	2,789	2,797	2,835	2,820	2,909	2,969	3,005	2,897	3,243	3,165	3,243	3,247
Updated Plan	45,406	37,725	2,712	2,625	2,743	2,771	2,881	2,833	2,760	2,778	2,731	2,729	2,936	2,958	3,030	3,070	3,124	3,112	3,163	3,203
Updated Plan with Legacy Purchase/Sale and Jur Future	45,503	37,719	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,702	2,699	2,919	2,941	3,015	3,065	3,163	3,098	3,154	3,205
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	45,565	37,780	2,719	2,633	2,752	2,778	2,887	2,838	2,760	2,776	2,708	2,703	2,922	2,943	3,017	3,067	3,164	3,099	3,155	3,206
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	45,556	37,770	2,712	2,625	2,743	2,771	2,881	2,834	2,761	2,779	2,712	2,711	2,931	2,953	3,028	3,069	3,162	3,099	3,155	3,205
ND separation 2023	45,588	37,844	2,712	2,625	2,744	2,770	2,879	2,831	2,816	2,827	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CT	45,509	37,765	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CC	45,509	37,765	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,730	2,722	2,937	2,951	3,028	3,083	3,178	3,113	3,163	3,203
ND separation 2025, CT, no nuclear	45,577	37,832	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,749	2,746	2,952	2,965	3,040	3,101	3,191	3,118	3,170	3,212
ND separation 2025, CC, no nuclear	45,577	37,832	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,749	2,746	2,952	2,965	3,040	3,101	3,191	3,118	3,170	3,212
ND separation 2027	45,481	37,737	2,712	2,625	2,744	2,770	2,879	2,831	2,753	2,770	2,702	2,699	2,940	2,951	3,028	3,083	3,178	3,113	3,163	3,203

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	258	129	(21)	(44)	(79)	(66)	(61)	(50)	28	19	104	91	(27)	11	(26)	(173)	119	52	79	44
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	98	(5)	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	(17)	(17)	(15)	(4)	39	(14)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	159	56	8	8	9	7	6	5	(1)	(2)	(23)	(26)	(14)	(15)	(13)	(3)	40	(13)	(8)	3
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	150	45	0	0	0	0	(0)	1	1	1	(19)	(18)	(5)	(4)	(2)	(1)	39	(14)	(9)	2
ND separation 2023	183	120	0	0	1	(1)	(2)	(3)	55	50	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CT	103	40	0	0	1	(1)	(2)	(3)	(7)	(8)	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CC	103	40	0	0	1	(1)	(2)	(3)	(7)	(8)	(1)	(7)	1	(6)	(2)	13	54	1	(0)	(0)
ND separation 2025, CT, no nuclear	171	108	0	0	1	(1)	(2)	(3)	(7)	(8)	18	17	15	7	10	31	67	5	6	8
ND separation 2025, CC, no nuclear	171	108	0	0	1	(1)	(2)	(3)	(7)	(8)	18	17	15	7	10	31	67	5	6	8
ND separation 2027	75	13	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	4	(6)	(2)	13	54	1	(0)	(0)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,500	2,064	148	139	143	143	149	152	152	154	156	155	160	163	165	158	178	173	177	177
Updated Plan	2,474	2,047	149	140	145	146	152	153	150	152	149	149	161	162	167	169	172	171	173	175
Updated Plan with Legacy Purchase/Sale and Jur Future	2,364	1,999	149	140	144	146	153	156	157	159	154	153	155	154	158	150	163	159	160	155
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,312	1,950	141	132	136	139	146	148	150	153	149	149	152	151	156	166	164	157	158	154
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,312	1,949	149	140	145	146	152	153	149	150	144	141	142	141	145	147	163	159	160	155
ND separation 2023	2,276	1,920	149	140	144	146	153	156	136	143	146	144	146	146	148	139	155	158	161	158
ND separation 2025, CT	2,319	1,960	149	140	144	146	153	156	157	159	143	148	149	149	151	142	158	161	164	161
ND separation 2025, CC	2,432	2,099	149	140	144	146	153	156	157	159	176	187	187	186	187	177	172	172	175	171
ND separation 2025, CT, no nuclear	2,262	1,909	149	140	144	146	153	156	157	159	132	142	144	145	147	140	143	145	146	148
ND separation 2025, CC, no nuclear	2,335	2,003	149	140	144	146	153	156	157	159	148	161	162	163	164	157	159	160	161	162
ND separation 2027	2,366	2,008	149	140	144	146	153	156	157	159	154	153	163	172	173	163	160	160	164	161

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	26	17	(1)	(1)	(3)	(2)	(2)	(2)	3	2	7	6	(1)	1	(2)	(11)	6	3	4	2
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(110)	(48)	(0)	(0)	(1)	1	2	3	7	8	6	4	(7)	(9)	(9)	(19)	(9)	(12)	(13)	(20)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(162)	(97)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(9)	(11)	(11)	(3)	(8)	(14)	(15)	(21)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(162)	(98)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(19)	(21)	(22)	(22)	(8)	(12)	(13)	(20)
ND separation 2023	(198)	(127)	(0)	(0)	(1)	1	2	3	(14)	(9)	(3)	(4)	(15)	(17)	(19)	(30)	(17)	(13)	(12)	(17)
ND separation 2025, CT	(155)	(87)	(0)	(0)	(1)	1	2	3	7	8	(6)	(1)	(12)	(14)	(16)	(27)	(14)	(10)	(9)	(14)
ND separation 2025, CC	(42)	52	(0)	(0)	(1)	1	2	3	7	8	28	38	26	23	20	8	1	1	2	(4)
ND separation 2025, CT, no nuclear	(212)	(138)	(0)	(0)	(1)	1	2	3	7	8	(17)	(7)	(17)	(17)	(20)	(29)	(29)	(26)	(27)	(27)
ND separation 2025, CC, no nuclear	(139)	(44)	(0)	(0)	(1)	1	2	3	7	8	(1)	12	1	1	(3)	(12)	(13)	(10)	(12)	(13)
ND separation 2027	(109)	(39)	(0)	(0)	(1)	1	2	3	7	8	6	4	2	9	6	(6)	(11)	(11)	(10)	(14)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,377	3,458	3,493	3,567	3,673	3,738	3,838	3,948	4,028	4,130	4,216	4,364	4,470	4,692	4,819	4,899	5,006	5,150	5,255
3,255	3,334	3,372	3,440	3,528	3,607	3,695	3,779	3,870	3,964	4,214	4,329	4,407	4,603	4,785	4,889	4,996	5,138	5,246
3,266	3,350	3,408	3,487	3,580	3,642	3,734	3,822	3,892	4,006	4,272	4,391	4,469	4,675	4,868	4,955	5,081	5,207	5,336
3,267	3,351	3,408	3,488	3,581	3,643	3,734	3,822	3,892	4,006	4,272	4,391	4,469	4,675	4,868	4,955	5,081	5,207	5,336
3,267	3,351	3,409	3,489	3,582	3,645	3,737	3,825	3,896	4,009	4,272	4,391	4,469	4,675	4,867	4,954	5,081	5,207	5,336
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302
3,265	3,342	3,397	3,471	3,561	3,626	3,708	3,813	3,889	3,985	4,154	4,363	4,463	4,670	4,861	4,945	5,071	5,197	5,302
3,265	3,342	3,397	3,471	3,561	3,626	3,708	3,813	3,889	3,985	4,154	4,363	4,463	4,670	4,861	4,945	5,071	5,197	5,302
3,264	3,341	3,396	3,469	3,560	3,625	3,707	3,812	3,888	3,984	4,154	4,363	4,463	4,669	4,861	4,945	5,071	5,196	5,302

121	123	121	126	145	131	143	170	158	166	2	34	63	88	34	10	10	12	9
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	15	36	47	52	36	39	43	22	42	58	62	63	72	83	66	86	69	91
12	16	36	48	53	37	40	44	22	42	58	62	63	72	83	66	86	69	91
12	17	37	49	55	38	42	46	26	45	58	61	62	71	83	65	85	69	90
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56
10	8	25	30	33	19	13	34	19	21	(60)	34	56	66	76	56	75	59	56
10	8	25	30	33	19	13	34	19	21	(60)	34	56	66	76	56	75	59	56
8	6	24	29	32	18	12	33	18	20	(61)	34	56	66	76	56	75	58	56

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
185	190	193	197	204	208	213	220	224	230	235	244	250	263	270	274	280	289	294
178	182	185	189	194	198	203	208	213	218	232	239	245	257	269	275	281	289	295
169	173	174	171	171	172	192	197	198	200	201	203	206	208	206	207	238	246	247
168	171	173	169	170	193	193	194	196	198	199	201	204	207	205	205	236	245	246
168	172	173	169	169	170	189	194	194	197	201	203	206	208	207	207	238	247	248
153	154	157	159	161	164	188	194	196	198	199	202	204	208	210	213	216	220	216
156	157	160	162	163	165	190	195	197	199	201	203	206	209	211	214	218	221	224
164	166	168	169	170	173	175	177	180	183	185	188	191	195	198	201	205	209	213
150	151	154	156	157	159	184	191	193	195	198	200	203	207	209	212	215	219	222
163	165	166	168	169	171	174	176	179	182	185	188	191	195	198	201	205	209	212
155	157	159	162	163	165	189	194	196	198	200	203	205	209	211	214	217	221	224

7	8	8	8	10	10	10	12	11	12	3	4	5	5	1	(1)	(1)	(1)	(1)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(8)	(9)	(11)	(18)	(22)	(26)	(11)	(11)	(15)	(19)	(32)	(37)	(39)	(50)	(62)	(68)	(43)	(43)	(48)
(10)	(11)	(12)	(19)	(24)	(5)	(10)	(13)	(17)	(21)	(34)	(38)	(40)	(51)	(64)	(70)	(45)	(45)	(50)
(9)	(10)	(12)	(20)	(25)	(28)	(14)	(14)	(18)	(22)	(32)	(36)	(38)	(49)	(62)	(68)	(43)	(43)	(48)
(25)	(28)	(28)	(29)	(33)	(35)	(15)	(14)	(17)	(21)	(33)	(38)	(40)	(50)	(59)	(62)	(65)	(69)	(79)
(22)	(25)	(25)	(27)	(31)	(33)	(13)	(12)	(16)	(19)	(32)	(37)	(39)	(49)	(57)	(61)	(63)	(68)	(71)
(13)	(16)	(17)	(20)	(23)	(26)	(28)	(31)	(33)	(36)	(47)	(51)	(53)	(62)	(71)	(73)	(76)	(80)	(83)
(28)	(31)	(31)	(33)	(37)	(39)	(19)	(17)	(20)	(23)	(35)	(39)	(41)	(51)	(60)	(63)	(66)	(70)	(73)
(15)	(17)	(18)	(21)	(25)	(27)	(29)	(32)	(34)	(36)	(48)	(51)	(53)	(63)	(71)	(74)	(76)	(80)	(83)
(22)	(25)	(25)	(27)	(31)	(33)	(14)	(14)	(17)	(20)	(32)	(37)	(39)	(49)	(58)	(61)	(64)	(68)	(71)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	49,238	41,396	2,790	2,673	2,762	2,806	2,925	3,160	3,189	3,194	3,268	3,263	3,355	3,414	3,458	3,366	3,568	3,466	3,559	3,582
Updated Plan	48,129	40,405	2,811	2,717	2,840	2,866	2,981	3,140	3,088	3,058	3,046	3,046	3,171	3,179	3,237	3,294	3,382	3,359	3,440	3,498
Updated Plan with Legacy Purchase/Sale and Jur Future	48,154	40,381	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,019	3,018	3,153	3,165	3,225	3,292	3,414	3,342	3,430	3,497
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	48,215	40,442	2,819	2,725	2,849	2,873	2,987	3,146	3,087	3,056	3,025	3,022	3,156	3,168	3,227	3,294	3,415	3,343	3,431	3,498
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	48,207	40,432	2,811	2,717	2,840	2,866	2,981	3,141	3,089	3,059	3,030	3,029	3,166	3,178	3,238	3,296	3,414	3,343	3,430	3,497
ND separation 2023	48,281	40,487	2,811	2,717	2,842	2,865	2,979	3,138	3,132	3,098	3,037	3,032	3,160	3,166	3,228	3,304	3,423	3,352	3,437	3,500
ND separation 2025, CT	48,216	40,422	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,037	3,032	3,160	3,166	3,228	3,304	3,423	3,352	3,437	3,500
ND separation 2025, CC	48,216	40,422	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,037	3,032	3,160	3,166	3,228	3,304	3,423	3,352	3,437	3,500
ND separation 2025, CT, no nuclear	48,287	40,492	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,057	3,056	3,175	3,180	3,241	3,323	3,436	3,357	3,444	3,509
ND separation 2025, CC, no nuclear	48,287	40,492	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,057	3,056	3,175	3,180	3,241	3,323	3,436	3,357	3,444	3,509
ND separation 2027	48,199	40,405	2,811	2,717	2,842	2,865	2,979	3,138	3,081	3,050	3,019	3,018	3,163	3,166	3,228	3,304	3,423	3,352	3,437	3,500

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	1,109	992	(21)	(43)	(78)	(60)	(56)	19	101	136	223	217	184	235	221	72	186	106	119	85
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	25	(24)	0	0	1	(1)	(2)	(3)	(7)	(8)	(27)	(28)	(18)	(14)	(12)	(1)	32	(17)	(10)	(1)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	87	38	8	8	9	7	6	5	(1)	(2)	(21)	(24)	(16)	(11)	(10)	1	33	(16)	(10)	(0)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	78	28	0	0	0	0	(0)	1	1	1	(16)	(17)	(6)	(1)	1	2	31	(17)	(10)	(0)
ND separation 2023	153	83	0	0	1	(1)	(2)	(3)	45	40	(9)	(15)	(11)	(13)	(9)	10	41	(7)	(3)	2
ND separation 2025, CT	87	17	0	0	1	(1)	(2)	(3)	(7)	(8)	(9)	(15)	(11)	(13)	(9)	10	41	(7)	(3)	2
ND separation 2025, CC	87	17	0	0	1	(1)	(2)	(3)	(7)	(8)	(9)	(15)	(11)	(13)	(9)	10	41	(7)	(3)	2
ND separation 2025, CT, no nuclear	159	88	0	0	1	(1)	(2)	(3)	(7)	(8)	11	10	4	1	4	30	54	(2)	4	11
ND separation 2025, CC, no nuclear	159	88	0	0	1	(1)	(2)	(3)	(7)	(8)	11	10	4	1	4	30	54	(2)	4	11
ND separation 2027	70	(0)	0	0	1	(1)	(2)	(3)	(7)	(8)	(27)	(28)	(9)	(13)	(9)	10	41	(7)	(3)	2

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,709	2,271	153	145	148	149	155	174	176	177	181	181	186	189	192	186	197	191	196	197
Updated Plan	2,632	2,203	155	146	151	151	157	171	169	168	167	167	175	175	179	182	187	185	189	192
Updated Plan with Legacy Purchase/Sale and Jur Future	2,585	2,179	154	146	150	152	159	174	176	176	173	171	170	168	171	165	179	176	179	177
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,531	2,128	147	138	142	144	152	166	170	170	167	167	167	166	169	180	180	173	177	175
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,532	2,127	155	146	151	151	157	171	168	167	163	160	157	155	159	162	179	175	178	176
ND separation 2023	2,284	1,944	154	146	150	152	159	174	136	143	145	144	146	145	147	138	152	155	158	155
ND separation 2025, CT	2,350	2,008	154	146	150	152	159	174	176	176	143	148	149	148	150	141	155	158	161	158
ND separation 2025, CC	2,318	2,061	154	146	150	152	159	174	176	176	171	181	179	177	177	166	158	157	157	151
ND separation 2025, CT, no nuclear	2,288	1,950	154	146	150	152	159	174	176	176	131	140	142	143	144	137	140	141	143	144
ND separation 2025, CC, no nuclear	2,202	1,945	154	146	150	152	159	174	176	176	139	150	150	150	149	141	140	141	140	140
ND separation 2027	2,417	2,075	154	146	150	152	159	174	176	176	173	171	162	170	172	161	158	157	161	157

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	77	68	(1)	(1)	(3)	(2)	(2)	2	7	9	14	13	11	14	13	4	10	6	7	5
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(47)	(24)	(0)	(0)	(1)	1	2	3	7	8	6	4	(5)	(7)	(7)	(17)	(7)	(9)	(10)	(15)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(101)	(75)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(8)	(9)	(9)	(2)	(6)	(12)	(12)	(17)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(100)	(76)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(18)	(20)	(20)	(20)	(7)	(10)	(11)	(16)
ND separation 2023	(349)	(259)	(0)	(0)	(1)	1	2	3	(33)	(26)	(22)	(23)	(29)	(30)	(32)	(44)	(34)	(30)	(31)	(37)
ND separation 2025, CT	(282)	(195)	(0)	(0)	(1)	1	2	3	7	8	(24)	(20)	(26)	(27)	(29)	(41)	(31)	(27)	(28)	(34)
ND separation 2025, CC	(314)	(142)	(0)	(0)	(1)	1	2	3	7	8	4	13	5	2	(2)	(16)	(28)	(28)	(32)	(41)
ND separation 2025, CT, no nuclear	(344)	(252)	(0)	(0)	(1)	1	2	3	7	8	(37)	(27)	(33)	(32)	(35)	(45)	(47)	(44)	(46)	(48)
ND separation 2025, CC, no nuclear	(430)	(258)	(0)	(0)	(1)	1	2	3	7	8	(29)	(17)	(25)	(26)	(30)	(41)	(46)	(44)	(49)	(52)
ND separation 2027	(215)	(128)	(0)	(0)	(1)	1	2	3	7	8	6	4	(12)	(5)	(7)	(21)	(29)	(28)	(28)	(35)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,698	3,779	3,815	3,776	3,878	3,937	3,934	4,033	4,101	4,190	4,269	4,401	4,490	4,694	4,800	4,865	4,954	5,079	5,171
3,556	3,640	3,679	3,640	3,729	3,805	3,793	3,867	3,951	4,034	4,272	4,374	4,434	4,614	4,772	4,863	4,951	5,076	5,167
3,562	3,647	3,707	3,676	3,770	3,826	3,814	3,891	3,952	4,054	4,304	4,406	4,465	4,650	4,818	4,887	4,993	5,099	5,212
3,562	3,648	3,708	3,676	3,770	3,827	3,815	3,891	3,952	4,054	4,304	4,406	4,465	4,650	4,818	4,887	4,993	5,099	5,212
3,563	3,648	3,709	3,678	3,772	3,829	3,818	3,894	3,956	4,057	4,304	4,405	4,464	4,650	4,817	4,886	4,992	5,099	5,211
3,569	3,654	3,710	3,672	3,765	3,827	3,803	3,902	3,969	4,056	4,218	4,413	4,495	4,684	4,854	4,924	5,031	5,138	5,229
3,569	3,654	3,710	3,672	3,765	3,827	3,803	3,902	3,969	4,056	4,218	4,413	4,495	4,684	4,854	4,924	5,031	5,138	5,229
3,569	3,654	3,710	3,672	3,765	3,827	3,803	3,902	3,969	4,056	4,218	4,413	4,495	4,684	4,854	4,924	5,031	5,138	5,229
3,570	3,655	3,712	3,674	3,766	3,828	3,804	3,903	3,970	4,056	4,219	4,413	4,495	4,684	4,855	4,924	5,031	5,139	5,230
3,570	3,655	3,712	3,674	3,766	3,828	3,804	3,903	3,970	4,056	4,219	4,413	4,495	4,684	4,855	4,924	5,031	5,139	5,230
3,569	3,654	3,710	3,672	3,765	3,827	3,803	3,902	3,969	4,056	4,218	4,413	4,495	4,684	4,854	4,924	5,031	5,138	5,229

142	140	136	136	149	132	141	166	151	156	(4)	27	56	80	28	3	3	3	4
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	7	28	36	40	22	22	24	2	20	31	32	31	37	45	24	42	23	45
7	8	29	37	41	22	22	24	2	20	31	32	31	37	45	24	42	23	45
7	9	30	38	43	24	25	27	5	23	32	32	30	36	45	24	42	23	44
13	14	32	33	35	22	11	35	19	22	(54)	40	61	71	82	61	80	62	62
13	14	32	33	35	22	11	35	19	22	(54)	40	61	71	82	61	80	62	62
13	14	32	33	35	22	11	35	19	22	(54)	40	61	71	82	61	80	62	62
14	15	33	34	37	23	12	36	20	23	(54)	40	61	71	83	61	80	63	62
14	15	33	34	37	23	12	36	20	23	(54)	40	61	71	83	61	80	63	62
13	14	32	33	35	22	11	35	19	22	(54)	40	61	71	82	61	80	62	62

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
203	208	211	209	215	219	219	224	228	234	238	246	251	263	269	272	277	284	290
195	200	202	200	205	209	208	212	217	222	236	242	246	258	268	273	278	285	291
192	197	199	192	193	195	210	215	217	219	223	227	230	234	234	235	264	273	275
191	196	198	190	192	214	211	213	215	217	222	225	229	233	233	234	263	272	274
191	196	197	190	191	193	206	212	213	215	223	227	231	235	235	236	265	274	276
149	150	152	155	156	158	181	187	188	190	191	193	195	198	200	203	206	209	205
152	153	155	157	158	160	182	188	189	191	192	194	196	199	201	204	207	210	213
141	141	141	141	140	141	141	142	143	145	145	147	148	150	151	152	154	155	157
146	147	149	151	152	154	177	183	185	187	189	191	194	197	199	202	205	208	210
139	139	140	140	139	140	140	141	142	144	145	146	148	149	150	152	153	155	156
152	153	155	157	158	160	181	186	188	190	192	194	196	199	201	204	207	210	212

8	9	9	9	10	10	11	12	11	12	2	4	5	5	1	(1)	(1)	(1)	(1)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3)	(2)	(3)	(8)	(12)	(14)	1	3	(0)	(3)	(12)	(15)	(16)	(24)	(34)	(38)	(14)	(12)	(15)
(4)	(4)	(5)	(10)	(14)	4	3	0	(3)	(5)	(14)	(16)	(17)	(25)	(35)	(39)	(15)	(14)	(17)
(4)	(3)	(5)	(10)	(14)	(17)	(2)	(0)	(4)	(7)	(12)	(14)	(15)	(23)	(33)	(37)	(13)	(12)	(15)
(46)	(49)	(50)	(45)	(49)	(51)	(27)	(26)	(29)	(32)	(45)	(49)	(51)	(60)	(68)	(70)	(72)	(76)	(86)
(43)	(47)	(47)	(43)	(47)	(49)	(26)	(25)	(28)	(31)	(44)	(48)	(50)	(59)	(66)	(69)	(71)	(75)	(78)
(54)	(59)	(61)	(59)	(65)	(69)	(67)	(70)	(74)	(77)	(90)	(95)	(98)	(108)	(117)	(121)	(125)	(130)	(134)
(49)	(53)	(53)	(49)	(53)	(55)	(31)	(29)	(32)	(35)	(46)	(50)	(52)	(61)	(69)	(71)	(74)	(77)	(80)
(56)	(60)	(62)	(60)	(66)	(70)	(68)	(71)	(75)	(78)	(91)	(95)	(98)	(109)	(117)	(121)	(125)	(130)	(134)
(43)	(47)	(47)	(43)	(47)	(50)	(27)	(26)	(29)	(32)	(44)	(48)	(50)	(59)	(67)	(69)	(71)	(75)	(78)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	55,557	44,258	2,790	2,672	2,760	2,803	2,925	3,173	3,216	3,231	3,330	3,332	3,447	3,516	3,586	3,526	3,922	3,854	4,063	4,205
Updated Plan	53,230	42,438	2,811	2,716	2,839	2,863	2,976	3,142	3,092	3,074	3,075	3,081	3,254	3,264	3,337	3,424	3,597	3,597	3,772	3,915
Updated Plan with Legacy Purchase/Sale and Jur Future	53,384	42,459	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,047	3,052	3,235	3,255	3,329	3,427	3,622	3,584	3,770	3,925
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	53,443	42,518	2,819	2,724	2,848	2,870	2,982	3,147	3,091	3,071	3,053	3,056	3,238	3,257	3,330	3,429	3,623	3,584	3,770	3,926
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	53,464	42,534	2,811	2,716	2,839	2,863	2,976	3,143	3,092	3,075	3,059	3,065	3,250	3,270	3,344	3,434	3,625	3,588	3,774	3,930
ND separation 2023	53,219	42,376	2,811	2,716	2,840	2,862	2,974	3,139	3,125	3,101	3,053	3,053	3,225	3,236	3,312	3,414	3,604	3,566	3,747	3,893
ND separation 2025, CT	53,168	42,325	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,053	3,053	3,225	3,236	3,312	3,414	3,604	3,566	3,747	3,893
ND separation 2025, CC	53,168	42,325	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,053	3,053	3,225	3,236	3,312	3,414	3,604	3,566	3,747	3,893
ND separation 2025, CT, no nuclear	53,220	42,377	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,070	3,074	3,236	3,245	3,319	3,427	3,613	3,566	3,749	3,900
ND separation 2025, CC, no nuclear	53,220	42,377	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,070	3,074	3,236	3,245	3,319	3,427	3,613	3,566	3,749	3,900
ND separation 2027	53,166	42,324	2,811	2,716	2,840	2,862	2,974	3,139	3,084	3,065	3,047	3,052	3,229	3,236	3,312	3,414	3,604	3,566	3,747	3,893

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,327	1,820	(21)	(43)	(78)	(60)	(51)	31	124	157	255	251	193	252	250	102	326	257	291	290
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	154	21	0	0	1	(1)	(2)	(3)	(7)	(9)	(27)	(29)	(19)	(10)	(8)	3	25	(13)	(2)	10
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	213	80	8	8	9	7	6	5	(1)	(3)	(22)	(26)	(16)	(8)	(6)	4	26	(13)	(2)	10
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	234	96	0	0	0	0	(0)	1	1	1	(16)	(16)	(4)	6	8	9	28	(9)	2	15
ND separation 2023	(11)	(61)	0	0	1	(1)	(2)	(3)	34	27	(22)	(29)	(29)	(28)	(25)	(10)	7	(31)	(25)	(22)
ND separation 2025, CT	(62)	(112)	0	0	1	(1)	(2)	(3)	(7)	(9)	(22)	(29)	(29)	(28)	(25)	(10)	7	(31)	(25)	(22)
ND separation 2025, CC	(62)	(112)	0	0	1	(1)	(2)	(3)	(7)	(9)	(22)	(29)	(29)	(28)	(25)	(10)	7	(31)	(25)	(22)
ND separation 2025, CT, no nuclear	(10)	(61)	0	0	1	(1)	(2)	(3)	(7)	(9)	(5)	(8)	(18)	(19)	(17)	3	16	(31)	(23)	(15)
ND separation 2025, CC, no nuclear	(10)	(61)	0	0	1	(1)	(2)	(3)	(7)	(9)	(5)	(8)	(18)	(19)	(17)	3	16	(31)	(23)	(15)
ND separation 2027	(64)	(114)	0	0	1	(1)	(2)	(3)	(7)	(9)	(27)	(29)	(25)	(28)	(25)	(10)	7	(31)	(25)	(22)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	3,072	2,437	153	145	148	149	155	175	178	179	185	185	191	195	199	195	218	214	225	233
Updated Plan	2,930	2,322	155	146	151	151	157	172	169	169	169	169	180	180	185	190	199	199	209	217
Updated Plan with Legacy Purchase/Sale and Jur Future	2,732	2,248	154	146	150	152	159	174	176	177	175	173	172	171	175	170	188	185	193	192
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,681	2,200	147	138	142	144	151	166	170	171	169	169	169	168	173	187	189	183	191	191
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,679	2,197	155	146	151	151	157	171	168	168	165	162	159	158	162	167	188	185	193	192
ND separation 2023	2,368	1,987	154	146	150	152	159	174	137	144	148	147	149	148	151	142	159	163	166	164
ND separation 2025, CT	2,433	2,050	154	146	150	152	159	174	176	177	145	150	152	152	154	145	162	166	169	166
ND separation 2025, CC	2,747	2,299	154	146	150	152	159	174	176	177	184	196	197	197	200	193	191	193	199	199
ND separation 2025, CT, no nuclear	2,376	1,998	154	146	150	152	159	174	176	177	134	144	146	148	150	143	147	149	151	153
ND separation 2025, CC, no nuclear	2,667	2,221	154	146	150	152	159	174	176	177	158	173	176	179	182	178	181	186	189	192
ND separation 2027	2,503	2,121	154	146	150	152	159	174	176	177	175	173	167	175	177	168	165	165	169	166

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	142	114	(1)	(1)	(3)	(2)	(2)	3	8	10	16	15	12	15	15	6	18	15	16	16
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(197)	(74)	(0)	(0)	(1)	1	2	3	7	8	6	4	(8)	(10)	(10)	(20)	(11)	(14)	(16)	(24)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(249)	(123)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	(0)	(10)	(12)	(12)	(3)	(10)	(16)	(17)	(26)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(250)	(126)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(20)	(22)	(23)	(23)	(11)	(14)	(16)	(25)
ND separation 2023	(562)	(335)	(0)	(0)	(1)	1	2	3	(32)	(25)	(21)	(23)	(31)	(32)	(34)	(48)	(40)	(36)	(42)	(53)
ND separation 2025, CT	(496)	(272)	(0)	(0)	(1)	1	2	3	7	8	(24)	(19)	(28)	(29)	(31)	(45)	(37)	(33)	(39)	(50)
ND separation 2025, CC	(183)	(23)	(0)	(0)	(1)	1	2	3	7	8	15	26	18	17	16	3	(8)	(6)	(10)	(18)
ND separation 2025, CT, no nuclear	(554)	(324)	(0)	(0)	(1)	1	2	3	7	8	(35)	(25)	(33)	(32)	(35)	(46)	(53)	(50)	(58)	(64)
ND separation 2025, CC, no nuclear	(262)	(102)	(0)	(0)	(1)	1	2	3	7	8	(11)	4	(4)	(1)	(2)	(12)	(18)	(13)	(20)	(25)
ND separation 2027	(427)	(202)	(0)	(0)	(1)	1	2	3	7	8	6	4	(13)	(5)	(8)	(22)	(35)	(34)	(40)	(51)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
4,431	4,605	4,699	4,813	4,973	5,137	5,308	5,515	5,672	5,847	6,012	6,312	6,507	6,804	7,035	7,220	7,426	7,679	7,893
4,078	4,245	4,325	4,418	4,549	4,720	4,862	5,028	5,181	5,349	5,827	6,063	6,266	6,567	6,841	7,051	7,266	7,513	7,794
4,098	4,268	4,370	4,475	4,611	4,765	4,912	5,081	5,214	5,403	5,902	6,145	6,352	6,662	6,950	7,139	7,375	7,606	7,883
4,099	4,269	4,370	4,476	4,612	4,766	4,913	5,081	5,214	5,403	5,902	6,145	6,352	6,662	6,950	7,139	7,375	7,606	7,883
4,104	4,275	4,377	4,483	4,620	4,774	4,922	5,091	5,225	5,413	5,904	6,144	6,351	6,662	6,950	7,138	7,374	7,605	7,882
4,068	4,233	4,333	4,429	4,562	4,720	4,855	5,044	5,181	5,351	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,563	7,817
4,068	4,233	4,333	4,429	4,562	4,720	4,855	5,044	5,181	5,351	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,563	7,817
4,068	4,233	4,333	4,429	4,562	4,720	4,855	5,044	5,181	5,351	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,563	7,817
4,070	4,235	4,334	4,430	4,563	4,721	4,856	5,045	5,182	5,352	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,564	7,818
4,070	4,235	4,334	4,430	4,563	4,721	4,856	5,045	5,182	5,352	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,564	7,818
4,068	4,233	4,333	4,429	4,562	4,720	4,855	5,044	5,181	5,351	5,792	6,103	6,318	6,628	6,914	7,100	7,334	7,563	7,817

354	361	374	395	424	417	445	487	490	498	185	249	241	237	194	169	160	167	100
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	24	45	57	62	45	50	52	33	54	75	82	85	95	109	88	109	93	89
21	24	45	58	62	46	50	53	33	54	75	82	85	95	109	88	109	93	89
26	30	52	65	70	54	60	63	44	64	77	82	85	95	108	87	108	93	88
(10)	(11)	8	11	13	0	(7)	16	(1)	2	(36)	40	52	61	72	48	67	51	24
(10)	(11)	8	11	13	0	(7)	16	(1)	2	(36)	40	52	61	72	48	67	51	24
(10)	(11)	8	11	13	0	(7)	16	(1)	2	(36)	40	52	61	72	48	67	51	24
(8)	(10)	9	12	14	1	(6)	17	0	3	(35)	40	52	61	72	49	68	51	24
(8)	(10)	9	12	14	1	(6)	17	0	3	(35)	40	52	61	72	49	68	51	24
(10)	(11)	8	11	13	0	(7)	16	(1)	2	(36)	40	52	61	72	48	67	51	24

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
246	256	262	269	278	288	297	309	318	328	337	355	366	383	396	406	418	432	444
226	235	240	245	253	263	271	280	289	299	326	340	352	371	388	400	412	426	442
211	218	221	216	217	222	242	250	253	258	265	271	279	281	279	281	320	331	338
209	217	220	214	216	245	244	247	251	256	263	269	277	280	277	280	319	330	337
210	217	220	214	215	220	239	246	250	255	265	271	279	282	279	282	320	332	339
158	160	163	166	168	171	199	205	207	210	212	215	218	222	226	229	233	238	235
161	163	166	168	170	172	200	206	209	211	213	216	220	224	227	231	235	239	243
196	200	204	208	212	217	222	227	233	239	244	250	257	265	271	279	286	295	302
155	157	160	162	164	167	195	201	204	207	210	214	217	221	224	228	232	237	241
194	199	202	207	211	216	221	226	232	238	244	250	257	264	271	278	286	295	302
161	162	165	168	170	172	199	205	207	210	213	216	219	223	227	230	234	239	243

20	21	22	23	25	25	27	29	29	30	11	15	13	12	8	7	6	6	2
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(15)	(17)	(19)	(30)	(36)	(41)	(28)	(30)	(36)	(41)	(61)	(69)	(74)	(90)	(109)	(119)	(92)	(95)	(104)
(16)	(18)	(20)	(31)	(37)	(18)	(27)	(33)	(38)	(43)	(63)	(71)	(75)	(91)	(110)	(120)	(93)	(96)	(106)
(16)	(18)	(20)	(32)	(38)	(43)	(31)	(34)	(39)	(44)	(61)	(69)	(73)	(89)	(108)	(118)	(91)	(94)	(104)
(67)	(75)	(77)	(80)	(85)	(92)	(72)	(75)	(82)	(89)	(114)	(125)	(134)	(149)	(162)	(170)	(179)	(188)	(207)
(64)	(72)	(74)	(77)	(83)	(90)	(71)	(74)	(80)	(87)	(113)	(124)	(133)	(148)	(161)	(169)	(177)	(187)	(200)
(30)	(35)	(36)	(38)	(41)	(46)	(49)	(53)	(56)	(60)	(82)	(90)	(95)	(106)	(116)	(121)	(126)	(131)	(140)
(71)	(78)	(80)	(83)	(89)	(96)	(76)	(79)	(85)	(91)	(115)	(126)	(135)	(150)	(163)	(171)	(180)	(189)	(202)
(32)	(37)	(38)	(39)	(42)	(47)	(50)	(54)	(57)	(61)	(82)	(90)	(95)	(107)	(117)	(121)	(126)	(131)	(140)
(65)	(73)	(75)	(77)	(83)	(91)	(72)	(75)	(82)	(88)	(113)	(124)	(133)	(148)	(161)	(169)	(178)	(187)	(200)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	43,132	36,704	2,690	2,582	2,664	2,704	2,819	2,784	2,789	2,794	2,824	2,807	2,883	2,939	2,967	2,846	3,091	3,000	3,028	2,983
Updated Plan	43,366	36,913	2,712	2,625	2,742	2,771	2,883	2,840	2,773	2,780	2,730	2,727	2,905	2,928	2,994	3,020	3,035	3,013	3,026	3,027
Updated Plan with Legacy Purchase/Sale and Jur Future	43,346	36,857	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,702	2,698	2,886	2,907	2,974	3,011	3,072	2,992	3,008	3,018
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	43,407	36,918	2,719	2,633	2,752	2,778	2,889	2,845	2,772	2,778	2,708	2,702	2,889	2,909	2,976	3,013	3,073	2,993	3,008	3,019
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	43,397	36,907	2,712	2,625	2,742	2,771	2,883	2,841	2,774	2,781	2,712	2,709	2,899	2,919	2,987	3,014	3,071	2,992	3,008	3,019
ND separation 2023	43,633	37,113	2,712	2,625	2,744	2,770	2,881	2,837	2,833	2,837	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CT	43,546	37,026	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CC	43,546	37,026	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CT, no nuclear	43,614	37,093	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,758	2,756	2,932	2,945	3,015	3,065	3,119	3,033	3,043	3,046
ND separation 2025, CC, no nuclear	43,614	37,093	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,758	2,756	2,932	2,945	3,015	3,065	3,119	3,033	3,043	3,046
ND separation 2027	43,506	36,986	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,702	2,698	2,921	2,932	3,003	3,047	3,106	3,028	3,037	3,037

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	(234)	(209)	(21)	(44)	(79)	(67)	(64)	(56)	16	14	93	80	(22)	12	(26)	(174)	57	(13)	2	(44)
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(20)	(56)	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	(19)	(21)	(19)	(9)	37	(21)	(18)	(9)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	41	5	8	8	9	7	6	5	(1)	(2)	(23)	(26)	(16)	(19)	(17)	(7)	38	(20)	(17)	(8)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	31	(6)	0	0	0	0	(0)	1	1	1	(18)	(18)	(6)	(8)	(7)	(6)	37	(21)	(18)	(9)
ND separation 2023	267	200	0	0	1	(1)	(2)	(3)	60	57	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CT	180	113	0	0	1	(1)	(2)	(3)	(7)	(8)	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CC	180	113	0	0	1	(1)	(2)	(3)	(7)	(8)	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CT, no nuclear	248	180	0	0	1	(1)	(2)	(3)	(7)	(8)	28	29	27	18	22	45	84	20	18	19
ND separation 2025, CC, no nuclear	248	180	0	0	1	(1)	(2)	(3)	(7)	(8)	28	29	27	18	22	45	84	20	18	19
ND separation 2027	140	73	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	16	5	10	27	72	15	11	10

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,355	1,997	148	139	143	143	149	152	152	154	155	154	158	161	163	155	169	164	165	162
Updated Plan	2,356	2,000	149	140	145	146	152	154	150	152	149	149	159	161	165	166	166	165	165	165
Updated Plan with Legacy Purchase/Sale and Jur Future	2,305	1,972	149	140	144	146	154	156	158	160	154	153	154	153	157	148	159	155	154	149
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,252	1,922	141	132	136	139	146	149	151	154	149	149	151	151	155	163	160	153	153	147
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,254	1,922	149	140	145	146	152	153	150	151	144	141	141	140	144	145	160	155	154	149
ND separation 2023	2,241	1,901	149	140	144	146	154	156	135	142	145	143	145	144	146	137	152	155	158	154
ND separation 2025, CT	2,286	1,943	149	140	144	146	154	156	158	160	142	147	148	147	149	140	155	157	161	157
ND separation 2025, CC	2,255	1,997	149	140	144	146	154	156	158	160	170	180	179	176	177	165	158	156	157	151
ND separation 2025, CT, no nuclear	2,227	1,889	149	140	144	146	154	156	158	160	131	140	142	143	144	137	140	141	143	144
ND separation 2025, CC, no nuclear	2,141	1,884	149	140	144	146	154	156	158	160	139	150	150	149	149	141	140	140	140	140
ND separation 2027	2,332	1,990	149	140	144	146	154	156	158	160	154	153	161	169	171	160	157	157	160	157

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	(2)	(2)	(1)	(1)	(3)	(2)	(2)	(2)	2	2	6	5	(1)	1	(2)	(11)	3	(1)	(0)	(3)
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(51)	(27)	(0)	(0)	(1)	1	2	3	7	8	6	4	(5)	(8)	(8)	(18)	(7)	(10)	(11)	(16)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(104)	(77)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(8)	(10)	(10)	(3)	(6)	(12)	(13)	(17)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(103)	(77)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(18)	(20)	(21)	(21)	(7)	(10)	(11)	(16)
ND separation 2023	(116)	(99)	(0)	(0)	(1)	1	2	3	(15)	(10)	(4)	(5)	(15)	(17)	(18)	(29)	(15)	(10)	(7)	(10)
ND separation 2025, CT	(71)	(57)	(0)	(0)	(1)	1	2	3	7	8	(7)	(2)	(11)	(13)	(15)	(26)	(12)	(7)	(4)	(7)
ND separation 2025, CC	(102)	(3)	(0)	(0)	(1)	1	2	3	7	8	22	31	19	16	12	(1)	(8)	(9)	(8)	(14)
ND separation 2025, CT, no nuclear	(130)	(111)	(0)	(0)	(1)	1	2	3	7	8	(18)	(8)	(17)	(18)	(21)	(29)	(27)	(24)	(22)	(21)
ND separation 2025, CC, no nuclear	(216)	(116)	(0)	(0)	(1)	1	2	3	7	8	(10)	2	(9)	(11)	(16)	(25)	(26)	(24)	(25)	(25)
ND separation 2027	(25)	(10)	(0)	(0)	(1)	1	2	3	7	8	6	4	2	9	6	(6)	(9)	(8)	(5)	(8)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,062	3,104	3,117	3,125	3,212	3,236	3,261	3,333	3,381	3,451	3,505	3,591	3,662	3,848	3,935	3,977	4,044	4,146	4,218
3,033	3,080	3,101	3,112	3,184	3,226	3,246	3,297	3,362	3,425	3,580	3,645	3,672	3,823	3,961	4,026	4,089	4,191	4,242
3,031	3,080	3,121	3,140	3,216	3,240	3,259	3,312	3,356	3,437	3,604	3,669	3,695	3,851	3,997	4,043	4,124	4,207	4,287
3,031	3,081	3,122	3,140	3,216	3,241	3,260	3,313	3,356	3,437	3,604	3,669	3,695	3,851	3,997	4,043	4,124	4,207	4,287
3,032	3,082	3,123	3,142	3,218	3,242	3,263	3,315	3,359	3,440	3,604	3,668	3,694	3,851	3,996	4,042	4,123	4,206	4,286
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,053	3,098	3,137	3,151	3,227	3,254	3,265	3,338	3,388	3,452	3,515	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,053	3,098	3,137	3,151	3,227	3,254	3,265	3,338	3,388	3,452	3,515	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307

29	24	16	13	28	10	15	36	19	27	(76)	(53)	(10)	25	(27)	(49)	(45)	(46)	(24)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(2)	0	20	28	32	14	14	16	(6)	12	23	24	23	29	36	17	35	15	45
(2)	1	21	29	33	15	14	16	(6)	12	23	24	23	29	36	17	35	15	45
(1)	1	21	30	34	16	17	19	(3)	15	23	23	22	28	35	16	34	15	44
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
20	18	36	39	43	27	19	41	26	27	(66)	32	56	66	76	58	77	59	65
20	18	36	39	43	27	19	41	26	27	(66)	32	56	66	76	58	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
167	169	171	172	177	179	180	185	187	192	194	200	204	214	219	222	226	231	236
165	167	169	170	174	176	177	180	184	187	196	200	202	213	222	226	229	235	238
161	164	165	161	161	161	178	182	182	183	183	184	186	188	188	188	215	223	223
160	163	164	159	160	180	179	180	180	181	182	183	184	187	186	186	214	221	222
160	163	164	159	159	159	175	179	179	180	183	185	186	189	188	188	216	223	224
149	150	152	155	156	158	181	187	188	190	191	193	195	198	200	203	206	209	205
152	153	155	157	158	160	182	188	189	191	192	194	196	199	201	204	207	210	213
141	141	141	141	140	141	141	142	143	145	145	147	148	150	151	152	154	155	157
146	147	149	151	152	154	177	183	185	187	189	191	194	197	199	202	205	208	210
139	139	140	140	139	140	140	141	142	144	145	146	148	149	150	152	153	155	156
151	152	155	157	158	160	181	186	188	190	192	194	196	199	201	204	207	210	212

2	2	2	2	3	3	3	5	4	4	(2)	(0)	1	2	(2)	(4)	(4)	(4)	(3)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3)	(3)	(4)	(9)	(13)	(15)	1	2	(1)	(4)	(13)	(16)	(17)	(24)	(34)	(38)	(14)	(13)	(15)
(5)	(4)	(5)	(10)	(14)	4	2	(0)	(3)	(6)	(14)	(17)	(18)	(26)	(35)	(39)	(15)	(14)	(16)
(4)	(4)	(5)	(11)	(15)	(17)	(2)	(1)	(5)	(7)	(13)	(15)	(16)	(24)	(33)	(37)	(13)	(12)	(15)
(16)	(17)	(17)	(15)	(18)	(18)	4	7	4	2	(5)	(7)	(7)	(15)	(21)	(23)	(23)	(26)	(33)
(13)	(14)	(14)	(12)	(16)	(16)	5	8	6	4	(4)	(6)	(6)	(13)	(20)	(21)	(22)	(25)	(25)
(24)	(26)	(28)	(29)	(33)	(35)	(36)	(38)	(40)	(43)	(51)	(53)	(55)	(63)	(71)	(73)	(76)	(80)	(81)
(19)	(20)	(20)	(18)	(22)	(22)	0	3	1	(0)	(7)	(9)	(8)	(16)	(23)	(24)	(25)	(27)	(28)
(25)	(28)	(29)	(30)	(35)	(36)	(37)	(39)	(41)	(43)	(51)	(54)	(55)	(63)	(71)	(74)	(76)	(80)	(82)
(13)	(15)	(14)	(13)	(16)	(17)	4	7	4	3	(4)	(6)	(6)	(14)	(20)	(22)	(22)	(25)	(26)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	49,224	39,310	2,691	2,580	2,663	2,703	2,818	2,780	2,785	2,794	2,840	2,829	2,932	2,999	3,050	2,957	3,427	3,369	3,507	3,578
Updated Plan	48,316	38,764	2,712	2,624	2,742	2,770	2,877	2,825	2,744	2,771	2,726	2,729	2,970	2,993	3,076	3,131	3,235	3,236	3,334	3,422
Updated Plan with Legacy Purchase/Sale and Jur Future	48,424	38,754	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,696	2,698	2,952	2,976	3,062	3,127	3,266	3,219	3,325	3,424
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	48,482	38,813	2,719	2,632	2,751	2,777	2,883	2,830	2,743	2,768	2,702	2,701	2,954	2,978	3,063	3,129	3,267	3,220	3,325	3,425
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	48,503	38,828	2,712	2,624	2,742	2,770	2,877	2,825	2,745	2,772	2,708	2,711	2,966	2,992	3,077	3,134	3,269	3,224	3,329	3,429
ND separation 2023	48,411	38,804	2,712	2,624	2,743	2,769	2,875	2,822	2,795	2,814	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CT	48,338	38,732	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CC	48,338	38,732	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CT, no nuclear	48,386	38,779	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,735	2,734	2,972	2,987	3,072	3,147	3,278	3,221	3,324	3,415
ND separation 2025, CC, no nuclear	48,386	38,779	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,735	2,734	2,972	2,987	3,072	3,147	3,278	3,221	3,324	3,415
ND separation 2027	48,318	38,712	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,696	2,698	2,965	2,979	3,066	3,135	3,269	3,222	3,322	3,409
Delta to Scen 2:																				
IRP Reference Case with Updated Assumptions	909	546	(21)	(44)	(79)	(67)	(59)	(45)	40	24	114	101	(38)	6	(27)	(175)	192	133	172	156
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	108	(10)	0	0	1	(1)	(2)	(3)	(8)	(9)	(30)	(31)	(18)	(17)	(15)	(4)	31	(17)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	166	49	8	8	9	7	6	5	(1)	(3)	(24)	(27)	(16)	(15)	(13)	(3)	32	(16)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	187	64	0	0	0	0	(0)	1	1	1	(18)	(18)	(4)	(1)	1	2	34	(12)	(5)	7
ND separation 2023	95	40	0	0	1	(1)	(2)	(3)	50	43	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CT	23	(33)	0	0	1	(1)	(2)	(3)	(8)	(9)	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CC	23	(33)	0	0	1	(1)	(2)	(3)	(8)	(9)	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CT, no nuclear	70	14	0	0	1	(1)	(2)	(3)	(8)	(9)	8	5	2	(6)	(4)	16	43	(15)	(10)	(7)
ND separation 2025, CC, no nuclear	70	14	0	0	1	(1)	(2)	(3)	(8)	(9)	8	5	2	(6)	(4)	16	43	(15)	(10)	(7)
ND separation 2027	2	(53)	0	0	1	(1)	(2)	(3)	(8)	(9)	(30)	(31)	(5)	(14)	(11)	3	35	(14)	(12)	(13)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,704	2,148	148	139	142	143	149	151	152	154	156	155	161	165	168	162	189	185	193	196
Updated Plan	2,642	2,107	149	140	145	146	151	153	149	151	149	149	163	164	170	173	178	178	183	188
Updated Plan with Legacy Purchase/Sale and Jur Future	2,443	2,033	149	140	144	146	153	155	156	159	154	153	155	155	159	152	167	164	167	163
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,392	1,984	141	132	136	138	145	148	150	153	148	149	153	152	157	169	168	162	166	162
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,391	1,982	149	140	145	146	151	152	148	150	144	141	143	142	146	149	168	164	167	163
ND separation 2023	2,324	1,944	149	140	144	146	153	155	136	144	147	146	148	147	150	141	159	162	166	163
ND separation 2025, CT	2,366	1,983	149	140	144	146	153	155	156	159	144	149	151	151	153	144	161	165	169	166
ND separation 2025, CC	2,678	2,231	149	140	144	146	153	155	156	159	183	195	196	196	199	192	191	192	198	198
ND separation 2025, CT, no nuclear	2,312	1,934	149	140	144	146	153	155	156	159	134	144	146	148	150	143	147	149	151	152
ND separation 2025, CC, no nuclear	2,603	2,156	149	140	144	146	153	155	156	159	158	173	176	179	182	178	181	186	189	191
ND separation 2027	2,412	2,030	149	140	144	146	153	155	156	159	154	153	166	174	176	167	164	164	168	166
Delta to Scen 2:																				
IRP Reference Case with Updated Assumptions	62	40	(1)	(1)	(3)	(2)	(2)	(1)	3	2	7	7	(2)	0	(2)	(11)	11	7	9	9
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(198)	(75)	(0)	(0)	(1)	1	2	3	7	8	6	4	(8)	(10)	(11)	(20)	(11)	(14)	(16)	(24)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(249)	(123)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(10)	(12)	(13)	(3)	(10)	(16)	(17)	(26)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(251)	(126)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(8)	(20)	(23)	(23)	(23)	(11)	(14)	(16)	(25)
ND separation 2023	(317)	(163)	(0)	(0)	(1)	1	2	3	(12)	(8)	(2)	(3)	(15)	(17)	(20)	(31)	(20)	(16)	(17)	(25)
ND separation 2025, CT	(276)	(125)	(0)	(0)	(1)	1	2	3	7	8	(4)	1	(12)	(14)	(17)	(28)	(17)	(13)	(14)	(22)
ND separation 2025, CC	37	124	(0)	(0)	(1)	1	2	3	7	8	34	46	33	32	30	19	12	14	15	10
ND separation 2025, CT, no nuclear	(330)	(173)	(0)	(0)	(1)	1	2	3	7	8	(15)	(4)	(17)	(16)	(20)	(29)	(32)	(29)	(32)	(35)
ND separation 2025, CC, no nuclear	(38)	49	(0)	(0)	(1)	1	2	3	7	8	9	24	13	15	13	5	3	7	6	4
ND separation 2027	(229)	(77)	(0)	(0)	(1)	1	2	3	7	8	6	4	3	10	7	(6)	(14)	(14)	(15)	(22)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,775	3,907	3,975	4,151	4,291	4,420	4,655	4,831	4,968	5,125	5,270	5,519	5,693	5,979	6,184	6,343	6,528	6,759	6,954
3,536	3,656	3,717	3,875	3,986	4,123	4,333	4,472	4,609	4,757	5,151	5,351	5,518	5,794	6,050	6,235	6,425	6,650	6,884
3,547	3,672	3,754	3,923	4,040	4,159	4,374	4,517	4,633	4,801	5,218	5,424	5,593	5,879	6,148	6,314	6,524	6,732	6,975
3,548	3,673	3,754	3,924	4,040	4,160	4,374	4,518	4,633	4,801	5,218	5,424	5,593	5,879	6,148	6,314	6,524	6,732	6,975
3,553	3,678	3,760	3,931	4,048	4,168	4,383	4,527	4,644	4,811	5,220	5,424	5,592	5,879	6,147	6,314	6,524	6,732	6,975
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,532	3,650	3,728	3,893	4,006	4,128	4,336	4,497	4,618	4,767	5,102	5,387	5,572	5,859	6,125	6,287	6,496	6,703	6,920
3,532	3,650	3,728	3,893	4,006	4,128	4,336	4,497	4,618	4,767	5,102	5,387	5,572	5,859	6,125	6,287	6,496	6,703	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920

239	251	259	277	305	297	322	359	359	368	118	168	176	185	134	107	103	110	70
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	16	37	48	53	37	41	45	24	44	66	73	75	85	98	79	99	83	92
12	16	37	49	54	37	41	45	24	44	66	73	75	85	98	79	99	83	92
17	22	44	56	62	45	50	55	35	54	68	72	75	85	98	78	99	82	91
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(4)	(6)	11	18	20	5	3	25	9	10	(49)	36	54	65	76	52	71	53	37
(4)	(6)	11	18	20	5	3	25	9	10	(49)	36	54	65	76	52	71	53	37
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
208	215	220	231	239	247	260	270	278	287	295	310	319	336	347	356	367	380	391
194	201	205	214	220	228	240	248	255	264	286	298	308	326	341	352	363	376	389
179	184	186	184	184	187	211	217	219	223	225	229	235	236	232	233	270	280	285
178	182	184	182	183	210	212	214	217	221	223	227	233	234	230	232	269	279	284
178	183	184	182	182	185	208	214	216	220	225	229	235	236	232	234	271	281	286
158	160	163	166	168	171	199	205	207	210	212	215	218	222	226	229	233	238	235
161	163	166	168	170	172	200	206	209	211	213	216	220	224	227	231	235	239	243
195	200	204	208	212	217	222	227	233	239	244	250	257	265	271	279	286	295	302
155	157	160	162	164	167	195	201	204	207	210	214	217	221	224	228	232	237	241
194	198	202	207	211	216	221	226	232	238	244	250	257	264	271	278	286	295	302
161	162	165	168	170	172	199	205	207	210	213	216	219	223	227	230	234	239	243

14	15	16	17	19	19	20	22	22	23	9	12	11	10	6	5	4	5	2
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(15)	(17)	(19)	(30)	(36)	(41)	(29)	(31)	(36)	(41)	(61)	(69)	(74)	(90)	(109)	(119)	(93)	(95)	(104)
(16)	(18)	(20)	(31)	(38)	(18)	(27)	(33)	(38)	(43)	(63)	(71)	(75)	(91)	(111)	(120)	(94)	(97)	(105)
(16)	(18)	(20)	(32)	(38)	(43)	(32)	(34)	(39)	(44)	(61)	(69)	(73)	(89)	(109)	(118)	(92)	(95)	(103)
(36)	(41)	(42)	(48)	(52)	(57)	(41)	(43)	(48)	(54)	(74)	(83)	(90)	(103)	(115)	(122)	(129)	(137)	(154)
(33)	(38)	(39)	(45)	(50)	(56)	(40)	(41)	(47)	(53)	(73)	(82)	(89)	(102)	(114)	(121)	(128)	(136)	(146)
2	(1)	(1)	(6)	(8)	(11)	(18)	(21)	(23)	(25)	(42)	(48)	(51)	(61)	(70)	(73)	(76)	(81)	(86)
(39)	(44)	(45)	(51)	(56)	(61)	(45)	(46)	(51)	(57)	(76)	(84)	(91)	(104)	(117)	(123)	(130)	(139)	(148)
0	(2)	(2)	(7)	(10)	(12)	(19)	(22)	(24)	(26)	(42)	(48)	(51)	(61)	(70)	(73)	(77)	(81)	(87)
(33)	(38)	(39)	(46)	(50)	(56)	(41)	(43)	(48)	(54)	(73)	(82)	(89)	(102)	(114)	(121)	(128)	(137)	(146)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	43,132	36,704	2,690	2,582	2,664	2,704	2,819	2,784	2,789	2,794	2,824	2,807	2,883	2,939	2,967	2,846	3,091	3,000	3,028	2,983
Updated Plan	43,366	36,913	2,712	2,625	2,742	2,771	2,883	2,840	2,773	2,780	2,730	2,727	2,905	2,928	2,994	3,020	3,035	3,013	3,026	3,027
Updated Plan with Legacy Purchase/Sale and Jur Future	43,346	36,857	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,702	2,698	2,886	2,907	2,974	3,011	3,072	2,992	3,008	3,018
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	43,407	36,918	2,719	2,633	2,752	2,778	2,889	2,845	2,772	2,778	2,708	2,702	2,889	2,909	2,976	3,013	3,073	2,993	3,008	3,019
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	43,397	36,907	2,712	2,625	2,742	2,771	2,883	2,841	2,774	2,781	2,712	2,709	2,899	2,919	2,987	3,014	3,071	2,992	3,008	3,019
ND separation 2023	43,633	37,113	2,712	2,625	2,744	2,770	2,881	2,837	2,833	2,837	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CT	43,546	37,026	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CC	43,546	37,026	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,739	2,732	2,918	2,932	3,003	3,047	3,106	3,028	3,037	3,037
ND separation 2025, CT, no nuclear	43,614	37,093	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,758	2,756	2,932	2,945	3,015	3,065	3,119	3,033	3,043	3,046
ND separation 2025, CC, no nuclear	43,614	37,093	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,758	2,756	2,932	2,945	3,015	3,065	3,119	3,033	3,043	3,046
ND separation 2027	43,506	36,986	2,712	2,625	2,744	2,770	2,881	2,837	2,766	2,772	2,702	2,698	2,921	2,932	3,003	3,047	3,106	3,028	3,037	3,037

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	(234)	(209)	(21)	(44)	(79)	(67)	(64)	(56)	16	14	93	80	(22)	12	(26)	(174)	57	(13)	2	(44)
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(20)	(56)	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	(19)	(21)	(19)	(9)	37	(21)	(18)	(9)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	41	5	8	8	9	7	6	5	(1)	(2)	(23)	(26)	(16)	(19)	(17)	(7)	38	(20)	(17)	(8)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	31	(6)	0	0	0	0	(0)	1	1	1	(18)	(18)	(6)	(8)	(7)	(6)	37	(21)	(18)	(9)
ND separation 2023	267	200	0	0	1	(1)	(2)	(3)	60	57	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CT	180	113	0	0	1	(1)	(2)	(3)	(7)	(8)	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CC	180	113	0	0	1	(1)	(2)	(3)	(7)	(8)	8	5	13	5	10	27	72	15	11	10
ND separation 2025, CT, no nuclear	248	180	0	0	1	(1)	(2)	(3)	(7)	(8)	28	29	27	18	22	45	84	20	18	19
ND separation 2025, CC, no nuclear	248	180	0	0	1	(1)	(2)	(3)	(7)	(8)	28	29	27	18	22	45	84	20	18	19
ND separation 2027	140	73	0	0	1	(1)	(2)	(3)	(7)	(8)	(29)	(30)	16	5	10	27	72	15	11	10

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,355	1,997	148	139	143	143	149	152	152	154	155	154	158	161	163	155	169	164	165	162
Updated Plan	2,356	2,000	149	140	145	146	152	154	150	152	149	149	159	161	165	166	166	165	165	165
Updated Plan with Legacy Purchase/Sale and Jur Future	2,305	1,972	149	140	144	146	154	156	158	160	154	153	154	153	157	148	159	155	154	149
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,252	1,922	141	132	136	139	146	149	151	154	149	149	151	151	155	163	160	153	153	147
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,254	1,922	149	140	145	146	152	153	150	151	144	141	141	140	144	145	160	155	154	149
ND separation 2023	2,241	1,901	149	140	144	146	154	156	135	142	145	143	145	144	146	137	152	155	158	154
ND separation 2025, CT	2,286	1,943	149	140	144	146	154	156	158	160	142	147	148	147	149	140	155	157	161	157
ND separation 2025, CC	2,255	1,997	149	140	144	146	154	156	158	160	170	180	179	176	177	165	158	156	157	151
ND separation 2025, CT, no nuclear	2,227	1,889	149	140	144	146	154	156	158	160	131	140	142	143	144	137	140	141	143	144
ND separation 2025, CC, no nuclear	2,141	1,884	149	140	144	146	154	156	158	160	139	150	150	149	149	141	140	140	140	140
ND separation 2027	2,332	1,990	149	140	144	146	154	156	158	160	154	153	161	169	171	160	157	157	160	157

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	(2)	(2)	(1)	(1)	(3)	(2)	(2)	(2)	2	2	6	5	(1)	1	(2)	(11)	3	(1)	(0)	(3)
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(51)	(27)	(0)	(0)	(1)	1	2	3	7	8	6	4	(5)	(8)	(8)	(18)	(7)	(10)	(11)	(16)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(104)	(77)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(8)	(10)	(10)	(3)	(6)	(12)	(13)	(17)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(103)	(77)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(7)	(18)	(20)	(21)	(21)	(7)	(10)	(11)	(16)
ND separation 2023	(116)	(99)	(0)	(0)	(1)	1	2	3	(15)	(10)	(4)	(5)	(15)	(17)	(18)	(29)	(15)	(10)	(7)	(10)
ND separation 2025, CT	(71)	(57)	(0)	(0)	(1)	1	2	3	7	8	(7)	(2)	(11)	(13)	(15)	(26)	(12)	(7)	(4)	(7)
ND separation 2025, CC	(102)	(3)	(0)	(0)	(1)	1	2	3	7	8	22	31	19	16	12	(1)	(8)	(9)	(8)	(14)
ND separation 2025, CT, no nuclear	(130)	(111)	(0)	(0)	(1)	1	2	3	7	8	(18)	(8)	(17)	(18)	(21)	(29)	(27)	(24)	(22)	(21)
ND separation 2025, CC, no nuclear	(216)	(116)	(0)	(0)	(1)	1	2	3	7	8	(10)	2	(9)	(11)	(16)	(25)	(26)	(24)	(25)	(25)
ND separation 2027	(25)	(10)	(0)	(0)	(1)	1	2	3	7	8	6	4	2	9	6	(6)	(9)	(8)	(5)	(8)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,062	3,104	3,117	3,125	3,212	3,236	3,261	3,333	3,381	3,451	3,505	3,591	3,662	3,848	3,935	3,977	4,044	4,146	4,218
3,033	3,080	3,101	3,112	3,184	3,226	3,246	3,297	3,362	3,425	3,580	3,645	3,672	3,823	3,961	4,026	4,089	4,191	4,242
3,031	3,080	3,121	3,140	3,216	3,240	3,259	3,312	3,356	3,437	3,604	3,669	3,695	3,851	3,997	4,043	4,124	4,207	4,287
3,031	3,081	3,122	3,140	3,216	3,241	3,260	3,313	3,356	3,437	3,604	3,669	3,695	3,851	3,997	4,043	4,124	4,207	4,287
3,032	3,082	3,123	3,142	3,218	3,242	3,263	3,315	3,359	3,440	3,604	3,668	3,694	3,851	3,996	4,042	4,123	4,206	4,286
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,053	3,098	3,137	3,151	3,227	3,254	3,265	3,338	3,388	3,452	3,515	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,053	3,098	3,137	3,151	3,227	3,254	3,265	3,338	3,388	3,452	3,515	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307
3,051	3,096	3,135	3,150	3,225	3,253	3,264	3,337	3,387	3,451	3,514	3,677	3,728	3,889	4,037	4,083	4,165	4,250	4,307

29	24	16	13	28	10	15	36	19	27	(76)	(53)	(10)	25	(27)	(49)	(45)	(46)	(24)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(2)	0	20	28	32	14	14	16	(6)	12	23	24	23	29	36	17	35	15	45
(2)	1	21	29	33	15	14	16	(6)	12	23	24	23	29	36	17	35	15	45
(1)	1	21	30	34	16	17	19	(3)	15	23	23	22	28	35	16	34	15	44
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65
20	18	36	39	43	27	19	41	26	27	(66)	32	56	66	76	58	77	59	65
20	18	36	39	43	27	19	41	26	27	(66)	32	56	66	76	58	77	59	65
18	16	34	38	42	26	18	40	25	26	(66)	32	56	66	76	57	77	59	65

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
167	169	171	172	177	179	180	185	187	192	194	200	204	214	219	222	226	231	236
165	167	169	170	174	176	177	180	184	187	196	200	202	213	222	226	229	235	238
161	164	165	161	161	161	178	182	182	183	183	184	186	188	188	188	215	223	223
160	163	164	159	160	180	179	180	180	181	182	183	184	187	186	186	214	221	222
160	163	164	159	159	159	175	179	179	180	183	185	186	189	188	188	216	223	224
149	150	152	155	156	158	181	187	188	190	191	193	195	198	200	203	206	209	205
152	153	155	157	158	160	182	188	189	191	192	194	196	199	201	204	207	210	213
141	141	141	141	140	141	141	142	143	145	145	147	148	150	151	152	154	155	157
146	147	149	151	152	154	177	183	185	187	189	191	194	197	199	202	205	208	210
139	139	140	140	139	140	140	141	142	144	145	146	148	149	150	152	153	155	156
151	152	155	157	158	160	181	186	188	190	192	194	196	199	201	204	207	210	212

2	2	2	2	3	3	3	5	4	4	(2)	(0)	1	2	(2)	(4)	(4)	(4)	(3)
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(3)	(3)	(4)	(9)	(13)	(15)	1	2	(1)	(4)	(13)	(16)	(17)	(24)	(34)	(38)	(14)	(13)	(15)
(5)	(4)	(5)	(10)	(14)	4	2	(0)	(3)	(6)	(14)	(17)	(18)	(26)	(35)	(39)	(15)	(14)	(16)
(4)	(4)	(5)	(11)	(15)	(17)	(2)	(1)	(5)	(7)	(13)	(15)	(16)	(24)	(33)	(37)	(13)	(12)	(15)
(16)	(17)	(17)	(15)	(18)	(18)	4	7	4	2	(5)	(7)	(7)	(15)	(21)	(23)	(23)	(26)	(33)
(13)	(14)	(14)	(12)	(16)	(16)	5	8	6	4	(4)	(6)	(6)	(13)	(20)	(21)	(22)	(25)	(25)
(24)	(26)	(28)	(29)	(33)	(35)	(36)	(38)	(40)	(43)	(51)	(53)	(55)	(63)	(71)	(73)	(76)	(80)	(81)
(19)	(20)	(20)	(18)	(22)	(22)	0	3	1	(0)	(7)	(9)	(8)	(16)	(23)	(24)	(25)	(27)	(28)
(25)	(28)	(29)	(30)	(35)	(36)	(37)	(39)	(41)	(43)	(51)	(54)	(55)	(63)	(71)	(74)	(76)	(80)	(82)
(13)	(15)	(14)	(13)	(16)	(17)	4	7	4	3	(4)	(6)	(6)	(14)	(20)	(22)	(22)	(25)	(26)

MN, SD, WI Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	49,224	39,310	2,691	2,580	2,663	2,703	2,818	2,780	2,785	2,794	2,840	2,829	2,932	2,999	3,050	2,957	3,427	3,369	3,507	3,578
Updated Plan	48,316	38,764	2,712	2,624	2,742	2,770	2,877	2,825	2,744	2,771	2,726	2,729	2,970	2,993	3,076	3,131	3,235	3,236	3,334	3,422
Updated Plan with Legacy Purchase/Sale and Jur Future	48,424	38,754	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,696	2,698	2,952	2,976	3,062	3,127	3,266	3,219	3,325	3,424
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	48,482	38,813	2,719	2,632	2,751	2,777	2,883	2,830	2,743	2,768	2,702	2,701	2,954	2,978	3,063	3,129	3,267	3,220	3,325	3,425
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	48,503	38,828	2,712	2,624	2,742	2,770	2,877	2,825	2,745	2,772	2,708	2,711	2,966	2,992	3,077	3,134	3,269	3,224	3,329	3,429
ND separation 2023	48,411	38,804	2,712	2,624	2,743	2,769	2,875	2,822	2,795	2,814	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CT	48,338	38,732	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CC	48,338	38,732	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,718	2,714	2,962	2,979	3,066	3,135	3,269	3,222	3,322	3,409
ND separation 2025, CT, no nuclear	48,386	38,779	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,735	2,734	2,972	2,987	3,072	3,147	3,278	3,221	3,324	3,415
ND separation 2025, CC, no nuclear	48,386	38,779	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,735	2,734	2,972	2,987	3,072	3,147	3,278	3,221	3,324	3,415
ND separation 2027	48,318	38,712	2,712	2,624	2,743	2,769	2,875	2,822	2,737	2,762	2,696	2,698	2,965	2,979	3,066	3,135	3,269	3,222	3,322	3,409

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	909	546	(21)	(44)	(79)	(67)	(59)	(45)	40	24	114	101	(38)	6	(27)	(175)	192	133	172	156
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	108	(10)	0	0	1	(1)	(2)	(3)	(8)	(9)	(30)	(31)	(18)	(17)	(15)	(4)	31	(17)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	166	49	8	8	9	7	6	5	(1)	(3)	(24)	(27)	(16)	(15)	(13)	(3)	32	(16)	(9)	2
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	187	64	0	0	0	0	(0)	1	1	1	(18)	(18)	(4)	(1)	1	2	34	(12)	(5)	7
ND separation 2023	95	40	0	0	1	(1)	(2)	(3)	50	43	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CT	23	(33)	0	0	1	(1)	(2)	(3)	(8)	(9)	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CC	23	(33)	0	0	1	(1)	(2)	(3)	(8)	(9)	(8)	(15)	(8)	(14)	(11)	3	35	(14)	(12)	(13)
ND separation 2025, CT, no nuclear	70	14	0	0	1	(1)	(2)	(3)	(8)	(9)	8	5	2	(6)	(4)	16	43	(15)	(10)	(7)
ND separation 2025, CC, no nuclear	70	14	0	0	1	(1)	(2)	(3)	(8)	(9)	8	5	2	(6)	(4)	16	43	(15)	(10)	(7)
ND separation 2027	2	(53)	0	0	1	(1)	(2)	(3)	(8)	(9)	(30)	(31)	(5)	(14)	(11)	3	35	(14)	(12)	(13)

ND Costs ($M)

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	2,704	2,148	148	139	142	143	149	151	152	154	156	155	161	165	168	162	189	185	193	196
Updated Plan	2,642	2,107	149	140	145	146	151	153	149	151	149	149	163	164	170	173	178	178	183	188
Updated Plan with Legacy Purchase/Sale and Jur Future	2,443	2,033	149	140	144	146	153	155	156	159	154	153	155	155	159	152	167	164	167	163
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	2,392	1,984	141	132	136	138	145	148	150	153	148	149	153	152	157	169	168	162	166	162
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	2,391	1,982	149	140	145	146	151	152	148	150	144	141	143	142	146	149	168	164	167	163
ND separation 2023	2,324	1,944	149	140	144	146	153	155	136	144	147	146	148	147	150	141	159	162	166	163
ND separation 2025, CT	2,366	1,983	149	140	144	146	153	155	156	159	144	149	151	151	153	144	161	165	169	166
ND separation 2025, CC	2,678	2,231	149	140	144	146	153	155	156	159	183	195	196	196	199	192	191	192	198	198
ND separation 2025, CT, no nuclear	2,312	1,934	149	140	144	146	153	155	156	159	134	144	146	148	150	143	147	149	151	152
ND separation 2025, CC, no nuclear	2,603	2,156	149	140	144	146	153	155	156	159	158	173	176	179	182	178	181	186	189	191
ND separation 2027	2,412	2,030	149	140	144	146	153	155	156	159	154	153	166	174	176	167	164	164	168	166

Delta to Scen 2:

	NPV	NPV 2040	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
IRP Reference Case with Updated Assumptions	62	40	(1)	(1)	(3)	(2)	(2)	(1)	3	2	7	7	(2)	0	(2)	(11)	11	7	9	9
Updated Plan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Updated Plan with Legacy Purchase/Sale and Jur Future	(198)	(75)	(0)	(0)	(1)	1	2	3	7	8	6	4	(8)	(10)	(11)	(20)	(11)	(14)	(16)	(24)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Restack Solar, CBED, Biomass	(249)	(123)	(8)	(8)	(9)	(7)	(6)	(5)	1	2	(0)	0	(10)	(12)	(13)	(3)	(10)	(16)	(17)	(26)
Updated Pref Plan with Legacy Purchase/Sale and Jur Future, Share 1500MW wind	(251)	(126)	0	0	0	0	(0)	(1)	(1)	(1)	(5)	(8)	(20)	(23)	(23)	(23)	(11)	(14)	(16)	(25)
ND separation 2023	(317)	(163)	(0)	(0)	(1)	1	2	3	(12)	(8)	(2)	(3)	(15)	(17)	(20)	(31)	(20)	(16)	(17)	(25)
ND separation 2025, CT	(276)	(125)	(0)	(0)	(1)	1	2	3	7	8	(4)	1	(12)	(14)	(17)	(28)	(17)	(13)	(14)	(22)
ND separation 2025, CC	37	124	(0)	(0)	(1)	1	2	3	7	8	34	46	33	32	30	19	12	14	15	10
ND separation 2025, CT, no nuclear	(330)	(173)	(0)	(0)	(1)	1	2	3	7	8	(15)	(4)	(17)	(16)	(20)	(29)	(32)	(29)	(32)	(35)
ND separation 2025, CC, no nuclear	(38)	49	(0)	(0)	(1)	1	2	3	7	8	9	24	13	15	13	5	3	7	6	4
ND separation 2027	(229)	(77)	(0)	(0)	(1)	1	2	3	7	8	6	4	3	10	7	(6)	(14)	(14)	(15)	(22)

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
3,775	3,907	3,975	4,151	4,291	4,420	4,655	4,831	4,968	5,125	5,270	5,519	5,693	5,979	6,184	6,343	6,528	6,759	6,954
3,536	3,656	3,717	3,875	3,986	4,123	4,333	4,472	4,609	4,757	5,151	5,351	5,518	5,794	6,050	6,235	6,425	6,650	6,884
3,547	3,672	3,754	3,923	4,040	4,159	4,374	4,517	4,633	4,801	5,218	5,424	5,593	5,879	6,148	6,314	6,524	6,732	6,975
3,548	3,673	3,754	3,924	4,040	4,160	4,374	4,518	4,633	4,801	5,218	5,424	5,593	5,879	6,148	6,314	6,524	6,732	6,975
3,553	3,678	3,760	3,931	4,048	4,168	4,383	4,527	4,644	4,811	5,220	5,424	5,592	5,879	6,147	6,314	6,524	6,732	6,975
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920
3,532	3,650	3,728	3,893	4,006	4,128	4,336	4,497	4,618	4,767	5,102	5,387	5,572	5,859	6,125	6,287	6,496	6,703	6,920
3,532	3,650	3,728	3,893	4,006	4,128	4,336	4,497	4,618	4,767	5,102	5,387	5,572	5,859	6,125	6,287	6,496	6,703	6,920
3,531	3,649	3,726	3,891	4,005	4,127	4,335	4,496	4,617	4,766	5,102	5,387	5,571	5,859	6,125	6,287	6,496	6,702	6,920

239	251	259	277	305	297	322	359	359	368	118	168	176	185	134	107	103	110	70
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	16	37	48	53	37	41	45	24	44	66	73	75	85	98	79	99	83	92
12	16	37	49	54	37	41	45	24	44	66	73	75	85	98	79	99	83	92
17	22	44	56	62	45	50	55	35	54	68	72	75	85	98	78	99	82	91
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36
(4)	(6)	11	18	20	5	3	25	9	10	(49)	36	54	65	76	52	71	53	37
(4)	(6)	11	18	20	5	3	25	9	10	(49)	36	54	65	76	52	71	53	37
(5)	(8)	10	17	19	4	2	24	8	9	(49)	35	54	65	75	52	71	53	36

2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
208	215	220	231	239	247	260	270	278	287	295	310	319	336	347	356	367	380	391
194	201	205	214	220	228	240	248	255	264	286	298	308	326	341	352	363	376	389
179	184	186	184	184	187	211	217	219	223	225	229	235	236	232	233	270	280	285
178	182	184	182	183	210	212	214	217	221	223	227	233	234	230	232	269	279	284
178	183	184	182	182	185	208	214	216	220	225	229	235	236	232	234	271	281	286
158	160	163	166	168	171	199	205	207	210	212	215	218	222	226	229	233	238	235
161	163	166	168	170	172	200	206	209	211	213	216	220	224	227	231	235	239	243
195	200	204	208	212	217	222	227	233	239	244	250	257	265	271	279	286	295	302
155	157	160	162	164	167	195	201	204	207	210	214	217	221	224	228	232	237	241
194	198	202	207	211	216	221	226	232	238	244	250	257	264	271	278	286	295	302
161	162	165	168	170	172	199	205	207	210	213	216	219	223	227	230	234	239	243

14	15	16	17	19	19	20	22	22	23	9	12	11	10	6	5	4	5	2
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(15)	(17)	(19)	(30)	(36)	(41)	(29)	(31)	(36)	(41)	(61)	(69)	(74)	(90)	(109)	(119)	(93)	(95)	(104)
(16)	(18)	(20)	(31)	(38)	(18)	(27)	(33)	(38)	(43)	(63)	(71)	(75)	(91)	(111)	(120)	(94)	(97)	(105)
(16)	(18)	(20)	(32)	(38)	(43)	(32)	(34)	(39)	(44)	(61)	(69)	(73)	(89)	(109)	(118)	(92)	(95)	(103)
(36)	(41)	(42)	(48)	(52)	(57)	(41)	(43)	(48)	(54)	(74)	(83)	(90)	(103)	(115)	(122)	(129)	(137)	(154)
(33)	(38)	(39)	(45)	(50)	(56)	(40)	(41)	(47)	(53)	(73)	(82)	(89)	(102)	(114)	(121)	(128)	(136)	(146)
2	(1)	(1)	(6)	(8)	(11)	(18)	(21)	(23)	(25)	(42)	(48)	(51)	(61)	(70)	(73)	(76)	(81)	(86)
(39)	(44)	(45)	(51)	(56)	(61)	(45)	(46)	(51)	(57)	(76)	(84)	(91)	(104)	(117)	(123)	(130)	(139)	(148)
0	(2)	(2)	(7)	(10)	(12)	(19)	(22)	(24)	(26)	(42)	(48)	(51)	(61)	(70)	(73)	(77)	(81)	(87)
(33)	(38)	(39)	(46)	(50)	(56)	(41)	(43)	(48)	(54)	(73)	(82)	(89)	(102)	(114)	(121)	(128)	(137)	(146)

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company 2013 Electric Rate Increase Application	**Case No. PU-12-813**
Northern States Power Company Advanced Determination of Prudence – Courtenay Wind Application	**Case No. PU-13-706**
Northern States Power Company Advanced Determination of Prudence – Odell Wind Application	**Case No. PU-13-707**
Northern States Power Company Advanced Determination of Prudence – Pleasant Valley Application	**Case No. PU-13-708**
Northern States Power Company Advanced Determination of Prudence – Border Winds Application	**Case No. PU-13-742**
Northern States Power Company 150 MW Border Winds Project – Rolette County, ND Public Convenience & Necessity	**Case No. PU-13-743**
Northern States Power Company Advanced Determination of Prudence – NG Generators Application	**Case No. PU-13-194**
Northern States Power Company Red River Valley NG Unites 1&2 – Hankinson, ND Public Convenience &Necessity	**Case No. PU-13-195**

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Philip J. Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matters under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Philip J. Martin

Subscribed and sworn to before me this 10th day of July, 2017.

Notary Public
My commission expires: 1/31/2020

JOHN S. LIVINGSTON
NOTARY PUBLIC - MINNESOTA
My Commission Expires
January 31, 2020