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Direct Testimony and Schedules
Farah L. Mandich

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL22-____
Exhibit___(FLM-1)

Resource Prudence

June 30, 2022

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Farah L. Mandich. I am the Director of Resource Planning and Bidding for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company). The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company's affiliate, Northern States Power, a Wisconsin corporation (NSPW), provides electric service to customers in Wisconsin and Michigan. The Company and NSPW, together under the Interchange Agreement, own and operate the five-state integrated NSP System.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since April 2019 in the areas of Regulatory Affairs and Resource Planning. I have been in my current position since September 2021. In my first role with the Company, in the Regulatory Affairs department, I worked with cross-functional teams to develop Integrated Resource Plan and resource acquisition filings for NSP.

Prior to joining Xcel Energy, I worked as a Policy Advisor for Southern California Edison, a large investor-owned utility in California. In this role, I supported development of Integrated Resource Planning and resource acquisition regulatory filings before the California Public Utilities Commission. My statement of qualifications is provided as Exhibit___(FLM-1), Schedule 1.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in South Dakota, North Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition and retirement decisions for electric generation resources. Among other things, I oversee our resource planning efforts to evaluate long-term generation resource portfolio plans, conduct economic evaluations of potential resource additions, and conduct bid processes for new resource acquisitions.

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

A. The purpose of my testimony is to support the prudence of the following resource additions and retirement decisions that the Company has made since the Company's last South Dakota rate case:

- Retirement of Allen S. King Generating Plant (King) and Sherburne County Generating Station Unit 3 (Sherco 3) in 2028 and 2030, respectively;
- Roll-in of sixteen wind projects (Wind Projects) that were previously approved for inclusion in the Infrastructure Rider into rate base;
- Repowering of the 100.5 MW Grand Meadows Wind Project; and
- Cancellation of the Prairie Island Extended Power Uprate (EPU).

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

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

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO SHERCO 3 AND KING IN THIS CASE?

A. The Company requests that the Commission find the Company's planned retirement dates for Sherco 3 and King prudent and allow the Company to adjust the remaining lives of the plants for depreciation purposes as further described by Company Witness Ms. Laurie Wold. The Company is planning to retire these large coal-fired units several years ahead of their originally planned retirement dates. As shown in the economic analysis I describe later in my Testimony, the Company's decision to retire these plants is a net benefit for customers under a range of future scenarios, given that they can be replaced with more cost-effective resources.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE WIND PROJECTS IN THIS CASE?

A. The Company requests that the Commission approve the "roll-in" of several Wind Projects to allow recovery of these resources in base rates: Pleasant Valley, Border, Courtenay, Foxtail, Lake Benton, Crowned Ridge II, Blazing Star I & II, Freeborn, Jeffers, Mower Wind, Dakota Range I and II, Northern Wind, Nobles Wind and a proxy price for Community Wind North. Cost recovery of these Wind Projects has previously been found prudent and they have been approved by the Commission for inclusion in the Infrastructure Rider; the Company is now requesting that these Projects be rolled into base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO GRAND MEADOWS IN THIS CASE?

A. The Company requests that the Commission find that the Company's proposed repowering of the 100.5 MW Grand Meadows Wind Project is prudent and allow recovery of this repowered project in base rates. Grand Meadows is expected to achieve commercial operation in 2023, and therefore the Company did not request inclusion of Grand Meadows in its 2021 Infrastructure Rider filing. As a result, the Commission has not yet had the opportunity to review the prudence of this project; however, as I discuss further below, the Company's analysis demonstrates that the Grand Meadows repowering will generate savings of **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million, assuming it would otherwise be replaced by a generic wind resource at the end of the existing plant's life, and **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings when market energy is used as the replacement resource in the model. These savings are on a present value of revenue requirements (PVRR) basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My Testimony is organized as follows:

- Section II presents a summary of the types of economic analysis discussed throughout my testimony;
- Section III presents the Company's decision to retire Sherco 3 and King earlier than anticipated, and the prudence of that decision;
- Section IV presents the Company's proposed roll-in of the Wind Projects from the Infrastructure Rider into base rates.
- Section V describes the Company's addition of the 100.5 MW Grand Meadows Wind Project and the prudence of that investment;
- Section VI describes the Company's decision to undertake, and subsequently cancel, the Prairie Island EPU; and,
- Section VII sets forth my conclusions and recommendations regarding the prudence of these various resource additions and retirements.

II. SUMMARY OF TYPES OF ECONOMIC ANALYSIS

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

A. The Company has used three different types of economic analyses to evaluate the PVRR impacts of resource additions and retirements, all of which are discussed at various points in my testimony: (1) a pro forma modeling approach, (2) an analysis using the Strategist resource planning model (Strategist), and (3) an analysis using the EnCompass resource planning model (EnCompass).

Q. WHAT IS A PRO FORMA MODELING ANALYSIS?

A. A pro forma analysis is a simple way to isolate the anticipated costs or benefits of making changes to a specific resource without engaging in full system production cost and expansion plan modeling. This approach uses project cost and production information, along with the Company's financial assumptions, to evaluate the present value and annual cost implications of a proposed acquisition. In general, the pro forma model provides us a simpler view of the economic costs or benefits of a single project, based on revenue requirements, than Strategist or EnCompass. We often use this modeling internally, to estimate revenue requirements for inclusion in Strategist and EnCompass modeling, and to evaluate existing resource repowering proposals – where the relevant analysis is related to an existing unit on the system rather than a decision to add incremental resources.

Q. WHAT IS THE STRATEGIST RESOURCE PLANNING MODEL?

A. Strategist is a modeling program that the Company used for many years to simulate the operation of the NSP System and estimate the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. Strategist is a load duration model, in which the model plans capacity to a peak demand value each year and subsequently assesses whether the plan is energy sufficient to cover other periods of time. Until recently, the Company used this tool for the majority of its resource planning efforts. Compared to the pro forma analysis, Strategist helps us evaluate proposed acquisitions in the broader context of the integrated NSP System and our most recent Integrated Resource Plan's Preferred Plan by fully evaluating the impacts of an action relative to our entire resource portfolio.

Q. WHAT IS THE ENCOMPASS MODELING TOOL?

A. Like Strategist, Encompass is a capacity expansion tool that allows the Company to optimize resource expansion plans based on a set of assumptions. One of the primary differences in the models is that Encompass evaluates resource needs and cost on a chronological hourly basis, which better accounts for hourly variations on our system than the Strategist model's load duration approach. This is an important feature that allows us to better account for the variable nature of renewable energy and duration-limited resources, such as energy storage or demand response. A full description of the EnCompass modeling tool is included in Schedule 2 to my Testimony. While we sometimes still use components of the Strategist model to develop revenue requirement estimates to input into EnCompass, all of our planning is now done using the EnCompass tool.

III. SHERCO 3 AND KING

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

A. In this section, I explain the basis for the Company's request that the Commission find our planned retirement dates for Sherco 3 and King prudent and allow the Company to adjust its depreciation rates accordingly.

A. Summary of Decision to Retire Sherco 3 and King

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

A. The Sherburne County Generating Station (Sherco) in Becker, Minnesota is the Company's largest power plant in the Midwest, with its three coal-fired units capable of providing a total of approximately 2,200 MW of electricity. Sherco Unit 3 was placed in service in 1987 and is has a production capacity of approximately 927 MW. Sherco 3 is 41 percent owned by the Southern Minnesota Municipal Power Agency (SMMPA), which is composed of municipal power companies operating on a cooperative basis. Sherco Units 1 and 2 were placed in service in 1976 and 1977, respectively, and have a production capability of approximately 650 MW each.

Q. IS THE COMPANY MAKING ANY REQUESTS WITH RESPECT TO SHERCO UNITS 1 AND 2 IN THIS RATE CASE?

A. Yes. Both Sherco Units 1 and 2 have current approved retirement dates in South Dakota for depreciation purposes of December 2022. As Company Witness Ms. Laurie Wold discusses, the Company is proposing to extend the remaining life at Sherco Units 1 and 2 to 2026 and 2023, respectively, to reflect our current plans for the retirement of each unit, and to reallocate the depreciation reserve for Sherco Units 1 and 2 to Sherco Unit 3, in order to mitigate rate impacts on customers.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ALLEN S. KING PLANT.

A. The Allen S. King (King) Power Plant is a single-unit coal-fired generating facility located on the St. Croix River in Oak Park Heights, Minnesota. The King plant was placed in service in 1968 and has a total nameplate capacity of 598 MW. The King plant underwent a significant rehabilitation from 2004-2007 as part of Xcel Energy's Metro Emissions Reduction Project (MERP).

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO KING AND SHERCO 3 IN THIS RATE CASE?

A. The Company is asking the Commission to adjust the remaining lives of King and Sherco 3 for depreciation purposes to match the Company's planned retirement dates for these units in 2028 and 2030, respectively. As I discuss further below, Company management first proposed to retire the King plant in 2028 (nine years early) and Sherco 3 in 2030 (four years early) in 2019, and this plan recently was approved by the Minnesota Public Utilities Commission (MPUC) in the Company's 2020-2034 Upper Midwest Integrated Resource Plan (IRP).

Q. WHAT ARE THE CURRENT REMAINING LIVES OF KING AND SHERCO 3 IN SOUTH DAKOTA?

A. The current depreciable life of King is through June 2037. For Sherco 3, the current depreciable life is through December 2034.

Q. WHEN DID THE COMPANY ANNOUNCE ITS PLAN TO RETIRE KING AND SHERCO 3 IN 2028 AND 2030, RESPECTIVELY?

A. The Company first announced its current retirement plans for King and Sherco 3 as part of the Company's upcoming resource planning process in 2019. In connection with this plan, the Company commissioned, reviewed, and undertook various economic and reliability related analyses to determine that it would be prudent to retire King in 2028 and Sherco 3 in 2030. As a result, both of these retirement dates were included in the Company's Preferred Plan in the 2019 Integrated Resource Plan.

Q. WHAT KIND OF ANALYSES DID THE COMPANY PERFORM REGARDING THE DECISION TO RETIRE KING AND SHERCO 3 IN ITS 2019 RESOURCE PLANNING PROCESS?

A. The Company performed a Baseload Study that included the following components, addressing system reliability and economic analysis:

- Midcontinent Integrated Systems Operator, Inc. (MISO) Attachment Y2 preliminary retirement studies, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns;
- Xcel Energy Transmission Reliability Studies, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems;
- Industry insights, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO Renewable Integration Impact Analysis (RIIA), which provide important insights into the combined effects of baseload generator

retirements in a region and grid impacts at increasing levels of renewable penetration; and

- A focused Strategist analysis, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

B. Reliability Analyses

Q. LET'S DISCUSS THE STUDIES YOU REFERENCED IN MORE DETAIL. AT A HIGH LEVEL, WHAT DO THE RELIABILITY ANALYSES ADDRESS WITH RESPECT TO THE PLANNED COAL RETIREMENTS?

A. The reliability analyses the Company undertook address, broadly, the concept of grid stability; in other words, whether the retirement of these two large baseload coal facilities will cause voltage, thermal or other stability concerns on the grid that would need to be mitigated in order for the plants to be able to retire. Grid stability is an engineering aspect of planning that our typical integrated resource planning economic modeling does not address, both because it can be highly locationally specific and it measures grid operation on a timescale much more granular than our economic modeling. That said, we want our analysis to capture the economic costs of those engineering study results; for example, mitigation measures that MISO may require of us in our resource plan modeling (per, for example the MISO Y2 study), to be sure we are appropriately accounting for the likely costs and benefits of those retirements as best we can, with the information we have at the time. For studies that are more qualitative and general to the broader MISO grid (such as the RIIA study), we also take information from those reports into account when evaluating potential future portfolios against each other.

Q. PLEASE DESCRIBE THE MISO Y2 AND RELIABILITY STUDIES.

A. The current process for retirement of generation resources in the MISO footprint is generally governed by Attachment Y to the MISO Tariff. Preliminary retirement studies fall under Attachment Y2, which is a confidential MISO analysis to determine if any adverse system stability impacts would occur as a result of potential generating resource retirement. The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. The Company submitted seven Attachment Y2 study requests with MISO, including retirement scenarios for King and Sherco 3. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues. We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our resource planning modeling of the baseload unit retirements. These represent an appropriate proxy of potential costs to inform the economic aspect of our Baseload Study, although the final scope and cost of mitigations will be determined when the units retire.

We further supplemented the MISO analysis with our own technical studies examining traditional NERC reliability measures such as system stability and response. This provides a more robust look at potential impacts from baseload changes on the NSP system and the regional MISO grid than MISO's Y2 studies. These technical studies simulated a number of varied conditions that consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. Note that these studies did not examine the early retirement of King and Sherco specifically, but the overall trend toward retirement of large baseload plants.

Q. WHAT WERE THE RESULTS OF THE MISO Y2 AND XCEL ENERGY RELIABILITY STUDIES?

A. In general, the MISO Y2 studies found that incremental retirements of baseload resources created manageable reliability impacts on the NSP System. The study analyzing the combined retirement of King and Sherco 3 found the need for an estimated $38.2 million to address several thermal overloads that the study identified may occur upon the units retiring. As noted above and discussed further below, we incorporated the MISO planning level estimated costs from the Y2 studies into our economic modeling of the baseload retirement scenarios for King and Sherco 3.

Xcel Energy's Transmission Reliability Studies provided a more robust analysis of the potential retirement of our remaining baseload units. In general, these studies found that – with currently available technologies – the system will need to retain a certain level of synchronous generation to ensure reliability, but that it is operable without traditional baseload generation like coal plants.

Q. PLEASE DESCRIBE THE MISO RIIA AND NERC STUDIES.

A. In 2017, MISO initiated a detailed exploration of assumptions regarding the way the electrical grid will work in the future in light of the "profound" change in the types of generating resources across its operating area and the implications that such a shift means for long-standing power system design and operational practices. The MISO RIIA study has three focus areas: (1) Resource Adequacy, or the ability to maintain the Planning Reserve Margin; (2) Energy Adequacy, or the ability to operate within generator limits such as ramp rates, min/max capacity, etc., transmission limits/ratings, and system limits such as energy balance and operating reserves; and (3) Operating Reliability, or the ability to operate the system within acceptable voltage and thermal limits and the ability to maintain stable frequency and voltage, and meet system performance requirements. In 2019, when we first determined that early retirement was likely appropriate, the MISO RIIA Study was ongoing, but one of the key conclusions was that renewable integration complexity increases sharply from 30 percent to 40 percent penetration.

NERC published its Generator Retirement Scenario Special Reliability Assessment on December 18, 2018 as part of its ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American bulk energy system (BES). NERC's key conclusion was that the generator retirements that are occurring disproportionately affect large baseload, solid-fuel generation (coal and nuclear), and it underscores the importance of taking a measured approach to baseload unit retirement that includes thorough examination of potential reliability implications.

Q. WHAT ARE THE IMPLICATIONS OF THESE RELIABILITY ANALYSES ON YOUR IRP AND THE DECISION TO RETIRE KING AND SHERCO 3?

A. In all, the reliability studies confirmed that there are stability implications of retiring large baseload units from our system, but also that those concerns can be addressed with other investments. They also confirmed that some synchronous generation (or a like transmission solution) is broadly needed on the grid to maintain stability, which confirms to us the importance of firm dispatchable generation broadly – though not necessarily these specific coal units – as part of our future portfolio. They also show that the transition away from large emitting baseload generation resources must be carefully managed in order to maintain resource adequacy and grid stability. These are all findings that we kept front of mind as we designed our economic analyses, which I discuss further below.

Q. WAS THERE ADDITIONAL CONSIDERATION GIVEN TO RELIABILITY IMPACTS BEYOND THESE STUDIES?

A. Yes. Reliability considerations are central to our resource planning process. In addition to the studies discussed above, we plan our system to be able to meet our capacity needs without reliance on the MISO capacity auction. As I discuss further below, when we evaluate potential future plans, we consider metrics such as the firm capacity to peak demand ratio, the number of shortfall events, the potential for unserved energy and loss of load hours, and the maximum 3-hour net load ramp. Through our resource planning process, we thoroughly considered the reliability impact of changing the retirement dates for Sherco 3 and King to ensure that we can continue to provide reliable service to our customers.

C. Economic Analyses

Q. DID THE COMPANY PERFORM ANY ECONOMIC ANALYSIS OF THE PROPOSED RETIREMENT OF KING AND SHERCO 3 IN 2028 AND 2030, RESPECTIVELY?

A. Yes. We developed fifteen scenarios with varying combinations and timing of baseload unit retirements. These scenarios also identified the size, type, and timing of new resources needed to continue meeting customers' needs and achieve our goal to reduce carbon emission 80 percent by 2030. We compared these scenarios to a Reference Scenario, which was essentially a "business as usual" case based on our prior (2016-2030) Resource Plan with respect to all of the baseload units retiring at their then-scheduled retirement dates.

Through this analysis, the scenario that eventually became the Company's Preferred Plan in its resource planning cycle was Scenario 9, in which King would be retired in 2028, Sherco 3 retired in 2030, the Monticello Nuclear Generating Plant (Monticello) extended until 2040, and the Prairie Island Nuclear Generating Plant (Prairie Island) units would operate through the end of their current licenses. In the Reference Scenario, King was scheduled to retire in 2037 and Sherco Unit 3 was scheduled to retire in 2040.[1] The Scenario 9 retirement assumptions are shown in Table 1 below. The full assumptions used in the 2019 Strategist modeling are provided in Exhibit___(FLM-1), Schedule 3.

Table 1: Scenario 9 Retirement Assumptions

Baseload Unit	Reference Scenario	Scenario 9/Preferred Plan Retirement Assumptions
A.S. King	2037	2028
Sherco Unit 3	2040	2030
Monticello	2030	2040
Prairie Island Unit 1	2033	2033
Prairie Island Unit 2	2034	2034

[1] In the subsequent modeling, discussed further below, the Sherco Unit 3 was modeled with a 2034 retirement date to reflect its depreciation life.

Q. HOW DID THE COMPANY ANALYZE THE DIFFERENT SCENARIOS?

A. After identifying the scenarios for analysis, we utilized the Strategist modeling tool to identify sets of resources needed to continue to meet customer needs for each scenario, along with their resultant costs and emissions impacts. We also included the planning level mitigation cost estimates from the MISO Y2 studies, as I discussed earlier.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S ECONOMIC ANALYSIS?

A. As noted above, the Company analyzed 15 different planning scenarios, representing various combinations of baseload retirements and/or extensions in the 2020-2034 planning period. Figures 1 and 2 below show the net present value delta of the modeled cost of each Scenario compared to the Reference Scenario, with negative values representing customer savings relative to the Reference Scenario and positive values representing increased costs. Figure 1 provides the Scenario deltas on a PVSC (present value of societal cost) basis which include the costs for carbon dioxide and other emissions. Figure 2 provides the Scenario deltas on a PVRR basis (present value of revenue requirements) which does not include any costs for emissions. In general, the plans that favored early coal retirements and nuclear extensions were the lowest cost plans on both a PVSC and PVRR basis.

Figure 1: Scenario PVSC Deltas from Reference Case

($2019 millions)

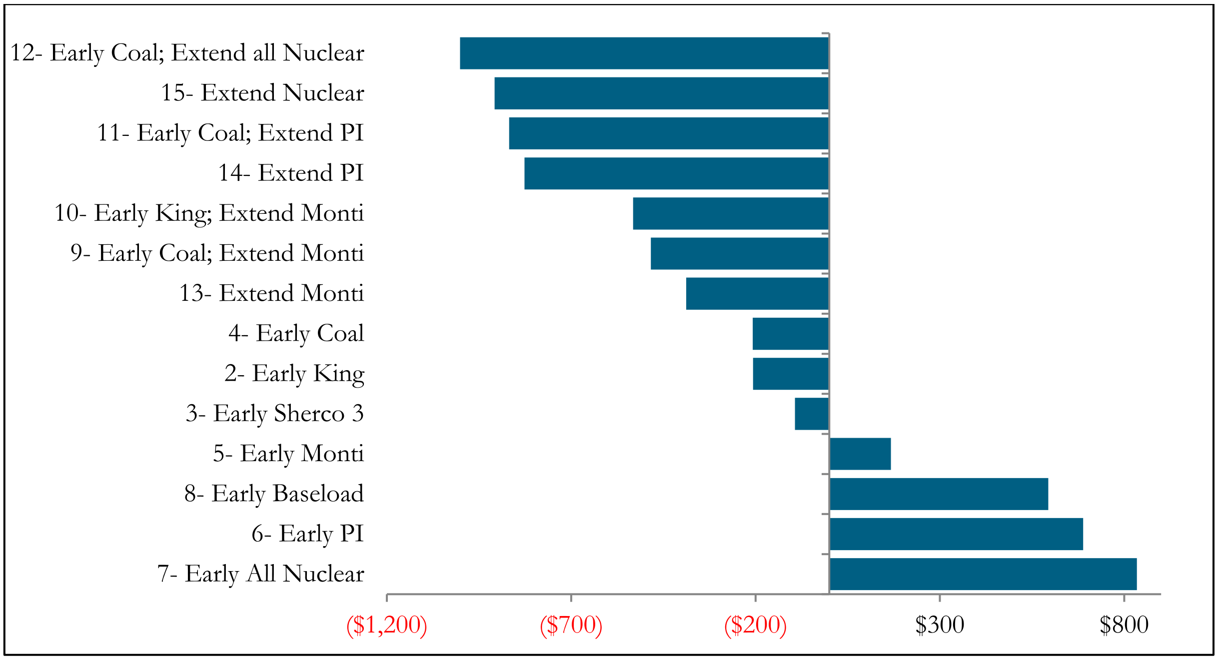
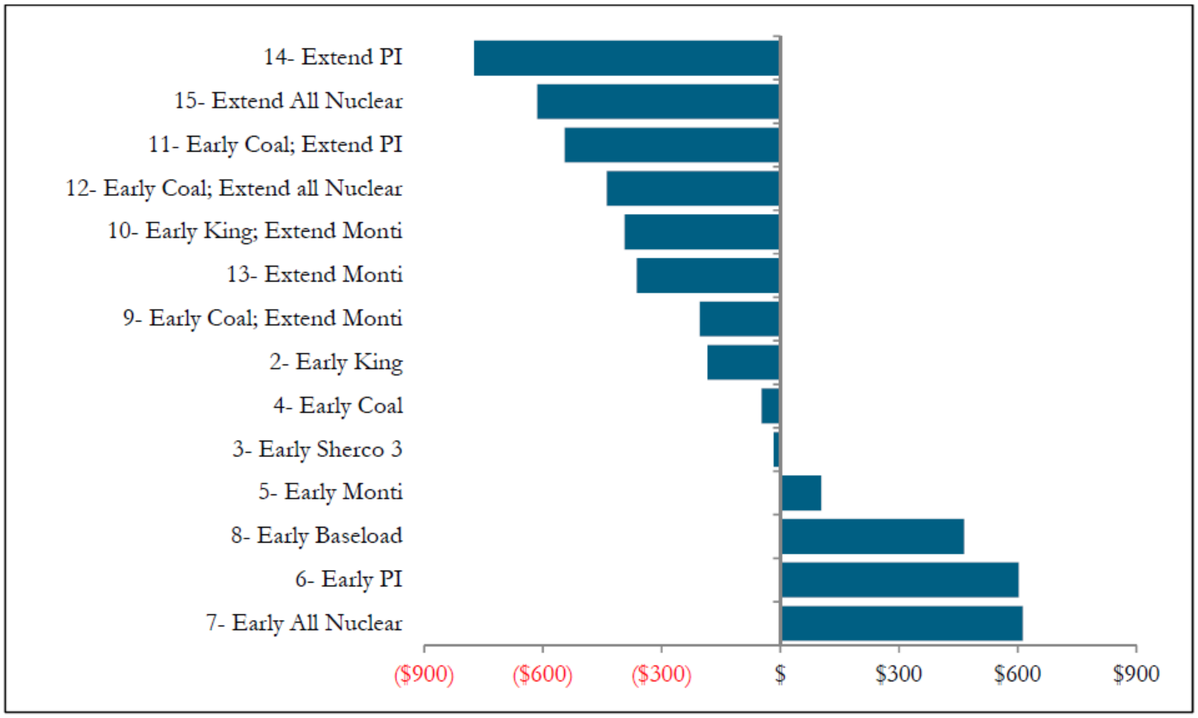


Figure 2: Scenario PVRR Deltas from Reference Case ($2019 millions)[2]



Q. WHAT DO FIGURES 1 AND 2 SHOW?

A. These figures show that the retirement of coal units were found in our 2019 Strategist modeling to be economically prudent, both as standalone decisions and in combination, and regardless of whether carbon costs are considered. We tested scenarios that examine Early Sherco retirement only (Scenario 3), Early King retirement only (Scenario 2) and several scenarios that retire both units early (scenarios labeled "Early Coal," including 4, and 9-12). All such scenarios resulted in savings relative to the Reference Case.[3] Further, scenarios that layer on nuclear unit extensions at the same time as early coal retirements generally resulted in the highest levels of savings. Figure 1 shows that early coal shutdown

[2] Note the PVRR deltas shown depict NPV for 2020-2045.

[3] I.e. net present value deltas from 0 are negative in the charts above, exemplifying that the scenario results in less costs than the Reference Case.

combined with extension of all nuclear units (Scenario 12) results in the most savings compared to the Reference Case, but Scenario 9 – which retires coal early but only extends Monticello – can achieve substantial savings in its own right while preserving the opportunity to extend Prairie Island in the future. Figure 2 shows that even when emissions costs are not considered, retirement of King in 2028 and Sherco 3 in 2030 is expected to result in savings for customers when compared with the Reference Scenario.

Q. HOW ARE THE COSTS OF EMISSIONS INCLUDED IN THE PVSC CALCULATION?

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

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

A. While no federal carbon regulation was in place at the time the 2019 IRP was filed, PVSC calculations are an important indicator of the costs and benefits of different resource portfolios under a future in which we would be subject to future environmental regulations. Planning a system without consideration of this potential regulation is a risk to customers, as these regulations can be implemented faster than the Company can change its resource portfolio and thus have the potential to impose costly environmental compliance investments later. Thus, PVSC calculations, while not required in South Dakota, are helpful to assess cost risks to customers and are an important decision-making tool for our Company's leadership when selecting a Preferred Plan.

Q. DID THE COMPANY SCREEN OUT ANY OF THE SCENARIOS SHOWN IN FIGURES 1 AND 2?

A. Yes. Because Prairie Island's license is not due to expire until the 2033-2034 timeframe, at the end of the planning period, the Company felt there was value in deferring a decision on Prairie Island license extension until a future Resource Planning process. The Company continues to work with the local community around Prairie Island on considerations regarding plant life extension. Ultimately, however, Scenario 9 preserves our opportunity to subsequently transition to other scenarios that could achieve more savings while also meeting our carbon reduction goals. As a result, the Company eliminated from consideration cases that included a Prairie Island extension, as shown in Figures 3 and 4 below.

Figure 3: Scenario PVSC Deltas from Reference Case, PI Extension Cases Eliminated ($2019 millions)

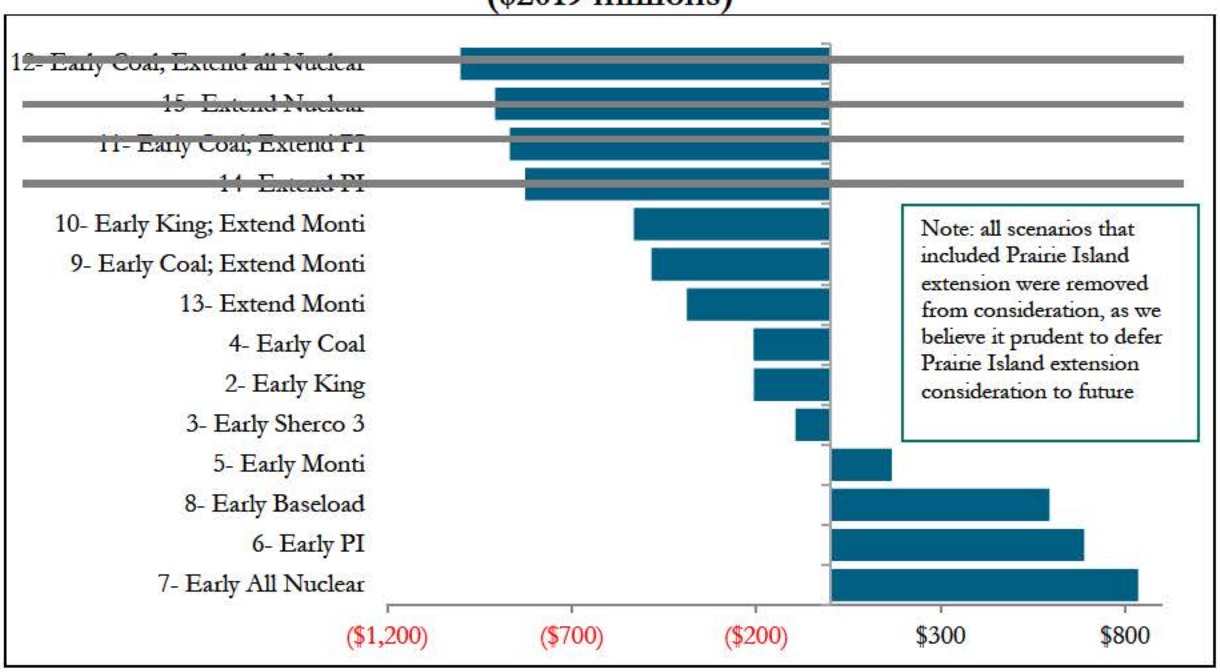
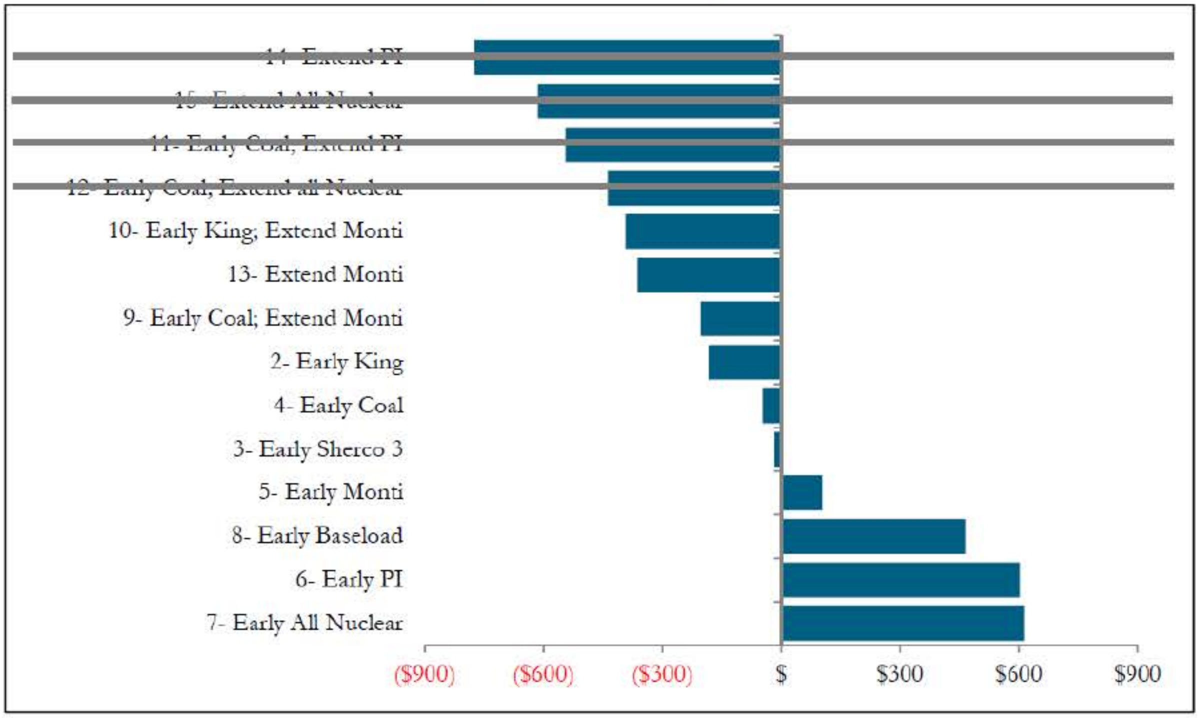


**Figure 4: Scenario PVRR Deltas from Reference Case,
PI Extension Cases Eliminated
($2019 millions)**



Q. WHAT WERE THE EXPECTED COST SAVINGS FOR SCENARIO 9?

A. The Strategist modeling indicated that Scenario 9, under which King would be retired in 2028, Sherco 3 retired in 2030, and Monticello extended to 2040, yielded customer savings of $204 million on a PVRR basis and $484 million on a PVSC basis in the 2020-2045 period, relative to the Reference Case. The Company also conducts sensitivities to test whether a particular scenario is robust across a broad range of future market conditions. Most of these sensitivities examine individual assumptions differences in isolation, so we can evaluate the impact of – for example – higher or lower market prices independent of any other changes. The sensitivity analysis demonstrated that Scenario 9 was expected to generate customer savings relative to the Reference

Case in all sensitivities analyzed, with a range of $96 million to nearly $750 million.

Q. DID THE COMPANY UPDATE THIS ANALYSIS DURING THE COURSE OF ITS RESOURCE PLANNING PROCESS?

A. Yes. The Company filed a Supplement to its IRP in June 2020. We made updates to several modeling inputs, accounting for the passage of time and further analysis requirements and, as noted above, we used the EnCompass modeling tool for the first time. The EnCompass model provides the additional capability of modeling our system on a chronological hourly basis. The more granular forecasting capabilities of EnCompass provide a more precise view of our future energy and capacity needs in light of increasing levels of variable renewables and duration limited resources on our system. We primarily used those modeling results to develop our Supplement Preferred Plan. The full Strategist and EnCompass assumptions used for the June 2020 modeling are provided in Exhibit___(FLM-1), Schedule 4.

In this same time period, we conducted updated reliability analyses in order to confirm that the proposed baseload retirements and transition to intermittent renewable resources would not jeopardize reliability on the system.

Q. HOW DID THE SUPPLEMENT PREFERRED PLAN DIFFER FROM YOUR INITIAL PLAN?

A. As noted above, we implemented the switch to EnCompass modeling for the Supplement Preferred Plan analyses. EnCompass better reflects grid operations and values a more complete range of resource attributes than Strategist modeling. Whereas an hourly chronological model will examine the value and performance capabilities of various resources relative to customer needs across each hour in a sample set of days and weeks – or a full year – a model that utilizes load duration curves for capacity expansion simulations primarily values capacity adequacy at an annual peak and assesses a more "averaged" value for energy. As a result, EnCompass expansion plans better account for resource contributions of variable renewables and duration limited resources – like battery energy storage – that may not be fully addressed in load duration modeling. As a result, the portfolios from our EnCompass modeling included a more diverse set of resources, balancing solar additions with more wind and firm peaking generation additions, than the Strategist expansion plans.

Q. DID THE JUNE 2020 ANALYSIS IMPACT YOUR DECISION TO RETIRE KING AND SHERCO 3 EARLY?

A. No. The updated economic and reliability analyses confirmed our decision to retire King and Sherco 3 and extend the life of the Monticello nuclear plant. We evaluated the same baseload retirement scenarios as in our initial plan. Figures 5 and 6 show the results of June 2020 analysis using both the Strategist and Encompass models:

Figure 5: Baseload Scenario PVSC Deltas, Relative to the Reference Case, in Strategist and EnCompass Modeling

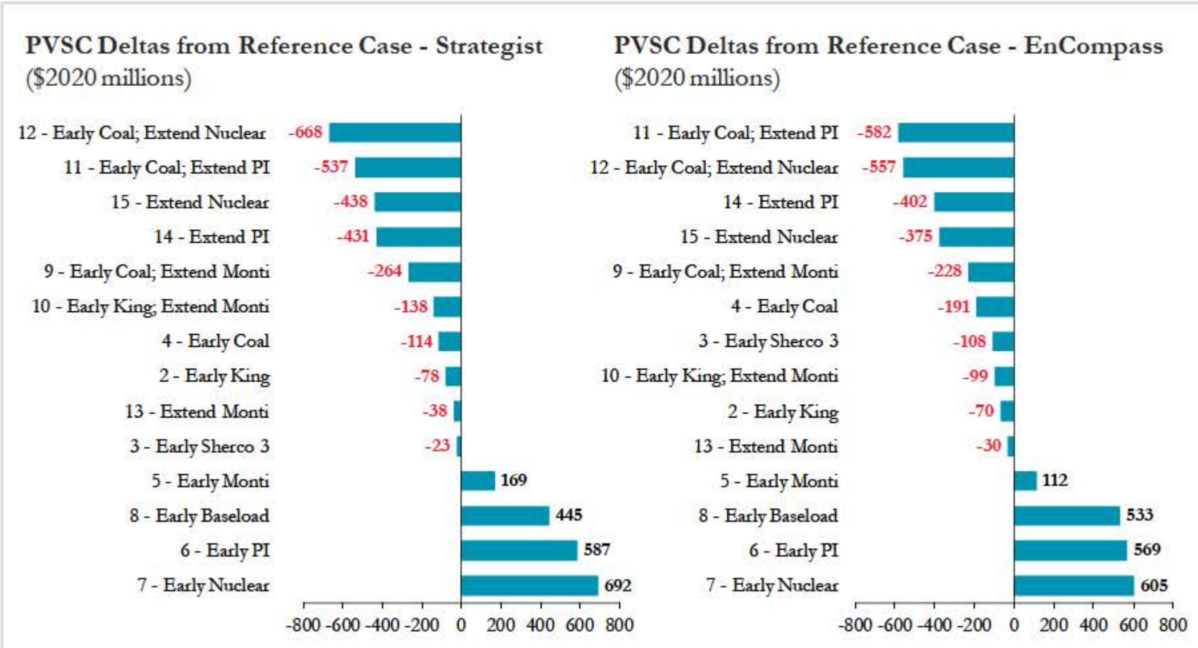
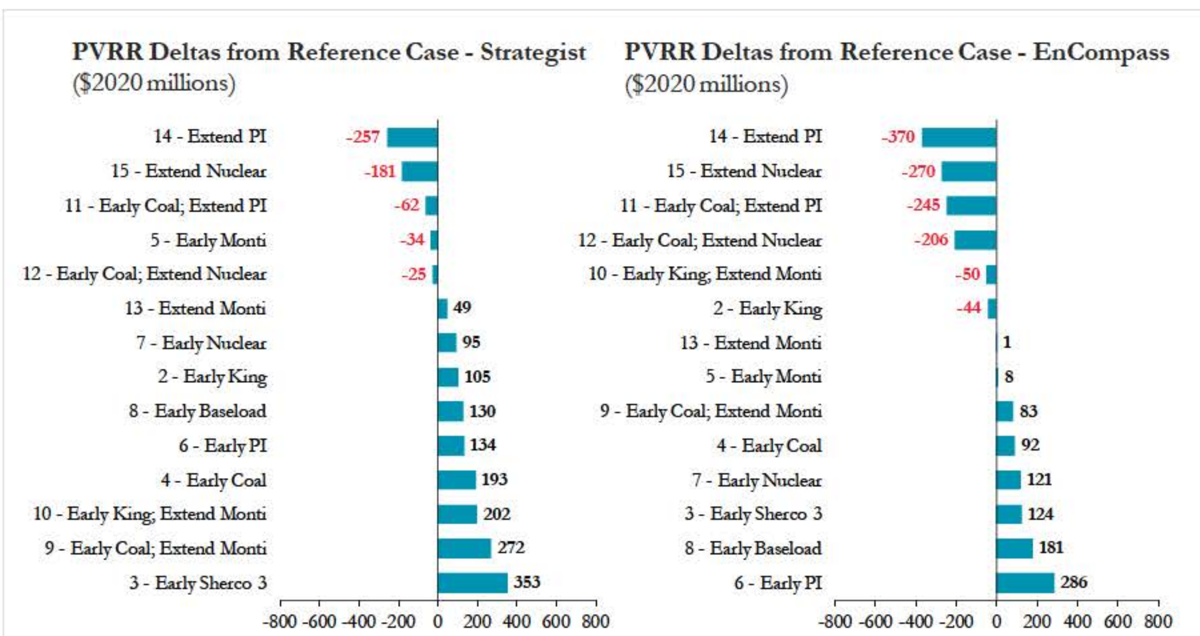


Figure 6: Baseload Scenario PVRR Deltas from the Reference Case



Q. WHAT DO FIGURES 5 AND 6 SHOW?

A. Figures 5 and 6 show that retirement of King in 2028 and Sherco 3 in 2030, which when considered together are referred to as "Early Coal" scenarios, continue to perform well when combined with extension of the nuclear plants. The Early Coal scenarios fare better on PVSC than a PVRR basis, but Scenario 12 generates savings compared with the Reference Scenario even when emissions costs are not considered. Further, while not shown in the figure above, Scenarios 9 and 12 were the only Scenarios that were able to achieve Xcel Energy's carbon reduction goals, which endeavor to reduce our carbon emissions attributable to serving customers by 80 percent from 2005 levels by 2030. Consistent with our initial analysis and selection of Scenario 9 as the basis of our Preferred Plan, the Company eliminated from consideration cases that included a Prairie Island extension, in order to preserve the option to extend later but address nearer term needs now. Our options after eliminating Prairie Island extension cases are shown in Figures 7 and 8 below.

Figure 7: 2020-2045 EnCompass PVSC Deltas from Reference Case

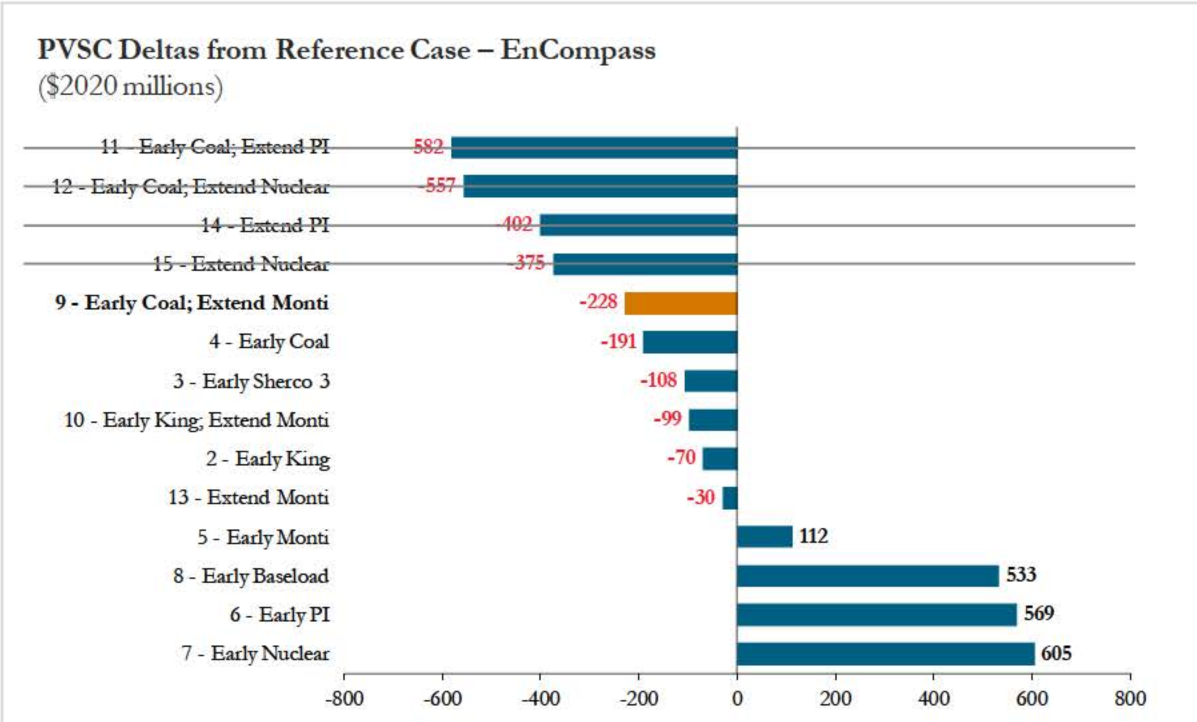
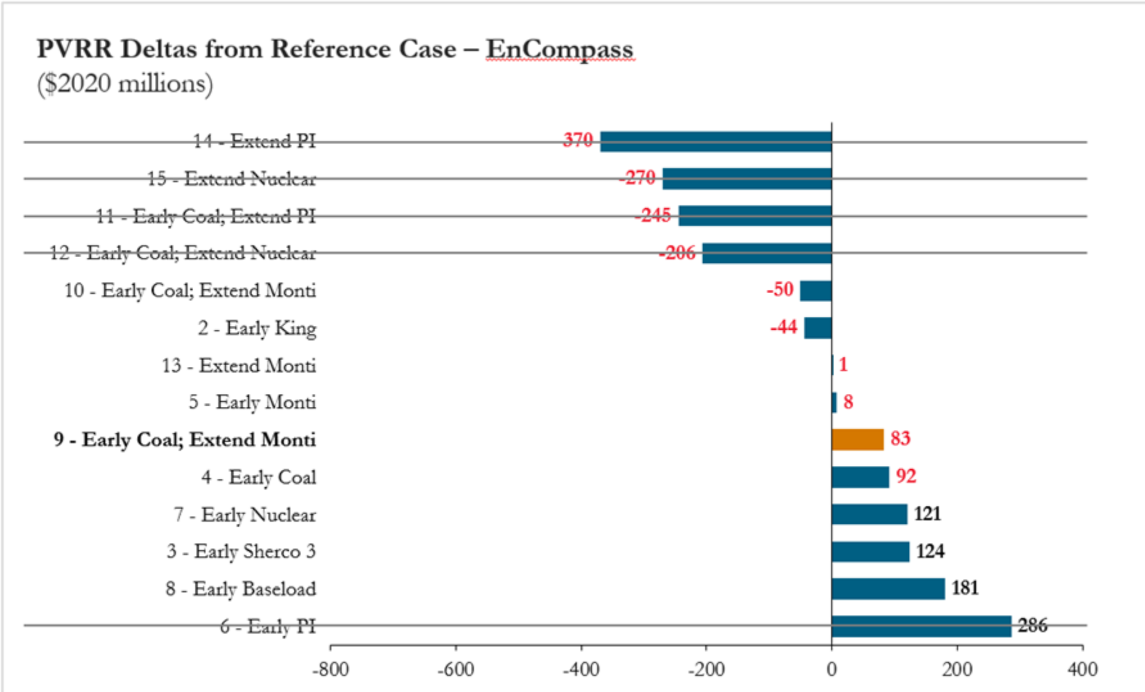


Figure 8: 2020-2045 EnCompass PVRR Deltas from Reference Case



Q. WHAT DO FIGURES 7 AND 8 SHOW?

A. Figures 7 and 8 show that on a PVSC basis, Scenario 9 provides the most cost-savings when the scenarios that include the extension of Prairie Island are set aside. While Scenario 9 shows somewhat increased costs on a PVRR basis, by preserving the option to extend Prairie Island, the selection of Scenario 9 allows for the option of transitioning to a scenario that would results in cost savings while achieving our carbon reduction goals. For this and other reasons as further described in our IRP, the EnCompass analysis confirmed that Scenario 9 continued to be an appropriate choice to form the basis of our Preferred Plan. Moreover, as discussed further below, additional analysis showed that an updated Scenario 9 would achieve savings on a PVRR basis.

Q. WHAT WAS THE ADDITIONAL ANALYSIS CONDUCTED AFTER THE JUNE 2020 IRP SUPPLEMENT ?

A. As part of our preparation of an "Alternate Plan" for our IRP in June 2021, the Company analyzed an updated Scenario 9 that removed the addition of a gas-fired combined cycle unit at the Sherco site, and added transmission tie-lines to re-utilize the available interconnection rights for other resources at both Sherco and King. As with the earlier analysis, we conducted additional analysis on the reliability of the Alternate Plan. A summary of the Alternate Plan is provided in Table 2 below, and the full assumptions used in this modeling are provided in Exhibit___(FLM-1), Schedule 5.

Table 2: Company Plan Performance Across Selected Key Planning Metrics

	Plan	Updated Scenario 9	Alternate Plan
Cost	PVSC delta ($ million, cost/(savings) relative to Reference Case)	($234)	($606)
	PVRR delta ($ million, cost/(savings) relative to Reference Case)	$96	($46)
Environment	Carbon reduction by 2030 (percent, from 2005 levels)	80%	86%
	Total carbon-free generation, 2034 (percent of total generation)	73%	82%
Risk and Reliability	Firm capacity-to-peak demand ratio	0.63	0.58
	Sensitivities - range of cost deltas relative to Reference Case	(1,090) – 124 *Median: (202)*	(2,163)-16 *Median: (544)*
	2034 Native capacity shortfall events	0	0
	2034 expected unserved energy (EUE)	0	0
	Loss of Load Hours (LOLH)	0	0
	2034 maximum 3-hour net load ramp under base assumptions (MW)	4,081	4,484

Q. WHAT DOES TABLE 2 SHOW?

A. Overall, both the Company's Supplement Plan as updated in Table 2 (Updated Scenario 9) and the Alternate Plan meet the goals of our core planning objectives, to reduce carbon at a reasonable cost, while also maintaining reliability and mitigating risk. The Supplement Plan achieves 80 percent carbon reduction and PVSC savings of $234 million relative to the Reference Case, but resulted in costs on a PVRR basis (consistent with our findings in our

Supplement modeling). The Alternate Plan achieves more savings on a PVSC basis ($606 million) as well as $46 million of savings on a PVRR basis. Both plans maintain reliability and mitigate customer risk, by including sufficient firm dispatchable generation to cover a substantial portion of customer load. Particularly in the winter where – as we have seen again in recent years – significant customer needs may occur when variable renewables cannot be "switched on" like a dispatchable generator with physical fuel often can. In the absence of a formal seasonal resource adequacy construct in MISO, being able to meet the majority of the Company's winter load with dispatchable resources on our system is a critically important risk and reliability consideration.

Q. HAS THE MINNESOTA COMMISSION APPROVED THE COMPANY'S PLANS TO RETIRE KING AND SHERCO 3?

A. Yes. In an April 15, 2022 order, the MPUC approved the Company's Alternate Plan reflecting this retirement plan, and also expressly ordered the Company to retire the King plant in 2028 and Sherco Unit 3 in 2030.[4] The Company has begun work to implement the Alternate Plan.

D. Summary

Q. WAS THE COMPANY'S DECISION TO RETIRE KING AND SHERCO 3 IN 2028 AND 2030, RESPECTIVELY, PRUDENT AT THE TIME THE DECISION WAS MADE?

A. Yes. The analysis supporting our initial decision to select Scenario 9 – including early retirement of both King and Sherco 3 – showed that customers would benefit from this decision relative to alternate scenarios in which the units were

[4] Minnesota Public Utilities Commission, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS, *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368 (April 15, 2022), Order Point 2.A.(4).

kept online to their previous retirement dates. Subsequent analyses in our IRP in 2020 and 2021 confirmed this decision with updated inputs.

Q. WHAT DOES THE COMPANY REQUEST IN THIS RATE CASE WITH REGARD TO KING AND SHERCO 3?

A. In this Rate Case, we are asking the Commission to adjust the remaining lives of these units to match our current plans to retire King and Sherco 3 in 2028 and 2030, respectively. As I stated earlier, our analysis of the plan to retire King and Sherco 3 at the dates proposed has demonstrated that Company leadership made the prudent choice in 2019 and in subsequent re-evaluations of our plans.

IV. WIND PROJECTS ROLL-IN

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

A. In this section, I explain the basis for the Company's request to roll sixteen Wind Projects that are currently being recovered through the Infrastructure Rider into base rates. The Wind Projects that are the subject of this request are: Pleasant Valley, Border, Courtney, Foxtail, Lake Benton, Crowned Ridge II, Blazing Star I, Blazing Star II, Freeborn, Jeffers, Community Wind North, Mower Wind, Dakota Range I and II, Northern Wind, and Nobles Wind. The Company requests that the Commission find the additions of the Wind Projects to be prudent and approve recovery of these resources in base rates.

A. Background on Wind Projects

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF EACH OF THE WIND PROJECTS

A. The Wind Projects that the Company is requesting be rolled into base rates, all of which are currently included in the Infrastructure Rider, are as follows:

- **Pleasant Valley**: The Pleasant Valley Wind Farm has an operating capacity of 200 MW and was placed in-service in November 2015. Pleasant Valley was approved by the Commission in Docket No. EL14-058.
- **Border**: The Border Wind Farm has an operating capacity of 150 MW and was placed in-service in December 2015. Border was approved by the Commission in Docket No. EL14-058.
- **Courtenay**: The Courtenay Wind Farm has an operating capacity of 200 MW and was placed in-service in December 2016. Courtenay was approved by the Commission in Docket No. EL15-038.

- **<u>Foxtail</u>**: The Foxtail facility has an operating capacity of 150 MW and was placed in-service in December 2019. Foxtail was approved by the Commission in Docket No. EL18-040.
- **<u>Lake Benton</u>**: The Lake Benton facility has an operating capacity of 100 MW and was placed in-service in November 2019. Lake Benton was approved by the Commission in Docket No. EL18-040.
- **<u>Crowned Ridge II</u>**: The Crowned Ridge Build-Own-Transfer (BOT) project was approved by the Commission in Docket No. EL18-040. The Crowned Ridge Wind Project, located in Codington, Deuel, and Grant counties in South Dakota, initially consisted of two parts: a 300 MW PPA (Crowned Ridge I) and a 300 MW BOT project (Crowned Ridge II). Due to a MISO study that identified high costs associated with required transmission upgrades, the Company ultimately only transacted for 200 MW of Crowned Ridge I and 200 MW of Crowned Ridge II. Crowned Ridge II achieved commercial operation in late 2020 and qualifies for 100 percent Production Tax Credits (PTCs).
- **<u>Blazing Star I</u>:** The Blazing Star I facility has an operating capacity of 200 MW and was placed in-service in April 2020. Blazing Star I was approved by the Commission in Docket No. EL18-040.
- **<u>Blazing Star II</u>**: The Blazing Star II project is a 200 MW project located in Lincoln County, Minnesota that was approved by the Commission in Docket No. EL19-035. Blazing Star II achieved commercial operation in January 2021 and qualifies for 100 percent PTCs.
- **<u>Freeborn</u>**: The Freeborn project was also approved by the Commission in Docket No. EL19-035 and is a 200 MW project located near Glenville, Minnesota. Freeborn achieved commercial operation in May 2021, slightly

later than anticipated due to permitting delays and global supply chain issues caused by COVID-19. Despite the delay, the Freeborn project qualifies for 100 percent PTCs.

- **<u>Jeffers</u>**: Jeffers is a 44 MW repowering project in Cottonwood County, Minnesota that was approved by the Commission in Docket No. EL20-026. The repowering project increased the output generated at Jeffers and requalified the project for new PTCs. Jeffers achieved commercial operation in January 2021 and qualifies for 100 percent PTCs.
- **<u>Community Wind North</u>**: Community Wind North is a 26.4 MW repowering project in Lincoln County, Minnesota. The Commission approved a proxy price recovery for Community Wind North consistent with the previous PPA in Docket No. EL20-026. The repowering increased the output generated at Community Wind North and requalified the project for new PTCs. Community Wind North achieved commercial operation in January 2021 and qualifies for 100 percent PTCs.
- **<u>Mower Wind</u>**: Mower Wind is a 98.9 MW repowering project in Mower County, Minnesota that was also approved by the Commission in Docket No. EL20-026. The repowering increased the output generated at Mower and requalified the project for new PTCs. Mower Wind achieved commercial operation in December 2020 and qualifies for 100 percent PTCs.
- **<u>Dakota Range I and II</u>**: the Dakota Range I & II (Dakota Range) project is a 302.4 MW self-build wind project located 20 miles north of Watertown, South Dakota that was approved by the Commission in Docket No. EL20-026. The Commission granted a permit to construct the Dakota Range facility on July 23, 2018 in Docket EL18-003, and granted the transfer of

the permit to the Company on March 9, 2020. Dakota Range achieved commercial operation in January 2022, and qualifies for 100 percent PTCs.

- **Northern Wind**: Northern Wind is a BOT project located in Murray County, Minnesota and consisting of a 100 MW repowered facility and a 20 MW expansion immediately adjacent to the existing facility. The Commission approved Northern Wind in Docket No. EL21-028. The project is expected to achieve commercial operation in December 2022.
- **Nobles Wind**: Nobles Wind is a 201 MW repowering project located in Nobles County, Minnesota that was originally placed into service in 2010. The repowering will replace internal nacelle components, hub, and blades, resulting in an increase to the capacity factor and a total nameplate capacity of 214.4 MW. The Commission approved the Nobles Wind repowering in Docket No. EL21-028. The project is expected to achieve commercial operation in December 2022.

B. Economic Analysis of the Wind Projects

Q. DID THE COMPANY PERFORM AN ECONOMIC ANALYSIS ON EACH OF THE WIND PROJECTS PRIOR TO EACH PROJECT BEING ADDED?

A. Yes. The Company performed capacity expansion modeling on each of the Wind Projects that shows the expected net costs or benefits of each of the Projects at the time we decide to add each project to our system.. Tables 3 through 8 below show the expected net benefits of each of the Wind Projects at the time of the acquisition decision.

Tables 3–8 —Wind Projects Benefits

Table 3: Courtenay, Pleasant Valley, and Border (2015-2016 COD)

Wind Farm	MW	PVSC	PVRR - Base Case ($ millions)	PVRR - Low Gas ($ millions)
Courtenay	200	($147)	($60)	($10)
Pleasant Valley	200	($200)	($90)	($17)
Border	150	($124)	($45)	$8

Table 4: 1550 Wind Portfolio and Dakota Range (2020-2021 COD)

Wind Farm	MW	PVSC	PVRR - Base Case ($ millions)	PVRR - Low Gas ($ millions)
Crowned Ridge II	200	($447)	($245)	($137)
Lake Benton	100	($139)	($50)	($12)
Blazing Star I	200	($377)	($159)	($72)
Blazing Star II	200	($361)	($144)	($57)
Foxtail	150	($274)	($109)	($44)
Freeborn	200	($325)	($131)	($50)
Dakota Range I & II	302	($295)	($167)	($91)

Table 5: Jeffers and CWN (2021 COD)

PVSC	($32)
PVSC -Low Gas	($17)
PVRR	($7)

Table 6: Mower (2020 COD)

Wind Farm	MW	PVSC	PVRR - Base Case	Wind Farm
Mower	99	($44)	($49)	($48)

Table 7: Wind Repower Portfolio (includes Nobles-2022 COD)

PVSC	($260)
PVRR	($163)
PVRR - Low Gas	($98)

Table 8: Northern Wind Repower (2022 COD)

PVSC	($58)
PVRR	($54)
PVRR - Low Gas	($62)

Q. WHAT DO TABLES 3 THROUGH 8 SHOW?

A. Tables 3 through 8 show the benefits of the Wind Projects based on the PVSC and PVRR analyses, and also include a PVRR "low gas" sensitivity. These Tables show that all of the Wind Projects were found to be expected to provide net benefits to customers under their respective base case scenarios (i.e. relative to a case where they were not pursued), and all but one of the Wind Projects provide a net benefit under its respective low fuel cost scenario.

Q. WHAT DO THE "LOW GAS" COLUMNS IN THE ABOVE TABLES REPRESENT?

A. This column represents an analysis in which each project was evaluated relative to its base case under a future assumption of low coal, gas, and market prices. This is a helpful benchmark because, as wind plants are typically viewed as a fixed-cost hedge against variable fuel prices, it shows whether the wind investments would still yield savings even if future fuel prices were lower than expected in our base assumptions. Although not shown in the Tables, a future scenario in which gas prices were much higher than anticipated would result in more customer savings due to the fuel savings generated by the wind projects. This trade off – moving toward higher fixed-cost but zero variable-cost renewable energy rather than plants with higher marginal production costs , where fuel prices can vary substantially, is the basis of the Company's "Steel for Fuel" strategy.

Q. WILL THE EXPECTED BENEFITS SHOWN IN TABLES 3 THROUGH 8 CHANGE IF THE PROJECTS ARE ROLLED INTO BASE RATES?

A. No. The net benefits shown in Tables 3 through 8 represent the expected PVSC and PVRR impact of adding each of the Wind Projects to the NSP System as modeled at the time of each respective decision, regardless of whether the costs of each resource are recovered through the Infrastructure Rider or base rates. Furthermore, Tables 3 through 8 show the expected net benefits of the Wind Facilities at the time they were proposed, thus these calculations will not change if the Wind Projects are rolled into base rates.

Q. WHAT IS THE SOURCE OF THE SAVINGS SHOWN IN TABLES 3 THROUGH 8?

A. The savings shown in Tables 3 through 8 are generally due to the decreased fuel costs of the Wind Projects outweighing the costs of adding the Projects over the life of each project. Thus, the projects are anticipated to result in long-term energy costs that will be lower than they would otherwise have been had the given wind resource not been selected. In a future scenario in which natural gas costs are lower, the fuel savings from the Wind Projects are diminished to a certain extent. On the flip side, however, we expect wind additions to show higher benefits under a future scenario in which gas prices are higher.

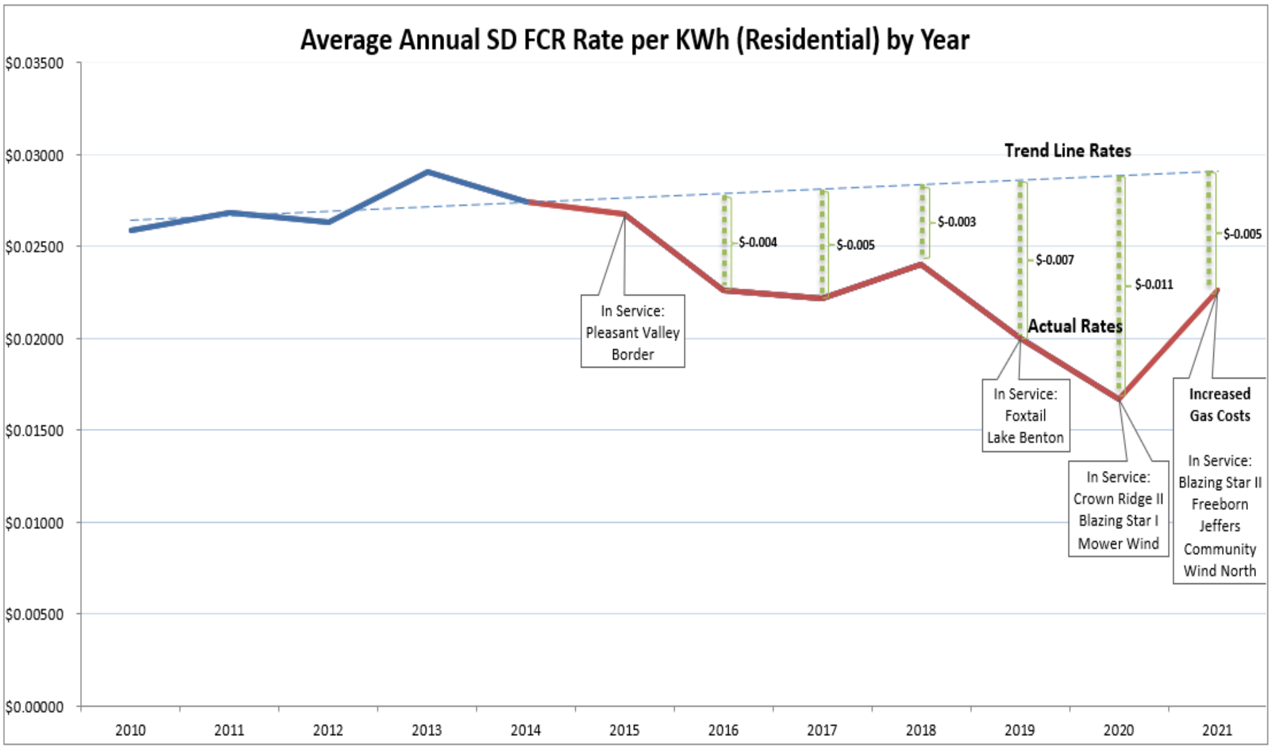
Q. WHEN WILL THE SAVINGS FROM THE WIND PROJECTS OCCUR?

A. It is difficult to demonstrate the actual occurrence of the estimated savings for each Wind Project because the comparison being made is to the costs (occurring over the life of the project) of a future resource alternative that will never actually be experienced. Thus, the modeling we conduct to evaluate projects is most appropriately viewed as an economic decision-making tool – comparing a future system with the plant in question to a future without it – rather than an indication of specific rate savings. However, historical trends in our fuel and purchased energy costs as reflected in the Fuel Clause Charge Rider (FCC) appear to show that energy cost savings have occurred in recent years that can at least partially be the result of the Company's use of wind resources, including the Wind Projects.

Q. PLEASE ELABORATE.

A. Figure 9 below represents a graph of the annual average monthly FCC rates from 2010 through 2021 for residential customers in South Dakota, as shown in the solid line. Note that in the period from 2010-2015, prior to the addition of most of Xcel Energy's major wind resources, energy rates were on an upward trend, as indicated by the dashed line labeled "Trend Line Rates." However, from 2015 to 2020, which coincides with the timing of the addition of several of the Wind Projects as shown in the Figure, we saw the FCC rates fall to nearly half their 2013 peak. The FCC rates did rise again in 2021, primarily due to an increase in gas costs offsetting the downward pressure on the FCC generated by the additions of the Wind Projects.

Figure 9: Average Annual SD FCC Rate per KWh (Residential) 2010-2021



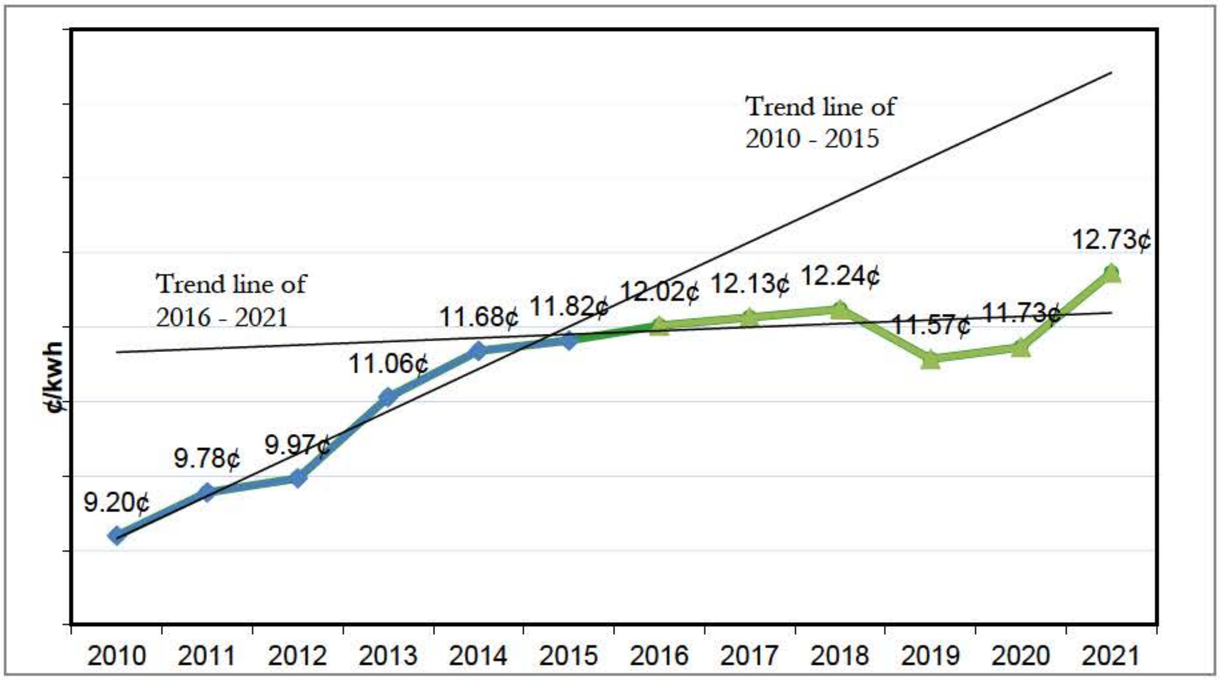
Q. WHAT DOES FIGURE 9 TELL US REGARDING SAVINGS FOR CUSTOMERS?

A. Figure 9 shows that, for example, the delta between the 2020 average rate (around 1.7¢/kWh) and the rate that would have been expected in 2020 based on the trend of costs from 2010 – 2015 (about 2.7¢/kWh) is approximately 1¢/kWh. For a typical residential customer using 750 kWh a month, this reflects an approximate savings of $7.50 per month.

Q. ARE THERE OTHER INDICATIONS THAT THE WIND PROJECTS ARE BENEFITTING CUSTOMERS?

A. Yes. Figure 10 below shows the historical average "all-in" residential electric rate per kWh (i.e., including all base, riders, and FCC rates) by year. This Figure shows that the price trend from 2016-2021 is lower than the trend from 2010-2015, coinciding with the Company's investment in wind resources and the Wind Projects.

Figure 10: Xcel Energy Average Residential Electric Rate in SD (2010 – 2020)



Q. WHAT DO YOU CONCLUDE FROM FIGURE 10?

A. Figure 10 provides support for the proposition that wind additions, including the Wind Projects, have driven lower overall energy costs for South Dakota consumers compared to costs anticipated if the wind was not added, as modeled by the Company in its various resource filings. I note that lower gas commodity cost also contributed to the lower fuel costs customers have seen in recent years. The combination of lower gas costs and wind generation allowed for cost savings by offsetting more expensive generation. As shown in Figure 9, above, fuel costs increased in 2021. This increase was driven by the increase in gas commodity costs. While this increase in gas commodity costs has resulted in an increase in the FCC rates, the wind generation provides a hedge against fuel costs, keeping the fuel costs lower than they would have been without the wind additions.

Q. DO YOU EXPECT THE SAME TO BE TRUE FOR THE WIND PROJECTS THAT HAVE NOT YET COME ONLINE?

A. Yes. As shown in Tables 3 through 8 above, the planned additions among the Wind Projects, including Northern Wind, and Nobles Wind repower, are all expected to generate savings for customers, so I would expect those projects to continue putting downward pressure on rates in the future due to the fuel cost savings associated with wind generation.

C. Summary

Q. WERE THE ADDITIONS OF THE WIND PROJECTS PRUDENT?

A. Yes. As I described above, the Commission has approved each of the Wind Projects for recovery in the Infrastructure Rider, based on the Company's demonstration of the prudence of the addition of each Wind Project in its annual Infrastructure Rider Petitions. In addition, the Company's economic analysis indicates each of the Wind Projects is expected to generate savings for customers on a PVRR basis, and that the fuel cost benefits of wind generation are already being reflected in customer bills.

Q. WHAT IS THE COMPANY'S REQUEST REGARDING THE WIND PROJECTS IN THIS RATE CASE?

A. The Company is requesting that the Commission roll the sixteen Wind Projects described above into rate base and thus allow the Company to recover the cost of these resources in base rates.

V. GRAND MEADOWS REPOWERING

Q. PLEASE SUMMARIZE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. The purpose of this section of my testimony is to provide information supporting the Company's addition of the Grand Meadows Wind Project (Grand Meadows). The Company is requesting in this rate case that the Commission allow recovery of the costs of Grand Meadows in base rates.

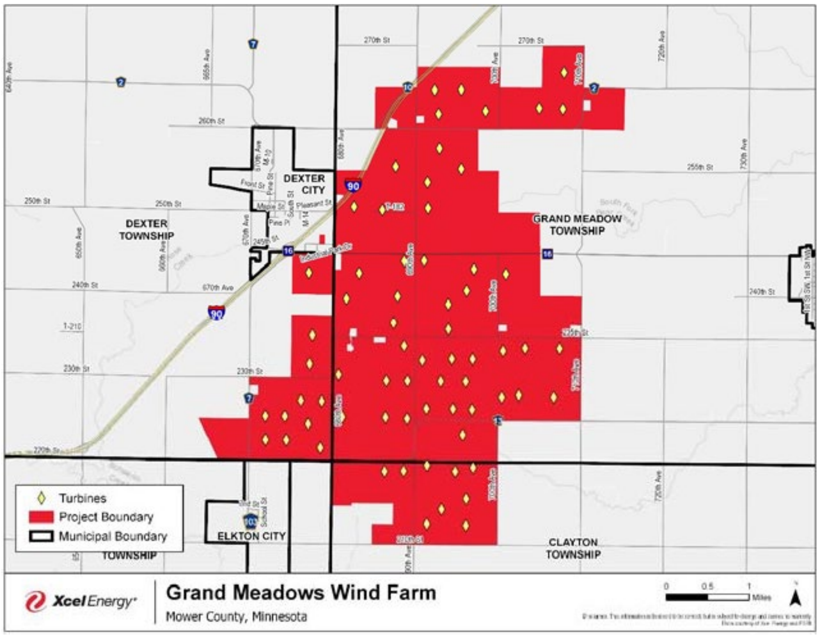
A. Background

Q. PLEASE PROVIDE A BRIEF SUMMARY OF GRAND MEADOWS.

A. Grand Meadows is a 100.5 MW wind repowering project located in Mower County, Minnesota. The facility was originally placed into service in 2008, interconnecting at the Pleasant Valley 161 kV substation via a generator interconnection agreement (GIA) between the Company and Great River Energy (GRE). The proposed project will uprate the existing turbines by replacing internal and external components, while continuing to use the existing GIA. We expect the repowered project will commence operation in 2023, and that the repowering work will extend Grand Meadows' useful life with new components expected to last for a renewed 20-year period.

Figure 11 shows the location of the existing Grand Meadows facility and proposed repowering.

Figure 11: Grand Meadows Wind Repower Location



Q. WHAT ARE THE EXPECTED RESULTS OF THE GRAND MEADOWS REPOWERING?

A. The Grand Meadows repowering is expected to achieve a net capacity factor (NCF) of approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, resulting in an average annual production of approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** per year, depending on final layout and turbine selection. This represents an efficiency gain of **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, relative to the existing facility's estimated average annual gross energy production. Total capital costs for the Grand Meadows Repower are currently estimated at approximately **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** including Allowance for Funds Used During Construction (AFUDC), which also covers decommissioning expenses for the removed components. Given the estimated COD of 2023, we believe the project will qualify for **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** PTCs over its first ten years of repowered operation. The estimated levelized cost of electricity (LCOE) for the repowered Grand Meadows facility is **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, which represents a **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** reduction in LCOE relative to the existing facility.

Q. HAS THE COMPANY INCLUDED GRAND MEADOWS IN A PREVIOUS INFRASTRUCTURE RIDER PROJECT ELIGIBILITY PETITION?

A. No. Because Grand Meadows is not expected to commence operation until 2023, the Company did not include it in its 2021 Infrastructure Rider Project Eligibility Petition.

Q. IS THE COMPANY CURRENTLY RECOVERING ANY COSTS ASSOCIATED WITH GRAND MEADOWS?

A. Yes. Since the Grand Meadow project is a repowering of an existing Company resource, the costs of the existing resource were included when rates were set in the last rate case. The cost of the existing resource will be included in the revenue requirement for the repowered project.

Q. WHAT IS THE COMPANY REQUESTING FROM THE COMMISSION WITH RESPECT TO GRAND MEADOWS IN THIS CASE?

A. The Company requests that the Commission find the Company's decision to repower the Grand Meadows facility be prudent and to allow recovery of the costs and energy of this project in base rates.

B. Economic Analysis of the Grand Meadows Repowering

Q. HOW DID THE COMPANY EVALUATE THE ECONOMIC IMPACT OF THE PROPOSED GRAND MEADOWS REPOWERING?

A. The Company first performed a "pro forma" spreadsheet analysis on the individual Grand Meadows repowering. The pro forma analysis was performed by comparing a "change case," in which the repowering is completed, to two different "base case" alternatives if it were not repowered: one that assumed the Grand Meadows facility would be replaced by generic wind at the end of its current life, and another analysis using market energy as the replacement resource in the base case. Then, the Company used EnCompass to analyze the Grand Meadows project on a portfolio basis with other projects that moved forward as part of the same wind repowering RFP.

Q. WHAT WERE THE RESULTS OF THE PRO FORMA ANALYSIS OF THE GRAND MEADOWS REPOWERING?

A. The pro forma analysis using generic wind as the assumed replacement resource indicated that the repowering of Grand Meadows would result in **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** million in savings on a system-wide basis. These savings are on a present value of revenue requirements (PVRR) basis and do not include carbon dioxide costs, other environmental externality values, or costs for potential future carbon emissions regulations.

The pro forma analysis using market energy as the replacement resource for Grand Meadows if the project were not repowered indicated that the Grand Meadows repowering would result in **[TRADE SECRET DATA BEGINS**

TRADE SECRET DATA ENDS] million in PVRR savings.

Q. HOW DID THE COMPANY USE ENCOMPASS TO EVALUATE THE PROPOSED GRAND MEADOWS REPOWERING?

A. The Company used EnCompass to model the Grand Meadows repowering as part of a broader portfolio of wind repowering projects that were shortlisted in response to the Company's RFP and moved forward (Wind Repower Portfolio). The Wind Repower Portfolio consisted of the Grand Meadows (100.5 MW), Border Winds (150 MW), Nobles Wind (201 MW), and Pleasant Valley Wind (200 MW), self-build projects, as well as the repowering of three smaller PPAs. We conducted this portfolio analysis to validate that the full Wind Repower Portfolio would yield customer benefits.

In our pro forma analysis, we had already established that the Grand Meadows project would be expected to provide customer benefits, relative to a future in which the existing plant remained in service until the end of its asset or contract life and was then replaced with a generic wind resource or market energy. However, in a full system planning analysis we may select from a wide variety of resources to replace an expiring resource, or – depending on the loads and resources on the system at the time – it may not need to be replaced at all. Portfolio modeling in the EnCompass tool allows us to simulate our future system and evaluate these tradeoffs.

Q. WHAT MODELING INPUTS AND ASSUMPTIONS WERE USED IN THE ENCOMPASS MODELING?

A. We evaluated the Wind Repower Portfolio's economic impact to our system using a Base Case consistent with the Company's 2020-2034 Upper Midwest

Integrated Resource Plan Supplement plan that I discussed in Section III.C above. Our complete modeling assumptions for this analysis are attached to my Direct Testimony as Exhibit___(FLM-1), Schedule 4.

Our analysis takes this Base Case, in which none of the Wind Repowering Portfolio projects are repowered and compares it to a Change Case in which the proposed Wind Repower Portfolio replaces the relevant existing resource(s) in our overall generation portfolio. The Company's full Upper Midwest system resource portfolio is then re-optimized in order to evaluate whether moving forward with these repowered projects will provide benefits or result in additional costs on a system-wide basis.

Q. WHAT WAS THE RESULT OF THE ENCOMPASS ANALYSIS?

A. We evaluated the overall Wind Repower Portfolio in comparison to the Base Case. The results of the EnCompass analysis showed that the overall portfolio of repowered projects would result in net savings for our customers, including under sensitivity analyses for high and low gas, coal, and market prices. The results of the EnCompass analysis are set forth in Table 9 below.

Table 9: PVSC and PVRR Savings Resulting from the Wind Repower Portfolio

Present Value Measure	Cost/(Savings) ($2020 millions)
PVSC	(260)
PVRR (No CO2 Costs)	(163)
Sensitivities	
Low Gas, Coal, and Market Prices	(98)
High Gas, Coal, and Market Prices	(248)

The PVSC cost savings in the table above include costs for carbon dioxide and other emissions as discussed above. The PVRR scenario and sensitivities do not include carbon dioxide costs, other externality values, or potential future regulatory costs for carbon emissions. These results show that, as a whole, we expect that the Wind Repower Portfolio will result in significant net benefits to our customers.

Q. IS IT POSSIBLE TO DETERMINE THE PORTION OF THIS COST SAVINGS REPRESENTED BY THE GRAND MEADOWS PROJECT?

A. No, not in the EnCompass modeling conducted for this case. The EnCompass modelling was done on the entire Wind Repower Portfolio, which includes the four self-build projects and three PPA projects as noted above. However, we know that the bulk of the customer savings result from the self-build projects, which are significantly larger than the PPA projects. In addition, as I noted above, the pro forma analysis showed that each of the individual projects in the Wind Repower Portfolio will result in customer savings. Accordingly, the

Company is confident that the Grand Meadow repowering will provide material benefits to customers.

C. Summary

Q. PLEASE SUMMARIZE WHY THE COMPANY'S DECISION TO REPOWER GRAND MEADOWS WAS PRUDENT.

A. The Grand Meadows repowering project will increase the efficiency and capacity of an existing wind resource serving the NSP system, will re-qualify the facility for PTCs, and was found to generate savings for customers in all scenarios analyzed, including as a standalone project and as part of a broader portfolio of wind repowering projects. As a result, the Company's decision to invest in the repowering of Grand Meadows was prudent and we request that the Commission approve the project for recovery in base rates.

VI. PRAIRIE ISLAND EXTENDED POWER UPRATE

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

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

A. Prairie Island Plant and Uprate Overview

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND NUCLEAR GENERATING PLANT.

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

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

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND EPU PROJECT.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. WHAT HAPPENED NEXT?

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

B. Prairie Island Change of Circumstances

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

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

Q. WHY WAS THE EPU PROJECT SIZE REDUCED?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Our modeling indicated that, even with the changes in circumstances discussed above, the Prairie Island EPU was still projected to provide a net benefit to customers across all of the scenarios modeled. Specifically, the Company calculated that the most probable estimate from the modeling at that time resulted in $50 million in PVRR savings. However, in a retrospective analysis, the overall benefits of the EPU when compared to the next best alternative had fallen from $433 million to $278 million when accounting for the implementation delay and reduction in size of the project. The results of this analysis are shown in Table 10 below.

Table 10

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

Original Filing

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

Changed Timing Only

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

Changed Timing and Size

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

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

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

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

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

A. The Company assessed the total benefits of the uprates by incorporating the revised fuel cycles into the modeling for the EPU that was conducted in March 2012. This analysis indicated that the total benefits of the uprates declined to $10 million PVRR, compared to the $50 million estimated in the Company's March analysis. The results of this analysis are shown in Table 11 below.

Table 11

PVRR Benefits of Prairie Island EPU

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

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

A. Yes. The uncertainty around the NRC processes at the time held out the possibility of additional project delay and the concomitant increase in costs. Timing delays could have added up to an additional $30 million in lost PVRR benefits of the projects. Additionally, the Project benefits would have been further reduced by lower natural gas prices or low load growth. As shown in Table 12 below, several of these scenarios resulted in an increase to the PVRR rather than a savings in the updated modeling.

Table 12

Sensitivity Analysis of Prairie Island EPU

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

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

C. Cancellation of the Prairie Island EPU Project

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

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

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

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

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

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

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

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

D. Summary

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

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

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE COMPANY'S DECISION TO ADJUST THE RETIREMENT DATES FOR KING AND SHERCO 3 TO 2028 AND 2030, RESPECTIVELY.

A. The Company's decision to adjust the retirement dates for King and Sherco 3 is prudent because the Company's economic analysis at the time determined that customers would benefit from the decision, relative to other scenarios in which the plants were kept online. These benefits were confirmed by subsequent analyses of the retirement plans for King and Sherco 3. Additionally, our reliability analyses found that the reliability issues associated with retiring these baseload resources could be managed with appropriate additional investments and planning.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE WIND PROJECTS THE COMPANY PROPOSES TO ROLL IN TO BASE RATES.

A. The Company requests that the Commission roll the sixteen Wind Projects described above into base rates on the grounds that the Commission has already approved recovery of these resources in the Infrastructure Rider based on the Company's prior demonstration of the prudence of each of the projects. The Company's economic analysis shows that each of the Wind Projects is expected to generate savings for customers, and that on the whole, the addition of the Wind Projects has caused downward pressure on fuel costs and customer rates.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF THE GRAND MEADOWS REPOWERING.

A. The Company's decision to invest in the repowering of Grand Meadows is prudent based on the Company's economic analysis, which found that the proposed repowering is expected to generate savings for customers in all scenarios analyzed. The repowering will increase the efficiency and output of the existing facilities, and will allow the Company to re-qualify the facility for federal tax credits to the benefit of customers. The Company requests that the Commission approve the Grand Meadows repowering project for recovery in base rates.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PRUDENCE OF CANCELING THE PRAIRIE ISLAND EPU.

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

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

A. Yes, it does.