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Direct Testimony and Schedules
Christopher J. Shaw

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-24-___
Exhibit___(CJS-1)

Resource Planning

December 2, 2024

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Prefiled Direct Testimony and Schedules of Christopher J. Shaw - Redacted

Northern States Power Company

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Christopher J. Shaw. I am the Director, Resource Planning, for Northern States Power Company-Minnesota (NSP, the Company, or Xcel Energy).

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Company. The Company provides electric service to customers in Minnesota, North Dakota, and South Dakota (collectively the NSPM States). The Company is a wholly owned subsidiary of Xcel Energy Inc. 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 approved by the Federal Energy Regulatory Commission, own and operate the five-state integrated NSP System.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I began working at Xcel Energy in November 2015 as Principal Rate Analyst. I became a Regulatory Policy Manager in 2019, and became Director of Resource Planning in 2023, which is my current position. Prior to joining Xcel Energy, I worked for the Minnesota Department of Commerce and the Minnesota Attorney General's Office. In my current role, I oversee the Resource Planning team working on the development of resource plans and acquisitions for the NSP System. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. My statement of qualifications is provided as Exhibit___(CJS-1), Schedule 1.

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

A. The purpose of my Direct Testimony is to support the prudence of the following resource additions and retirement decisions that impact the test year:

- Retirement of Allen S. King Generating Plant (King) in 2028;
- Retirement of Sherburne County Generating Station Units 1, 2 and 3 (Sherco 1, Sherco 2, and Sherco 3) in 2026, 2023, and 2030, respectively;
- Extension of the useful life of the Monticello Nuclear Generating Plant from 2030 to 2040;
- Addition of Sherco Solar 1 and 2;
- Addition of a Long Duration Battery Storage pilot project at Sherco;
- The Mankato Energy Center II 314 megawatt (MW) purchase power agreement (PPA);
- A five-year extension on two Manitoba Hydro PPAs; extension of Refuse Derived Fuel (RDF) facilities at French Island 1-2 to 2040, Red Wing and Wilmarth each to 2037, and Bayfront 5&6 to 2034;
- The addition of 28 MW of reciprocating engines at Blue Lake plant to account for needed system support in light of the retirement of the Inver Hills facility due to age.

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

A. My understanding is that North Dakota law provides for the recovery of capital that is "honestly and prudently invested" by the utility. Under general utility ratemaking principles, a resource addition or other investment is prudent if the utility's action was reasonable when considering all relevant circumstances at the time the decision was made in light of all of the information that was then available. Prudence does not require the optimum outcome, only one based on decision-making that generally would be found to be reasonable in light of the circumstances. In North Dakota, prudence is assessed under both *quantitative* factors in the form of costs to customers (without giving effect to environmental externalities), as well as *qualitative* factors such as regulatory risk and reliability considerations.

When assessing prudence, North Dakota statutes prohibit using "environmental externality values in the planning, selection or acquisition of electric resources."[1] Under the statutes, "environmental externality values" are specifically defined as:

> numerical costs or quantified values that are assigned to represent either: (1) environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or (2) the alleged costs of complying with future environmental laws or regulations that have not yet been enacted.[2]

More recently (as of 2023), North Dakota regulations also prohibit using environmental externalities such as "carbon cost, greenhouse gas reduction goals, renewable energy standards, emissions goals, or other externalities" in selecting a North Dakota "preferred" resource plan.[3]

However, North Dakota statutes and regulations also require utilities to provide information on, and the Commission to consider, "qualitative" benefits of

[1] N.D. Cent. Code § 49-02-23.
[2] *Id.*
[3] North Dakota Amin. Code § 69-09-12-03.

resource planning decisions,[4] and utilities "may provide alternative scenarios with sensitivities based on proposed and current federal, state, and utility goals and mandates relating to carbon cost, emissions goal, or other externalities."[5] Moreover, there is longstanding Commission precedent (dating back to at least 2008) holding that, "[w]hile the Commission is prohibited from considering quantitative environmental externality values, the Commission can consider the possibility of carbon regulation in a qualitative manner."[6] In that 2008 decision, the Commission upheld Otter Tail Power's and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of a coal plant.

While the Commission also has generally applied a "need + least-cost" standard to assessing prudence, that standard is merely a shorthand to provide a framework in which to assess the analysis of a resource decision. As a result, although the Company cannot utilize environmental externalities such as the cost of carbon or the cost of complying with potential (i.e., not yet enacted) future carbon regulations on a *quantitative* basis in North Dakota to justify the prudence of a decision to add or retire a resource, the Company and the Commission can – and I would argue must – consider such factors in a *qualitative* manner as general indicators of risk and reliability factors in assessing the reasonableness of a utility's decisions. When applying its judgment to the Company's actions, the Commission should recognize that there typically is not a singular "prudent" decision, but rather a range of reasonable outcomes that

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[4] *See* N.D. Admin. Code § 69-09-12-03, and 04; *see also* N.D. Cent. Code § 49-05-17.
[5] North Dakota Amin. Code § 69-09-12-03
[6] August 27, 2008 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER in Case Nos. PU-06-481 and PU-06-482 (upholding Otter Tail Power's and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of a coal plant).

can be considered prudent when holistically considering quantitative cost factors and qualitative factors such as energy reliability, cost reliability, regulatory risks, resource availability risks, and more. In other words, just because one course of action may be found to be prudent, that does not mean another course necessarily is imprudent. Through that lens, the Company's resource decisions should be found prudent in light of the myriad factors the Company must consider and balance to arrive at its resource decisions.

Q. IN EACH INDIVIDUAL RESOURCE SELECTION, DOES THE COMPANY ALWAYS SELECT THE LEAST-COST RESOURCE?

A. No, not always, nor would it be prudent to do so. Obviously, cost is a key consideration in our resource planning analyses, and much of my discussion below with regard to specific decisions will focus on a quantitative analysis comparing the modeled costs of various options. However, the Company must make decisions that result in the right overall portfolio of generation resources to serve our customers, and that requires us to also take into account other considerations, including stability, reliability, and potential risks. As I noted above, the consideration of risk can and does include a qualitative assessment of risks related to environmental considerations, including the risk of future environmental regulations.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO KING AND SHERCO 1, 2, AND 3 IN THIS RATE CASE?

A. The Company requests that the Commission find that the retirement of Sherco 2 in 2023, planned retirement of Sherco 1 in 2026, planned retirement of King in 2028, and planned retirement of Sherco 3 in 2030 are all prudent and allow the Company to collect the remaining book value for Sherco 2 in the test year and adjust the remaining lives of the other plants for depreciation purposes as further described by Company witness Mark P. Moeller. The Company is retiring these large coal-fired units prior to their Commission-set remaining lives used for ratemaking purposes. 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 EXTENSION OF THE MONTICELLO NUCLEAR GENERATING PLANT?

A. The Company requests that the Commission find that the Company's planned life extension of the Monticello Nuclear Generating Plant from 2030 to 2040 is prudent and allow for a corresponding adjustment in depreciation and recovery of associated capital investments in base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE ADDITION OF SHERCO SOLAR 1 AND 2?

A. The Company requests that the Commission find that the Company's addition of Sherco Solar 1 and 2 in 2024 and 2025 is prudent and allow recovery of these resources in base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE ADDITION OF A LONG DURATION BATTERY STORAGE PILOT PROJECT AT SHERCO?

A. The Company requests that the Commission find that the Company's addition of a Long Duration Battery Storage pilot project at Sherco in 2025 is prudent and allow recovery of this resource in the base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE EXTENSION OF THE MANKATO ENERGY CENTER II PPA?

A. The Company requests that the Commission find that the Company's Mankato Energy Center II 314 MW PPA is prudent and allow recovery of this resource extension in the base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE FIVE-YEAR MANITOBA HYDRO PPA?

A. The Company requests that the Commission find that the Company's two five-year PPAs with Manitoba Hydro beginning in 2025—one for 200 MW of summer system sale and the other for diversity exchange of 350 MW in the first three years and 200MW in the final two years only—to partially replace the existing Manitoba Hydro PPA (for a 500 MW system sale and 350 MW diversity exchange) that is set to expire in 2025, is prudent, and allow recovery of this resource extension in the base rates.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE EXTENSION OF FOUR RDF FACILITIES?

A. The Company requests that the Commission find that the Company's extension of four Refused Derived Fuel (RDF) waste-to-energy generating facilities—at French Island 1-2 to 2040, Red Wing and Wilmarth each to 2037, and Bayfront 5&6 to 2034—is prudent, and allow the Company to adjust its depreciation for the facilities accordingly.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO THE RECIPROCATING ENGINES AT BLUE LAKE?

A. The Company is requesting approval of its plans to replace the retiring Blue Lake Unit 3 capacity with 28 MW of new Reciprocating Internal Combustion Engine generator (RICE) capacity, including improvements to the existing Blue Lake Units 7 and 8 to increase redundancy and reliability. The Company further requests that the Commission allow the Company to recover the costs through base rates.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- Section II presents a summary of the types of economic analysis discussed throughout my testimony.
- Section III presents the Company's decision to retire Sherco 1, 2, and 3 and King earlier than anticipated, and the prudence of that decision.
- Section IV presents the Company's proposed extension of the Monticello Nuclear Generating Plant and the prudence of that decision.
- Section V describes the Company's addition of 460 MW with Sherco Solar 1 and 2, and the prudence of those additions.
- Section VI describes the Company's decision to add a Long Duration Battery Storage pilot project at Sherco, and the prudence of that decision.
- Section VII describes the Company's decision with regard to the Mankato Energy Center II 314 MW PPA.
- Section VIII describes additional solutions for capacity needs and the prudence of the following decisions to: 1) enter into two five-year PPAs with Manitoba Hydro (one for 200 MW of summer system sales, and the

other for 350 MW of diversity exchange in the first three years and 200 MW in the final two years) to partially replace the existing PPA set to expire in 2025), 2) extend four RDF facilities, 3) extend the Cannon Falls PPA for three years after the current PPA expires in 2025, and 4) replace the retiring Blue Lake Unit 3 capacity with 28 MW of new RICE capacity.

- Section IX discusses additional considerations, outside of the economic and reliability considerations discussed for individual resource decisions, that are common factors, namely (A) corporate goals and state and federal legal mandates for reducing carbon emissions and replacing fossil-fuel-powered electricity with carbon-free energy; and (B) the Company's attempt to ease the tensions between these aforementioned emissions-reduction goals and North Dakota's policy mandates via the Company's proposed Resource Treatment Framework, and the Commission's rejection thereof.
- Section X concludes my testimony.

II. SUMMARY OF TYPES OF ECONOMIC ANALYSIS

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

A. The Company has used two types of economic analyses to evaluate the Present Value of Revenue Requirements (PVRR) impacts of resource additions and retirements, both of which are discussed at various points in my testimony: (1) an analysis using the Strategist resource planning model (Strategist); and (2) an analysis using the EnCompass resource planning model (EnCompass).

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 was 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. Strategist helped us evaluate proposed acquisitions in the broader context of the integrated NSP System by fully evaluating the impacts of an action relative to our entire resource portfolio. Until about four years ago, the Company used this tool for the majority of its resource planning efforts. This shifted after our June 2020 Supplement to our 2020-2034 Resource Plan, when we used the EnCompass modeling tool for the first time.

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 Exhibit___(CJS-1), Schedule 2 to my testimony. As noted above, our first time using Encompass was in our June 2020

Supplement to our 2020-2034 Resource Plan.[7] 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 1, 2, 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 decision to retire Sherco Unit 2 on December 31, 2023 and the planned retirements of Sherco Unit 1 in 2026, King in 2028, and Sherco Unit 3 in 2030, and the Company's request that it be allowed to adjust its depreciation rates accordingly.

A. Summary of Decision to Retire Sherco 1, 2, and 3, and King

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SHERCO FACILITY.

A. The Sherco Generating Station in Becker, Minnesota is the Company's largest power plant. Sherco Units 1 and 2 were placed in service in 1976 and 1977, respectively, and have a production capability of approximately 650 MW each. Sherco 3 was placed in service in 1987, has a production capacity of approximately 927 MW, and 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 Unit 2 was retired on December 31, 2023. The Company and SMMPA have agreed to retire Sherco 3 in 2030.

[7] 2020-2034 Upper Midwest Resource Plan Supplement, Northern States Power Company, Case No. PU-19-220 (June 30, 2020).

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

A. The Allen S. King plant is a single-unit coal-fired generating baseload 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). The Company plans to retire King in 2028.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO SHERCO UNITS 1, 2, AND 3, AND KING IN THIS RATE CASE?

A. The Company is asking the Commission to allow for recovery of the remaining undepreciated book value of the Sherco 2 unit in the test year. The Company is also asking the Commission to adjust the depreciation expenses of Sherco 1, King, and Sherco 3 to match the Company's announced retirement dates for these units in 2026, 2028, and 2030, respectively.

Q. WHAT ARE THE CURRENT REMAINING LIVES OF KING AND SHERCO 1, 2, AND 3 IN NORTH DAKOTA?

A. In North Dakota, the Company's currently approved depreciation expense for Sherco 1 and 2 reflect a retirement date of January 1, 2035, as initially set in Case No. PU-07-776[8] and reaffirmed in Case No. PU-20-441.[9] The Sherco 3 current depreciable life is through December 2034 in North Dakota. The King current depreciable life of King is through June 2037 in North Dakota.

[8] *See* ORDER ADOPTING SETTLEMENT, Case No. PU-07-776 (Dec. 31, 2008).

[9] *See* ORDER ON SETTLEMENT, Northern States Power Company 2021 Electric Rate Increase Application, Case No. PU-20-441 (Aug. 18, 2021).

Q. HAS THE COMMISSION MADE ANY PRIOR DECISIONS WITH RESPECT TO THE ACCELERATED RETIREMENT OF THE SHERCO AND KING COAL PLANTS?

A. Yes, on the accelerated retirement of Sherco 1 and 2. No, on the accelerated retirement of Sherco 3 and King. Specifically, the Commission-approved settlement from our last North Dakota electric rate case in 2021 agreed that that the depreciation expense for Sherco 1 and 2 would continue to reflect the previously approved retirement date of January 1, 2035, expressly without prejudice to the Company's plans to retire those units sooner, and expressly allowing the Company to seek adjustment to those units' remaining lives and seek recovery of stranded costs in a future rate case.[10] As for Sherco Unit 3 and King, the Company included these accelerated retirements in its 2020-2034 Resource Plan filed on an informational basis with the Commission in 2019, and in our 2024-2040 North Dakota Resource Plan, filed with the Commission in April 2024,[11] on which the Commission has not issued a final ruling.

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH DECISIONS IN OTHER STATES WITH JURISDICTION OVER SHERCO AND KING?

A. The Minnesota Public Utilities Commission (MPUC) has approved the retirements for Sherco 1, 2, 3, and King for 2026, 2023, 2030, and 2028, respectively.[12] The South Dakota Public Utilities Commission (SDPUC)

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[10] *See* ORDER ON SETTLEMENT, Northern States Power Company 2021 Electric Rate Increase Application, Case No. PU-20-441 (Aug. 18, 2021).

[11] *See* 2024-2040 North Dakota Resource Plan, Case No. PU-24-160, at Chapter 4 (PDF 69). https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=160# (Apr. 8, 2024).

[12] *See* ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS in MPUC Docket No. E002/RP-15-21 (Jan. 11, 2017) (Sherco 1 and 2 retirement); *See also In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS (Apr. 15, 2022), at Order Point 2.A.4 (Sherco 3 and King).

approved depreciable lives of 2026 and 2023 for Sherco 1 and 2, respectively, but continues to assume a December 2034 depreciable life for Sherco 3 and June 2037 depreciable life for King, pursuant to a settlement in the last South Dakota rate case. That settlement was expressly without prejudice to the prudence of the Company's proposal for accelerated retirement of those units and expressly left open the opportunity for the Company to renew its request to alter the depreciation lives and rates for Sherco 3 and King in its next South Dakota rate case.[13] The South Dakota settlement further provides that if the Company "has not commenced a rate case to change base rates prior to the retirement of Sherco 3 and/or King, the Company may include any undepreciated plant amounts for each plant in a regulatory asset (with a return at WACC) for each plant and amortize such regulatory asset(s) over the remaining authorized depreciable life of such plant." Accordingly, the Company's proposal in this case is consistent with the MPUC's decisions with respect to all four units and is consistent with the SDPUC's decisions with respect to Sherco 1 and 2 and provides for a mechanism to address the retirement of Sherco 3 and King at the appropriate time.

Q. IS THE COMPANY'S PROPOSAL IN THIS CASE CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes, the Company's actual and proposed retirement dates for Sherco and King

[13] *See* Settlement Stipulation at 4, and ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION, SDPUC Docket No. EL22-017, *In the Matter of the Application of Northern States Power Company dba Xcel Energy for Authority to Increase its Electric Rates,* https://puc.sd.gov/dockets/Electric/2022/EL22-017.aspx; *see also* Xcel Energy 2024-2040 North Dakota Resource Plan, at PDF 35 (Apr. 8, 2024).

are consistent with the ND Preferred Plan in the Company's North Dakota Resource Plan, filed with the Commission in April 2024.[14]

Q. AT A HIGH LEVEL, WHEN AND HOW DID THE COMPANY MAKE ITS DECISIONS TO RETIRE SHERCO UNITS 1, 2, AND 3, AND KING?

A. Broadly speaking, the Company made decisions on these retirements at two separate times. First, the Company made the decision to retire Sherco Units 1 and 2 during our 2015 resource planning cycle (for the 2016-2030 planning period)[15] based on cost, reliability, and risk analyses and discussions with customers and stakeholders at the time, which led the Company to conclude that it would be prudent to retire Sherco 1 and 2 in 2026 and 2023, respectively, and transition to a combination of flexible natural gas resources and renewable generation. Subsequent analyses have reinforced the prudence of the Company's decision to retire Sherco 1 and 2, as the economics of the decision continue to support prudence over time.

The Company determined to retire Sherco Unit 3 and King as a part of its 2019 resource planning process, based on economic and reliability analyses that led the Company to conclude it would be prudent to retire King in 2028 and Sherco 3 in 2030.

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[14] *See* Xcel Energy's 2024-2040 North Dakota Resource Plan, Case No. PU-24-160, at Chapter 4 (PDF 69) https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=160# (Apr. 8, 2024).
[15] *See* Upper Midwest Resource Plan 2016-2030, Northern States Power Company, Case No. PU-15-019 (Jan. 5, 2015).

B. Sherco 1 and 2 Retirement Decision and Analyses

Q. WHAT KINDS OF FINANCIAL AND RELIABILITY ANALYSES HAS THE COMPANY PERFORMED TO SHOW THAT THE SHERCO 1 AND 2 RETIREMENTS ARE PRUDENT AND IN THE PUBLIC INTEREST?

A. The Company has performed many economic analyses over the years exploring the possibility of retiring Sherco 1 and 2, including but not limited to:

- Lifecycle Management (LCM) Studies performed during the 2010 and 2015 resource planning cycles, and 2015 Strategist resource planning model;
- an August 2020 EnCompass analysis that found that retiring Sherco 1 and 2 in 2026 and 2023 would produce $13 million in PVRR savings for customers as compared to operating those units through 2034; and
- as part of the Company's most recent Resource Plan (for 2024–2040) filed with the Commission in April 2024 in Case No. PU-24-160, the Company used EnCompass modeling software to stress-test its "ND Preferred Plan," which includes the retirement of Sherco 1 and 2, as well as Sherco 3 and King, at dates consistent with the proposal in this case.

The Company also performed three technical studies to examine the transmission reliability impacts of retiring the Sherco Units 1 and/or 2: (1) a Midcontinent Independent System Operator (MISO) Attachment Y2 Study; (2) an Xcel Energy Transmission Reliability Study, performed in conjunction with Siemens Power Technologies International (Siemens); and (3) a System Restoration Analysis.

Q. WHAT HAS BEEN THE GENERAL TREND OF THE ECONOMIC ANALYSES?

A. Our analyses have demonstrated that the decision to retire Sherco 1 and 2 was not only prudent at the time the decision initially was made, but that decision has become even more economically advantageous over time. In 2010, when the Company first examined the potential for retiring Sherco 1 and 2, our study noted that natural gas prices and potential environmental regulations were key drivers in the economics of Sherco 1 and 2. Although the information, economics, and regulatory landscape at that time led the Company to decide that the then-most prudent course of action was to maintain the units in operation, that information changed in subsequent analyses. By 2015, the Company's analyses of potential risks associated with maintaining Sherco 1 and 2 pointed clearly towards retirement. Our analyses found that our October 2015 Updated Plan (for 2016-2030), which included the accelerated retirement of Sherco 1 and 2 alongside significant additions of wind and solar resources by 2030, would produce virtually no additional costs compared to our 2010 Resource Plan Baseline ($1 million on a PVRR basis, as discussed below and shown in Table 1 below). And, although the Updated Plan was projected to add about $300 million in costs compared to an earlier-proposed 2015 resource plan that did not include accelerated retirements, there also loomed potential environmental regulatory compliance requirements that could cost $250 million *per unit* (i.e., $500 million for the two units) to install Selective Catalytic Reduction technology (SCR).

Based on the totality of this information and potential risks, the Company determined that the most prudent course of action would be to retire Sherco 1 and 2 in 2026 and 2023, respectively, and take advantage of low-cost gas and low-cost renewables to transition our fleet and position ourselves for the future.

Q. BECAUSE PRUDENCE DETERMINATIONS LOOK AT PRUDENCE AT THE TIME A DECISION WAS MADE, PLEASE PROVIDE MORE DETAIL ON THE RESULTS OF THE 2015 ANALYSES SUPPORTING THE 2015 DECISION TO RETIRE SHERCO 1 AND 2.

A. The Company forecasted in its original 2016–2030 Resource Plan filed in January 2015[16] that it could operate Sherco 1 and 2 without significant investments in SCR, based on the draft version of the Clean Power Plan proposed in June 2014.[17] Accordingly, the Company proposed to continue to operate Sherco 1 and 2 through 2030, albeit at reduced levels. However, after that January 2015 Resource Plan filing, the U.S. Environmental Protection Agency (EPA) issued the final Clean Power Plan (CPP) rule,[18] which strengthened the risk that the Company might need to install SCR to continue to legally operate Sherco 1 and 2.[19] Around the same time, the Company also engaged in extensive discussions with stakeholders and customers, increasing numbers of whom wanted cleaner energy. Further, extensions and expansions of the solar Investment Tax Credit (ITC) and Production Tax Credit (PTC)

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[16] Case No. PU-15-019.
[17] 79 FR 34830, 34903–4 (June 18, 2014), https://www.federalregister.gov/documents/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating
[18] The EPA published the final Clean Power Plan Rule on August 3, 2015. https://19january2017snapshot.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants_.html. The official version was published in the Federal Register on October 23, 2015. *See* 80 Fed. Reg. 64966 (Oct. 23, 2015), https://www.govinfo.gov/content/pkg/FR-2015-10-23/pdf/2015-22848.pdf.
[19] The CPP did not make certain that SCR would be required, because such implementation details would be determined by yet-to-be-developed *state* plans. The CPP, pursuant to Clean Air Act Section 111(d), established emissions performance levels for existing power plants based on what the EPA determined to be the best system of emission reduction (BSER). States then develop state plans that will achieve these EPA-approved emission performance levels, using measures determined by the states (which measure could include SCR, but could also include other compliance mechanisms).

for renewable energy made replacing baseload, fossil-fuel generation more economically attractive.[20]

Because of these new regulatory and financial risks and opportunities and stakeholder demands, the Company decided to re-analyze the possibility of accelerating the retirement Sherco 1 and 2 alongside making larger additions of wind (1,800 MW) and solar (2,100 MW) resources by 2030, in its October 2015 update to its 2016–2030 Resource Plan (October 2015 Updated Plan). In an analysis presented to the Commission in a January 29, 2016 Supplement to the 2016–2030 Resource Plan,[21] the Company used a Strategist resource planning model to analyze the potential costs of the October 2015 Updated Plan on both: (a) a PVRR basis, which allows the Company to quantitatively evaluate the cost of a resource without accounting for environmental externalities; and (b) a Present Value of Societal Costs (PVSC) basis, which serves as one way the Company can qualitatively consider a broader range of implications and risks of its resource decisions, in part through putting a price on externalities such as the cost of carbon and externality values for criteria pollutants.

As illustrated in Table 1 below, on a PVRR basis, the modeling showed that the October 2015 Updated Plan would cost only $1 million more than continuing the then-current 2010 Resource Plan ($45.606 billion versus $45.605 billion, respectively), primarily because the Sherco 1 and 2 retirements in the October

[20] In 2015, the Consolidated Appropriations Act, 2016 (P.L. 114-113) (enacted Dec. 18, 2015) extended both the PTC and the ITC. *See* Cong. Res. Serv., *The Renewable Energy Production Tax Credit: In Brief, R43453,* at 4 (Apr. 29, 2020), https://sgp.fas.org/crs/misc/R43453.pdf; *See* Cong. Res. Serv., *The Energy Credit or Energy Investment Tax Credit (ITC) F10479* (Apr. 23, 2021), https://crsreports.congress.gov/product/pdf/IF/IF10479.
[21] 2015 Resource Plan Supplement, Case No. PU-15-019 (Jan. 29, 2016).

2015 Updated Plan would be paired with the significant low-cost wind and solar additions noted above. As compared to the original January 2015 Resource Plan, however, the October 2015 Updated Plan would cost about $300 million more on a PVRR basis ($45.302 billion versus $45.606 billion, respectively), primarily because the October 2015 Updated Plan would move solar resources earlier in the planning period to capitalize on favorable market pricing associated with the extension of the federal ITC, and this plan would also add a combined cycle plant at Sherco.

On a PVSC basis, the numbers were significantly more favorable for the October 2015 Updated Plan. Specifically, the modeling showed that, on a PVSC basis, the October 2015 Updated Plan would provide considerable savings as compared to the January 2015 Resource Plan (approximately $165 million in savings) and even more as compared to continuation of the 2010 Resource Plan (approximately $1.129 billion in savings).

Table 1
Economic Analyses of October 2015 Update and January 2015 Versions of 2016-2040 Resource Plan

	PVRR ($M, 2015)	PVSC ($M, 2015)	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Reference Case (2010 Plan Continuation)	$45,605	$52,422	400	No
Oct. 2015 Updated Plan	$45,606	$51,293	3,200	Yes
Jan. 2015 Plan	$45,302	$51,458	3,200	Uncertain
North Dakota Plan	$45,473	$52,620	0	No

In light of the fact that the October 2015 Updated Plan (with the accelerated Sherco early 1 and 2 retirements) was modeled to be approximately the same cost on a PVRR basis and yield significant savings on a PVSC basis as compared to continuing the 2010 Resource Plan, and additionally would be compliant with the CPP, which threatened to impose significant regulatory compliance costs for operating Sherco 1 and 2 into the future—the Company concluded that the October 2015 Updated Plan appropriately balanced the costs and future risks, uncertainties, and associated reliability concerns, while taking advantage of the certainty of low-cost renewables and available tax credits.

Q. IN EVALUATING THE PRUDENCE OF THE COMPANY'S 2015 DECISION TO RETIRE SHERCO 1 AND 2, HOW SHOULD THE COMMISSION CONSIDER THE COMPANY'S EVALUATION OF NOT ONLY PVRR CALCULATIONS, BUT ALSO PVSC CALCULATIONS, ENVIRONMENTAL REGULATIONS WITH UNCERTAIN REQUIREMENTS, AND POST-2015 ANALYSES?

A. As I detailed in Section I above, North Dakota statutes,[22] regulations,[23] and longstanding Commission precedent[24] provide that a resource decision may be prudently made based on both *quantitative* factors (costs to customers, without giving effect to environmental externalities) and *qualitative* factors such as regulatory risk and reliability considerations. Accordingly, the Company and the Commission can consider PVSC calculations and the potential regulatory

[22] The Commission may "consider qualitative benefits" in evaluating resource planning decisions. *See* N.D. Cent. Code § 49-05-17(2), (3).

[23] Utilities must provide information on "qualitative benefits" of their resource planning decisions. *See* N.D. Amin. Code § 69-09-12-03, and 04. Utilities may also "provide alternative scenarios with sensitivities based on proposed and current federal, state, and utility goals and mandates relating to carbon cost, emissions goal, or other externalities." N.D. Amin. Code §69-09-12-03.

[24] August 27, 2008 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER in Case Nos. PU-06-481 and PU-06-482 (upholding Otter Tail Power's and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of a coal plant).

compliance costs in a qualitative manner as risk indicators, alongside PVRR analyses.

In the case of the Company's decision to accelerate the retirement of Sherco 1 and 2, I want to first and foremost emphasize that this decision is supported by quantitative economic analyses conducted at the time of the 2015 decision, without qualitative considerations. As detailed above, the Company found in 2015 that, on a PVRR basis, the October 2015 Updated Plan, which included the accelerated retirement of Sherco 1 and 2 in 2026 and 2023 alongside significant wind and solar additions, would be essentially cost-neutral as compared to continuation of our 2010 plan.

Qualitative consideration of regulatory compliance risks further drives home the prudence of the Company's decision. For example, consideration of the Clean Power Plan (CPP) was valid because it was a final federal rule, in place at the time of the decision, that made significant compliance costs likely even if the CPP's full implications were uncertain because state compliance plans had not yet been adopted. Further, even though the CPP was subsequently stayed and then repealed,[25] it was indicative of a trend of increasingly stringent regulations that pose serious financial risks to long-term coal plants operations,

[25] The Supreme Court stayed implementation of the Clean Power Plan in February 2016. *See* https://19january2017snapshot.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants_.html. It was subsequently repealed and replaced by the Affordable Clean Energy (ACE) Rule. *See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, 84 Fed. Reg. 32520 (Jul. 8, 2019), https://www.govinfo.gov/content/pkg/FR-2019-07-08/pdf/2019-13507.pdf; *see also* https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule. In turn, the ACE Rule was subsequently repealed, and how now been replaced by new rules finalized in spring 2024. *See* https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-suite-standards-reduce-pollution-fossil-fuel.

as evidenced in part by the EPA's finalization of a suite of four rules in April/May 2024 that imposes stringent requirements on existing coal power plants to control carbon emissions, mercury and toxic metal emissions, coal ash, and wastewater.[26]

In sum, because the Company's decision to accelerate the retirement of Sherco 1 and 2 is supported by quantitative economic considerations, giving qualitative consideration to PVSC analyses, compliance cost risks of the CPP and other regulations, is like adding a fourth leg to a three-legged stool: they are unnecessary to, yet further solidify, the conclusion that the decision was and continues to be prudent.

Q. PLEASE DESCRIBE THE RELIABILITY STUDIES PERFORMED IN ANALYZING THE SHERCO 1 AND 2 RETIREMENTS.

A. The Company performed three technical studies to examine the transmission reliability impacts of retiring the Sherco Units 1 and/or 2: (1) a MISO Attachment Y2 Study; (2) an Xcel Energy Transmission Reliability Study, performed in conjunction with Siemens Power Technologies International (Siemens); and (3) a System Restoration Analysis. The Company's conclusions from these studies were that: (1) ceasing operation of Sherco Units 1 and 2 would create system conditions that require mitigation; and (2) siting dispatchable, thermal generation at the Sherco site would (at the time of the

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[26] *See Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants* (Apr. 25, 2024), https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-suite-standards-reduce-pollution-fossil-fuel. Although there are ongoing legal challenges to the rule that would require coal-fired power plants operating past 2039 to reduce their carbon emissions by 90 percent by 2032, no court yet has placed a stay on the rule. We note that this regulation is an active and applicable requirement and must be accounted for in our planning on a quantitative basis unless and until it changes.

study) be the most cost-effective solution and would provide the greatest level of certainty in terms of cost and reliability to meet the Company's energy and capacity requirements, maintain reliability for its customers, and support the Company's vision of a clean energy future.

It is important to note that the assumptions used in these studies were based on expected conditions at the time they were initiated in early 2015. The system is dynamic and expected conditions can change (and have changed) as new generation comes online, new transmission lines are constructed, or existing lines are reconfigured. Ultimately at the time of these studies, we concluded that we knew our system worked well, and to the extent replacement generation was located in similar electrical locations, we were confident the grid would continue to perform well. That ultimate conclusion holds true today even as we have continued to evolve our total resource package, including adding solar rather than a combined cycle unit (as had been the plan) at the Sherco site, (and have conducted additional reliability studies throughout that evolution), as discussed later in my testimony.

C. Sherco 3 and King Retirement Decision and Analyses

Q. WHEN AND HOW DID THE COMPANY MAKE ITS DECISION TO RETIRE KING AND SHERCO 3 IN 2028 AND 2030, RESPECTIVELY?

A. The Company developed its current retirement plans for King and Sherco 3 as part of the Company's resource planning process in 2019. In connection with this plan, the Company commissioned, reviewed, and undertook various economic and reliability-related analyses, which demonstrated that it would be prudent to retire King in 2028 and Sherco 3 in 2030. In addition, accelerated retirement of King and Sherco 3 would help the Company meet its corporate goal, announced in December 2018, to reduce carbon emissions by 80 percent below 2005 levels by 2030. Additionally, more recent Minnesota mandates—to generate or procure sufficient carbon-free energy to match 80 percent of the Company's Minnesota retail load by 2030, and 90 percent by 2035, and 100 percent by 2040[27]—will require the Company to reduce, if not eliminate, coal production from our resource mix. As a result of all of these factors, both of these retirement dates were included in the Company's Preferred Plan in the 2019 Integrated Resource Plan (which planned for the 2020–2034 period).

Q. WHAT KINDS OF FINANCIAL AND RELIABILITY ANALYSES HAS THE COMPANY PERFORMED TO SUPPORT THAT RETIRING SHERCO 3 AND KING IS PRUDENT AND IN THE PUBLIC INTEREST?

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

- 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

[27] *See* Minn. Stat. § 216.1691, Minn. Laws 2023, chp. 7 (enacted in 2023).

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.

1. *Reliability Analyses for Sherco 3 and King*

Q. AT A HIGH LEVEL, WHAT DO THE RELIABILITY ANALYSES ADDRESS WITH RESPECT TO THE PLANNED RETIREMENT OF SHERCO 3 AND KING?

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 units will cause voltage, thermal or other stability concerns on the grid that would need to be mitigated 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 (i.e., 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 XCEL ENERGY 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 issues the studies identified. The Company submitted Attachment Y2 study requests with MISO for 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 accelerated 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 for two reconductor projects and one rebuild project 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, minimum/maximum 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 accelerated retirement was likely appropriate, the MISO RIIA Study was ongoing, but one of the key conclusions was that the complexity, and cost, of integrating renewable resources increases sharply as they move 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). One of NERC's key findings was that the generator retirements that are occurring disproportionately involve large baseload, solid-fuel generation (coal and nuclear). Because such retirements are tending to be replaced with newer and relatively more variable kinds of resources, this 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, while there are stability implications of retiring large baseload units from our system, those concerns can be addressed with other investments. They also confirmed that some synchronous generation (or a similar 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. In addition to giving weight to metrics and conclusions of the studies discussed above, we plan our system to be able to meet our capacity needs without reliance on the MISO capacity auction, because MISO's Resource Adequacy (RA) construct will not necessarily ensure there is sufficient firm capacity online to cover the needs of load serving entities. The MISO region relies on Load Serving Entities (LSEs) and market participants to supply the generation resources needed to serve load. MISO also oversees a market to ensure the resources that are available are used efficiently to serve load across the MISO footprint. While MISO can manage the distribution of resources, it cannot ensure that there is enough power generation to meet demand and does not guarantee that there will be enough firm capacity to meet the needs of LSEs. In fact, MISO's 2022–23 Planning Resource Auction resulted in a capacity shortfall for the MISO North/Central Region. Moreover, the relatively large size of Xcel Energy in the MISO region would make reliance on MISO's capacity market particularly risky—Xcel Energy's Upper Midwest System constitutes approximately 50 percent of the load in MISO Zone 1 and approximately seven percent of the load in the entire MISO footprint from Manitoba to Louisiana. Therefore, the Company reasonably does not rely on the MISO Planning Resource Auction (PRA) for securing capacity for single-year periods as a resource planning option, and it is crucial that we continue to plan for a system with sufficient capacity to meet our customer's energy needs.

2. *Economic Analyses for Sherco 3 and King*

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

A. As a part of our 2019 resource planning process for the 2020-2034 period, we developed 15 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 corporate goal (announced in December 2018) to reduce carbon emission 80 percent below 2005 levels by 2030. This analysis also effectively aligns with the recent legislation passed in Minnesota requiring that we generate or procure sufficient carbon-free energy to match 80 percent of the Company's Minnesota retail load by 2030, and 90 percent by 2035, and 100 percent by 2040.[28] 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 (including the accelerated retirement of Sherco 1 and 2).

Through this analysis, the scenario that eventually became the Company's Preferred Plan[29] in its 2019 resource planning cycle for the 2020-2034 period was Scenario 9, in which King would be retired in 2028, Sherco 3 retired in

[28] *See* Minn. Stat. § 216.1691, Minn. Laws 2023, chp. 7 (enacted in 2023).
[29] We note that the 2019 plan and the "preferred plan" therein pre-date the North Dakota requirement to include a North Dakota Preferred Plan, which rule became effective in 2023. *See* N.D. Admin Code § 69-09-12-03.

2030, the Monticello Nuclear Generating Plant (Monticello) extended from 2030 to 2040, and the Prairie Island Nuclear Generating Plant (Prairie Island) units would operate through the end of their current licenses (2033/34). In the Reference Scenario (based on the 2016-2030 Resource Plan), King was scheduled to retire in 2037 and Sherco Unit 3 was scheduled to retire in 2040.[30] The Scenario 9 retirement assumptions are shown in Table 2 below. The full assumptions used in the 2019 Strategist modeling are provided in Exhibit___(CJS-1), Schedule 3 to my testimony.

Table 2
2019 Scenario 9 Retirement Assumptions*

Baseload Unit	Reference Scenario	2019 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

* These retirement dates reflect the assumptions and choices in the 2020-2034 Resource Plan prepared in 2019. We note that our most recent resource plan filed with the Commission in April 2024 for the 2024–2040 period continues to assume 2028 and 2030 retirements for King and Sherco 3, respectively, but extends Monticello even further (to 2050) and also extends Prairie Island to 2053/54.

Q. HOW DID THE COMPANY ANALYZE THE DIFFERENT SCENARIOS IN ITS 2019 PLANNING?

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

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

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 2019 ECONOMIC ANALYSIS?

A. As noted above, the Company analyzed 15 different planning scenarios as a part of its 2019 resource planning, 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 below provides the Scenario deltas on a PVRR basis (present value of revenue requirements), which does not include any costs for emissions. Figure 2 below provides the Scenario deltas on a PVSC (present value of societal cost) basis, which include the costs for carbon dioxide and other emissions. In general, the plans that favored accelerated coal retirements and nuclear extensions were the lowest-cost plans on both a PVSC and PVRR basis.

Figure 1
2019 Planning Scenarios – PVRR Deltas from Reference Case
($2019 millions)

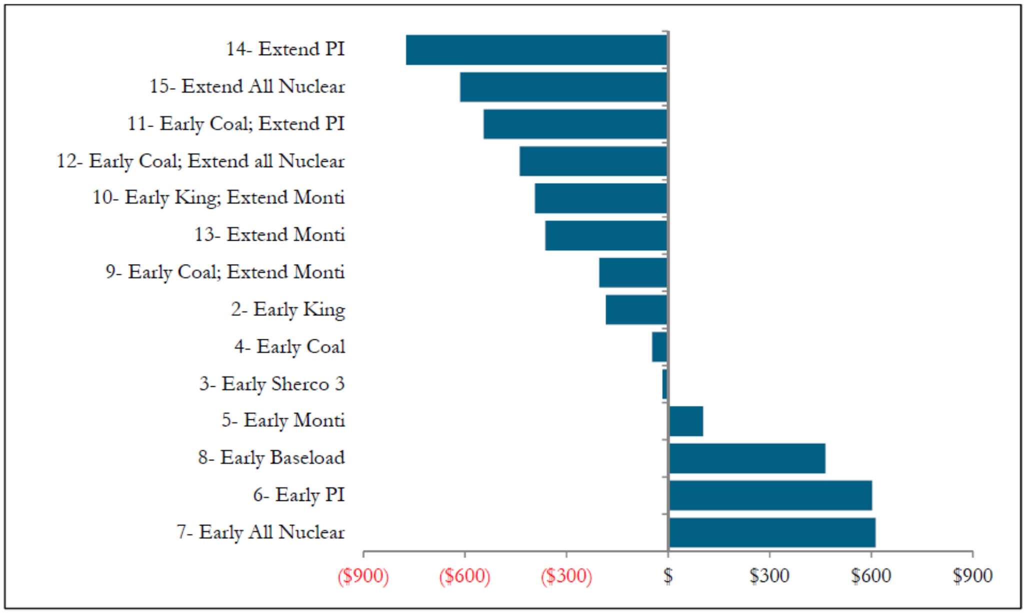
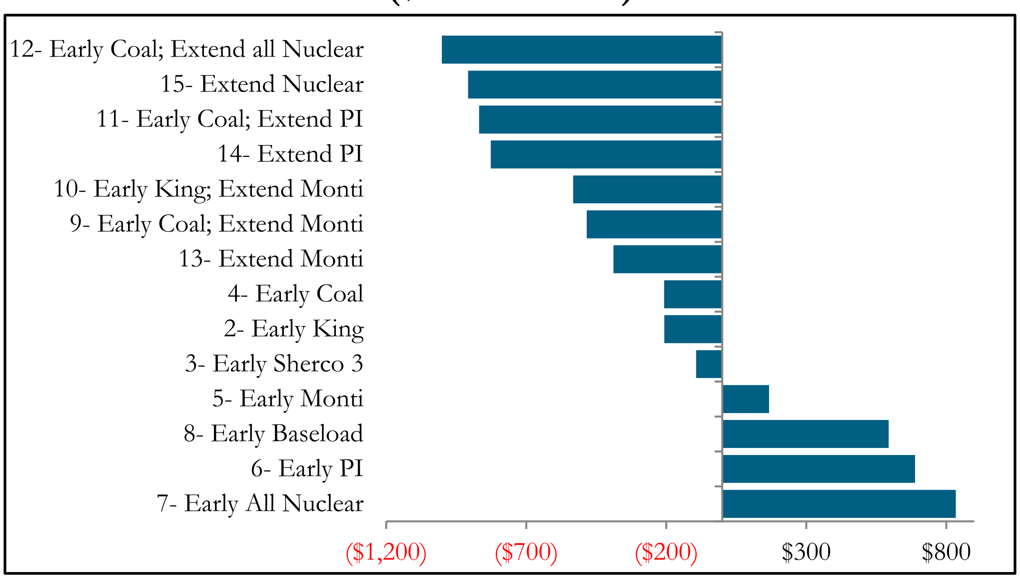


Figure 2
2019 Planning Scenarios — PVSC Deltas from Reference Case
($2019 millions)



Note the PVRR and PVSC deltas shown depict Net Present Value (NPV) for 2020-2045.

Q. WHAT DO FIGURES 1 AND 2 ABOVE SHOW?

A. These figures show that the retirements of Sherco 3 and King were found in our 2019 Strategist modeling to be economically prudent from both a PVRR and PVSC basis, both as standalone decisions and in combination, and regardless of whether carbon costs are considered. We tested scenarios that examine accelerated Sherco 3 retirement only (Scenario 3, labeled as "Early Sherco 3"), accelerated King retirement only (Scenario 2, labeled as "Early King") 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.[31] Further, scenarios that layered on nuclear unit extensions at the same time as accelerated coal retirements generally resulted in the highest levels of savings.

Figure 1 above shows that on a PVRR basis (i.e., when environmental externalities are not considered), accelerated retirement of King and/or Sherco (Scenarios 2–4 and 9–12) would result in savings for customers when compared with the Reference Scenario, and that the savings are greater when both King and Sherco 3 are retired in 2028 and 2030, respectively (as opposed to just one of those retirements), and the savings become yet greater when the coal retirements are combined with extension of the nuclear units (Scenarios 9–12). Accelerated shutdown of Sherco 3 and King is expected to yield more savings when extending either *both* Prairie Island and Monticello, or Prairie Island alone, while accelerated shutdown of Sherco 3 and King combined with extension of Monticello alone would still yield significant (albeit less) savings on a PVRR basis.

[31] 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.

Figure 2 above shows that that on a PVSC basis (i.e., when including the value of environmental externalities as required in Minnesota), accelerated shutdown of Sherco 3 and King combined with extension of all nuclear units (Scenario 12) results in the most savings on a PVSC basis compared to the Reference Case, but retiring Sherco 3 and King accelerated while only extending Monticello (Scenario 9) can nevertheless achieve substantial savings on a PVSC basis, while preserving the opportunity to extend Prairie Island in the future. This analysis supported the selection of Scenario 9 while additional work was being done with respect to the ability to extend the life of Prairie Island. Had there been more certainty with respect to the future of Prairie Island at the time we developed our Resource Plan, we would have selected Scenario 12.

It is worth noting that the Company's current North Dakota Resource Plan for 2024–2040 (filed with the Commission in April 2024) proposes to extend *both* Monticello and Prairie Island, which the 2019 modeling predicted would yield greater savings than extending Monticello alone (compare Scenario 12 with Scenario 9).

Q. WAS THE COMPANY'S SELECTION OF SCENARIO 9 AND LATER PROPOSAL TO IMPLEMENT SCENARIO 12 PRUDENT?

A. Yes. The Company operates a large, diverse system that spans over five states. As I noted above, the Integrated System brings the benefits of size to all of our customers. However, managing the Integrated System also introduces complexity when accounting for the need to weigh the many competing needs and requirements of all of our customers across these five states. Additionally, when making resource decisions, it is not as simple as determining that Plant X will retire and will be replaced with Plant Y. Rather, we must take an all-solutions approach to meeting our capacity needs and making choices on behalf of our customers. This is why the Scenarios we analyze identified portfolios of resource additions and retirements rather than each unit in isolation.

When all of these factors are taken into account, Scenarios 9 and 12 are clearly prudent. They result in considerable cost savings to customers on a PVRR basis and allow us to continue to operate the Integrated System in a manner that weighs the many considerations that we must consider in all of the states we serve.

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

A. First, regardless of qualitative considerations like PVSC calculations, the Company's decision to retire Sherco 3 and King is supported by quantitative economic considerations alone. As detailed above, the Company's 2019 analyses found that this decision would yield significant economic savings for customers on a PVRR basis alone, in addition to on a PVSC basis. The PVSC calculations further bolster the determination of prudence already supported by the PVRR calculations, as detailed more below.

Under North Dakota statutes,[32] and longstanding Commission precedent,[33] a resource decision may be prudently made based on both *quantitative* factors

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[32] The Commission may "consider qualitative benefits" in evaluating resource planning decisions. *See* N.D. Cent. Code § 49-05-17(2), (3). North Dakota regulations also require utilities to provide information on "qualitative benefits" of their resource planning decisions. *See* N.D. Amin. Code § 69-09-12-03 and 04. Utilities may also "provide alternative scenarios with sensitivities based on proposed and current federal, state, and utility goals and mandates relating to carbon cost, emissions goal, or other externalities." N.D. Amin. Code §69-09-12-03.

[33] August 27, 2008 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER in Case Nos. PU-06-481 and PU-06-482 (upholding Otter Tail Power's and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of a coal plant).

(costs to customers, without giving effect to environmental externalities) and *qualitative* factors such as regulatory risk and reliability considerations, as I detailed in Section I. Therefore, PVSC calculations and regulatory risks may be considered qualitatively as indicators of future risk and reliability issues, even if such calculations can't be used as the quantitative justification for resource decisions as indicators of future risk and reliability issues.

PVSC calculations can also be helpful in weighing the risk of future environmental regulations. Planning a system without any consideration of 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 costlier environmental compliance investments later. At a minimum, uncertainty surrounding regulation needs to be accounted for as we make resource decisions.

This uncertainty is evidenced in part by the fact that, even though the federal 2015 Clean Power Plan was repealed and replaced by the less stringent Affordable Clean Energy (ACE) Rule in 2019,[34] the ACE Rule in turn has been repealed and subsequently replaced by new rules finalized in April/May of 2024 (and therefore may now be considered in future quantitative analyses under North Dakota law) that impose stringent requirements on existing coal power

[34] The Supreme Court stayed implementation of the Clean Power Plan in February 2016. *See* https://19january2017snapshot.epa.gov/cleanpowerplan/clean-power-plan-existing-power-plants_.html. It was subsequently repealed and replaced by the Affordable Clean Energy Rule. *See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*, 84 Fed. Reg. 32520 (Jul. 8, 2019), https://www.govinfo.gov/content/pkg/FR-2019-07-08/pdf/2019-13507.pdf; *see also* https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule. In turn, that rule was subsequently repealed, and how now been replaced by new rules finalized in spring 2024.

plants to control carbon emissions, as well as mercury and toxic metal emissions, coal ash, and wastewater.[35] In particular, the spring 2024 rule promulgated under Section 111(d) of the Clean Air Act would require coal-fired power plants operating past 2039 to reduce their carbon emissions by 90 percent by 2032. Accordingly, if Sherco 3 were to continue to operate to the 2040 retirement date assumed in the 2016–2030 Resource Plan, it would need to make significantly costly carbon control investments by 2032, which would likely make its continued operation economically untenable.[36]

But again, I want to reiterate that regardless of qualitative considerations like PVSC calculations, the Company's decision to retire Sherco 3 and King is supported by quantitative PVRR economic considerations alone, as detailed above.

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

A. Yes. Because Prairie Island's license is not due to expire until the 2033–34 timeframe, which was at the end of the resource planning period (2020–2034) that was current at the time the 2019 decision was made, and to allow for further outreach with impacted communities, the Company determined there was value in deferring a decision on Prairie Island license extension until a future resource planning process, and decided to eliminate from further consideration (in 2019)

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[35] *See Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants* (Apr. 25, 2024), https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-suite-standards-reduce-pollution-fossil-fuel.

[36] Although there are ongoing legal challenges to the rule that would require coal-fired power plants operating past 2039 to reduce their carbon emissions by 90 percent by 2032, no court yet has placed a stay on the rule.

cases that included a Prairie Island extension (Scenarios 11, 12, 14, and 15). The Company subsequently decided, in its 2024 Resource Plan (filed with the Commission in April 2024), to capitalize on the predicted additional economic savings by proposing an extension of Prairie Island (to 2053–54).

Q. WHAT WERE THE EXPECTED COST SAVINGS FOR THE 2019 PREFERRED SCENARIO (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 that was modeled, relative to the Reference Case.

The Company also conducted sensitivities tests to examine whether a particular scenario would be 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.

Q. HAS THE COMPANY UPDATED ITS ANALYSES OF THE SHERCO 3 AND KING RETIREMENT DECISION SINCE 2019?

A. Yes. The Company filed a Supplement to its IRP in June 2020 that included updated analyses.[37] The Company also conducted updated energy adequacy, reliability and cost analyses for the 2024 North Dakota Resource Plan submitted to the Commission in April 2024.[38]

Q. WHAT UPDATED ANALYSES WERE CONDUCTED FOR THE JUNE 2020 SUPPLEMENT TO THE 2019 IRP?

A. We made updates to several modeling inputs, accounting for the passage of time and further analysis requirements. 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. We also updated our economic analyses using the EnCompass modeling tool for the first time and primarily used the EnCompass modeling results to develop our Supplement Preferred Plan. We switched to EnCompass because it better reflects grid operations and values a more complete range of resource attributes than Strategist modeling. The EnCompass model provides the additional capability of modeling our system on a chronological hourly basis. 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. By contrast, 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.

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[37] *See* Supplement to the 2020–2034 Upper Midwest Resource Plan, Northern States Power Company, Case No. PU-19-220 (June 30, 2020), https://www.psc.nd.gov/database/documents/19-0220/016-010.pdf.
[38] *See* 2024-2040 North Dakota Resource Plan, Northern States Power Company, Case No. PU-24-160 (Apr. 8, 2024), https://www.psc.nd.gov/database/documents/24-0160/001-010.pdf.

Therefore, 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, 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. The full Strategist and EnCompass assumptions used for the June 2020 modeling are provided in Exhibit___(CJS-1), Schedule 4 to my testimony.

Q. WHAT WERE THE RESULTS OF THE JUNE 2020 ANALYSES FOR KING AND SHERCO 3?

A. As shown in Figures 3 and 4 below, our June 2020 modeling found that the retirements of King in 2028 and Sherco 3 in 2030 (referred together as "Early Coal" scenarios) continue to perform well when combined with extensions of both nuclear plants (Scenario 12) or with a Prairie Island extension alone (Scenario 11) under both the Strategist and EnCompass models, yielding significant financial savings on both a PVRR (Figure 3) and PVSC (Figure 4) basis as compared to the Reference Scenario. But when the 2028 and 2030 retirements of King and Sherco are combined with extending only the Monticello nuclear plant and not the Prairie Island nuclear plant (Scenario 9), significant savings continue to be achieved on a PVSC basis, but add costs on a PVRR basis. Similarly, the accelerated retirement of Sherco 3 and King as a standalone decision (i.e., without combining this decision with nuclear extensions) continued to yield savings on a PVSC basis, but added costs on a PVRR basis, though accelerated retirement of King alone (Scenario 2, labeled as "Early King"), and accelerated King plus Monticello extension (Scenario 10, labeled as "Early King; Extend Monti") would continue to yield savings on a PVRR basis under the EnCompass model.

Figure 3
June 2020 Analyses – Baseload Scenario PVRR Deltas from the Reference Case

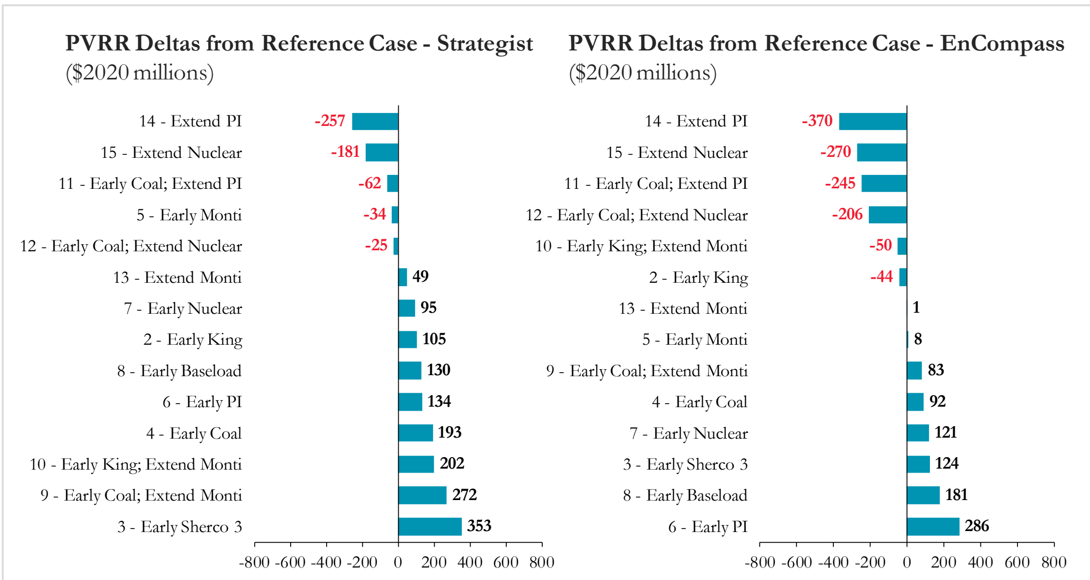
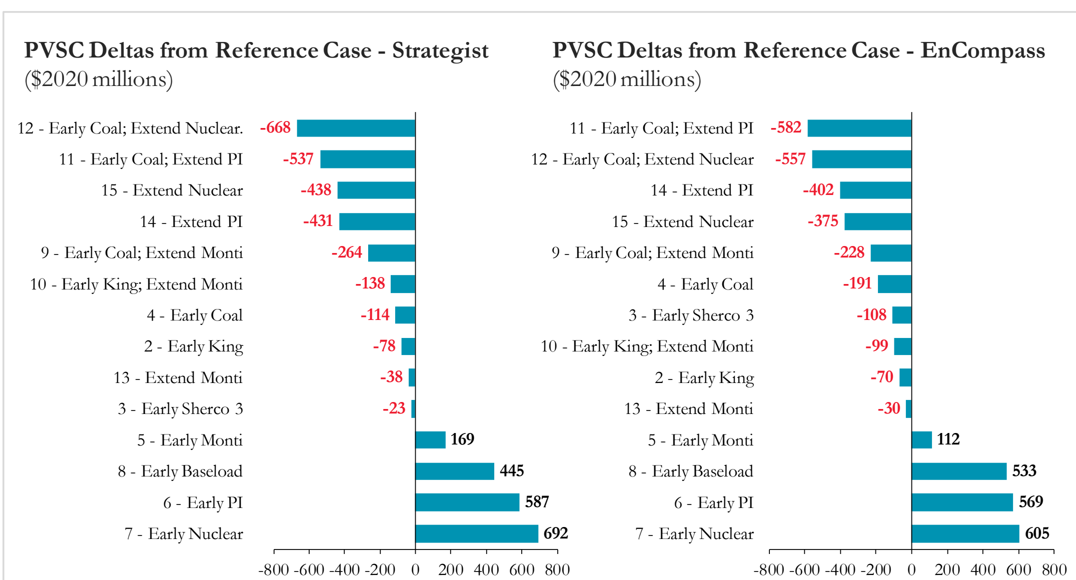


Figure 4
June 2020 Analyses – Baseload Scenario PVSC Deltas, Relative to the Reference Case, in Strategist and EnCompass Modeling



Q. DID THE JUNE 2020 ANALYSIS IMPACT YOUR DECISION TO ACCELERATE THE RETIREMENT OF KING AND SHERCO 3?

A. The June 2020 Analysis confirmed our decision to move forward with Scenario 9 while we continued the work necessary to extend Prairie Island and Scenario 12. On an economic basis, the EnCompass modeling showed that, on a PVRR basis, accelerated retirement of King and Sherco 3 when combined with extensions of *both* nuclear plants (Scenario 12) would yield financial savings. In other words, our work in this timeframe supported that Scenario 12 from the last resource planning cycle was the most prudent way forward for the Company, which is now reflected in the Company's 2024 Resource Plan (for 2024-2040) filed with the Commission in April 2024. We also note that a 2050 Monticello extension combined with a 2053-2054 Prairie Island extension is included in the settlement agreement recently filed with the MPUC.[39]

D. Summary

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

A. Yes. As I discussed earlier, the Company's decision to retire Sherco 1 and 2 is supported by quantitative economic considerations, and even more so when considering qualitative factors. The Company's 2015 modeling showed that, on a PVRR basis (i.e., purely economic), its October 2015 Updated Plan, which included the retirement of Sherco 1 and 2 in 2026 and 2023, respectively, alongside additions of wind and solar, would be essentially cost-neutral as

[39] *See* Settlement Agreement (October 2, 2024) in a combined filing for *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, MPUC Docket No. E002/CN-23-212, and *In the Matter of Northern States Power Company d/b/a Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. E002/RP-24-67.

compared to the continuation of our 2010 IRP. Further, when factoring in qualitative factors like regulatory risks and corresponding significant compliance costs, alongside opportunities to shift to more flexible resources, as well as the demands of customers and other stakeholders, the prudence of the decision to retire Sherco 1 and 2 becomes increasingly apparent.

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. As discussed above and shown in Figures 1 and 2, the Strategist modeling leading to our decision in 2019 to retire King and Sherco 3 in 2028 and 2030, respectively, showed this decision was economically prudent from both a PVSC and PVRR basis (i.e., regardless of whether carbon costs are considered), yielding economic savings both as standalone decisions and even more so in combination, and even more still when combined with nuclear plant extensions. Because determinations of prudence are based on the information and circumstances at the time a decision was made, this alone establishes the prudence of our 2019 decision to accelerate the retirement of Sherco 3 and King.

Q. WHAT DOES THE COMPANY REQUEST THAT THE COMMISSION DECIDE WITH RESPECT TO KING AND SHERCO 1, 2, AND 3 IN THIS CASE?

A. The Company requests that the Commission: (i) find that the retirement of Sherco 2 in 2023, planned retirement of Sherco 1 in 2026, planned retirement of King in 2028, and planned retirement of Sherco 3 in 2030 are all prudent; (ii) allow for recovery of the remaining undepreciated book value of the Sherco 2 unit in the test year; and (iii) allow the Company to adjust depreciation expenses of Sherco 1, King, and Sherco 3 to match the Company's announced retirement dates for these units in 2026, 2028, and 2030, respectively. As indicated in my discussions above, the Company's analyses of these decisions demonstrate that customers would see a net benefit under a range of future scenarios when considering that they can be replaced with more cost-effective and reliable resources.

IV. MONTICELLO EXTENSION

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

A. In this section, I explain the basis for the Company's request that the Commission find the proposed extension of the Monticello Nuclear Generating Plant (Monticello Plant or Monticello) from 2030 to 2040 to be prudent and allow the Company to adjust its depreciation rates accordingly.[40]

A. Summary of Decision to Extend Monticello

Q. PLEASE PROVIDE AN OVERVIEW OF THE MONTICELLO PLANT.

A. The Monticello Plant is a core baseload generating unit in the Company's fleet, providing electricity 24-hours a day, seven days a week for extended periods of time to meet steady demand for electric power. It is a single-unit, 671 MW nuclear-powered, boiling water reactor generating station located in Monticello, Minnesota. Since the Monticello Plant began operations in 1971, it has generated over 200 million megawatt-hours (MWh) of electricity, and together with the Prairie Island nuclear plant represents nearly 30 percent of the total

[40] Although the North Dakota Preferred Plan in the Company's 2024–2040 Resource Plan filed with the Commission in April 2024 in Case No. PU-24-160 would extend Monticello even further--to 2050--in this Rate Case the Company's request is simply to approve a 2040 extension and corresponding depreciation adjustment. The Company may seek to further extend the retirement date to 2050 in a subsequent rate case.

electricity our customers require today. No other generating facilities in the Company's current portfolio can provide such consistent, reliable, carbon-free energy and capacity. For this reason, the Company is seeking to extend the life of Monticello for an additional 10-year period from its currently set retirement of 2030 to our new proposed retirement date of September 8, 2040.

Q. HAS THE COMPANY MADE ANY NOTABLE INVESTMENTS OR UPGRADES TO THE MONTICELLO PLANT IN RECENT HISTORY?

A. Yes. Over the past 15 years, the Company has undertaken several major capital projects at the Monticello Plant to increase its capacity and improve the safety and efficiency of the plant. With these investments, the Company was able to replace nearly all of the systems that support the reactor and power generation equipment at the Plant, resulting in a state-of-the-art facility that achieves industry-leading results in terms of safety, plant performance, and management of the Company's costs to achieve that performance. The Monticello Plant provides substantial customer benefits given the fixed costs associated with nuclear fuel, during a period when high inflation and severe weather events are causing other types of fuel prices to rise. Given these already-made investments to modernize the Monticello Plant and the critical role it plays in providing consistent baseload generation and reliability in the NSP system, it is prudent to extend Monticello's life.

Q. WOULD THE COMPANY NEED TO OBTAIN ANY OTHER APPROVALS OR MAKE OTHER INVESTMENTS TO EXTEND THE MONTICELLO PLANT'S LIFE PAST 2030?

A. Yes. Among other things, the Company will need to obtain a Subsequent License Renewal (SLR) to operate past the Monticello Plant's current Nuclear Regulatory Commission (NRC) license expiration on September 8, 2030. The

Company filed its SLR application with the NRC on January 9, 2023. This SLR would be Monticello's second NRC license renewal and would extend the Plant's life from 60 to 80 years, with a new expiration date of September 8, 2050. Applications for SLRs are not uncommon in the industry. Indeed, most nuclear plants nationwide (including both Monticello and Prairie Island) have renewed their operating license once already, more than half will need a second SLR by 2040, and five will need SLRs by 2030. A Feasibility Study commissioned by the Company determined that an SLR for the Monticello Plant should be financially prudent and technically viable. The Feasibility Study identified no fatal flaws, technical issues, or environmental concerns that would hold up the SLR process or prevent operation of the Plant during the 20-year SLR period. Further, the Company's previous experience with completion of the SLR process already for Monticello in 2006 and Prairie Island in 2014 will help it navigate many of the relicensing requirements for the second SLR. Accordingly, the Company is optimistic about the outcome of an SLR application for the Monticello Plant.

In addition to needing to obtain an SLR, the Company will need to make certain capital and operational investments in the Monticello Plant. For example, although the investments the Company has made over the last 15 years will significantly mitigate the scope of future investments needed to license the Plant, investments will need to be made to expand the existing dry storage for spent fuel rods at the Independent Fuel Storage Installation (ISFSI) at the Plant because the ISFSI will be full, with no space for additional storage, by 2030. In fact, even if the Plant does not obtain an NRC subsequent license renewal and begins decommissioning in 2030, the existing ISFSI will still need to be expanded as part of decommissioning to accommodate all of the spent fuel on-site.

The expansion of the Monticello ISFSI through 2040 required a Certificate of Need (CN) from the MPUC, which the Company received approval for in August 2023; the MPUC issued its written Order in October 2023 (Docket No. E002/CN-21-668). An April 2022 MPUC Order had already largely approved the Company's proposed capacity additions in its June 2021 IRP "Alternate Plan" filing, and approved the Company continuing to seek a Monticello extension via the requisite CN process for the spent fuel storage expansion and pursuing an operating license extension from the NRC.[41] A 2050 Monticello extension combined with a 2053-2054 Prairie Island extension is also included in the settlement agreement recently filed with the MPUC; their decision is anticipated in the first half of 2025.[42]

Continuing to operate the Monticello Plant beyond 2030 will also require continued capital investments in future years as part of the Company's Aging Management Programs (AMPs). In addition to the 36 AMPs currently implemented at the Monticello Plant and five additional activities that would be credited as AMPs in the SLR, the Feasibility Study identified several AMPs that would need to be expanded or added in order to obtain the second SLR. The Company has budgeted $2 million for initial implementation of these new and expanded AMPs, and ongoing O&M expenditures would be required for these AMPs if the SLR is granted.

[41] *See* Order (Apr. 15, 2022), MPUC Docket No. E002/RP-19-368.
[42] *See* Settlement Agreement (filed on October 2, 2024) in a combined filing for *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, MPUC Docket No. E002/CN-23-212, and *In the Matter of Northern States Power Company d/b/a Xcel Energy's Upper Midwest Integrated Resource Plan*, MPUC Docket No. E002/RP-24-67. A CN application for the Prairie Island Nuclear Generating Plant was filed on February 7, 2024 in MPUC Docket No. E002/CN-24-68 and is currently still in review by the MPUC.

Making these investments will ensure that the Monticello Plant will continue to provide important reliability and resource diversity benefits as the NSP System continues to transition to more variable renewable generating resources in the future.

Q. IS THE COMPANY'S REQUEST TO EXTEND MONTICELLO CONSISTENT WITH DECISIONS IN OTHER STATES WITH JURISDICTION OVER MONTICELLO?

A. Yes. On April 15, 2022, the MPUC approved the Company continuing to seek Monticello extension to 2040 via the requisite CN process for the spent fuel storage expansion and pursuing an operating license extension from the NRC. As noted above, in 2023 the MPUC granted a CN for the expansion of the Monticello ISFSI through 2040. Shortly after the MPUC makes a decision on the Company's 2024-2040 Upper Midwest Integrated Resource Plan, we intend to seek an additional 10-year expansion of the IFSFI to support a life extension of the Monticello plant from 2040 to 2050 through the MPUC.

On May 24, 2023, the SDPUC approved a settlement agreeing to extend the depreciation lives and rates for Monticello to represent a useful life to the end of 2040, to coincide with the Company's expected 10-year extension to Monticello's operations in its 2019 resource plan.[43]

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[43] *See* Settlement Stipulation at 5, and ORDER GRANTING JOINT MOTION FOR APPROVAL OF SETTLEMENT STIPULATION, SDPUC Docket No. EL22-017, *In the Matter of the Application of Northern States Power Company dba Xcel Energy for Authority to Increase its Electric Rates,* https://puc.sd.gov/dockets/Electric/2022/EL22-017.aspx.

Q. IS THE COMPANY'S PROPOSAL TO EXTEND MONTICELLO TO 2040 CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. As discussed above, the preferred plan in the Company's prior resource plan (filed in 2019, for the 2020-2034 period) extended Monticello to 2040. The North Dakota Preferred Plan in the Company' most recent North Dakota Resource Plan, filed with the Commission in April 2024 (for the period of 2024–2040) goes a step further, proposing to extend the life of Monticello from 2040 to 2050.[44] Because the Commission has not yet taken up the Resource Plan filed in 2024, nor has the Company yet received the other regulatory approvals discussed above for a 2050 Monticello extension, the Company's request in this Rate Case is to true-up the depreciation of Monticello with the currently effective 2019 MN IRP approval of extended operations through 2040 and MPUC CN approval of spent fuel storage through 2040. Accordingly, the Company is currently requesting to adjust Monticello's depreciation to 2040, not 2050, at this time.

Q. AT A HIGH LEVEL, WHEN AND HOW DID THE COMPANY MAKE ITS DECISIONS TO EXTEND MONTICELLO?

A. The Company first made the decision to extend the Monticello Plant to 2040 as a part of its 2019 resource planning cycle for the 2020–2034 period. We then filed a request for an Advance Determination of Prudence (ADP) with the Commission in February 2023 to extend Monticello to 2050, but we subsequently rescinded that request and reintroduced it as a component of the

[44] *See* 2024-2040 North Dakota Resource Plan, Northern States Power Company, Case No. 24-160, at Chapter 4 (PDF 69) https://apps.psc.nd.gov/webapps/cases/pscasedetail?getId=24&getId2=160# (Apr. 8, 2024).

holistic resource planning package filed with the Commission in April 2024, in the 2024–2040 North Dakota Resource Plan.

The Company initiated analyses of the Monticello Plant's extension because its current NRC license is set to expire in 2030, and, accordingly, if the Company does not make the necessary investments to extend the license and operation of the Monticello Plant, the Company will need to replace the substantial capacity and energy it provides to the system. Therefore, as part of the 2020-2034 Upper Midwest Integrated Resource Plan filed in 2019, the Company analyzed alternatives for replacing the capacity and energy provided by the Monticello Plant. For this, the Company developed 15 scenarios with varying combinations and timing of baseload unit retirements and compared them to a Reference Scenario based on the prior (2016–2030) Resource Plan.

In general, these analyses found that extending the life of the Monticello Plant: (1) is cost-effective from a PVRR basis; (2) generates considerable savings from a PVSC basis when environmental externalities are considered; (3) is critical to achieving the Company's goals (announced in December 2018) to reduce carbon emissions by 80 percent below 2005 levels by 2030 (as well as the subsequent mandates imposed by Minnesota to generate or procure sufficient carbon-free energy to match 80 percent of the Company's Minnesota retail load by 2030, 90 percent by 2035, and 100 percent by 2040[45]); and (4) ensures that the Company maintains a robust share of firm and dispatchable generation relative to peak load across seasons.

[45] *See* Minn. Stat. § 216.1691, Minn. Laws 2023, chp. 7 (enacted in 2023).

In addition, in conjunction with its ADP application filed with the Commission in February 2023, the Company conducted additional analysis to further evaluate what resources would replace Monticello if it were retired in 2030, including a replacement case using North Dakota planning assumptions.

Q. PLEASE SUMMARIZE THE RESULTS OF THESE ANALYSES.

A. The Company's 2019 IRP analysis (looking at 2020–2034) found that, in general, extending the life of the Monticello Plant as part of the total package of resource planning decisions proposed was cost-effective from both a PVRR and PVSC basis and would ensure that the Company maintains a robust share of firm and/or dispatchable generation relative to peak load across seasons. In the analysis of replacement scenarios included in the Company's ADP application, when the Monticello Plant is not extended, the capacity provided by Monticello is most cost-effectively replaced by generic gas combustion turbines (CTs), and its energy value is replaced primarily with additional generic wind generation. This modeling showed a slight relative cost for the Monticello Plant extension scenario versus a case in which the model is free to select an optimized replacement resource. However, as I discuss below, this retirement and CT replacement scenario would leave customers more exposed to wholesale markets and price and supply volatility of other types of fuels. Overall, while the modeling of the extension of the Monticello Plant shows some additional cost versus a case in which it is retired and replaced by CTs and wind, the Company's analyses support a finding that extending the Monticello Plant is prudent due to important reliability, resource diversity, and cost volatility and fuel availability risk considerations.

B. Economic Analyses for Monticello Decision

Q. PLEASE SUMMARIZE HOW THE COMPANY ANALYZED THE MONTICELLO EXTENSION IN THE CONTEXT OF ITS BROADER 2019 RESOURCE PLANNING PROCESS.

A. As detailed in Section III.C.2 above in my discussion of Sherco 3 and King, development of the Company's 2020-2034 Resource Plan in 2019 involved analyzing 15 scenarios with varying combinations and timing of baseload unit retirements and replacement resources, using Strategist modeling to compare them to a Reference Scenario, which was essentially a "business as usual" case based on the prior (2016–2030) Resource Plan. These analyses eventually led to the Company selecting a scenario that would extend Monticello to 2040 while accelerating the retirement of the King and Sherco 3 coal units, in 2028 and 2030, respectively.

Q. WHAT WERE THE RESULTS OF THE COMPANY'S 2019 RESOURCE PLANNING ECONOMIC ANALYSIS?

A. The results of Strategist modeling conducted in 2019 are shown in Figures 1 and 2 above in Section III.C.2, in the discussion of the Sherco 3 and King accelerated retirements. These results show that extending the life of the Monticello Plant generates significant cost savings for customers relative to the Reference Scenario from both a PVRR and PVSC basis, as a standalone decision as well as when combined with the accelerated retirement of King and Sherco 3, and/or with extension of Prairie Island. In other words, the 2019 modeling showed that extending the Monticello Plant would be economically prudent regardless of whether carbon costs are considered and regardless of whether this decision was combined with other retirements or extensions.

Q. WHAT DID SUBSEQUENT RESOURCE PLANNING ANALYSES SHOW WITH RESPECT TO MONTICELLO?

A. In June 2020, the Company supplemented its Resource Plan with EnCompass modeling that found that extending Monticello would yield economic savings on a PVRR basis when combined with extending Prairie Island (without the accelerated retirement of Sherco 3 and King) or when combined with extending Prairie Island *and* accelerated retirement of Sherco 3 and King. The PVSC results yielded economic savings for those scenarios, as well as for extending Monticello alone. These results are shown in Figures 3 and 4 above in the discussion of the Sherco 3 and King retirements.

Q. DID THESE JUNE 2020 RESULTS CHANGE THE COMPANY'S PLANS FOR MONTICELLO?

A. No, the June 2020 updated modeling did not change the Company's decision to extend Monticello and in fact reinforced that decision, given that the modeling showed this decision would be economically prudent on a PVSC and PVRR basis in combination with certain other resource decisions. Additionally, the benefits of extending Monticello increased when combined with the benefits of extending Prairie Island (Scenario 12 in Figures 3 and 4) and, as noted above, the Company has proposed a Prairie Island extension in the 2024 Resource Plan (for 2024-2040) filed with the Commission in April 2024.

Q. DID THE COMPANY PERFORM ADDITIONAL ANALYSES ON THE MONTICELLO PLANT AFTER THE JUNE 2020 ANALYSIS DISCUSSED ABOVE?

A. Yes, in June 2021, as a part of preparation of an "Alternate Plan" for the Company's IRP, the Company conducted updated analyses (on both a PVRR basis and PVSC basis), including a scenario under North Dakota planning assumptions (no regulatory or externality values in the capacity expansion) in which the coal units retire (2023 for Sherco 2, 2026 for Sherco 1, 2028 for King, and 2030 for Sherco 3) and Monticello is extended.

Q. HOW ELSE DID THE COMPANY ANALYZE THE PROPOSED MONTICELLO EXPANSION SPECIFICALLY?

A. In our ADP application filed in February 2023, the Company analyzed the Monticello Plant extension individually by comparing a 2040 extension of Monticello to a replacement case in which Monticello is retired in 2030 as currently scheduled, to determine whether replacement alternatives would be more or less cost-effective and produce more or less reliability in terms of resource adequacy and cost-certainty.

Q. WHAT WERE THE RESULTS OF THAT ANALYSIS OF THE MONTICELLO REPLACEMENT OPTIONS?

A. Our analysis found that, if left to optimize the most cost-effective resources to replace Monticello, the model will choose to add or pull forward from later years approximately 750 MW of gas-fire combustion turbines (CTs), alongside 200 MW of additional wind resources and 50 MW of solar resources in the planning period, relative to the other "Alternate Plan" then-considered in June 2021. The Monticello replacement scenario was modeled to be more costly on a PVRR basis, resulting in $145 million in additional costs on a PVRR basis as compared to the 2021 IRP "Alternate Plan." This scenario would also result in increased exposure to market prices and volatility, and it would present resource reliability challenges. More specifically, this scenario would result in less native generation from NSP system resources and more reliance on market purchases, making our resource adequacy less certain.

Further, CTs are subject to more fuel price and availability volatility than nuclear units. While nuclear units have physical fuel in the plant that allows them to operate for long durations without additional exposure to fuel prices for each incremental MWh produced, natural gas is subject to daily and monthly price swings and availability constraints. Although the Company does employ appropriate hedging and fuel storage strategies to mitigate the volatility, in contrast to baseload nuclear, CTs do not typically have firm fuel delivery contracts and thus may rely on other types of fuel security (e.g., on-site storage of fuel oil or liquified natural gas). In any case, firm fuel contracts or reliance on higher-cost fuel for backup exposes CTs to higher potential upside costs of operation than nuclear units, which utilize fuel rods that typically produce for six years at a time. Thus, while CTs are an important part of our system for their flexibility and renewable integration attributes and do provide comparable accreditation values, they are not one-for-one replacements for nuclear baseload capacity in terms of the risk mitigation value they provide to the system.

Q. DOES THE INFLATION REDUCTION ACT AFFECT THE ECONOMICS OF THE MONTICELLO EXTENSION PROPOSAL?

A. The Inflation Reduction Act (IRA) includes tax benefits that would likely reduce costs below what we previously anticipated for the project, for the first two years of the extension.

C. Reliability and Resource Adequacy Analyses for Monticello

Q. ARE THERE ADDITIONAL BENEFITS OF EXTENDING MONTICELLO THAT THE COMPANY CONSIDERED AND SHOULD BE CONSIDERED BY THE COMMISSION?

A. Yes, as alluded to above, extending Monticello brings reliability and resource adequacy benefits. When we analyzed the reliability of extending Monticello to

2040, we found that our plan would be reliable under the typical meteorological year (TMY) assumptions, as well as under a stress test of more extreme weather conditions, such as the polar vortex experienced in 2019. Under those extreme conditions, our modeling showed that there would be no loss of load hours or unserved energy in the year tested (2034) and only one short event where our load would not be met with native capacity.

We also took into account the various resource types in our portfolio to ensure a balanced portfolio that provides appropriate capacity, energy, and flexibility attributes in aggregate. Generation resource diversity is important to maintain the robustness and resiliency of our generation portfolio. Further, as our portfolio shifts to greater portions of variable renewable energy, the grid becomes more complex, and maintaining some reliable baseload resources with a higher capacity factor, like Monticello, becomes correspondingly important. Nuclear generation is inherently more resistant to certain reliability events such as severe weather and fuel disruptions due to on-site fuel storage. From a resource planning perspective, we need a mix of large and small plants with their different operational attributes in order to maximize production and reduce risk. Our nuclear fleet adds important diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values.

D. Conclusion on Monticello

Q. WAS THE COMPANY'S DECISION TO EXTEND MONTICELLO PRUDENT AT THE TIME IT WAS MADE?

A. Yes. The results of our Strategist modeling conducted in 2019—when the

Monticello extension decision was first made—found that extending the life of the Monticello Plant generates significant cost savings for customers relative to the Reference Scenario from both a PVRR and PVSC basis, as a standalone decision as well as when combined with the accelerated retirement of King and Sherco 3, and/or with extension of Prairie Island. In other words, the 2019 modeling showed that extending the Monticello Plant would be economically prudent regardless of whether carbon costs are considered, and regardless of whether this decision was combined with other retirements or extensions.

Further, subsequent economic modeling (reflected in Figures 3 and 4 above) has shown that the Company's current plans in our 2024-2040 Resource Plan to combine the extension of Monticello with the extension of Prairie Island, alongside accelerating the retirement of King and Sherco 3 (Scenario 12 in the figures previously discussed), continues to yield savings on a PVRR and PVSC basis. Moreover, consideration of various reliability factors renews the conclusion that extending Monticello is prudent. The Monticello Plant provides critical baseload generation and fuel diversity benefits that are important for maintaining overall reliability on the NSP System. Additionally, the Monticello Plant provides carbon-free baseload generation, and in that respect, its continued operation is critical to reducing exposure to volatile prices of other types of fuels as well as future regulatory compliance costs associated with resources with significant air emissions. For these reasons, the Company's plan to invest in additional spent storage and federal licensing requirements to extend the life of the Monticello Plant was prudent when the decision was made in 2019 and continues to be prudent.

Q. WHAT IS THE COMPANY REQUESTING IN THIS RATE CASE WITH RESPECT TO MONTICELLO?

A. The Company requests that the Commission find that the Company's planned extension of the Monticello Nuclear Generating Plant from 2030 to 2040 is prudent and allow for an adjusted depreciation based on that retirement date, consistent with its approved 2020-2034 Resource Plan.

V. SHERCO SOLAR 1 AND 2 ADDITIONS

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

A. In this section, I explain the basis for the Company's request that the Commission find the proposed addition of Sherco Solar 1 and 2 is prudent and approve recovery of the costs and energy of these projects in base rates.

A. Summary of Sherco Solar 1 and 2 Addition Proposals

Q. PLEASE PROVIDE AN OVERVIEW OF THE SHERCO SOLAR 1 AND 2 PROJECTS.

A. The Sherco Solar 1 and 2 projects are grid-scale photovoltaic (PV) projects, together providing 460 MW of nameplate capacity. The Sherco Solar 1 and 2 projects are located in the vicinity of the Company's coal-powered Sherco Generating Station. This location is ideal because of the site's proximity to existing electrical and transportation infrastructure, existing transmission lines, and the Sherburne County Substation. Importantly, the Sherco Solar 1 and 2 projects will be able to reutilize the interconnection capacity made available with the December 31, 2023 retirement of the Sherco Coal Unit 2, as well as the planned retirement of Sherco Coal Unit 1 in 2026 and Sherco Coal Unit 3 in 2030. Sherco Solar 1 came into commercial operation in October 2024. Sherco Solar 2 is expected to achieve commercial operations in October 2025.

Q. PLEASE PROVIDE AN OVERVIEW OF WHEN AND HOW THE COMPANY MADE ITS DECISIONS TO ADD SOLAR RESOURCES AT THE SITE OF THE RETIRING SHERCO COAL GENERATING PLANT.

A. For nearly 15 years, the Company has been forecasting that a large capacity need would arise in the mid-2020s. The first time the Company identified this large forthcoming capacity need was in our 2011–2025 Resource Plan filed with the Commission in 2010,[46] and similar capacity needs continued to be forecast in subsequent resource plans, including in our 2016–2030 IRP filed in 2015 and the supplement thereto,[47] our 2020–2034 IRP filed in 2019 and the June 2020 supplement thereto,[48] and in our 2024-2040 North Dakota Resource Plan filed with the Commission in April 2024.[49] The June 2020 Supplement to the 2020–2034 IRP (which was the most recent IRP in place at the time the Company made the Sherco Solar decisions) forecasted a 92 MW net capacity deficit arising on the system in 2026 and growing to 1,016 MW by 2030.[50] The 2024–2040 IRP forecasts that, even assuming the Sherco Solar projects will come online in 2025, there will still be a need for additional capacity starting in 2027 and growing over time, which further emphasizes the necessity of filling the need identified by the prior IRP.

This capacity need identified in past IRPs is due to a variety of factors, including the then-pending expiration of several large PPAs (including but not limited to

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[46] Northern States Power Company, Case No. PU-10-580, 2011-2025 Resource Plan at p. 3-21 (Aug. 2, 2010).
[47] Northern States Power Company, Case No. PU-15-019, 2015 Upper Midwest Integrated Resource Plan (for 2016-2030) at p. 55 (Jan. 5, 2015).
[48] Northern States Power Company, Case No. 19-220, 2020-2034 Upper Midwest Resource Plan Supplement.
[49] Northern States Power Company, Case No. PU-24-160, 2024-2040 North Dakota Resource Plan (Apr. 8, 2024).
[50] Northern States Power Company, Case No. 19-220, 2020-2034 Upper Midwest Resource Plan Supplement at Att. A, p. 15-16 (June 30, 2020).

large hydroelectric contracts) as well as multiple retirements of existing Company-owned generation facilities, including the three Sherco Coal units planned for retirement in 2023, 2026, and 2030. It was the combination of all of those retirements and expirations, alongside an expected increase in demand, that contributed to the need identified in the 2020–2034 IRP for new generation resources beginning in 2026.

To resolve the identified capacity need, the Company took a portfolio approach that included adding solar generation, as well as Company-owned firm dispatchable capacity, among other resources to meet near-term capacity needs. More recently, we have extended multiple PPAs, and proposed the extension of Monticello and Prairie Island nuclear generating stations, additions of firm dispatchable resources as well renewable and storage additions in our most recent IRP. As a part of this portfolio approach, adding Company-owned solar at the site of the soon-to-be-retiring Sherco coal plant, using the Company's existing interconnection rights, was determined to be a cost-effective solution to reliably meet the identified need at the time the need was forecast to arise (by 2026). And it remains a reliable, cost-effective solution in the long-term, for reasons I will discuss later in my testimony.

The Company conducted a competitive request for proposals (RFP) processes for Sherco Solar 1 and 2 in early 2021. This process, alongside economic modeling and qualitative risk considerations, confirmed that building Company-owned solar at Sherco is a prudent solution for timely meeting a portion of the identified capacity need.

Q. HAS THE COMMISSION PREVIOUSLY MADE ANY DECISIONS WITH RESPECT TO SHERCO SOLAR 1 AND 2?

A. The Commission ruled on December 13, 2023 on the Company's application for an Advanced Determination of Prudence (ADP) for Sherco Solar 1 and 2.[51] The Company's ADP application, submitted on April 26, 2021, had requested that the Commission approve recovery not of the full cost of the Sherco Solar 1 and 2 project, but instead only recovery for the cost of what was, at that time, a similarly sized least-cost resource (as defined by North Dakota law) based on a proxy pricing methodology—a generic greenfield natural gas combustion turbine (CT) project. Between the time of the initial ADP application filing and the filing of rebuttal testimony approximately 18 months later, the modeled least-cost plan to prudently meet the identified capacity need became large-scale solar resources, coupled with material amounts of energy efficiency and conservation. The Sherco Solar 1 and 2 projects specifically were modeled to yield significant savings on a PVRR basis under North Dakota assumptions, largely because the IRA was enacted during the course of the proceeding and the Company anticipates that the Sherco Solar 1 and 2 project would qualify for the IRA's 10-year PTC and a 10 percent "energy community" bonus credit. The Commission's ruling acknowledged the testimony that the Project had come to be modeled as cost-effective during the course of the ADP proceeding.[52]

Nevertheless, the Commission found that, *at the time of project selection* in 2021, the Sherco Solar 1 and 2 projects were not the least-cost resource, and the "post-

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[51] *In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the 460 MW Sherco Solar Facility*, Case No. PU-21-152, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER, North Dakota Public Service Commission (Dec. 13, 2023).
[52] *Ibid.*

hoc justification" (i.e., the IRA tax credits) did not "not support … granting an advanced determination of prudent … particularly in view of further changes [by MISO] in future capacity accreditation anticipated to degrade the value of the Project." The Commission also rejected the Company's proposal to use "proxy pricing" as part of an ADP request. However, the Commission acknowledged that "proxy pricing may be appropriate in some cases to address disputed resources," and a "proxy price for the [Sherco Solar 1 and 2] Project would be better addressed in a future rate proceeding considering all circumstances to determine just and reasonable rates."[53]

Because the Commission expressly left open the door for some type of cost-recovery of Sherco Solar 1 and 2 in a future rate proceeding considering all of the circumstances, and further because all of the Sherco Solar resources will be available to serve our customers across the Upper Midwest System, including North Dakota, we are now seeking cost recovery for inclusion of Sherco Solar 1 and 2 in rates.

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

A. The Company requests that the Commission find that the Company's addition of Sherco Solar 1 and 2 is prudent and allow recovery of these resources in base rates.

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[53] *Id.* at 4.

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH DECISIONS IN OTHER STATES?

A. Yes. The MPUC has approved the Sherco Solar 1 and 2 resource additions.[54] The SDPUC has not ruled on them.

B. Selection of Sherco Solar 1 and 2

Q. LET'S TALK MORE ABOUT HOW YOU'VE CHOSEN TO FILL THE CAPACITY NEEDS THAT WOULD ARISE IN 2026 AND BEYOND. YOU MENTIONED THAT COMPANY-OWNED SOLAR AT SHERCO WAS DETERMINED TO BE A PRUDENT WAY TO TIMELY MEET A PORTION OF THAT NEED. PLEASE PROVIDE MORE DETAIL ON WHY THAT IS.

A. The Company's 2019 IRP analysis indicated that a large-scale solar resource and material amounts of energy efficiency and other conservation measures are part of a least-cost plan to prudently meet the identified capacity need. Our "Alternate Plan" modeling analysis was conducted after exploring whether we could continue to plan a reliable system without the inclusion of the at-that-time planned Sherco combined cycle (CC) plant. The "Alternate Plan" submitted to our regulators showed that we could design a plan without the Sherco CC that remained reliable and better achieved our environmental and customer risk goals. The plans achieve this in part by reutilizing the Company's interconnection rights at its retiring coal facilities to add substantial amount of solar, wind and/or firm dispatchable generation at a lower cost than we would anticipate achieving if those resources were added through the MISO interconnection queue process. Under both Minnesota and North Dakota planning principles, solar is the first generation resource added to the system in the mid-2020s. See Table 3 and Table 4 below.

[54] MPUC Docket Nos. E002/M-20-891 and E002/M-22-403.

Table 3
NSP Alternate Plan Resource Additions by Year
(includes externality values)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	-	-	-	-	-	-	-	-	200	200	950
Solar	-	-	-	-	700	600	-	600	150	400	100
Firm Peaking	-	-	-	-	-	60	259	374	-	374	374
Storage	-	-	-	-	-	-	-	-	-	-	200

Table 4
NSP Alternate Plan North Dakota Scenario Resource Additions by Year
(excludes externality values)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	-	-	-	-	-	-	-	-	-	-	500
Solar	-	-	-	-	650	200	-	500	-	450	150
Firm Peaking	-	-	-	-	-	60	259	1,122	374	374	748
Storage	-	-	-	-	-	-	-	-	-	-	50

Q. YOU MENTIONED THE COMPANY USED COMPETITIVE SOLICITATION PROCESSES FOR SELECTING SHERCO SOLAR 1 AND 2. PLEASE PROVIDE MORE DETAILS.

A. First, in early 2021, the Company issued an RFP for solar proposals at the Sherco site. The RFP was specific to the Sherco site to ensure that the Company's existing interconnection rights at the Sherco site would be reused by the new project, in order to save both time and money. Three bids were submitted, which were reviewed under the oversight of our independent auditor (IA). Our IA, Guidehouse, validated our process, certifying that it believed the goals of our RFP were achieved, that project assessments were performed in a fair and consistent manner, and that there was no evidence that we unfairly advantaged any interested party or respondent to the RFP. This RFP process, consistent with prior MPUC orders and under the supervision of the IA, included protections to ensure that the Company's self-build proposals were not unfairly advantaged or given preferential consideration. After conducting this thorough and competitive RFP process described, it was determined that the Company's combined bid with NG Renewables offered the most beneficial project to meet our identified capacity need. Sherco Solar as proposed was the cheapest project bid and was to be the cheapest utility scale solar on the NSP System. By leveraging the expertise of both the Company and NG Renewable, we were able to ensure the Sherco Solar 1 and 2 projects would maximize benefits to customers.

In addition to that RFP, which offered valuable insight to alternative project pricing, we compared the chosen Sherco Solar 1 and 2 project to other solar resources on our system and in the region. This evaluation found that the proposed Sherco Solar projects would provide lower cost energy than any solar facility currently operating on the NSP system.

C. Economic Analyses for Sherco Solar 1 and 2

Q. PLEASE DESCRIBE THE ECONOMIC MODELING THE COMPANY PERFORMED FOR SHERCO SOLAR 1 AND 2.

A. At the time the Company filed its ADP application in April 2021 for Sherco Solar 1 and 2—before the enactment of the IRA and expansion of the PTC—North Dakota planning principles identified that a 374 MW firm dispatchable unit represented by a greenfield CT would be the least-cost resource to fill the identified capacity need. But because this Project was nevertheless chosen to move forward, the Company's ADP application did not request that the full

Project costs be recovered, but rather only the price of a firm dispatchable resource, using a proxy pricing methodology. Because of the structure of the Company's rate recovery ask to the Commission, the Company did not, at the time of its 2021 ADP application filing, conduct cost modeling using the EnCompass tool.

However, after the Company's initial 2021 ADP application, market and policy conditions changed, prompting the Company to update its modeling analysis in 2021 and submit an IRP "Alternate Plan" and a "Alternate Plan North Dakota Scenario," which the Company also detailed in its October 2022 Rebuttal Testimony of Company witness Farah Mandich for the Sherco Solar 1 and 2 ADP proceeding. As explained in that Rebuttal Testimony and noted above, the updated modeling showed that the least-cost plan to prudently meet the identified capacity need in 2024–2025 had become large-scale solar resources, coupled with material amounts of energy efficiency and conservation, under both North Dakota assumptions (excluding externality values) and Minnesota assumptions.

The Company's updated analysis also examined the economics of the Sherco Solar 1 and 2 project specifically (as opposed to generic solar), and found that the project would yield significant savings on a PVRR basis. The assumptions in this analysis included the benefits of the recently enacted IRA, which expanded tax benefits for clean energy resources in general, plus additional benefits for projects located in "energy communities." Specifically, assuming the Sherco Solar 1 and 2 project qualifies for the full PTC value and an additional 10 percent bonus for being located in an "energy community," the Company included a total PTC value of **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] for the first 10 years of the Sherco Solar 1 and 2 project.[55] The Company is committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

Q. WHAT WERE SPECIFIC RESULTS OF THE UPDATED ECONOMIC MODELING FOR SHERCO SOLAR 1 AND 2?

A. Our updated analysis found that the Sherco Solar 1 and 2 project would yield significant savings on a PVRR basis, albeit less than generic solar. Table 5 below shows the specific results of our updated analyses comparing the Reference Case (the "business as usual" scenario) to both the Company's IRP "Alternate Plan North Dakota Scenario" with generic solar and to the North Dakota Scenario with generic solar replaced by Sherco Solar 1 and 2, all under North Dakota planning assumptions.

As shown in Table 5, below, the Company's IRP Alternate Plan North Dakota Scenario with generic solar replaced by Sherco Solar 1 and 2 would result in a PVRR that is $466 million lower than the Reference Case (business-as-usual). This result was consistent with the cost savings assumptions assumed based on our generic solar costs.

[55] This estimate was dependent upon our then-current interpretation of Internal Revenue Service (IRS) guidance and expectations regarding the PTC transfer market.

Table 5
Updated (2021/22) PVRR Results for Sherco Solar 1 and 2

Analysis Case	2020–2045 Total System Cost Results ($ millions, PVRR)	2020–45 Delta from Reference Case
IRP Reference Case (IRA-Adjusted)	$35,903	
Sherco Solar 1 & 2 Base Case (IRP ND Alternative, IRA-Adjusted)	$35,366	($537)
Sherco Solar Change Case (IRP ND Alternative Scenario + Sherco Solar Project, IRA-Adjusted)	$35,437	($466)

Q. HOW DID THE PROJECTED LEVELIZED COST OF ENERGY (LCOE) FOR SHERCO SOLAR 1 AND 2 CHANGE AFTER TAKING INTO ACCOUNT INFLATION REDUCTION ACT TAX CREDITS AND OTHER UPDATED MARKET CONDITIONS?

A. The LCOE estimate after taking into account the project's assumed eligibility for the IRA's PTC and "energy community" bonus credit, and further assuming the sale or transfer of PTCs, is 24 percent lower than the LCOE originally projected in the initial ADP application. Our updated estimate resulted in an LCOE of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for the Sherco Solar 1 and 2 project, assuming that the project qualifies for the full 10-year PTC plus the 10 percent bonus credit under the "energy community" provision of the IRA, as well as the ITC.

Q. WHY AND HOW SHOULD THE COMMISSION TAKE INTO ACCOUNT CIRCUMSTANCES THAT HAVE ARISEN AFTER THE COMPANY FIRST MADE THE DECISION TO CONSTRUCT SHERCO SOLAR 1 AND 2 AND SUBMIT AN ADP APPLICATION IN EARLY 2021?

A. As I previously discussed, North Dakota law allows the Commission and the Company to consider both quantitative and qualitative considerations in prudence determinations. The Company's initial decision was supported by qualitative factors like preserving interconnection rights, in addition to corporate and state policy goals, and the enhanced tax credits and other market conditions that subsequently arose supported the Company's decision.

D. Summary

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

A. The Company requests that the Commission find that the Company's planned addition of Sherco Solar 1 and 2 is prudent and allow recovery of these resources in base rates.

Q. WERE THE COMPANY'S DECISIONS TO ADD THE SHERCO SOLAR 1 AND 2 PROJECT PRUDENT?

A. On the whole, the addition of Sherco Solar 1 and 2 is prudent because using Company-owned solar at the site of the soon-to-be-retiring Sherco coal plant, and using the Company's existing interconnection rights, was the most cost-effective solution to meet the relevant portion of the identified need at the time forecast to arise (by 2026) and remain a reliable, cost-effective solution in the long-term, i.e., without being exposed to the volatility of the MISO capacity market or other resource types. The Company's competitive solicitation process for Sherco Solar 1 and 2, alongside economic modeling and qualitative risk considerations, has confirmed that building Company-owned solar at Sherco is the most prudent solution for timely meeting the identified capacity need.

VI. ADDITION OF A LONG DURATION BATTERY STORAGE PILOT PROJECT AT SHERCO

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

A. In this section, I explain the basis for the Company's request that the Commission find our addition of a Long Duration Battery Storage pilot project at Sherco to be prudent and allow the Company to recover the costs thereof in our base rates.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE SHERCO LONG DURATION BATTERY STORAGE PILOT PROJECT.

A. The Company is developing a 10 MW/1,000 MWh Long Duration Battery Storage pilot project to be placed in service by year-end 2025 and co-located with the Sherco Solar projects discussed earlier in my testimony. This 100-hour, multi-day energy storage system will feature cutting-edge iron-air battery storage technology supplied by Form Energy that offers distinct economic and technical benefits. This type of battery offers a duration of output far greater than is available from lithium-ion batteries, a characteristic that is needed to ensure reliability during extended extreme weather events and renewable energy droughts. Additionally, the battery's technology is based on iron—which is extremely prevalent—as opposed to rare-earth elements like lithium. The use of iron, as opposed to rare-earth elements, makes the technology more readily scalable in the future. In addition, this technology is modular, meaning that it can be sited anywhere on the grid with modular architecture that can be configured to unique site requirements, including at our Sherco facility site. Moreover, the system costs are competitive with that of legacy power plants. Finally, because this battery system will be placed in service by year-end 2025, it will provide the Company with key insights as we seek to add additional solar and/or solar-plus-storage hybrid resources to our system between 2027 and 2032, consistent with our 2024–2040 North Dakota Resource Plan filed with the Commission in April 2024.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO THE SHERCO LONG DURATION BATTERY PILOT PROJECT IN THIS RATE CASE?

A. The Company requests that the Commission find our addition of a Long Duration Battery Storage pilot project at Sherco to be prudent and allow the Company to recover the costs thereof in our base rates.

Q. IS THE COMPANY'S PROPOSAL HEREIN CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes. The Company's 2024–2040 North Dakota Resource Plan identifies a need for additions of firm dispatchable resources and energy storage. The Battery Energy Storage Systems (BESS) modeled as part of our North Dakota Resource Plan are short-duration storage systems. However, although valuable, short-duration BESS cannot currently meet the longer duration dispatch needed from firm dispatchable resources. Instead, the primary value to our system that short-duration BESS provides is in aiding renewable integration, providing grid support, deferring some, but not all, traditional grid investments, and improving power quality.[56] Accordingly, acting now to pilot a 10 MW/100MWh multi-day, iron-air battery system at the Sherco site will provide the Company with key insights as we seek to meet those identified future storage needs and integrate

[56] *See* 2024-2040 North Dakota Resource Plan (Apr. 8, 2024), at 6-7, 10-11.

storage on a larger scale with additional renewable energy resources starting in 2027.

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH DECISIONS IN OTHER STATES WITH JURISDICTION OVER THIS RESOURCE?

A. The MPUC approved the project in its Order dated August 1, 2023 in Docket No. E002/M-23-119.[57] The SDPUC has not considered the project yet and will not do so until the next rate case in that jurisdiction.

Q. AT A HIGH LEVEL, WHEN AND HOW DID THE COMPANY MAKE ITS DECISIONS TO ADD THE SHERCO LONG DURATION BATTERY PILOT PROJECT?

A. The Company's interest in a long duration battery storage for the NSP System was initially prompted by Minnesota policy developments but has been subsequently supported in our North Dakota resource planning process.[58]

First, in 2019, the Minnesota State Legislature enacted legislation intended to spur the development of energy storage system pilot projects within the state. Minn. Stat. § 216B.16, subd. 7e authorizes a public utility to petition the Commission to recover costs associated with implementing an energy storage system pilot project.

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[57] *See* ORDER APPROVING PILOT PROJECT, *In the Matter of Xcel Energy's Petition for a Long-Duration Energy Storage System Pilot Project at Sherco,* MPUC Docket No. E002/M-23-119 (Aug. 1, 2023), https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={80DAB189-0000-CD1C-BE1B-3290ABA0A164}&documentTitle=20238-197913-01.

[58] Xcel Energy operating company Public Service Company of Colorado is also deploying a similar iron-air battery system in Colorado.

In addition, on December 31, 2019, the Minnesota Department of Commerce released its "Minnesota Energy Storage Cost-Benefit Analysis," which recommended energy storage become a regular part of the resource planning and competitive bidding processes. The Department emphasized the importance of gaining experience in operating energy storage and understanding both its limits and benefits to the grid.

Beyond Minn. Stat. § 216B.16, subd. 7e and the Department's analysis, the MPUC issued an Order on April 15, 2022 approving the Company's then-current IRP, while including several order points involving the analysis, consideration, and/or expedited deployment of energy storage resources. Specifically, the MPUC directed the Company to consider opportunities to deploy energy storage technologies on a schedule faster than our approved "Alternate Plan", and required the Company to pursue technologies that are found to be cost-effective and predicted to maintain reliability and support decarbonization.[59] The MPUC also required the Company to provide a deeper analysis of storage options in the subsequent IRP.[60]

Based on the above, the Company has determined it would be prudent to pilot and study a long duration battery system so that the Company can gain key insights and be better prepared to meet the identified future storage needs and integrate storage on a larger scale with additional renewable energy resources starting in 2027. The Company further determined that, by partnering with

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[59] ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS, MPUC Docket No. E002/RP-19-368 (Apr. 15, 2022), Order Point 5.
[60] *Id.* at Order Point 12.

Form Energy on an innovative 10 MW/1,000 MWh multi-day energy storage system pilot—particularly one that achieves bonus ITC qualification and benefits from grant funding from DOE and other grantors—the Company can gain important experience and insights related to managing an energy storage system at a reduced cost to customers.

Q. WHAT ECONOMIC CONSIDERATIONS AND ANALYSES HAVE GONE INTO THE COMPANY'S DECISION TO DEVELOP THE SHERCO LONG DURATION BATTERY PILOT PROJECT?

A. Some of the economic considerations that went into the Company's decision to develop the Sherco Long Duration Battery pilot project were its eligibility for various federal tax credits and federal and private grant funding. By leveraging these sources, the Company can test and use an important new asset at a reduced price. Specifically, under the recently passed IRA, the pilot project will not only qualify for the standard 30 percent ITC, but also an additional 10 percent bonus for being developed at our Sherco facility site, which qualifies as an "energy community." Form Energy's commitment to meeting domestic content requirements also qualifies the pilot project for an additional 10 percent bonus. In addition, the Company has now secured a grant agreement from the U.S. Department of Energy (DOE) for this pilot project, and funding will be received by the Company on a reimbursement basis. The Project has also received contingent commitments for private sector grant funding, to be received in a lump sum at substantial completion of the pilot project, expected in late 2025. Accordingly, the Company determined that it would be prudent to take advantage of these various grant and tax opportunities now to test out long duration battery technology on its system on a fairly small scale and at a minimized cost to our customers, in order to be better equipped to cost-effectively implement this technology on a larger scale in the future, should the results of the pilot project point toward larger-scale implementation.

Q. WHAT ARE THE ANTICIPATED COSTS OF THE SHERCO LONG DURATION BATTERY PILOT PROJECT?

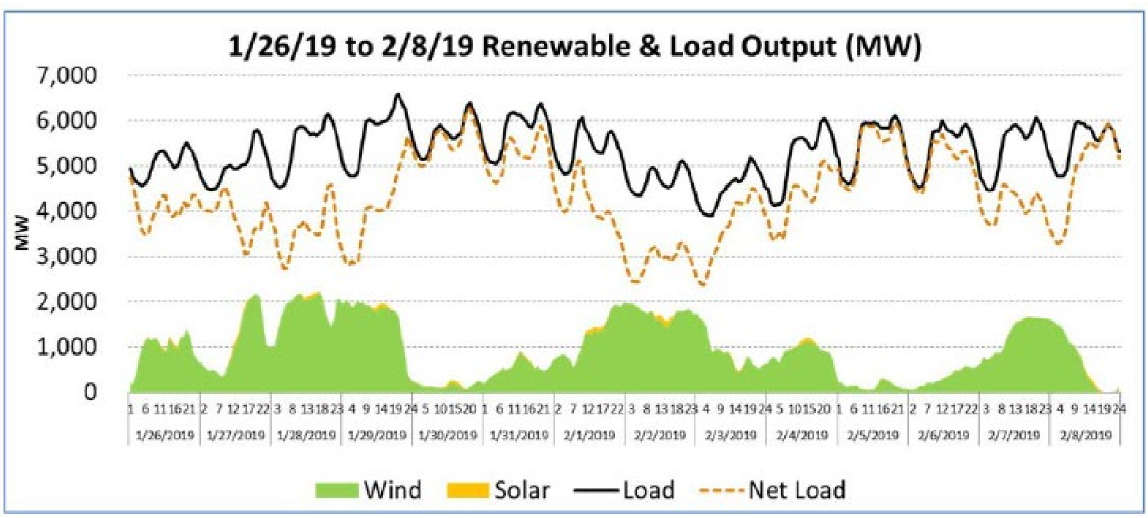
A. Including Allowance for Funds Used During Construction (AFUDC), the Company estimates that the entire 10 MW/1,000 MWh energy storage system should cost approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. We estimate **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** decommissioning costs (net of any salvage) in 2023 dollars, based on the high end of the range provided by Form Energy. The decommissioning costs are included in depreciation over the 10-year life of the asset. We note that while this represents our best estimate at the time we made the decision to move forward with the Sherco Long Duration Battery pilot project, decommissioning costs could change as disposal technology improves and estimates are refined.

After factoring in the applicable ITC treatment and grant funding, we estimate that the pilot project will cost approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** on a levelized basis. Should the Company realize additional tax savings from the IRA, we are committed to passing those savings onto our customers to further improve the pilot project's economics.

Q. WHAT OTHER CONSIDERATIONS HAVE GONE INTO THE COMPANY'S DECISION TO DEVELOP THE SHERCO LONG DURATION BATTERY PILOT PROJECT?

A. The Company considered that, from a system perspective, it is important to have the ability to test and pilot emerging energy technologies that can potentially help facilitate the efficient and reliable integration of new renewables and manage peak demand. In addition, it is critical that the Company invest in storage technologies that will allow us to smooth out the production curves of renewables on the system. Given the inherent variability of wind and solar generation, we have encountered multi-day periods with low renewable generation and high loads. For example, as shown below in Figure 5, this was the case during both the January 29-31, 2019 polar vortex, which was an extreme weather event marked by historic, severe, and sustained cold temperatures combined with high winds, as well as February 5, 2019, a normal winter peak period. Multi-day energy storage technologies, such as Form Energy's, will be crucial to meet our customers' energy requirements, without carbon emissions, every hour of every day.

Figure 5
Renewable Output and Load, January 26 – February 8, 2019



Conversely, there are many times during the year when renewable energy resources produce energy in excess of demand or transmission capacity, leading to congestion or curtailment of such resources. Long duration storage facilities, like the Sherco Long Duration Battery pilot project, have the potential to absorb such excess energy for discharge later during times when there is greater demand.

This pilot project will allow us to test an energy storage system and how we can use it to provide reliability and resiliency to customers. Additionally, the approach the Company has pursued for this pilot project allows us to carefully test an emerging energy storage technology ahead of potential, larger investments in energy storage while also minimizing costs to our customers.

Q. WAS THE COMPANY'S DECISION TO DEVELOP THE SHERCO LONG DURATION BATTERY PILOT PROJECT PRUDENT?

A. Yes. As discussed above, the Company's current North Dakota Resource Plan identifies a need for firm dispatchable resources, including energy storage. From a qualitative perspective, it is critical that the Company invest in storage technologies that will allow us to smooth out the production curves of renewables on the system, including both multi-day periods of low renewable generation combined with high loads, as well as times of high renewables generation in excess of demand or transmission capacity. Long duration storage facilities, like the Sherco Long Duration Battery pilot project, have the potential to help with both of those extremes. Further, from an economic planning perspective, long duration storage can also provide a hedge against the pricing volatility of other backup resources like the MISO Day-Ahead market and/or natural gas and coal prices.

From a quantitative perspective, it is prudent to take advantage of the above-discussed federal tax credits and federal and private grants to carefully test out this emerging technology at a low cost to our customers now, ahead of potential, larger investments, so that we are better positioned cost-effectively and reliably implement this kind of technological solution on a larger-scale in the future.

VII. MANKATO ENERGY CENTER II 314 MW GAS PPA

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

A. In this section, I explain the basis for and prudence of the Company's request to recover the capacity and energy costs associated with the power purchase agreement for the energy and capacity from the combined cycle turbine that was placed into service on June 4, 2019 at the Mankato Energy Center (MEC II). As detailed in my testimony below, the Company's decision to add the MEC II PPA was prudent because the forecast upon which the decision was made (the Fall 2011 Forecast) predicted a 500 MW capacity need to arise in 2019, and the MEC II PPA was found to provide the best, low-cost, dispatchable solution to partially fill that identified need. Although some other capacity forecasts identified different timing needs, they nevertheless predicted capacity needs. In the prior rate case, Advocacy Staff's Consultants relied on forecasts showing that the capacity needs would not arise until the mid-2020s to claim that the MEC II PPA was premature; however, that argument is now stale given the passage of time and the fact that we now are adding needed capacity to our system. The Company should thus be able to recover for the MEC II PPA on a prospective basis.

In 2019, the Company determined that the benefits of the MEC II PPA outweighed the differences in timing between the in-service date and various other capacity forecasts. In addition to being an important part of the Company's overall replacement plan for the retirement of baseload resources such as the Sherco generating station, the MEC II PPA provided unique and significant economic benefits. Accordingly, it was prudent for the Company to take advantage of those economic benefits rather than waiting until later for a resource that would most likely be more costly to North Dakota customers in the long term. The Company therefore requests that the Commission find the MEC II PPA prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the Fuel Clause Rider (FCR).

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE MANKATO ENERGY CENTER FACILITY AND PPA.

A. The Mankato Energy Center located in Mankato, Minnesota is a 760 MW 2x1 CC natural gas facility. Unit 1 (MEC I) is a 375 MW CC that was completed in 2006 by Calpine Corporation as a 1x1 CC with the intent to expand with a second unit. The capacity and energy of MEC I has been under contract with the Company since 2006 through a PPA that currently is scheduled to expire in 2026, which we are currently planning to extend. In June 2019, the facility was expanded with the addition of a second combustion turbine, transforming the facility to a 2x1 CC and adding approximately 345 MW of capacity (MEC II). MEC II is located on the same site and is incorporated into the existing footprint of the MEC I unit. The capacity and energy of MEC II is committed to the Company under a 20-year PPA which commenced in June 2019 and runs until 2039.

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

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

Q. IS THE COMPANY'S PROPOSAL CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes. MEC II has been operating since 2019 and has been an assumed resource for planning purposes since that time.

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH DECISIONS IN OTHER STATES WITH JURISDICTION OVER THIS RESOURCE?

A. Yes. The Company has been recovering the costs of the MEC II PPA in Minnesota and South Dakota since it was placed in service.

Q. HAS THE COMMISSION MADE ANY PREVIOUS DECISIONS WITH RESPECT TO THE MEC II PPA?

A. Yes. The Company first requested an ADP for the MEC II PPA in 2015 in Case No. PU-15-96. At the Company's request, the Commission dismissed the Company's application without prejudice to allow the Company to raise the issue with the Commission again in the future. The Company again requested in its last North Dakota rate case in 2020 that the Commission find the MEC II PPA prudent and allow recovery of the capacity costs of the contract in base rates. Ultimately, the Commission approved a settlement agreement in which the Company agreed to remove MEC II demand costs from the test year revenue requirements, expressly "without prejudice to a future determination of prudence for the Company's PPA for MEC II" and expressly allowing the

Company to "seek to recover prospective demand costs of the MEC II PPA in a future rate case."[61] Pursuant to that settlement agreement, the Company is now again seeking to recover for the MEC II PPA.

Q. WHEN AND HOW DID THE COMPANY MAKE ITS DECISION TO ENTER INTO THE MEC II PPA?

A. In our 2010 resource planning cycle,[62] the Company identified a need for up to 500 MW of incremental capacity by 2019 based on the Company's fall 2011 forecast (Fall 2011 Forecast), which updated the initial demand and energy forecast included in the 2010 Resource Plan. Specifically, the Fall 2011 Forecast identified a capacity need of approximately 150 MW beginning in 2017 growing up to approximately 500 MW by 2019. Based on this identified need, the Company determined that it would be prudent to add capacity to its system.

To meet this need, the Company initiated a "Competitive Acquisition Process" in Minnesota,[63] commonly referred to as the CAP/CON Proceeding, in order to ensure an open and competitive bidding process for the needed capacity. This process is required of the Company pursuant to the Minnesota Commission's orders. As part of the CAP/CON Proceeding, the Company obtained approval from the MPUC for capacity additions to meet the identified need of up to 500 MW of capacity by 2019 consistent with our 2010 Resource Plan.

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[61] *See* ORDER ON SETTLEMENT, at 3, 5. *In re Northern States Power Company 2021 Electric Rate Increase Application,* Case No. PU-20-441 (Aug. 18, 2021).
[62] Case No. PU-10-580.
[63] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of a Competitive Resource Acquisition Proposal and Certificate of Need*, MPUC Docket No. E002/CN-12-1240.

During the pendency of the CAP/CON, the Company developed several updated forecasts, including in the spring of 2012, in the fall of 2012, in the spring of 2013, in the fall of 2014, and in 2015. The Company's updated Spring 2013 forecast identified a slackening of need of 117 MW in 2017, 118 MW in 2018, and 123 MW in 2019. The September 2014 forecast suggested a capacity surplus through as late as 2023. Nevertheless, the updated forecasts continued to identify a significant capacity deficit beginning in the mid-2020s that would require resource additions on the NSP System. In other words, while there was agreement among the various forecasts that Xcel Energy would have a capacity need during the resource planning period, the exact timing of that need differed among the various forecast vintages.

Ultimately, on February 5, 2015, the MPUC issued an Order selecting the MEC II PPA for execution (among other resources), based on the Fall 2011 Forecast that was used in the Company's CAP/CON application. The MPUC used the Fall 2011 Forecast because it determined that this would be a conservative approach to best protect customers from uncertainty and ensure that generating capacity was installed in a timely fashion.

The Company agreed with this approach because, although the forecasts following the Fall 2011 Forecast showed a slackening of demand, they continued to indicate that the NSP System could be in deficit between 2017 and 2024. The Company also weighed the slackening of demand found in those subsequent demand forecasts against other factors present at the time, including: (1) anticipated MISO-wide capacity retirements at the time; (2) the favorable cost environment at the time; (3) an uncertain environmental regulatory environment; and (4) low capacity surplus margins. Given these considerations and the variability in our demand forecasts and the small margin that we had on our system at the time, it was prudent to move forward with capacity additions in case our forecasts were inaccurate, leaving the NSP System short on capacity.

This approach is consistent with the Company's general position that it is better for a utility to be long than short on capacity, since the utility has the obligation to serve all of its customers' needs under all reasonable circumstances and must have resources available to meet those needs. The benefits to this approach are that it provides the time needed to make resource decisions through the use of competitive processes to help bring down the cost of these resources. Additionally, it avoids exposing the Company – and ultimately customers – to the short-term capacity markets and the price uncertainty inherent with such markets.

Q. WHAT FINANCIAL CONSIDERATIONS AND ANALYSES DID THE COMPANY EVALUATE IN DETERMINING TO ENTER INTO THE MEC II PPA?

A. To help determine which of the resources identified through the CAP/CON process would best meet the forecasted need, the Company conducted a Strategist analysis that modeled portfolios consisting of different combinations of the resource proposals submitted in the CAP/CON proceeding that ranged from 358 MW to 636 MW. These proposals included peaking and intermediate resources. Specifically, in addition to the MEC II 345 MW CC unit, the Company also analyzed:

- The Company's proposal for a single CT unit at its Black Dog plant in 2017, 2018, or 2019 and two CT units at a new Red River Valley plant site near Hankinson, North Dakota in 2018 and 2019;

- Invenergy Thermal Development, LLC's proposal to add a single 179 MW natural gas CT at its existing Cannon Falls, Minnesota plant and two 179 MW CTs located at a new plant site near Hampton Corners, Minnesota, in 2017 or 2018;
- Geronimo Energy's proposal for distributed 1 solar generation, with an aggregate capacity of up to 100 MW, to be placed in service by the end of 2016 to take advantage of the federal ITC;
- Great River Energy's proposal for a three-year purchase of either 100 MW or 200 MW of resource capacity credits only, with no energy or generation associated with the purchase; and
- A generic large natural gas CC unit.

Q. WHAT WERE THE RESULTS OF THAT ECONOMIC ANALYSIS?

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

Table 6
2019 PVRR and PVSC Strategist Modeling Results for MEC II PPA and Other Resources

Resource Combination	203-2050 PVSC ($ millions)	2013-2050 PVRR with ND Assumptions ($ millions)
MEC II PPA + Black Dog 6	$45,368	$39,180
Black Dog 6 + RRV 1&2	$45,404	$39,198
Cost/(Savings) of MEC II PPA + Black Dog 6	($36)	($18)

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

A. Yes. In Case No. PU-15-96, the Company modeled the PVRR – which excludes externality costs – of the base case and compared it to the PVRR of adding the MEC II PPA. This analysis demonstrated that the MEC II PPA resulted in a lower PVRR than the base case in all but the Low Gas scenario. In the Base Case scenario, which used the Fall 2011 Forecast and North Dakota resource planning assumptions, the addition of MEC II resulted in an $11 million dollar savings over the life of the PPA on a PVRR basis. The results of this analysis are shown in Table 7 below.

Table 7
Total System Cost With/Without MEC II PPA

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

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

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

Q. WAS THE COMPANY'S DECISION TO ENTER INTO THE MEC II PPA PRUDENT?

A. The Company's decision to add the MEC II PPA was prudent because the forecast upon which the decision was made (the Fall 2011 Forecast) predicted a 500 MW capacity need to arise in 2019, and after conducting a competitive acquisition process to select the best, least-cost resources available to fill the identified need, it was determined that the MEC II PPA provided the best, low-cost, dispatchable solution to fill that identified need. The MEC II PPA gave the Company the best of both worlds with more efficient and cheaper CC energy production at construction costs competitive with a CT. In light of the construction and operational cost considerations alongside the qualitative benefits of CC energy production, the MEC II PPA was important as part of the Company's overall replacement plan for the retirement of baseload resources such as the Sherco generating station. Further, the benefits of the MEC II PPA outweighed the differences in timing between the in-service date and various other capacity forecasts. Due to the significant economic benefits that are unique to the MEC II project, it was prudent for the Company to take advantage of the low prices offered by the PPA rather than waiting until later for a resource that would most likely be more costly to North Dakota customers in the long term.

Q. WHAT CONCERNS WERE RAISED ABOUT THE MEC II PPA IN THE PRIOR RATE CASE?

A. In the last case, Commission Staff suggested that the MEC II PPA was premature because the need it was designed to address was forecasted to arise subsequent to the PPA. While the Company disagreed with that position given the favorable pricing of the PPA, at this point it is not relevant. Currently, it is clear that the capacity from MEC II is needed. Accordingly, the Company should be able to recover for the MEC II PPA going forward. The prior dispute regarding the timing of the capacity need is now irrelevant.

VIII. ADDITIONAL SOLUTIONS FOR CAPACITY NEEDS

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

A. In this section, I explain the basis for multiple additional ways the Company is meeting its capacity needs. As noted above, the Company has taken a portfolio approach to meeting its capacity needs in a reliable and cost-effective manner. This section specifically discusses: (A) the Company's decisions to enter into a five-year PPA extension with Manitoba Hydro for 200 MW capacity and energy plus 350 MW of capacity only) to partially replace the existing 835 MW PPA that set to expire in 2025; (B) the extension of RDF facilities at French Island 1-2 to 2040, Red Wing and Wilmarth each to 2037, and Bayfront 5&6 to 2034; (C) the extension of the Cannon Falls PPA; and (D) the capital additions for the peaking Blue Lake Units 9-11 to replace the retiring Blue Lake Unit 3 with new RICE capacity. This section also discusses the Company's request to allow the Company to recover the costs of these decisions.

A. Manitoba Hydro PPA

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE NEW MANITOBA HYDRO PPAS.

A. The Company has entered into two new short-term PPAs for the existing Manitoba Hydro project: (1) a five-year 200 MW summer system sale beginning in June 2025; and (2) a five-year diversity exchange beginning in June 2025 for 350 MW in the first three years and 200 MW diversity exchange in the last two years. Under the diversity exchange, Manitoba Hydro provides capacity in the summer and Xcel Energy provides Manitoba Hydro capacity in the winter. The existing expiring contract that is being replaced is for a 500 MW system sale and 350 MW diversity exchange.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO MANITOBA HYDRO PPA IN THIS RATE CASE?

A. The Company requests that the Commission find the five-year Manitoba Hydro PPA prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the FCR.

Q. AT A HIGH LEVEL, WHEN AND HOW DID THE COMPANY MAKE ITS DECISION TO EXTEND THIS PPA?

A. The Company has long relied on capacity and energy from Manitoba Hydro. By entering into a short-term PPA after the existing PPA expires in 2025 the Company will continue to take capacity and energy, albeit at a reduced amount, from Manitoba Hydro. The short-term extension preserves capacity to meet our system needs while allowing for further analysis and development of longer-term solutions.

Q. WHY IS THE FIVE-YEAR MANITOBA HYDRO PPA PRUDENT AND IN THE PUBLIC INTEREST?

A. The five-year PPA with Manitoba Hydro will address near-term capacity needs. Our 2024-2040 North Dakota Resource Plan shows a capacity deficit beginning in 2027. The five-year PPA, along with other actions, ensures we have sufficient capacity on our system while we develop longer-term solutions.

B. Refuse Derived Fuel Facilities

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

A. In this section, I explain the basis for the Company's decision to extend RDF facilities at French Island 1-2 to 2040 and Red Wing and Wilmarth each to 2037 and request that the Commission find these decisions to be prudent and allow the Company to adjust its depreciation for the facilities accordingly.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE RDF FACILITIES.

A. Xcel Energy's Red Wing, Wilmarth, and French Island Waste-to-Energy Generating Plants provide a reliable source of baseload power that contributes to the Company's ability to provide reliable renewable energy to customers in the NSP System. Unlike other forms of renewable energy, waste-to-energy generating plants can operate around the clock, supplying a consistent source of dispatchable power. These plants were slated for retirement in 2027. As part of the current Resource Plan, the Company extended the life and operations of these three plants, to 2037, 2037, and 2040 respectively.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO THE RDF FACILITIES IN THIS RATE CASE?

A. The Company is requesting that the Commission find prudent its decision extend RDF facilities at French Island 1-2 to 2040 and Red Wing and Wilmarth each to 2037, and to allow the Company to adjust its depreciation for the facilities accordingly.

Q. IS THE COMPANY'S PROPOSAL HEREIN CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes, the plant extensions were included in our current Resource Plan.

Q. WHEN AND HOW DID THE COMPANY MAKE ITS DECISIONS TO EXTEND THE FACILITIES?

A. The Company proposed to extend Red Wing, Wilmarth, and French Island in its current Resource Plan. These plants not only add significant value to our system and help us achieve our renewable energy goals with reliable power, but also provide value to the local communities they serve, including providing: (1) diversification of renewable energy sources; (2) landfill avoided costs and greenhouse gas emissions reductions; (3) encouragement of waste reduction and recycling; (4) jobs and economic growth; and (5) lower comparative costs thanks to negotiated tipping fees. For these reasons, these plants are a valued resource in not only the Company's generating fleet, but to the communities these plants serve.

Q. WAS THE COMPANY'S DECISION PRUDENT?

A. Yes. Continuing operations at these plants preserves a source of capacity and energy on our system and provides value to our customers and the communities they serve.

C. Cannon Falls PPA Extension

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE CANNON FALLS PPA AND EXTENSION THEREOF.

A. The Company has extended the Cannon Falls PPA for three years after the current PPA is set to expire in May, 2025 at pricing consistent with the existing PPA. This provides short-term capacity.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO CANNON FALLS PPA IN THIS RATE CASE?

A. The Company requests that the Commission find the short-term Cannon Falls PPA extension prudent and allow recovery of the capacity costs of the contract in base rates and the energy costs through the FCR.

Q. IS THE COMPANY'S PROPOSAL HEREIN CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes, the short-term extension was included in the current Resource Plan.

Q. WHEN AND HOW DID THE COMPANY MAKE ITS DECISION TO EXTEND THE CANNON FALLS PPA?

A. Similar to our approach to Manitoba Hydro, by entering into a short-term PPA extension, the Company will continue to take capacity and energy from an existing resource. The short-term extension preserves capacity to meet our system needs while allowing for further analysis and development of longer-term solutions.

Q. WAS THE COMPANY'S DECISION PRUDENT?

A. Yes. The short-term extension of the Cannon Falls PPA will address near-term capacity needs. Our current North Dakota Resource Plan shows a capacity deficit beginning in 2027. The short-term PPA, along with other actions, ensures we have sufficient capacity on our system while we develop longer-term solutions.

D. Blue Lake

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE BLUE LAKE FACILITY AND THE RECENT CAPITAL AND CAPACITY ADDITIONS AND RETIREMENT DECISION.

A. The Company plans to replace the retiring Blue Lake Unit 3 capacity with 28 MW of new Reciprocating Internal Combustion Engine generator capacity. The project includes improvements to the existing Blue Lake Units 7 and 8 to increase redundancy and reliability.

Q. WHAT IS THE COMPANY REQUESTING WITH RESPECT TO BLUE LAKE IN THIS RATE CASE?

A. The Company is requesting approval of the investment at Blue Lake and recovery of the costs through base rates.

Q. IS THE COMPANY'S PROPOSAL HEREIN CONSISTENT WITH ITS CURRENT RESOURCE PLAN?

A. Yes. The Blue Lake investments were included in our current Resource Plan.

Q. IS THE COMPANY'S REQUEST CONSISTENT WITH DECISIONS IN OTHER STATES WITH JURISDICTION OVER THIS RESOURCE?

A. The MPUC approved the Blue Lake investment in our 2020-2034 Resource Plan. It has not yet been presented to the SDPUC.

Q. WHEN AND HOW DID THE COMPANY MAKE THIS DECISION ON BLUE LAKE?

A. In our 2020-2034 Resource Plan, the Company provided its plans for the investments at Blue Lake as part of the analysis of our system restoration plans.

Q. WHY ARE THESE INVESTMENTS AT BLUE LAKE NECESSARY?

A. The Blue Lake investments are necessary because **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

Q. WAS THE COMPANY'S DECISION PRUDENT?

A. Yes. As discussed above, these investments will provide important reliability benefits to our system.

IX. ADDITIONAL CONSIDERATIONS COMMON TO ALL RESOURCE PLANNING DECISIONS

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

A. In this section, I discuss some additional considerations, outside of the economic and reliability considerations discussed above, that are common factors that play a role in all of our resource planning decisions. These include: (A) corporate goals and state and federal legal mandates for reducing carbon emissions and replacing fossil-fuel-powered electricity with carbon-free energy, and (B) the Company's attempt to ease the tensions between these aforementioned emissions-reduction goals and North Dakota's policy mandates via the Company's proposed Resource Treatment Framework, and the Commission's rejection thereof.

A. Emissions-Reduction Legal Mandates and Corporate Goals

Q. WHAT ARE THE COMPANY'S CORPORATE GOALS FOR REDUCING EMISSIONS?

A. The Company's corporate goals with respect to carbon emissions are to reduce carbon emissions by 80 percent below 2005 levels by 2030. These goals were first announced in December 2018, and have subsequently been reflected in legal mandates imposed by Minnesota, discussed next.

Q. WHAT ARE THE MOST RELEVANT EMISSIONS-REDUCTION MANDATES WITH WHICH THE COMPANY MUST COMPLY IN OTHER STATES AND AT A FEDERAL LEVEL?

A. Minnesota requires the Company to generate or procure the equivalent of 80 percent of its retail electric sales in Minnesota as carbon-free energy by 2030, 90 percent by 2035, and 100 percent by 2040.[64] At the federal level (and as implemented by the states through federally delegated authority), in addition to various other Clean Air Act mandates, the EPA finalized new rules in April/May of 2024 that impose stringent requirements on existing coal power plants to control carbon emissions under Section 111(d) of the Clean Air Act, as well as control mercury and toxic metal emissions, coal ash, and wastewater.[65] In particular, the most recent rule promulgated under Section 111(d) of the Clean Air Act would require coal-fired and gas-fired power plants operating past 2039 to reduce their carbon emissions by 90 percent by 2032.[66] Accordingly, long-term operation of coal and gas power plants would be extremely

[64] *See* Minn. Stat. § 216B.1691, Minn. Laws 2023, chp. 7 (enacted in 2023).
[65] *See Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants* (Apr. 25, 2024), https://www.epa.gov/newsreleases/biden-harris-administration-finalizes-suite-standards-reduce-pollution-fossil-fuel.
[66] Although there are ongoing legal challenges to the rule that would require coal-fired power plants operating past 2039 to reduce their carbon emissions by 90 percent by 2032, no court yet has placed a stay on the rule.

economically costly to the point of being untenable when comparing to the generally lower costs of other carbon-free resources.

Q. HOW DO THESE MANDATES AND GOALS FACTOR INTO THE COMPANY'S RESOURCE DECISION-MAKING, AND HOW SHOULD THE COMMISSION CONSIDER THEM?

A. The Company and the Commission alike must face the factual reality that the Company has legal mandates to meet in multiple jurisdictions. In addition to the mandates imposed by Minnesota and the federal government discussed above, the Company acknowledges that North Dakota statutes and regulations prohibit using environmental externalities in selecting its electric resources and its preferred resource plans in the state.[67] The Company concurrently recognizes that North Dakota statutes and regulations also require utilities to provide information on, and the Commission to consider, "qualitative" benefits of resource planning decisions,[68] and utilities "may provide alternative scenarios with sensitivities based on proposed and current federal, state, and utility goals and mandates relating to carbon cost, emissions goal, or other externalities."[69] Further, as I previously discussed, there is longstanding Commission precedent that "the Commission can consider the possibility of carbon regulation in a qualitative manner."[70] It should also be noted that North Dakota's prohibition on the costs of complying with environmental laws or regulations only applies to "future" such laws and regulations "that have not yet been enacted"; however, the latest rules promulgated under Section 111(d) have been enacted, are not stayed, and so costs of compliance are appropriately considered.

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[67] *See* N.D. Cent. Code § 49-02-23; North Dakota Amin. Code § 69-09-12-03.
[68] *See* N.D. Admin. Code § 69-09-12-03, and 04; *see also* N.D. Cent. Code § 49-05-17.
[69] North Dakota Amin. Code § 69-09-12-03.
[70] August 27, 2008 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER in Case Nos. PU-06-481 and PU-06-482 (upholding Otter Tail Power's and Montana-Dakota Utilities' consideration of the possibility of future carbon dioxide regulation in determining the prudence of their addition of a coal plant).

The various mandates of North Dakota, Minnesota, and the federal government may at times appear on their face to be in tension with one another, particularly when considering economic conditions of the *past*. But the economics of various energy resource types have changed over time, and currently carbon-free resources are often more economically beneficial and reliable than coal and gas-power resources. The Company has demonstrated this on a company-wide scale in its 2024-2040 North Dakota Resource Plan, in addition to the various resource-specific economic analyses discussed throughout my testimony. Accordingly, the Company has proven that its decisions are prudent under North Dakota standards, even while meeting its corporate carbon reduction goals and Minnesota's carbon reduction mandates.

B. Resource Treatment Framework

Q. WHAT WAS THE PROPOSED RESOURCE TREATMENT FRAMEWORK?

A. One outcome of the settlement of Case No. PU-12-813, was an agreement to negotiate a framework by which NSP would serve its customers with a mix of resources (real or proxy) consistent with North Dakota's energy policies.[71] This potential approach was initially referred to as a "restack" and then came to be called the Resource Treatment Framework (RTF). The Company engaged in lengthy discussions with Commission Staff and developed detailed proposals for such an approach. At a high level this included both a formal North Dakota resource planning process, something that has since been established by statute, and methodologies to allocate the costs of resources that are not approved by all of the NSP jurisdictions. In Case No. PU-12-813, the Company made multiple filings discussing its proposed approaches, which culminated in a December 21, 2018 filing in which it proposed a

[71] ORDER ADOPTING SETTLEMENT (Feb. 26, 2014), Case No. PU-12-813, Second Amended Comprehensive Settlement Agreement at Section II.A.

formal process that could lead to adoption of the RTF. The Commission, however, chose not to move forward with the RTF and then eventually accepted a recommendation to close the docket.

Q. WHAT IS THE RELEVANCE OF THE RTF TO THE COMMISSION'S CONSIDERATION OF RESOURCE ADDITIONS AND CHANGES IN THIS RATE CASE?

A. The Company believes that the resource decisions it is presenting in this Rate Case, which I have discussed above, are prudent under the standards applicable in all three of the NSP jurisdictions for the reasons I have discussed at length. However, to the extent there is significant disagreement on the part of the Commission, that would present practical difficulties for the Company. The Company cannot make two different decisions with regard to a given resource based on the differing priorities of our state commissions. The Company can either retire a plant or keep it operational, it cannot do both. There is also the issue of North Dakota customers paying for the costs of resources that provide them with energy and capacity even if the Commission disagrees with the acquisition decisions for those resources. In choosing to not move forward with the RTF, it appeared the Commission had decided that the divergence in priorities between states was not so large as to warrant a formal framework. In this Rate Case and moving forward, the Company hopes that will continue to be the case. If, however, there is substantial divergence, then the need for the RTF should be revisited.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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EXPERIENCE

Xcel Energy
Director, Resource Planning
Responsible for the development of resource plans and acquisitions for the five-state integrated Upper Midwest System, including the 2024-2040 Integrated Resource Plan (IRP).
Manager, Regulatory Policy
Principal Rate Analyst
Developed strategy, coordinated subject matter expert analysis and prepared filings for the 2019 IRP, the 2016 IRP, Resource Treatment Framework (RTF), and resource acquisitions. Represented the Company at hearings on the IRP and other resource related proceedings.

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

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

EDUCATION

University of Wisconsin Law School, Madison, WI
J.D.

University of Wisconsin-Madison, Madison, WI
B.A.
Major: Economics-Mathematical Emphasis

Mixed Integer Programming (MIP) in EnCompass

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

Economic Dispatch

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

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

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

Unit Commitment

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

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

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

Capacity Expansion

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

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

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

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

The MIP Process

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

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

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

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

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

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

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

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

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

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

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

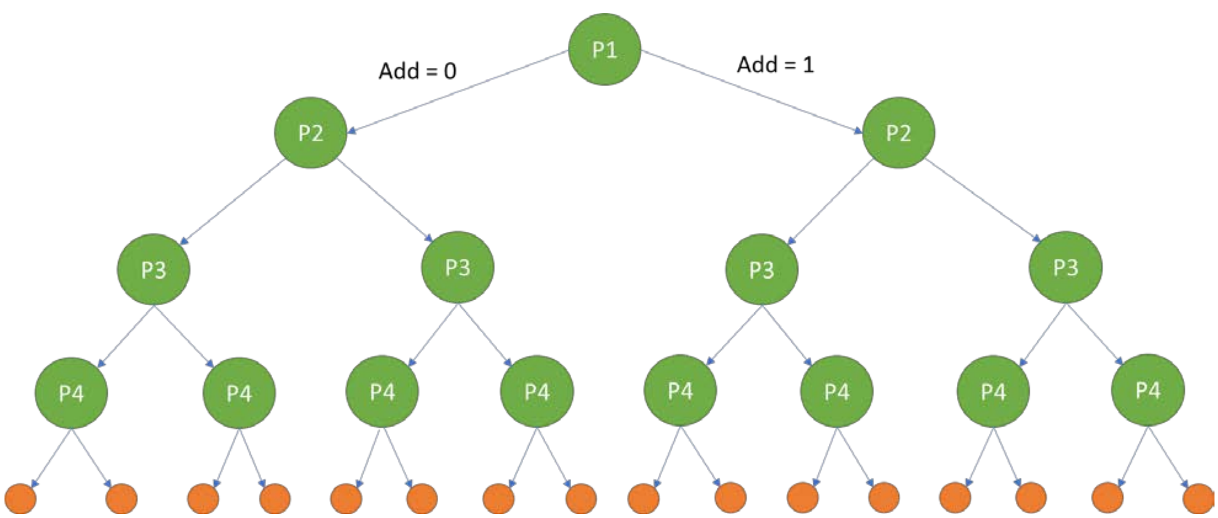
Objective Functions and the Unified Solution

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

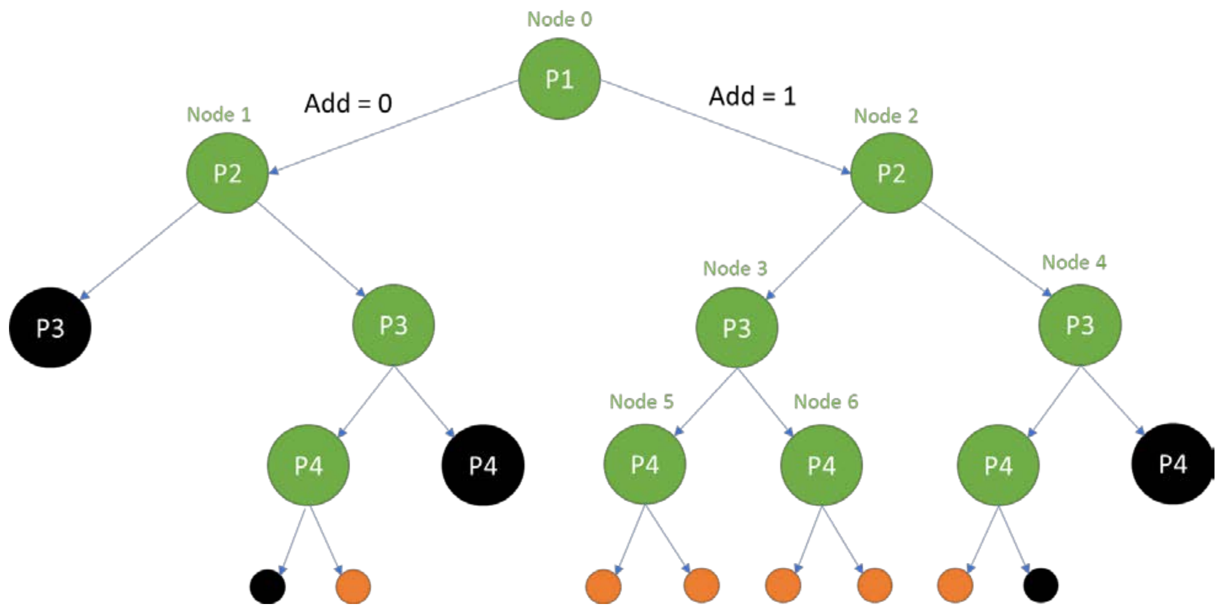
= 8 nodes to evaluate with dynamic programming, and 7 nodes with mixed integer programming. In a typical multi-year expansion problem, there are usually thousands of integer variables that can take values larger than 1. This makes the number of nodes to evaluate with a dynamic program skyrocket and requires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

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

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



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



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

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

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

Xpress Optimization Suite

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

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

APPENDIX F2 – STRATEGIST MODELING ASSUMPTIONS & INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

D. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 GPDIPD of

113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No.E999/CI-07-1199 and E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.
The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The "Load Forecast with 1.5% EE" shown in Table 4 below is the starting point for the Strategist load inputs. In all modeling scenarios, the "1.5% EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2047. In its place, three EE Bundles (discussed below) are included in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as "Forecast Without 1.5% EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Strategist Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table 5 and Table 6, and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

	High DER Growth		
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). The Bundles are included in Strategist as Proview Alternatives and any number of these Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast and, the same as for EE, are dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). These Bundles are included in Strategist as Proview Alternatives and any number of the Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	848	0	0	0	0	0	0
2019	924	0	0	0	0	0	0
2020	940	270	107	89	14,380	7,659	11,311
2021	955	290	112	97	15,724	8,150	12,587
2022	970	312	116	106	17,212	8,676	14,016
2023	989	322	120	110	18,124	9,137	14,758
2024	1007	339	132	101	19,512	10,277	13,829
2025	1023	380	145	92	22,305	11,459	12,858
2026	1038	392	151	93	23,475	12,207	13,326
2027	1053	406	159	95	24,786	13,080	13,845
2028	1066	421	168	97	26,245	14,086	14,418
2029	1054	438	178	99	27,859	15,231	15,047
2030	1043	456	189	101	29,637	16,522	15,734
2031	1032	476	201	104	31,551	17,926	16,467
2032	1021	497	214	106	33,612	19,451	17,251
2033	1010	519	227	109	35,832	21,109	18,088
2034	1000	542	242	112	38,224	22,911	18,984
2035	990	567	257	116	40,802	24,870	19,943
2036	981	594	274	119	43,582	26,999	20,971
2037	972	630	293	125	46,580	29,313	22,072
2038	963	660	312	129	49,814	31,829	23,253
2039	954	692	332	133	53,305	34,564	24,522
2040	945	726	353	138	57,073	37,537	25,884
2041	937	726	353	138	58,215	38,288	26,402
2042	929	726	353	138	59,379	39,054	26,930
2043	921	726	353	138	60,566	39,835	27,468
2044	913	726	353	138	61,778	40,632	28,018
2045	906	726	353	138	63,013	41,444	28,578
2046	898	726	353	138	64,274	42,273	29,150
2047	891	726	353	138	65,559	43,118	29,733
2048	884	726	353	138	66,870	43,981	30,327
2049	876	726	353	138	68,208	44,860	30,934
2050	869	726	353	138	69,572	45,758	31,552
2051	862	726	353	138	70,963	46,673	32,183
2052	854	726	353	138	72,382	47,606	32,827
2053	847	726	353	138	73,830	48,558	33,484
2054	839	726	353	138	75,307	49,530	34,153
2055	832	726	353	138	76,813	50,520	34,836
2056	825	726	353	138	78,349	51,531	35,533
2057	817	726	353	138	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The 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).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table 9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting in year 2022.

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

L. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

M. 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 137 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

We note additionally that interconnection costs for generic resources are included in the capital costs in Table 14 in Part U of this Appendix, and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	400	140

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

Q. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a twenty five year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs. The Company expects a transition from Solar*Rewards to non-incentivized DG over time due to the end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

R. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and 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

S. 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

T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy 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 are developed through a "Typical Wind Year" process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Utility-scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10, while DG/distributed solar does not.

The Reference Case assumes "no going back" on renewables, meaning that we are committed to pursuing repowering and/or contract extension opportunities for renewable resources that will expire , and renewable resources are replaced "in-kind" when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is approximately 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to approximately 4,500 GWhs by 2028. The Company has already procured the levels of wind contemplated in the previous Resource Plan, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast. 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

Table 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$15,000	$19,058	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$17.96	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$14.46	$16.19	$5.96	$6.27	$8.14
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

Table 16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	88
Equivalent Full Cycles per Year	156
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$10.53

Table 17: Levelized Capacity Costs by In-Service Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.14	$6.27	$5.96	$16.19	$14.46			
2019	$8.31	$6.40	$6.08	$16.51	$14.75			
2020	$8.47	$6.53	$6.20	$16.84	$15.04			
2021	$8.64	$6.66	$6.33	$17.18	$15.35			
2022	$8.81	$6.79	$6.46	$17.52	$15.65			
2023	$8.99	$6.93	$6.58	$17.88	$15.97	$10.53	$8.03	$13.71
2024	$9.17	$7.07	$6.72	$18.23	$16.28	$9.48	$6.99	$12.51
2025	$9.35	$7.21	$6.85	$18.60	$16.61	$8.91	$6.35	$11.92
2026	$9.54	$7.35	$6.99	$18.97	$16.94	$8.53	$5.90	$11.41
2027	$9.73	$7.50	$7.13	$19.35	$17.28	$8.24	$5.53	$11.04
2028	$9.93	$7.65	$7.27	$19.74	$17.63	$8.02	$5.20	$10.73
2029	$10.13	$7.80	$7.41	$20.13	$17.98	$7.83	$4.92	$10.49
2030	$10.33	$7.96	$7.56	$20.53	$18.34	$7.68	$4.65	$10.28
2031	$10.53	$8.12	$7.71	$20.94	$18.71	$7.54	$4.51	$10.19
2032	$10.75	$8.28	$7.87	$21.36	$19.08	$7.42	$4.39	$10.13
2033	$10.96	$8.44	$8.03	$21.79	$19.46	$7.31	$4.27	$10.08
2034	$11.18	$8.61	$8.19	$22.23	$19.85	$7.22	$4.16	$10.05
2035	$11.40	$8.79	$8.35	$22.67	$20.25	$7.13	$4.05	$10.02
2036	$11.63	$8.96	$8.52	$23.12	$20.65	$7.05	$3.94	$10.02
2037	$11.86	$9.14	$8.69	$23.59	$21.07	$6.98	$3.83	$10.03
2038	$12.10	$9.32	$8.86	$24.06	$21.49	$6.91	$3.73	$10.05
2039	$12.34	$9.51	$9.04	$24.54	$21.92	$6.85	$3.63	$10.07
2040	$12.59	$9.70	$9.22	$25.03	$22.36	$6.79	$3.53	$10.09
2041	$12.84	$9.89	$9.40	$25.53	$22.80	$6.73	$3.44	$10.11
2042	$13.10	$10.09	$9.59	$26.04	$23.26	$6.68	$3.36	$10.13
2043	$13.36	$10.29	$9.78	$26.56	$23.72	$6.63	$3.28	$10.15
2044	$13.63	$10.50	$9.98	$27.09	$24.20	$6.58	$3.20	$10.17
2045	$13.90	$10.71	$10.18	$27.63	$24.68	$6.54	$3.12	$10.20
2046	$14.18	$10.92	$10.38	$28.19	$25.18	$6.50	$3.10	$10.13
2047	$14.46	$11.14	$10.59	$28.75	$25.68	$6.46	$3.09	$10.07
2048	$14.75	$11.37	$10.80	$29.33	$26.19	$6.42	$3.07	$10.01
2049	$15.05	$11.59	$11.02	$29.91	$26.72	$6.38	$3.06	$9.96
2050	$15.35	$11.82	$11.24	$30.51	$27.25	$6.35	$3.04	$9.91
2051	$15.65	$12.06	$11.46	$31.12	$27.80	$6.31	$3.03	$9.85
2052	$15.97	$12.30	$11.69	$31.74	$28.35	$6.28	$3.01	$9.80
2053	$16.29	$12.55	$11.93	$32.38	$28.92	$6.25	$3.00	$9.76
2054	$16.61	$12.80	$12.16	$33.03	$29.50	$6.22	$2.98	$9.71
2055	$16.94	$13.06	$12.41	$33.69	$30.09	$6.19	$2.97	$9.66
2056	$17.28	$13.32	$12.66	$34.36	$30.69	$6.16	$2.95	$9.62
2057	$17.63	$13.58	$12.91	$35.05	$31.30	$6.13	$2.94	$9.58

Table 18: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 19: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 20: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26

**Distributed Solar costs represent at the meter values before grossing up for losses.*

ATTACHMENT A: HEAT RATE UPDATED

In Docket No. E999/CI-06-159 (In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005), the Minnesota Commission required the Company to file information on the fossil fuel efficiency (heat rate) of our generation units, and actions we are taking to increase the fuel efficiency of those units.

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2018 in Table 21 below.

Table 21: 2018 FERC Heat Rates

Unit	Heat Rate
AS King	10,013
Sherco	10,546
Monticello	10,505
Prairie Island	10,487
Black Dog (NG)	7,870
High Bridge	6,863
Riverside	7,172
French Island	23,570
Wilmarth	10,637

The Company's Performance Monitoring department performs routine heat rate testing and conducts heat balances of its generating units. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted. These tools factor into our assessment of the condition of these individual components, as well as how their respective performance levels will impact the overall efficiency of a given generating unit. Table 22 below shows a summary of NSP System heat rate testing from 2015-2018.

Table 22: Heat Rate Tests – 2015-2018

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Sherco U1	Coal Boiler	Heat Rate	2015
Bayfront U4	Combustion Turbine	Calculated Adjustment for Fuel Change	2016
King U1	Coal Boiler	Heat Rate	2016
Sherco U2	Coal Boiler	Heat Rate	2015, 2016
Black Dog U5/U2	Combined Cycle	Heat Rate	2015, 2017
High Bridge CC	Combined Cycle	Heat Rate	2017, 2018
Sherco U3	Coal Boiler	Heat Rate	2017
Black Dog U6	Combustion Turbine	Heat Rate	2018
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2017,2018

As part of its heat rate testing and reporting protocol, the Performance Monitoring group identifies potential heat rate improvement opportunities and validates actual performance enhancements. The Company does not look at heat rate improvements in isolation when considering plant improvement projects; rather, we perform a collective assessment of potential safety, efficiency, and environmental performance improvements as well as overall economics in developing our generation asset management objectives. Looking forward, the Company plans to continue our proactive cycle of heat rate testing and overall unit assessments at our generation units and implement improvements as opportunities arise.

ATTACHMENT B: WATER AND PLANT OPERATIONS

The Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings in Docket No. E002/RP-10-825 suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 4).

The Company's generating units are geographically positioned along major Minnesota waterways. The access to water accommodates the thermal needs of these generating units. As such, the Company's plant operations are governed by and comply with all applicable cooling water intake and discharge rules and regulations, which may indirectly affect Strategist modeling as discussed below.

The Clean Water Act Section 316(a) sets thermal limitations for discharges and the criteria and processes for allowing thermal variances. The Company's power plant discharge temperature limits and allowances for thermal emergency provisions are outlined in the plants' National Pollutant Discharge Elimination System (NPDES) permits. Additionally, Xcel Energy has policies which outline the conditions and procedures to implement during periods of energy emergencies that allow for limited thermal variances.

Section 316(b) of the Clean Water Act governs the design and operation of intake structures in order to minimize adverse environmental impacts to aquatic life. EPA issued new rules in August 2014 that will impact all plants that withdraw water for cooling purposes. The new rules require improvements to intake screening technology to minimize the number of aquatic organisms that are killed due to being stuck to the screens (referred to as "impingement). The rules also created a process for the state permitting agency to evaluate and determine if additional improvements are required to minimize the number of smaller organisms that pass through the intake screens and enter the plant cooling water system (referred to as "entrainment"). While the costs associated with the impingement compliance requirements are definable, the costs associated with the entrainment compliance requirements are uncertain.

Timing of the compliance requirements is site-specific and is determined by each site's NPDES permit renewal timeline.

While specific conditions, such as high water discharge temperatures, are not directly modeled in Strategist, the model reflects the impact of reducing plant output due to high water temperatures. Modeling in Strategist includes two methods to account for impacts due to changes in plant operations: each resource is modeled using a unit specific median unforced capacity rating, and the system needs are modeled with a planning reserve margin. By modeling the system needs with a planning reserve margin, the base level of required resources is assumed to be higher than those needed to meet the forecasted peak system demand. By modeling all units with an assumed level of forced outage, the base level of all available resources, modeled in aggregate, is assumed to be sufficient to represent resource availability due to emergency changes in plant operations. Thus the impact of reducing plant output due to high water temperatures is reflected through corrections to both obligation and resource adjustments.

ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following table shows load and resources using Installed Capacity Rating (ICAP) for the planning period, in compliance with the Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings.[1]

Table 23: Load and Resources Tables, 2020-2034 Planning Period

ICAP Rating - Load and Resources 2020-2034 Planning Period

Determination of Need	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Forecast Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO System Coincident (ICAP)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO Planning Reserve	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Obligation	10,670	10,641	10,660	10,627	10,595	10,537	10,498	10,495	10,556	10,558	10,589	10,599	10,733	10,885	10,892

Existing and Approved Resources	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Load Management, Existing	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management, Potential Study	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,471	2,471	2,471	2,471	1,773	1,773	1,773	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
Nuclear	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,053	1,053	1,053	527
Natural Gas/Oil	3,511	3,511	3,511	3,511	3,347	3,032	2,784	2,260	2,139	2,139	2,139	2,139	1,858	1,858	1,858
MEC	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Sherco CC	0	0	0	0	0	0	0	786	786	786	786	786	786	786	786
Biomass/RDF	107	107	107	84	84	60	60	60	19	19	19	19	19	19	19
Hydro	887	1,009	1,002	1,002	1,002	152	152	152	152	152	152	152	145	142	142
Wind	3,954	4,200	4,200	4,054	4,054	4,034	4,012	3,913	3,848	3,739	3,735	3,439	3,372	2,984	2,620
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Solar*Rewards Community	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Grid Scale Solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Existing Resources	15,117	15,530	15,569	15,438	14,620	13,477	13,243	12,732	12,543	12,448	12,460	11,536	11,200	10,837	9,968
Existing and Approved Net Resource (Need)/Surplus	4,446	4,889	4,909	4,811	4,025	2,941	2,745	2,237	1,987	1,890	1,871	937	466	-48	-924

Reference Plan Resource Additions/Retirements	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Natural Gas/Oil	0	0	0	0	0	0	0	0	0	0	0	0	220	570	920
Wind	0	0	0	126	171	242	307	379	389	496	512	568	598	1,122	2,702
Solar	0	0	0	0	0	251	251	752	1,002	1,252	1,253	1,753	2,004	2,004	2,004
Reference Plan Resource Adjustments	0	0	0	126	172	492	558	1,131	1,391	1,749	1,765	2,321	2,822	3,696	5,627
Reference Plan Net Resource (Need)/Surplus	4,446	4,889	4,909	4,937	4,197	3,433	3,303	3,367	3,379	3,639	3,636	3,258	3,288	3,647	4,702

[1] *See* Docket No. E002/RP-10-825. In addition to noting amendments to Minn. Stat. § 216B.2422, subd. 4, the Notice suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 2).

IV. MODELING ASSUMPTIONS AND INPUTS

Since filing our initial Resource Plan in July 2019, the Company has made several changes to its modeling approaches, inputs, and assumptions. Some of these changes in modeling approaches implemented based on discussions with the Department of Commerce (DOC or Department), and feedback from the Commission and stakeholders. Others reflect the passage of time and availability of more recent input and assumptions source material. While a more complete set of updated Strategist and EnCompass modeling assumptions is included in this section, we provide a summary of major changes below.

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Modeling constraints				
Carbon emissions constraint	▪ No constraint; baseload scenarios may not meet 80 percent reduction goal	▪ Removed modeling constraint of 80 percent carbon reduction by 2030	▪ Alignment with DOC preferred approach	▪ None
"No Going Back" wind replacement capacity	▪ No assumption that existing wind will be replaced when plants or contracts reach end of life	▪ Removed wind replacement capacity from baseline modeling	▪ Alignment with DOC preferred approach	▪ None
Reliability Requirement	▪ Modeling does not include 5.7 GW firm, dispatchable capacity floor; model optimizes resources to develop expansion plans	▪ Removed reliability requirement from baseline modeling	▪ EnCompass modeling better accounts for reliability in hourly chronological modeling ▪ Alignment with DOC preferred approach	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Near term wind availability constraint	▪ No generic wind option made available for model to select before 2026	▪ Generic wind available to select in modeling for each year	▪ Transmission constraints in near term are highly cost prohibitive, such that most greenfield projects are withdrawing from the interconnection queue	▪ Tested alternate sensitivity where wind is available in 2023
Market sales limit	▪ Limits market sales to 25 percent of retail load in EnCompass modeling	▪ Not applicable; no market sales limit capability in Strategist	▪ Limit sales risk exposure	▪ Tested alternate scenarios with unlimited market
Market and technology assumptions				
Market hourly price shaping	▪ Shaped hourly market prices based on retail load	▪ Hourly market price shaped based on thermal load	▪ Alignment with DOC preferred approach	▪ None
Fuel price forecasts	▪ Updated to Fall 2019 forecast vintage	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ High and low fuel price forecasts
Technology price forecasts for wind, solar, and storage	▪ Used National Renewable Energy Labs (NREL) *Annual Technology Baseline (ATB) 2019* assumptions	▪ Updated from 2018 ATB to 2019 ATB for wind and solar ▪ Shifted from using internal price assumptions to 2019 ATB for storage	▪ Previous inputs outdated	▪ Used High and low technology price forecasts in sensitivities

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind resource production	▪ Used 2019 NREL ATB price inputs for Technology Resource Group (TRG) 2	▪ Previously used 2018 ATB price assumptions for TRG 1, which reflected a higher capacity factor expectation	▪ We believe TRG 2 capacity factors better align with wind resource quality for remaining sites in our region	▪ None
Solar resource production	▪ Assumed 22 percent capacity factor in first year, with 0.5 percent per year degradation	▪ Previously assumed 17.7 percent levelized capacity factor	▪ Better alignment with performance of our existing solar resources	▪ None
Renewable transmission interconnect cost	▪ Wind: $500/kW ▪ Solar: $200/kW	▪ Wind: Increased from $400/kW for greenfield wind ▪ Solar: Increased from $140/kW	▪ MISO transmission constraints create upward pressure on interconnection costs	▪ None
Solar capacity accreditation	▪ 50 percent ELCC to 2023, declining to 30 percent in 2033 at a rate of 2 percent per year	▪ 50 percent ELCC for the full analysis period	▪ Aligns with assumptions used in MISO MTEP 2019 modeling	▪ Performed alternate scenario with 50 percent ELCC held constant

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
Wind capacity accreditation	▪ 16.7 percent ELCC throughout the planning period	▪ 15.6 percent ELCC throughout the planning period	▪ Updated to reflect MISO Zone 1 ELCC rather than MISO-wide assumptions ▪ Updated to match MISO's most recent Wind and Solar Capacity Credit report.	▪ None
Effective Reserve Margin	▪ Reserve margin updated to 3.46 percent, based on latest MISO LOLE Study (2020-2021)	▪ 2.98 percent effective reserve margin	▪ Updated to most recent LOLE study result	▪ None
Upper Midwest System Assumptions				
Unit retirement dates	▪ All existing unit retirement years with end of financial life	▪ Selected units used differing retirement dates for resource planning purposes	▪ Conforms with Commission direction	▪ None
Seasonal coal dispatch	▪ King and Sherco 2 do not dispatch from March-May and September-November, through 2023	▪ No units were modeled with seasonal dispatch	▪ Reflects Commission-approved operational practices	▪ None
Load forecasts	▪ Updated to fall 2019 internal forecast vintage	▪ Changed from fall 2018 internal forecast	▪ Previous inputs outdated	▪ None

Topic	Assumption	Change from Initial Filing	Rationale for Change	Sensitivity Performed?
DER forecasts	▪ Updated to latest vintage for each technology	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ Sensitivity on low load/high DER adoption
EV adoption forecasts	▪ Updated to latest vintage, aligned with most recent forecasts used in IDP	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated ▪ Conforms with Commission direction to better align forecasts across filings	▪ Sensitivity on high EV adoption
Nuclear budgets	▪ Updated to most recent vintage for Nuclear Decommissioning Trust, Operations and Maintenance and Capital Expenditure budgets	▪ Changed from vintage available prior to previous filing	▪ Previous inputs outdated	▪ None

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.47 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table IV-1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.72%	4.79%	2.19%	1.58%
Common Equity	52.39%	9.25%	4.85%	4.85%
Short-Term Debt	1.89%	3.55%	0.07%	0.05%
Total			**7.10%**	**6.47%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2 percent is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.9 percent from the 2020-2021 LOLE Study Report, published November 2019. The coincidence factor between the NSP System and MISO system peak is 95 percent. Therefore, the effective reserve margin is:

$$(95\, percent\ coincidence\ factor) x\ (1 + 8.9\, percent) - 1 = \mathbf{3.46}\, percent\ effective\ reserve\ margin\ for\ NSP$$

D. CO_2 Costs

The Present Value of Societal Cost (PVSC) Base Case CO_2 values are based on the high environmental cost values for CO_2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 Gross Domestic Product Implicit Price Deflator (GDPIPD) of 113.416 and then escalated at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.

The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table IV-2: CO_2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the three locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018. The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GDPIPD of 113.416. The high, low and midpoint externality costs will be used in the CO_2 sensitivities as described above.

Table IV-3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2019 load forecast is used as the base assumption and assumes that EV impacts growth continues throughout the forecast period. The energy efficiency (EE) forecast included in the base forecast developed by the Company's Load Forecasting department assumes somewhat less energy efficiency (EE) savings levels than those included in our initial Resource Plan's Preferred Plan. Please see Attachment A Section II for more information.

The "Load Forecast with EE" shown in Table IV-4 below is the starting point for the load inputs. In all modeling scenarios, the "EE" is removed – the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2048. In the initial filing, the three EE Bundles (discussed below) were optimized as Proview Alternatives. For this supplemental filing, the first two EE Bundles are included in all scenarios. The resulting forecast, before the optimized EE bundles are added, is shown below in Table IV-4 as "Forecast Without EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource, not a load modifier.

Table IV-4: Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with EE	Forecast without EE	Forecast with EE	Forecast without EE
2018	9,152	9,152	43,914	43,914
2019	9,084	9,084	43,558	43,558
2020	9,099	9,230	43,170	43,806
2021	9,079	9,312	42,741	44,018
2022	9,126	9,462	42,628	44,549
2023	9,165	9,604	42,440	45,004
2024	9,184	9,728	42,339	45,555
2025	9,238	9,849	42,324	45,976
2026	9,311	9,992	42,470	46,565
2027	9,414	10,164	42,757	47,296
2028	9,504	10,327	43,221	48,216
2029	9,525	10,416	43,006	48,432
2030	9,605	10,566	43,224	49,093
2031	9,679	10,710	43,420	49,734
2032	9,775	10,880	43,903	50,678
2033	9,979	11,058	44,532	51,299
2034	10,190	11,246	45,426	52,203
2035	10,343	11,269	46,158	52,299
2036	10,502	11,325	47,028	52,527
2037	10,673	11,393	47,647	52,503
2038	10,803	11,420	48,209	52,422
2039	10,936	11,449	48,833	52,394
2040	11,073	11,518	49,603	52,729
2041	11,209	11,585	50,055	52,737
2042	11,338	11,645	50,635	52,873
2043	11,467	11,701	51,267	53,048
2044	11,614	11,780	52,023	53,374
2045	11,722	11,818	52,468	53,375
2046	11,839	11,865	53,010	53,473
2047	11,951	11,903	53,545	53,547
2048	12,021	11,998	54,150	54,160
2049	12,045	12,045	54,202	54,202
2050	12,097	12,097	54,407	54,407
2051	12,149	12,149	54,611	54,611
2052	12,199	12,199	54,947	54,947
2053	12,252	12,252	55,022	55,022
2054	12,305	12,305	55,226	55,226
2055	12,357	12,357	55,431	55,431
2056	12,409	12,409	55,765	55,765
2057	12,461	12,461	55,840	55,840

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table IV-5 and Table IV-6 and are incremental/decremental to the forecast shown in Table IV-4.

Table IV-5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	592	65
2026	692	77
2027	812	85
2028	939	98
2029	1,202	118
2030	1,578	162
2031	2,028	205
2032	2,538	251
2033	3,137	305
2034	3,857	367
2035	4,716	438
2036	5,657	515
2037	6,672	596
2038	7,741	679
2039	8,851	766
2040	9,996	854
2041	11,114	940
2042	12,199	1,025
2043	13,241	1,118
2044	14,229	1,796
2045	15,159	2,520
2046	16,037	3,173
2047	16,877	3,796
2048	17,696	4,647
2049	18,660	4,908
2050	19,530	5,407
2051	20,634	5,947
2052	21,645	6,418
2053	22,656	6,896
2054	23,666	7,384
2055	24,677	7,877
2056	25,688	8,352
2057	26,699	8,840

**Demand values are coincident to system peak*

Table IV- 6: Low Load Sensitivity

High DER Growth		
Year	Energy (GWh)	Demand (Nameplate MW)
2018	0	0
2019	0	0
2020	0	0
2021	207	122
2022	180	106
2023	159	94
2024	270	159
2025	258	152
2026	423	250
2027	423	250
2028	635	374
2029	641	379
2030	740	437
2031	826	487
2032	913	538
2033	996	588
2034	1,082	639
2035	1,167	689
2036	1,256	739
2037	1,338	790
2038	1,423	840
2039	1,509	891
2040	1,598	941
2041	1,631	963
2042	1,580	933
2043	1,529	903
2044	1,482	872
2045	1,425	842
2046	1,350	797
2047	1,296	765
2048	1,245	733
2049	1,187	701
2050	1,131	668
2051	1,063	628
2052	1,009	594
2053	932	550
2054	872	515
2055	807	476
2056	742	437
2057	671	396

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota DOC's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are decremental (reducing energy and demand) to the "Forecast without EE" shown in Table IV-4.

Table IV- 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast. In the initial filing, the three DR Bundles were optimized as Proview Alternatives. For this Supplement, the first DR Bundle is included in all scenarios.

Table IV-8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	852	0	0	0	0	0	0
2019	928	0	0	0	0	0	0
2020	1012	33	107	90	1,752	7,659	11,311
2021	1027	165	112	98	8,917	8,150	12,587
2022	1041	232	117	107	12,748	8,676	14,016
2023	1055	294	121	110	16,489	9,137	14,758
2024	1066	341	133	101	19,512	10,277	13,829
2025	1072	382	145	92	22,305	11,459	12,858
2026	1077	394	152	93	23,475	12,207	13,326
2027	1078	407	159	95	24,786	13,080	13,845
2028	1077	423	168	97	26,245	14,086	14,418
2029	1071	440	178	99	27,859	15,231	15,047
2030	1059	458	190	102	29,637	16,522	15,734
2031	1048	478	202	104	31,551	17,926	16,467
2032	1037	499	215	107	33,612	19,451	17,251
2033	1026	521	228	110	35,832	21,109	18,088
2034	1016	545	243	113	38,224	22,911	18,984
2035	1005	570	259	116	40,802	24,870	19,943
2036	995	596	275	120	43,582	26,999	20,971
2037	985	624	293	123	46,580	29,313	22,072
2038	976	654	312	127	49,814	31,829	23,253
2039	966	686	332	132	53,305	34,564	24,522
2040	957	720	353	136	57,073	37,537	25,884
2041	948	720	353	136	58,215	38,288	26,402
2042	939	720	353	136	59,379	39,054	26,930
2043	930	720	353	136	60,566	39,835	27,468
2044	922	720	353	136	61,778	40,632	28,018
2045	914	720	353	136	63,013	41,444	28,578
2046	906	720	353	136	64,274	42,273	29,150
2047	898	720	353	136	65,559	43,118	29,733
2048	890	720	353	136	66,870	43,981	30,327
2049	882	720	353	136	68,208	44,860	30,934
2050	875	720	353	136	69,572	45,758	31,552
2051	868	720	353	136	70,963	46,673	32,183
2052	860	720	353	136	72,382	47,606	32,827
2053	853	720	353	136	73,830	48,558	33,484
2054	847	720	353	136	75,307	49,530	34,153
2055	840	720	353	136	76,813	50,520	34,836
2056	833	720	353	136	78,349	51,531	35,533
2057	827	720	353	136	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

Natural gas price forecasts are developed using a blend of market information (New York Mercantile Exchange, or NYMEX, futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five-year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table IV-9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low-price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting when the long-term fundamentally-based forecasts are blended with market information (NYMEX futures prices).

Table IV-9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98	$2.08	$2.60	$26.93	$20.98
2020	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13	$2.11	$2.26	$25.78	$20.13
2021	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06	$2.14	$2.23	$25.32	$19.06
2022	$2.19	$2.33	$26.92	$20.45	$2.17	$2.28	$26.33	$20.00	$2.24	$2.38	$27.52	$20.90
2023	$2.25	$2.45	$29.31	$22.19	$2.19	$2.34	$27.96	$21.17	$2.36	$2.57	$30.68	$23.23
2024	$2.30	$2.58	$30.00	$23.20	$2.22	$2.40	$27.94	$21.60	$2.46	$2.76	$32.16	$24.87
2025	$2.35	$2.79	$31.47	$24.36	$2.24	$2.50	$28.17	$21.80	$2.57	$3.11	$35.04	$27.12
2026	$2.40	$2.98	$32.30	$24.99	$2.27	$2.58	$28.01	$21.67	$2.69	$3.42	$37.09	$28.70
2027	$2.45	$3.12	$33.35	$26.71	$2.29	$2.64	$28.28	$22.64	$2.81	$3.66	$39.16	$31.36
2028	$2.51	$3.26	$34.09	$26.97	$2.32	$2.71	$28.25	$22.35	$2.93	$3.92	$40.92	$32.38
2029	$2.57	$3.44	$35.21	$28.25	$2.34	$2.78	$28.42	$22.79	$3.07	$4.24	$43.38	$34.80
2030	$2.62	$3.70	$38.27	$30.69	$2.37	$2.88	$29.83	$23.92	$3.20	$4.71	$48.76	$39.09
2031	$2.68	$3.87	$39.33	$32.07	$2.40	$2.95	$29.97	$24.44	$3.35	$5.04	$51.22	$41.77
2032	$2.75	$4.02	$39.75	$33.14	$2.43	$3.01	$29.71	$24.77	$3.51	$5.34	$52.76	$43.99
2033	$2.81	$4.10	$39.93	$33.46	$2.45	$3.03	$29.58	$24.79	$3.67	$5.48	$53.47	$44.80
2034	$2.87	$4.20	$41.13	$34.56	$2.48	$3.07	$30.08	$25.28	$3.83	$5.70	$55.76	$46.86
2035	$2.94	$4.35	$42.15	$35.66	$2.51	$3.13	$30.32	$25.65	$4.00	$6.00	$58.12	$49.17
2036	$2.99	$4.47	$42.79	$36.60	$2.53	$3.17	$30.37	$25.97	$4.14	$6.24	$59.80	$51.13
2037	$3.07	$4.65	$44.00	$38.21	$2.56	$3.24	$30.61	$26.58	$4.36	$6.63	$62.69	$54.44
2038	$3.14	$4.86	$44.95	$39.45	$2.60	$3.31	$30.60	$26.85	$4.58	$7.08	$65.43	$57.42
2039	$3.23	$5.04	$45.82	$40.48	$2.63	$3.37	$30.63	$27.06	$4.83	$7.47	$67.88	$59.98
2040	$3.31	$5.22	$46.61	$41.48	$2.66	$3.43	$30.61	$27.25	$5.06	$7.87	$70.25	$62.53
2041	$3.37	$5.32	$46.52	$41.48	$2.69	$3.46	$30.27	$26.99	$5.26	$8.10	$70.79	$63.12
2042	$3.45	$5.47	$47.61	$42.64	$2.72	$3.51	$30.57	$27.38	$5.51	$8.43	$73.40	$65.74
2043	$3.53	$5.62	$48.37	$43.71	$2.75	$3.56	$30.64	$27.69	$5.77	$8.78	$75.56	$68.28
2044	$3.62	$5.78	$49.72	$44.99	$2.79	$3.61	$31.04	$28.09	$6.05	$9.17	$78.79	$71.29
2045	$3.70	$5.99	$51.23	$46.37	$2.82	$3.68	$31.45	$28.46	$6.31	$9.65	$82.57	$74.73
2046	$3.78	$6.17	$52.49	$47.53	$2.85	$3.73	$31.74	$28.74	$6.59	$10.09	$85.85	$77.73
2047	$3.86	$6.29	$53.27	$48.57	$2.88	$3.77	$31.89	$29.08	$6.88	$10.40	$87.98	$80.22
2048	$3.95	$6.46	$54.39	$49.88	$2.91	$3.82	$32.15	$29.49	$7.20	$10.80	$90.96	$83.42
2049	$4.04	$6.66	$55.69	$50.92	$2.95	$3.88	$32.43	$29.65	$7.53	$11.30	$94.52	$86.43
2050	$4.13	$6.77	$56.64	$51.71	$2.98	$3.91	$32.70	$29.85	$7.87	$11.60	$96.97	$88.53
2051	$4.22	$6.96	$58.23	$53.16	$3.01	$3.96	$33.16	$30.27	$8.21	$12.08	$101.05	$92.24
2052	$4.31	$7.13	$59.62	$54.42	$3.04	$4.01	$33.56	$30.63	$8.57	$12.51	$104.64	$95.53
2053	$4.41	$7.29	$61.00	$55.68	$3.08	$4.06	$33.94	$30.99	$8.94	$12.95	$108.29	$98.85
2054	$4.50	$7.46	$62.38	$56.95	$3.11	$4.10	$34.33	$31.34	$9.33	$13.39	$111.97	$102.21
2055	$4.60	$7.62	$63.76	$58.21	$3.14	$4.15	$34.71	$31.69	$9.73	$13.83	$115.69	$105.61
2056	$4.69	$7.79	$65.15	$59.47	$3.17	$4.19	$35.09	$32.03	$10.12	$14.28	$119.45	$109.05
2057	$4.79	$7.95	$66.53	$60.73	$3.21	$4.24	$35.46	$32.37	$10.52	$14.74	$123.26	$112.52

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three-year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table IV-10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
$/kw-mo	4.57	4.66	4.75	4.85	4.95	5.05	5.15	5.25	5.35	5.46	5.57	5.68	5.80	5.91	6.03	6.15	6.27	6.40	6.53	6.66
	2038	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**
$/kw-mo	6.79	6.93	7.07	7.21	7.35	7.50	7.65	7.80	7.96	8.12	8.28	8.44	8.61	8.79	8.96	9.14	9.32	9.51	9.70	9.89

L. Effective Load Carrying Capability Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 16.7 percent of their nameplate rating per MISO 2020/2021 Wind Capacity Report. The ELCC for generic solar is based on the values provided in MISO's MTEP 2019 in Appendix E,[1] and is 50 percent of the alternating current (AC) nameplate capacity through 2023, declining 2 percent annually to 30 percent by 2033 where it remains for the rest of the forecast period. The ELCC assigned for a generic 4-hour battery is equal to 100 percent of the AC equivalent capacity. The ELCC used for hybrid options are the same as the individual components.

M. Spinning Reserve Requirement

Spinning reserve is the online 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 137 MW and is based on a 12-month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is used to cover events where there are not enough resources or market purchase energy available to meet system energy requirements. In Strategist, this is set to $500/MWh. Encompass uses the default value of $10,000/MWh. The primary reason for this difference is the way the models utilize this input. In Strategist's dispatch approach, the emergency energy is determined after the dispatch, when all resources have been utilized and an energy shortfall still exists. In EnCompass, emergency energy is a "soft constraint" that allows emergency energy to "dispatch" as a last resort resource, in order for the model to find a feasible solution. The EnCompass price is set to a high level to ensure that all other available resources – including those that may have a very high effective $/MWh cost resulting from startup costs spread over a very small required run time – are utilized before emergency energy.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

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[1] Available at: https://cdn.misoenergy.org//MTEP19%20Appendix%20E-Futures%20Assumptions382958.pdf

We note additionally that interconnection costs for generic resources are included in the capital costs in Table IV-14 in Part U of this section and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table IV-11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	500	200

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were not included in the model.

Table IV-12: Integration Costs

Integration Costs ($/MWh)		
Year	Wind	Solar
2018	0.00	0.00
2019	0.00	0.00
2020	0.41	0.41
2021	0.42	0.42
2022	0.43	0.43
2023	0.44	0.44
2024	0.45	0.45
2025	0.46	0.46
2026	0.47	0.47
2027	0.48	0.48
2028	0.49	0.49
2029	0.49	0.49
2030	0.50	0.50
2031	0.51	0.51
2032	0.53	0.53
2033	0.54	0.54
2034	0.55	0.55
2035	0.56	0.56
2036	0.57	0.57
2037	0.58	0.58
2038	0.59	0.59
2039	0.60	0.60
2040	0.62	0.62
2041	0.63	0.63
2042	0.64	0.64
2043	0.65	0.65
2044	0.67	0.67
2045	0.68	0.68
2046	0.69	0.69
2047	0.71	0.71
2048	0.72	0.72
2049	0.74	0.74
2050	0.75	0.75
2051	0.77	0.77
2052	0.78	0.78
2053	0.80	0.80
2054	0.81	0.81
2055	0.83	0.83
2056	0.84	0.84
2057	0.86	0.86

Q. Distributed Solar Generation and Community Solar Gardens

The distributed solar and Community Solar Gardens inputs are based on the most recent Company forecasts. Distributed Solar is modeled assuming a degradation of half a percent annually in generation. Community Solar Gardens are modeled assuming a degradation of half a percent annually in generation, and a twenty-five-year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs.

Table IV-13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)			
Year	Solar Rewards	Community Gardens	Total
2018	29	246	274
2019	61	504	565
2020	80	658	738
2021	95	714	809
2022	109	787	897
2023	123	841	964
2024	138	852	989
2025	152	853	1,005
2026	166	854	1,020
2027	180	855	1,035
2028	194	857	1,050
2029	208	858	1,066
2030	222	859	1,080
2031	236	860	1,095
2032	249	861	1,110
2033	263	862	1,125
2034	276	863	1,140
2035	290	864	1,154
2036	303	866	1,169
2037	317	867	1,184
2038	330	868	1,198
2039	343	869	1,212
2040	357	870	1,227
2041	370	871	1,241
2042	383	869	1,252
2043	396	852	1,247
2044	409	830	1,239
2045	421	818	1,239
2046	434	814	1,248
2047	447	808	1,255
2048	460	805	1,264
2049	472	805	1,277
2050	491	806	1,297
2051	504	807	1,311
2052	518	808	1,326
2053	531	809	1,340
2054	545	810	1,355
2055	559	811	1,369
2056	572	812	1,384
2057	586	812	1,398

R. Owned Unit Modeled Operating Characteristics and Costs

Company-owned units are modeled based upon their tested operating characteristics and 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

S. Thermal 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

T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy 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 and solar hourly patterns are developed through a "Typical Meteorological Year" process where individual months are selected from the years 2017-2020 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each unit. For units where generation data is not complete or not available, data from a nearby similar unit is used.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic renewable and battery costs are based on data from the NREL 2019 ATB. Utility-scale wind and solar costs shown in Tables IV-18 through IV-20 include transmission costs from Table IV-11 while DG/distributed solar does not.

The modeling no longer assumes "no going back" on renewables, which was the replacement of renewable resources for a similar resource when they reached the end of their life, but rather allows all renewable additions to be optimized.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind, solar, and battery costs are also based on the 2019 ATB data. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

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

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table IV-14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$31,725	$19,058	$2,165	$1,342	$2,165
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$37.98	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$15.26	$16.06	$5.91	$6.22	$8.06
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table IV-15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	16.7%	50% declines to 30%		
Capacity Factor	50.0%	22.0%	18.0%	18.0%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	500	200	0	0

Table IV-16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	85
Equivalent Full Cycles per Year	250
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$18.18

Table IV-17: Levelized Capacity Costs by Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.06	$6.22	$5.91	$16.06	$15.26			
2019	$8.22	$6.34	$6.02	$16.38	$15.56			
2020	$8.38	$6.47	$6.15	$16.71	$15.87	$20.04	$17.86	$22.94
2021	$8.55	$6.60	$6.27	$17.05	$16.19	$19.44	$16.81	$23.19
2022	$8.72	$6.73	$6.39	$17.39	$16.51	$18.82	$15.73	$23.45
2023	$8.89	$6.86	$6.52	$17.73	$16.85	$18.18	$14.62	$23.71
2024	$9.07	$7.00	$6.65	$18.09	$17.18	$17.52	$13.47	$23.97
2025	$9.25	$7.14	$6.78	$18.45	$17.53	$16.84	$12.30	$24.24
2026	$9.44	$7.28	$6.92	$18.82	$17.88	$16.63	$11.75	$24.51
2027	$9.63	$7.43	$7.06	$19.20	$18.23	$16.41	$11.18	$24.78
2028	$9.82	$7.58	$7.20	$19.58	$18.60	$16.19	$10.60	$25.06
2029	$10.02	$7.73	$7.34	$19.97	$18.97	$15.95	$10.00	$25.34
2030	$10.22	$7.88	$7.49	$20.37	$19.35	$15.71	$9.38	$25.62
2031	$10.42	$8.04	$7.64	$20.78	$19.74	$15.83	$9.38	$26.06
2032	$10.63	$8.20	$7.79	$21.19	$20.13	$15.94	$9.37	$26.50
2033	$10.84	$8.36	$7.95	$21.62	$20.53	$16.04	$9.36	$26.94
2034	$11.06	$8.53	$8.11	$22.05	$20.94	$16.15	$9.35	$27.40
2035	$11.28	$8.70	$8.27	$22.49	$21.36	$16.26	$9.33	$27.86
2036	$11.50	$8.88	$8.44	$22.94	$21.79	$16.36	$9.31	$28.32
2037	$11.73	$9.05	$8.60	$23.40	$22.23	$16.46	$9.28	$28.80
2038	$11.97	$9.24	$8.78	$23.87	$22.67	$16.56	$9.25	$29.28
2039	$12.21	$9.42	$8.95	$24.34	$23.12	$16.65	$9.21	$29.78
2040	$12.45	$9.61	$9.13	$24.83	$23.59	$16.74	$9.17	$30.27
2041	$12.70	$9.80	$9.31	$25.33	$24.06	$16.83	$9.13	$30.78
2042	$12.96	$10.00	$9.50	$25.83	$24.54	$16.76	$9.00	$30.97
2043	$13.22	$10.20	$9.69	$26.35	$25.03	$16.66	$8.85	$31.12
2044	$13.48	$10.40	$9.88	$26.88	$25.53	$16.55	$8.70	$31.25
2045	$13.75	$10.61	$10.08	$27.42	$26.04	$16.42	$8.53	$31.35
2046	$14.02	$10.82	$10.28	$27.96	$26.56	$16.26	$8.35	$31.41
2047	$14.30	$11.04	$10.49	$28.52	$27.09	$16.08	$8.16	$31.44
2048	$14.59	$11.26	$10.70	$29.09	$27.64	$15.88	$7.95	$31.42
2049	$14.88	$11.48	$10.91	$29.68	$28.19	$15.65	$7.73	$31.35
2050	$15.18	$11.71	$11.13	$30.27	$28.75	$15.39	$7.49	$31.23
2051	$15.48	$11.95	$11.35	$30.88	$29.33	$15.70	$7.64	$31.85
2052	$15.79	$12.19	$11.58	$31.49	$29.91	$16.01	$7.79	$32.49
2053	$16.11	$12.43	$11.81	$32.12	$30.51	$16.33	$7.95	$33.14
2054	$16.43	$12.68	$12.05	$32.76	$31.12	$16.66	$8.10	$33.80
2055	$16.76	$12.93	$12.29	$33.42	$31.75	$16.99	$8.27	$34.48
2056	$17.10	$13.19	$12.54	$34.09	$32.38	$17.33	$8.43	$35.17
2057	$17.44	$13.45	$12.79	$34.77	$33.03	$17.68	$8.60	$35.87

Table IV-18: Base Renewable Levelized Costs by Year

Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$28.29	$46.12	$61.16	$92.16
2021	$32.32	$48.12	$64.63	$94.44
2022	$36.53	$53.73	$74.07	$105.71
2023	$40.91	$53.81	$73.54	$102.31
2024	$36.03	$53.87	$72.96	$98.77
2025	$50.24	$53.93	$72.35	$95.07
2026	$50.28	$53.97	$71.70	$91.23
2027	$50.32	$53.99	$71.00	$87.23
2028	$50.36	$54.01	$70.26	$83.07
2029	$50.41	$54.00	$69.47	$78.75
2030	$50.46	$53.98	$68.64	$74.26
2031	$51.13	$54.60	$69.31	$74.25
2032	$51.81	$55.21	$69.97	$74.23
2033	$52.50	$55.83	$70.64	$74.17
2034	$53.19	$56.45	$71.31	$74.08
2035	$53.89	$57.07	$71.98	$73.96
2036	$54.60	$57.70	$72.65	$73.81
2037	$55.31	$58.32	$73.32	$73.62
2038	$56.03	$58.96	$73.98	$73.40
2039	$56.76	$59.59	$74.65	$73.15
2040	$57.49	$60.23	$75.31	$72.86
2041	$58.23	$60.94	$75.87	$73.52
2042	$58.98	$61.66	$76.42	$74.18
2043	$59.73	$62.38	$76.97	$74.84
2044	$60.49	$63.10	$77.51	$75.49
2045	$61.26	$63.83	$78.04	$76.15
2046	$62.03	$64.57	$78.56	$77.43
2047	$62.81	$65.31	$79.08	$78.73
2048	$63.60	$66.05	$79.58	$80.05
2049	$64.39	$66.80	$80.08	$81.40
2050	$65.19	$67.55	$80.56	$82.76
2051	$66.49	$68.90	$82.17	$84.42
2052	$67.82	$70.28	$83.81	$86.11
2053	$69.17	$71.69	$85.49	$87.83
2054	$70.56	$73.12	$87.20	$89.59
2055	$71.97	$74.58	$88.94	$91.38
2056	$73.41	$76.08	$90.72	$93.20
2057	$74.88	$77.60	$92.54	$95.07

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-19: Low Renewable Levelized Costs by Year

Low Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.70	$40.39	$46.57	$80.57
2021	$28.96	$41.44	$44.77	$80.58
2022	$32.43	$45.30	$50.58	$87.80
2023	$36.12	$44.66	$49.46	$82.47
2024	$30.57	$43.99	$48.30	$76.99
2025	$44.15	$43.29	$47.11	$71.34
2026	$43.59	$42.57	$45.87	$65.52
2027	$43.05	$41.82	$44.59	$59.54
2028	$42.55	$41.04	$43.26	$53.38
2029	$42.07	$40.23	$41.89	$47.05
2030	$41.62	$39.40	$40.48	$40.54
2031	$42.10	$39.43	$40.22	$40.29
2032	$42.57	$39.45	$39.94	$40.02
2033	$43.05	$39.46	$39.63	$39.73
2034	$43.53	$39.45	$39.30	$39.41
2035	$44.01	$39.43	$38.95	$39.06
2036	$44.50	$39.59	$38.57	$38.69
2037	$44.98	$39.74	$38.16	$38.29
2038	$45.47	$39.88	$37.72	$37.86
2039	$45.96	$40.01	$37.25	$37.41
2040	$46.45	$40.14	$36.75	$36.92
2041	$46.94	$40.51	$37.10	$37.03
2042	$47.43	$40.89	$37.46	$37.13
2043	$47.92	$41.26	$37.81	$37.22
2044	$48.41	$41.63	$38.17	$37.31
2045	$48.90	$42.01	$37.15	$37.38
2046	$49.40	$42.47	$37.76	$37.91
2047	$49.89	$42.93	$38.38	$38.45
2048	$50.38	$43.40	$39.01	$39.00
2049	$50.88	$43.87	$39.65	$39.55
2050	$51.37	$44.34	$40.30	$40.11
2051	$52.40	$45.23	$41.10	$40.92
2052	$53.44	$46.13	$41.93	$41.74
2053	$54.51	$47.06	$42.76	$42.57
2054	$55.60	$48.00	$43.62	$43.42
2055	$56.71	$48.96	$44.49	$44.29
2056	$57.85	$49.94	$45.38	$45.18
2057	$59.01	$50.94	$46.29	$46.08

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table IV-20: High Renewable Levelized Costs by Year

High Levelized Costs by First Full Year of Operation $/MWh (LCOE)				
	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$31.34	$47.98	$68.45	$98.01
2021	$36.42	$50.93	$73.59	$105.38
2022	$41.69	$58.00	$86.61	$124.02
2023	$47.16	$59.16	$88.34	$126.50
2024	$43.38	$60.35	$90.11	$129.03
2025	$58.71	$61.55	$91.91	$131.61
2026	$59.88	$62.79	$93.75	$134.24
2027	$61.08	$64.04	$95.63	$136.93
2028	$62.30	$65.32	$97.54	$139.67
2029	$63.55	$66.63	$99.49	$142.46
2030	$64.82	$67.96	$101.48	$145.31
2031	$66.11	$69.32	$103.51	$148.22
2032	$67.43	$70.71	$105.58	$151.18
2033	$68.78	$72.12	$107.69	$154.20
2034	$70.16	$73.56	$109.85	$157.29
2035	$71.56	$75.03	$112.04	$160.43
2036	$72.99	$76.53	$114.28	$163.64
2037	$74.45	$78.07	$116.57	$166.91
2038	$75.94	$79.63	$118.90	$170.25
2039	$77.46	$81.22	$121.28	$173.66
2040	$79.01	$82.84	$123.70	$177.13
2041	$80.59	$84.50	$126.18	$180.67
2042	$82.20	$86.19	$128.70	$184.29
2043	$83.85	$87.91	$131.28	$187.97
2044	$85.52	$89.67	$133.90	$191.73
2045	$87.23	$91.47	$136.58	$195.57
2046	$88.98	$93.30	$139.31	$199.48
2047	$90.76	$95.16	$142.10	$203.47
2048	$92.57	$97.06	$144.94	$207.54
2049	$94.43	$99.01	$147.84	$211.69
2050	$96.31	$100.99	$150.79	$215.92
2051	$98.24	$103.01	$153.81	$220.24
2052	$100.20	$105.07	$156.89	$224.65
2053	$102.21	$107.17	$160.02	$229.14
2054	$104.25	$109.31	$163.23	$233.72
2055	$106.34	$111.50	$166.49	$238.40
2056	$108.46	$113.73	$169.82	$243.16
2057	$110.63	$116.00	$173.22	$248.03

**Distributed Solar costs represent at the meter values before grossing up for losses.*

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY 2025 ELECTRIC RATE INCREASE APPLICATION	)))	Case No. PU-24-___

AFFIDAVIT OF
Christopher J. Shaw

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

Christopher J. Shaw

Subscribed and sworn to before me, this 20 day of November, 2024.

Notary Public
My Commission Expires:

MARIE V. HORNER
NOTARY PUBLIC - MINNESOTA
My Commission Expires 01/31/2025