414 Nicollet Mall
Minneapolis, MN 55401

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May 1, 2024

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
2025 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-24-___

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of our Annual Fuel Forecast in support of proposed monthly fuel cost charges for the months of January-December 2025.

Please note that portions of our Petition and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Rebecca Eilers at 612-330-5570 or rebecca.d.eilers@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA R. PETERSON
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Department of Commerce and the Office of the Attorney General. Pursuant to Minn. R. 7825.2840, we have provided notice of the availability of the report to all intervenors in the Company's two previous general rate cases.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Lauren Steinhaeuser
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
(612) 370-3578

C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is May 1, 2024. The Company's Petition proposes different monthly fuel cost charges for each month of the year 2025, and we propose to implement the monthly rate changes on the first day of each month for the 12 months beginning January 1, 2025. In order to provide customers 30 days' notice of the January 1, 2025 rate, we request that an Order be issued in this docket by November 30, 2024 as established in Appendix A of the June 12, 2019 Order in Docket No. E999/CI-03-802.

D. Statutes Controlling Schedule for Processing the Filing

The schedule for this filing is controlled by Commission Order rather than a particular statute or rule. The Commission's June 12, 2019 Order in Docket No. E999/CI-03-802 approved a procedural schedule for the initial filing, review, and approval of the Annual Fuel Forecast. Under this schedule, Comments are due on June 30, 2024, Reply Comments are due on July 30, 2024 and Response Comments are due on August 30, 2024. A Commission Order is expected by November 30, 2024. The Company plans to update inputs with more current information in its Reply Comments.

E. Utility Employee Responsible for Filing

Lisa Peterson
Director, Regulatory Pricing & Analysis
Xcel Energy
414 Nicollet Mall, 401-7th Floor
Minneapolis, MN 55401
612-330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Lauren Steinhaeuser
Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401-8th Floor
Minneapolis, MN 55401
lauren.steinhaeuser@xcelenergy.com

Christine Schwartz
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401-7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Schwartz at the Regulatory Records email address above.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2025 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES	DOCKET NO. E002/AA-24-___ **PETITION**

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission (Commission) this Petition requesting approval of the 2025 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2025. This Petition is submitted in compliance with the various Orders issued in Docket No. E999/CI-03-802 which implemented Fuel Clause Reform[1] and with the Commission's November 14, 2019 Order in our 2020 Fuel Forecast proceeding in Docket No. E002/AA-19-293.

We request recovery of approximately $889 million in total Fuel Clause costs for the Minnesota jurisdiction in 2025, or approximately $33.00/MWh. This is a decrease of approximately $134 million compared to Fuel Clause costs authorized by the Commission for 2024, corresponding to a 13.4 percent decrease in the average Fuel Clause Adjustment (FCA) rate forecast for 2025. We discuss the primary drivers for these costs later in this Petition.

This is the Company's sixth forecast filing in connection with the Fuel Clause Reform pilot process.[2] We note that the Commission approved this process as a three-year pilot program. As specified in the December 12, 2018 Order in Docket No. E999/CI-03-802, Minnesota Power, Xcel Energy, and Otter Tail Power submitted lessons

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[1] Orders dated December 17, 2017, December 12, 2018, and June 12, 2019, as well as March 12, 2024.
[2] The most recent forecast, the 2024 Fuel Forecast, was approved by the Commission's November 9, 2023 Order in Docket No. E002/AA-23-153.

learned reports on their experience implementing the pilot on August 15, 2023. The Commission's March 12, 2024 Order accepted each utility's report, approved several minor proposed changes, and allowed the Reform process to continue beyond the initial pilot period. We address compliance with the March 12 Order later in this Petition.

As discussed below, this Petition requests approval to implement specific fuel clause rates by month and customer class throughout 2025. These rates are based on forecasts developed by the Company using the PLEXOS software, which models the Company's system load and generating unit characteristics, along with fuel commodity prices and electric market prices. The forecast is summarized in Part A, Attachments 1 through 4, and the detailed output of the model is provided as Part F, Workpaper 2. We then take the monthly forecasts developed by this modeling and use the results to create the monthly Fuel Clause rates by customer class for which we seek approval. Part A, Attachment 1 presents the rate calculations by month and by class as we propose to implement them.

The data and calculations presented in connection with this Petition are necessarily complex in order to provide accurate pricing. We are available to meet with the Department to walk through our data and calculations in detail, and we are prepared to meet with other stakeholders to answer questions other parties may have about our process and the information in this filing.

As set out in the compliance matrix included with this Petition as Part C, Attachment 1, this Petition and its attachments include all required information from the December 17, 2017, and December 12, 2018, June 12, 2019, and March 12, 2024 Orders in Docket No. E999/CI-03-802, as well as the November 14, 2019 Order in Docket No. E002/AA-19-293. The remainder of this Petition discusses our process for forecasting fuel costs and Fuel Clause rates in 2025. Specifically, we discuss the following:

- The background leading to the Fuel Clause reform process, our proposed fuel cost charges for 2025, and proposed tariff revision reflecting the monthly fuel cost charges;
- The inputs and drivers in the Company's forecasts underlying our proposed fuel cost charges;
- The calculation of the specific monthly fuel cost charges based on the Company's forecast; and
- The efforts the Company is undertaking to manage price volatility and risk in our fuel and purchased power costs.

A Table of Contents outlining the attachments and workpapers we are providing in support of our request is included as an addendum to this Petition.

I. DESCRIPTION AND PURPOSE OF FILING

A. Background

On December 19, 2017, the Commission issued its ORDER APPROVING NEW ANNUAL FUEL CLAUSE ADJUSTMENT REQUIREMENTS AND SETTING FILING REQUIREMENTS in Docket No. E999/CI-03-802 (December 19 Order) which requires a utility's fuel rates to be set in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact. The Order specifies that these filings should include complete documentation supporting the proposed fuel rates, including information on Power Purchase Agreements (PPAs), estimates of costs for each type of fuel, and the proportion of each type of fuel, along with a complete description of any model used to develop the proposed $/MWh fuel rates, including but not limited to the identification and justification of the inputs and formulas used for all fuel types, and fully documented sales forecasts.

The Commission's December 12, 2018 Order in the same docket (December 12 Order) established January 1, 2020 as the implementation date for Fuel Clause Reform and also ordered that the forecast year be a calendar year. Each utility is required to file its Annual Fuel Forecast Petition in a separate docket.

In a June 12, 2019 Order, the Commission approved the disposition of reporting items from the Annual Automatic Adjustment of Charges reports (AAA) under the fuel clause mechanism in place at the time and set a procedural schedule for the initial filing, review and approval of the Annual Fuel Forecast process, which was agreed upon by the parties to the docket. Under this agreed upon schedule, Comments are due on July 1, 2024, Reply Comments are due on July 31, 2024, and Response Comments are due on August 30, 2024. A Commission Order is expected by November 30, 2024 to allow utilities to provide customers notice of the new rates 30 days before the first rate is implemented.

B. Summary of Proposed Rates and Customer Notification

Tables 1 and 2 below show the specific rates we request be implemented by month and by customer class as determined by our fuel forecast for 2025.

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Table 1
Proposed 2025 Monthly Fuel Clause Rates by Customer Class ($/kWh)

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD		On-Peak	Off-Peak
January	$0.03244	$0.03241	$0.03193	$0.04055	$0.02548	$0.02439
February	$0.03454	$0.03451	$0.03399	$0.04319	$0.02712	$0.02596
March	$0.03584	$0.03580	$0.03527	$0.04482	$0.02813	$0.02692
April	$0.03879	$0.03876	$0.03817	$0.04851	$0.03045	$0.02915
May	$0.03667	$0.03664	$0.03609	$0.04585	$0.02879	$0.02756
June	$0.03682	$0.03679	$0.03624	$0.04606	$0.02890	$0.02766
July	$0.03519	$0.03516	$0.03463	$0.04403	$0.02761	$0.02643
August	$0.03388	$0.03385	$0.03334	$0.04238	$0.02658	$0.02544
September	$0.03212	$0.03209	$0.03160	$0.04017	$0.02521	$0.02413
October	$0.02970	$0.02967	$0.02923	$0.03714	$0.02331	$0.02232
November	$0.02863	$0.02860	$0.02817	$0.03581	$0.02247	$0.02151
December	$0.02899	$0.02896	$0.02853	$0.03625	$0.02275	$0.02178

Table 2
Proposed 2025 Monthly Fuel Clause Rates for
C&I General Time of Use Service Pilot ($/kWh)

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04209	$0.03394	$0.01671
February	$0.04483	$0.03614	$0.01776
March	$0.04652	$0.03750	$0.01841
April	$0.05035	$0.04059	$0.01994
May	$0.04759	$0.03837	$0.01886
June	$0.04781	$0.03853	$0.01891
July	$0.04571	$0.03683	$0.01805
August	$0.04400	$0.03545	$0.01739
September	$0.04170	$0.03361	$0.01649
October	$0.03855	$0.03108	$0.01527
November	$0.03717	$0.02996	$0.01471
December	$0.03763	$0.03033	$0.01489

We will update the Company web site with the full year of monthly fuel cost charges by December 1, 2024, or upon approval by the Commission if approval is not received prior to December 1. The rates will be presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders. We do not propose any additional customer notice.

C. Revised Tariff Sheet

We provide as Part A, Attachment 5 redline and clean revisions to the Fuel Clause Rider tariff, Sheet No. 5-91.1, reflecting the monthly fuel cost charges we propose to implement. We will update the tariff sheet to reflect the actual monthly fuel cost charges to be implemented based on the Commission's decisions in this proceeding and will provide an updated final tariff sheet in a compliance filing within 10 days after the Order is received.

II. 2025 FORECAST FUEL AND PURCHASED ENERGY COSTS

The Company uses the PLEXOS software to model the NSP power supply system and forecast costs for fuel and purchased energy. As discussed below, the resultant forecast forms the basis of the rates projected for 2025 shown in Tables 1 and 2 above. PLEXOS has been used by the Company since 2015 to forecast fuel and purchased energy costs for all Xcel Energy operating companies.

PLEXOS uses mathematical programming and optimization techniques for power generation modeling and simulation. For forecast purposes, the unit commitment and economic dispatch logic of PLEXOS commits and dispatches NSP System generation resources, contractual assets, and electric markets to balance system energy demand and meet reserve requirements, while enforcing all generating resource and operation constraints at the least system cost. The PLEXOS simulation inputs include variables such as the NSP System load forecast, generating unit characteristics and operating parameters for owned resources as well as generating resources under PPAs, fuel commodity prices and electric market prices. The PLEXOS simulation is an hourly simulation such that several key inputs, such as NSP System load and wind patterns, are input with hourly profiles. Key input assumptions used to develop the PLEXOS forecast are discussed below, and key inputs are shown in Part F, Workpaper 1. Additionally, we discuss the drivers of the changes in costs for the 2025 test year and how we used the forecast to determine the rates shown above in Tables 1 and 2. More detail about the PLEXOS software modeling is described in Part B, Attachment 1.

A. 2025 Forecast Key Inputs

1. NSP System Load

The objective of the PLEXOS simulation is to commit and dispatch resources to meet the hourly load requirement at the lowest cost. The PLEXOS simulation determines the hourly load requirement based on the most recent forecast of monthly energy and monthly peak demands at the source developed by the Company's Sales Energy & Demand Forecasting group. Part B, Attachment 13 describes the forecasting process in detail. A summary of the monthly sales forecast is shown in Part G, Workpaper 1. The monthly load forecast is then converted into an hourly forecast by PLEXOS based on a typical hourly shape for the NSP system load.

2. Company-Owned Hydro Generation

Inputs for NSP-owned hydro generation in the PLEXOS model are based on a 30-year annual historical average of hydro generation results for NSP System plants. PLEXOS then creates an hourly generation forecast, which converts the annual historical average to an hourly generation profile based on historic hourly capacity factors. There is no fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases. See Part G, Workpaper 2.

3. Company-Owned Wind and Solar Generation

NSP-owned wind and solar generation inputs to the PLEXOS model use individual hourly profiles for each NSP-owned project. Profiles of hourly renewable generation for individual Midcontinent Independent System Operator (MISO) Commercial Pricing Nodes (CP Nodes) are developed based on historic weather data and exclude any prior historical curtailments. For new projects that do not yet have an annual generation profile, the profiles are based on plant design and localized weather data. Company-owned projects are modeled as curtailable projects since they can be curtailed by MISO. Curtailment of owned projects is forecast by the PLEXOS simulation. A white paper describing the renewable profile forecast process in detail is provided with this filing as Part B, Attachment 10. There is no fuel price input for wind or solar generation in the model because the generation does not require any fuel purchases.

4. Company-Owned Coal Generation

Each NSP-owned coal unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical Generation Availability Data System (GADS) data and expected conditions of the units going forward, including managed decline as plants near retirement. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 7.

Estimated replacement power costs for planned and forced outages are summarized in Part B, Attachment 7.

Coal prices are forecast based on coal purchases under contract and rail contracts in effect at the time of filing. Any coal requirements that are not under contract are forecast based on market prices. Supporting coal and rail pricing is provided with the filing as Part F, Workpaper 3. More detail on contracts, fuel procurement, and fuel supply is available in Part D, Attachments 1, 3, 4, 6 and 8. See also Part B, Attachments 2 and 3 for detailed information on fossil fuel costs and coal burn expenses.

Seasonal operations are assumed in this initial filing based on the November 8, 2023 Commission Order in Docket No. E999/CI-19-704 that approved seasonal operations at the Allen S. King plant. The remaining units at the Sherburne County station, Unit 1 and Unit 3, are assumed available to operate year-round in 2025. In addition, the 2025 filing assumes that the EPA "good neighbor" rule will go in effect in 2025. The rule limits NOx emissions for NSP plants during the ozone season which runs from May 1, 2025 through September 30, 2025. The proposal, if enacted for 2025, may require NSP to either purchase NOx allowances to allow generation and emissions beyond proposed limits or to limit operation at NSP coal plants to remain within emission limits in the proposal. We plan to monitor the status of the rule and update our modeling assumptions with the best available information in our July Reply Comments.

5. Company-Owned Wood/RDF Generation

Each NSP-owned wood/refuse derived fuel (RDF) unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each plant and determined based on historical performance of the plants. Wood and RDF prices are forecast based on existing contracts as shown in Part D, Attachment 5. More detail on fuel procurement and costs is available in Part D, Attachments 1 and 6.

6. Company-Owned Natural Gas Generation

Each NSP-owned natural gas unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants.

Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical GADS data and expected conditions of the units going forward. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three years of history. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 7. Estimated costs for planned and forced outages are summarized in Part B, Attachment 7. Natural gas fuel prices are based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time of filing. Monthly Ventura prices assumed in the filing as well as transport rates and supporting detail on the gas transport contracts for each plant are provided with the filing as Part F, Workpaper 4.

7. Company-Owned Nuclear Generation

Each NSP-owned nuclear unit is modeled in the PLEXOS simulation. Modeling parameters include monthly operating capacity based on the capability of each individual unit. Planned maintenance is input to the model based on the current overhaul schedule, which is included with the filing as Part B, Attachment 5. Forced outage rates are input for each unit and determined based on historical GADS data and expected conditions of the units going forward. Supporting calculations for forced outage rates are summarized in Part B, Attachment 6 and shown in detail in Part G, Workpaper 7. Estimated costs for planned and forced outages are summarized in Part B, Attachment 7. Nuclear fuel price is based on the Company's existing nuclear fuel contracts. Supporting nuclear fuel pricing is provided with the filing as Part B, Attachment 4 and Part D, Attachment 2. More detail on fuel supply is available in Part D, Attachment 8.

8. Purchased Natural Gas Generation

Each natural gas PPA is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are determined based on capabilities of the individual plants or according to terms specified in the PPA. Planned maintenance is input to the model based on the overhaul schedule provided by the PPA counterparty. Forced outage rates are input for each unit and based on the MISO calculation of each unit's eFORd based on three years of history. Natural gas fuel prices are forecast based on NYMEX futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on transport and delivery contracts in place at the time of filing. Monthly Ventura prices assumed in the filing as well as transport rates and supporting detail on the gas transport contracts for each plant are provided with the filing as Part F, Workpaper 4.

9. Purchased Solar Generation

Each solar PPA is modeled in the PLEXOS simulation with hourly profiles for each project. These profiles are based on historical results from projects with operational data. A white paper describing the solar profile forecast process in detail is provided with this filing as Part B, Attachment 10. The price for each solar PPA is based on the terms of each contract.

The Solar*Rewards Community program is modeled in the PLEXOS simulation and includes expectations of future growth based on current rules for gardens seeking to participate in the program.[3] Capacity assumptions are modeled in PLEXOS to determine MWh and average dollars per kWh. The program is modeled as one entity within PLEXOS with an assumed price for the program based on a weighted rate of different vintages of Value of Solar (VOS). Projected prices for future projects are calculated based on VOS vintage and anticipated completion date. The market cost of energy from the solar gardens generation is determined based on the assumed hourly Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers. Supporting documentation for solar gardens assumptions is included with this filing as Part B, Attachment 12 and Part G, Workpaper 5.

10. Purchased Wind Generation

Purchased wind modeled in the PLEXOS simulation uses hourly profiles for each individual project. Profiles of hourly renewable generation for individual MISO CP Nodes are developed based on historic weather data and exclude any prior historical curtailments. For new projects that do not yet have an annual generation profile, the profiles are based on turbine technology, plant design, and localized weather data. A white paper describing the wind profile forecast process in detail is provided with this filing as Part B, Attachment 10. Projects that MISO is allowed to curtail are modeled as curtailable projects. Projects for which curtailment is not allowed are modeled as non-curtailable projects. The price for each wind PPA is based on the terms of each contract. PPA pricing as modeled in the forecast is contained in Part B, Attachment 11. Curtailment cost supporting calculations have been included with the filing in Part G, Workpaper 6.

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[3] Recovery was approved by Commission Order on September 17, 2014 in Docket No. E002/M-13-867.

11. Purchased Generation - Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs and the PPA with Manitoba Hydro) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the Manitoba Hydro PPA). Price is determined based on contract terms or based on historical prices with assumed escalation. Where applicable, supporting calculations have been included with the filing in Part G, Workpaper 2.

12. Market Purchases and Sales

When solving to meet NSP System load, the PLEXOS simulation can purchase energy from a simulated MISO market if that source of supply results in lower cost than utilization of one of the NSP system dispatchable resources. The simulation can make this decision hourly within the constraints of the modeled system. In addition, the PLEXOS model forecasts intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through the hourly dispatch simulation based on projected hourly LMP prices for the NSP system. The forecasted sales revenue generated from the asset-based sales results in a reduction to system fuel costs, and is shown in Part A, Attachment 1. Forecast asset-based margins for 2025 are **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** and are reflected in the Net System Costs shown at line 35 of Part A, Attachment 1, page 1 of 3. Asset-based margins are the difference between asset-based Sales Revenues shown at line 29 less the underlying generation fuel costs incurred to make the asset-based sales which are part of the total fuel costs shown at line 27. A white paper that describes how the hourly prices are developed is included with the filing as Part B, Attachment 8.

13. Other FCA Costs

There are other costs that flow through the fuel clause adjustment (FCA) that are not part of the PLEXOS simulation. These cost categories generally do not impact the PLEXOS commit and dispatch algorithm and therefore can be included outside the simulation. This section lists these costs with a brief description of what they represent.

- Biomass PPA termination costs are included in the filing according to the terms of the termination agreement. Supporting documentation for the costs is included in Part G, Workpaper 4.

  - Benson Power LLC – Early termination of agreement covering the purchase of generation from poultry litter and wood fueled biomass facility.[4]
- Certain MISO market charges and revenues are not modeled in PLEXOS. This includes costs/revenues associated with transmission congestion, financial transmission rights (FTRs), incremental transmission losses, revenue sufficiency guarantee (RSG), revenue neutrality uplift (RNU) and ancillary services. The cost included in the filing is based on historical actual costs and revenues observed for these MISO charge types. A summary of MISO charges included in the 2025 forecast is provided as Part B, Attachment 9, and a spreadsheet detailing the historical data and the calculation of the forecast is included as Part F, Workpaper 5. The net MISO Day 2 and Day 3 costs and revenues for the 2025 forecast are **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS] as shown on Part B, Attachment 9.
- Gas demand and storage costs are costs associated with reserving gas delivery capacity and gas storage. The costs are based on contract terms for the capacity and storage contracts. Supporting detail for the contract terms and resultant costs are included in the filing in Part F, Workpaper 4.
- Rail car lease and maintenance costs include estimated lease, maintenance and tax costs associated with coal delivery to the King plant. The costs are based on historical amounts per "ton mile" (round trip from King to the source) multiplied by the forecast coal offtake (in tons). See Part F, Workpaper 3.

14. FCA Exclusions

PPAs that serve the Renewable*Connect program are included in the PLEXOS model.[5] The Renewable*Connect program uses a pool of resources that includes projects that have been serving Windsource, in addition to several new projects. Because costs for these programs are covered by specific fees paid by subscribers to the programs, an adjustment is made to remove the PPA costs related to those programs from the PLEXOS model. Relatedly, sales to these program participants are removed from Minnesota retail sales used in determining the FCA rate for Minnesota

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[4] Recovery was approved by Commission Order on January 23, 2018 in Docket No. E002/M-17-530.
[5] Recovery of the Renewable*Connect Pilot Program was approved by Commission Order on February 27, 2017 in Docket No. E002/M-15-985. Recovery of the Renewable*Connect expansion was approved by Commission Order on August 12, 2019 in Docket No. E002/M-19-33 and rates for the program were approved by Commission Order on May 18, 2023 in Docket No. E002/M-21-222.

customers. Support for the Renewable*Connect forecast is found in Part G, Workpaper 8.

15. Future Model Updates

As noted in Table 1 of the March 1, 2019 Joint Comments filed in Docket No. E999/CI-03-802 which outlines the Procedural Schedule Dates for Fuel Clause Reform implementation, utilities will update their forecast inputs in July Reply Comments. The Company anticipates updating the following items, but will also update additional inputs if there are substantive changes:

- Natural Gas Prices,
- LMP,
- Fuel Oil,
- Gas transport costs,
- Coal prices (including diesel, rail, spot and contracts),
- MISO costs,
- Company-owned resource inputs,
- other PPA changes and approvals, and
- other inputs, as necessary, that materially impact costs.

B. Test Year Drivers

Total FCA costs for the Minnesota jurisdiction are forecast to decrease by $134 million from FCA costs authorized by the Commission for 2024. Table 3 compares costs for several key categories at the NSP system level and the total impact to the Minnesota jurisdiction. Costs forecast for the initial 2025 filing are shown in column A and are compared to costs authorized for 2024 as shown in column B.

Table 3
Fuel and Purchased Power Cost Comparisons ($000)

	A		B		A - B
	2025		2024		2025
	Filing		Authorized(1)		change
	[PROTECTED DATA BEGINS				
PPA Terminations					
Solar Gardens - Total					
Congestion/FTR					
Coal					
Gas					
Other					
Total NSP System Costs					
Asset-Based Sales Revenues					
Solar Gardens - Above Market					
Renewable Connect					
Net NSP System Costs					
					PROTECTED DATA ENDS]
MN Jurisdiction Costs	$697,329		$764,429		($67,100)
Solar Gardens - Above Market	$182,742		$249,377		($66,635)
Biomass Buyout Costs	$8,490		$8,942		($451)
Total MN Costs	$888,562		$1,022,748		($134,186)
Total MN sales (MWh)	26,922		26,842		80
MN FCA Rate (cent/kWh)	3.300		3.810		(0.510)

(1) Forecast included in Reply Comments filed July 31, 2023 in Docket No. E002/AA-23-153. Approved in November 9, 2023 Commission Order.

The forecast cost decrease for 2025 is driven by lower costs for purchases from PPAs scheduled to terminate prior to and during 2025, lower Solar*Rewards Community program costs, lower net congestion/FTR costs, and lower costs for coal generation, and is offset by higher forecast costs for natural gas generation and lower revenues from asset-based sales into the MISO market. Each of these drivers will be discussed in the remainder of this section.

1. PPA Terminations

Two contracts for purchases of energy are scheduled to terminate in 2024: one with the St. Paul Cogeneration facility and the second with the Hennepin Energy Resource Company. In addition, two contracts with Manitoba Hydro are scheduled to terminate in 2025. Taken together, termination of these four fixed energy contracts reduces costs in 2025 by almost $142 million, as shown in Table 3. Together, these four contracts provided a sizable amount of energy to the NSP system, which is partially replaced by greater natural gas generation, in addition to lower surplus energy available to sell into MISO. At current market prices, offsetting costs for natural gas generation and offsetting revenues for surplus generation sales are lower than the average price for the fixed energy provided by these contracts resulting in a net decrease in costs for 2025, as shown in Table 3.

*2. Solar*Rewards Community Program Costs*

The 2025 test year includes projected decreased costs for the Solar*Rewards Community program. Costs for the program are forecast to decline by $65 million at the NSP system level with $67 million lower costs direct assigned to the Minnesota jurisdiction in above market costs, as shown in Table 3. Lower costs are anticipated due both to lower volume of generation forecast for the program in addition to a lower overall average rate for energy purchases from the program.

The volume of energy purchased from the program is forecast to decrease by 7.8 percent from levels authorized for 2024 based on actual installations through 2023, which came in below projections based on the number of applications. The 2025 forecast includes expectations of future growth based on current rules for gardens seeking to participate, which allow broader participation in the program.

The average rate for purchases of energy from the program is also forecast to decline by 12.9 percent ($39 million) as compared to the average rate authorized for 2024. The decrease is driven by the Commission's February 15, 2024 verbal decision in Docket No. E002/M-13-867, which lowers the bill credits for gardens currently paid at the Annual Retail Rate (ARR) to the 2017 VOS vintage rates beginning on April 1, 2025. Therefore this reduction represents a partial year impact.

The above market costs correspondingly decrease due to lower forecast volume of purchases in addition to less spread between the market rate, which is based on forecast LMP, and the anticipated lower average garden rate due to the ARR to VOS conversion. The Solar*Rewards Community program results in an annual FCA rate for Minnesota customers that is $6.79/MWh, or 21 percent, higher than the rate would be without this program.

Pursuant to Minn. Statute 216B.1641 subd.11, utilities must exclude the net cost of community solar garden generation from the fuel clause adjustment for customers who are eligible for this exemption. Order Point 5C of the Commission's December 28, 2023 Order Implementing New Legislation Governing Community Solar Gardens in Docket Nos. E002/CI-23-335 and E002/M-13-867 approved the Company's proposal to calculate this credit by dividing forecasted CSG above market costs by the forecasted net FCA kWh. Based on the proposed fuel forecast, the Company has calculated the net cost of generation for CSGs as 0.679 cent per kWh for 2025. The Company requests approval of this rate for purposes of excluding the net cost of CSG generation costs for customers eligible for exemption.

We expect to have systems in place on January 1, 2025 to apply this exclusion. The Company expects to file the tariff language for this exclusion in compliance with the pending Order authorizing this exemption tariff.[6] The Company anticipates that in the coming months we will file a motion in two dockets (this 2025 fuel clause docket and the above-mentioned CSG docket). In that motion, we will seek authorization:

- to put the Commission approved net cost of generation rate in our exemption tariff language;
- of an effective date of January 1, 2025 for the net cost of generation exception rate; and
- of a process for updates to the net cost of generation exemption rate in future fuel clause dockets.

3. Net Congestion/FTR Costs

Congestion costs net of FTR revenues are assumed to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2025 as compared to authorized costs for 2024. The forecast of congestion costs is based on actual data which has **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Congestion costs, which have been high since 2021, are primarily driven by large additions of renewable energy in the MISO footprint without sufficient addition of transmission to deliver energy from generators to load centers within the MISO footprint. The Company monitors congestion costs regularly, and will update our forecast in our July Reply Comments based on the most recent actual costs. Part B, Attachment 9 shows MISO costs by category and Part F, Workpaper 5 provides further details on the calculation of forecast costs for 2025.

4. Coal Generation Costs

Coal generation costs are forecast to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2025 relative to authorized costs for 2024 as shown in Table 3. The decrease is driven by lower forecast volume of coal generation, due to assumed seasonal operations at Allen S. King plant and the EPA "good neighbor" rule which is assumed to be in effect by the 2025 ozone season. In

[6] Docket No. E002/CI-23-335

addition, unit costs for coal and rail delivery are forecast to decline by 2.6 percent for 2025 further contributing to the decrease in costs for coal generation.

5. Natural Gas Generation Costs

Costs for natural gas-fired generation are forecast to increase by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for 2025 as compared to costs authorized for 2024. Most of the increase in costs is driven by higher forecast volume of natural gas generation, which is forecast to increase by 7.8 percent over volumes authorized for 2024. Natural gas generation is forecast to increase due to lower forecast coal and nuclear generation, in addition to less fixed energy from PPAs scheduled to terminate, as discussed in section *i*. Natural gas prices as reflected by NYMEX futures for 2025 are, on average, approximately equal to natural gas prices authorized for 2024. Forward LMP prices in MISO forecast continued high gas generation for 2025 for system needs as well as for asset-based sales into the MISO market due to the efficient combined-cycle generation in the NSP portfolio.

6. Asset-Based Sales Revenues

Asset-Based sales revenues are projected to decrease by **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** compared to revenues authorized for 2024 as shown in Table 3. The decline in revenue is driven by the forecast reduction in coal, nuclear, and fixed energy from PPA terminations previously discussed. Lower generation from these resources results in less surplus generation available to sell into MISO as more energy is required for NSP system needs. Forward LMP for the 2025 test year are projected to be 7.3 percent higher than prices authorized for 2024, offsetting the impact of less generation slightly. The 2025 average hourly LMP assumed in the forecast is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** that was authorized for 2024. Despite lower forecast revenue, off-system sales are still providing a significant offset to costs forecast for 2025.

C. Customer Class Rate Calculation

The Company has allocated fuel clause costs to Minnesota using the FERC-approved Interchange Agreement tariff, which governs cost allocation between our NSP-Minnesota and NSP-Wisconsin operating companies. The Interchange Agreement is a formula rate which assigns charges between these two operating companies for costs related to the integrated electric system, including the fuel and purchased power costs that are recovered through the fuel clause. We have assigned costs to the NSP-

Minnesota operating company through the application of the Interchange Agreement energy allocator. We then allocated the NSP-Minnesota fuel costs to the Minnesota jurisdiction using the sales allocator. This allows customers and the Company to remain whole on prudently incurred fuel cost recovery, as Minnesota customers would pay for their allocation of the fuel costs assigned to the NSPM operating company.

To determine the proposed monthly fuel cost by customer class, we take the 2025 NSP system forecasted costs, and add in the forecasted recovery of the Minnesota jurisdiction biomass PPA termination costs and the above market Community Solar Gardens costs which are direct-assigned to the Minnesota jurisdiction. The sum of the Minnesota jurisdiction costs divided by the forecasted Minnesota jurisdiction MWh sales subject to the FCA (excluding Renewable*Connect program MWh) yields the Minnesota jurisdiction per unit cost. This per unit cost multiplied by the Fuel Adjustment Factor (FAF), including the Class Ratio Adjustment, determines the proposed monthly class fuel cost charge (FCC) factors. Finally, a Class Ratio Adjustment is applied in order to match forecasted recovery with forecasted expense. Part A, Attachment 1, page 3 shows the development of the adjustment and class rates, as well as the resulting total fuel revenues which equal total forecasted fuel expense. Part A, Attachment 1, page 2 summarizes the rates by month and by customer class using the Class Ratio Adjustment.

III. MANAGING PRICE RISK VOLATILITY

The Company addresses fuel and purchased power price risk through an integrated analysis of its future costs. The Company manages risk associated with planned outages by scheduling maintenance for its generating facilities during periods when energy demand, and prices, is expected to be relatively low. These periods typically occur in the fall and spring when weather conditions are more moderate. The Company submits outage information to MISO for approval.

In a separate analysis, the Company analyzes its FTR position in the MISO market to ensure that the Company is hedged to the extent possible against congestion cost risk. The Company operates in the MISO wholesale energy and ancillary services market, which uses security constrained regional dispatch with LMP and FTRs to provide a partial hedge against congestion risk. The Company periodically reviews its FTR portfolio to ensure that it is properly hedged, given the limitations of the FTR auction process, against congestion cost risk in the MISO day-ahead market (there is no FTR protection in the real-time market). The Company analyzes key congestion risks between our generation and purchase power nodes and our load nodes to determine the optimal FTR portfolio. The Company can adjust this portfolio annually through

the MISO FTR allocation process and monthly through the FTR auction process. **[PROTECTED DATA BEGINS**
PROTECTED DATA ENDS]

Finally, the Company reviews its exposure to fuel price risk. Historically, this has been a long-term issue for the NSP System due to the predominance of coal and nuclear energy in our generation fleet, but the increase in natural gas-fired generation and purchased power in the resource portfolio helps mitigate this risk.

Xcel Energy's current coal acquisition strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. Implementation of this strategy **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's strategy is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] Xcel Energy's coal acquisition strategy also **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

The Company contracts for natural gas storage with Northern Natural Gas (NNG) and ANR Pipeline to provide operational flexibility and to ensure availability of fuel for power plant operations. Storage gas also provides price stability and certainty throughout the year as previously stored gas can be withdrawn to displace daily spot purchases if and when market prices spike. Gas stored with ANR Pipeline is purchased during the summer and used as a source of supply during the winter months. The Company's storage service with NNG is provided under a service requested by NSP specifically for electric generation customers effective June 1, 2018. Through this service, NSP has more flexibility to inject and withdraw throughout the year to manage daily swings in demand for gas fired generation. Unlike traditional storage services, which must be filled during the summer months for use during the winter, the Electric Generation service on NNG allows withdrawals, and hence protection, against price volatility year-round, including the summer months when electric demand peaks. With the potential variability in generating units being dispatched, a significant portion of system requirements may be covered through use of storage, therefore the Company does not use financial instruments to hedge natural gas purchases for generation.

IV. COMPLIANCE ITEMS

A. MISO Day 2 Reporting

In compliance with the Commission's December 21, 2005 ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION in Docket No. E002/M-04-1970 *et al.*, this section provides information related to MISO Day 2 accounting and activity. Specifically, we provide the following information in compliance with the Order:

5. Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810.

The Company's real-time market strategy currently is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] The Company believes that this strategy meets the intent of the Commission's Order in Docket No. E002/M-04-1970 **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

Other compliance with this Order will be addressed as needed in the March 1 True-Up filing.

B. Rule Variances

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). Please see Part C, Attachment 2 for a list of relevant dockets.

The Commission's December 12, 2018 Order varied Minn. R. 7825.2600, subp. 3 and June 12, 2019 Order varied Minn. R. 7825.2800, .2810, .2820, .2830, and .2840 to accommodate the new fuel cost adjustment method and process.[7]

C. Recurring Information Request Responses

The March 14, 2024 Order in Docket No. E999/CI-03-802 requires utilities in their future initial FCA filings, to incorporate answers to the recurring information requests (IRs), including the most recent three-year average of actual annual data compared to forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages and a comparison of the actual winter energy purchase amounts to the forecast amounts, with an explanation of a variance of five percent or greater. We provide below a summary of each recurring information request to which we have provided a response.

We have attempted to identify all IRs that would be considered recurring. However, if the Department identifies additional IRs it considers to be recurring, we ask that the Department issue an IR in this docket noting that they consider it to be recurring, and we will include responses to those additional recurring IRs in our next Fuel Forecast filing.

1. Petition Attachments (DOC IR No. 13, Docket No. E002/AA-21-295 and DOC IR No. 10, Docket No. E002/AA-22-179)

Question: Provide spreadsheets for all tables in the Petition, with links and formulas intact and include calculations for all outputs and sources/justification for all inputs.

Response: Live spreadsheets have been provided for this Petition and we will continue to provide in future FCA filings.

2. Sales Forecast (DOC IR No. 1, Docket No. E002/AA-23-153)

Question: Provide actual Net System MWh Sales for the last three years of actual annual data and provide Net System GWH at the production level for the same time period.

Response: This information is provided in Part H, Attachment 1.

[7] Docket No. E999/CI-03-802

3. *Actuals – Annual Data Comparison (DOC IR No. 2, Docket No. E002/AA-23-153)*

Question: In the same format as Part A, Attachment 1, page 1 of 3, provide actuals for the past three years, three-year average of actual data compared to the forecast for the FCA components for generation costs, purchase costs, inter-system sales and outages. Explain reason for deviations of 5 percent or more when comparing forecast $/MWh to actuals and three year average $/MWh.

Response: This information is provided in Part H, Attachment 1.

4. *MISO Costs and Revenues, Three Years Actual (DOC IR No. 3, Docket No. E002/AA-23-153)*

Explain in detail where forecasted total MISO Day 2 (energy market) and MISO Day 3 (ancillary services market) costs and revenues are reflected and provide comparable total forecasted net MISO Day 2 and net MISO Day 3 costs and revenues. Also provide actual net MISO Day 2 and MISO Day 3 costs and revenues for the past three calendar years.

MISO Day 2 and Day 3 costs and revenues are shown at lines 23, 24, and 29 of Part A, Attachment 1, page 1 and summarized in Part H, Attachment 2. 2025 Test Year MISO Forecast with Net MISO Day 2 and Day 3 costs and revenues as well as Actual MISO Day 2 and Day 3 costs and revenues are provided in Part H, Attachment 2.

5. *Asset-Based Margins (DOC IR 4, Docket No. E002/AA-23-153)*

Question: Explain in detail where forecasted asset-based margins are and provide forecasted asset-based margins.

Response: Asset-based margins for 2025 are reflected in the Net System Costs shown at line 35 of Part A, Attachment 1, page 1 of 3. Asset-based margins are the difference between asset-based Sales Revenues shown at line 29 less the underlying generation fuel costs incurred to make the asset-based sales which are part of the total fuel costs shown at line 27.

Our estimate of asset-based margins is included at line 35 for 2025 as noted on page 10 of our Petition narrative.

We plan to return 100 percent of asset-based margins to ratepayers as required by the April 24, 2006 settlement agreement in the Company's 2006 test year electric rate case

(Docket No. E002/GR-05-1428) and approved in the Commission's July 6, 2006 Order in that docket (Order Point No. 2). The calculations on Part A, Attachment 1, page 1 of 3 return 100 percent of asset-based margins to customers through inclusion of 100 percent of the asset-based sales revenues at line 29 and 100 percent of the asset-based sales cost at line 27.

Table 4 below provides actual asset-based margins for the past three calendar years.

Table 4
Asset-Based Margins (millions)

2021	$128.3	Actual
2022	$188.3	Actual
2023	$80.7	Actual

6. *Non-Asset Based Margins (DOC IR No. 5, Docket No. E002/AA-23-153)*

Question: Explain if we are required to share any non-asset-based margins with ratepayers. If so, provide the percentage that we are required to share and explain where forecasted non-asset based margins are reflected. Also, provide forecasted non asset-based margins and provide actual non-asset-based margins for the past three calendar years.

Response: Consistent with the Commission's May 14, 2012 Order in our test year 2011 general electric rate case (Docket No. E002/GR-10-971), the Non-Asset Based Margins are no longer credited through the fuel clause adjustment in the Minnesota jurisdiction. Therefore, no Non-Asset Based margins are included in Part A, Attachment 1, page 1 of 3.

7. *Outages (DOC IR No. 6, Docket No. E002/AA-23-153)*

Question: Provide actual planned and unplanned MWh's and costs for the past three calendar years and in outage MWhs and total dollar cost, explain any differences of 5 percent or more in the forecast versus the three-year average actuals and forecast versus last completed year actuals.

Response: This information is provided in Part H, Attachment 3.

8. *Congestion Costs (DOC IR No. 7, Docket No. E002/AA-23-153)*

Question: Provide actual congestion charges in the same format for the past three calendar years and provide forecasted current-year congestion charges that were approved by the Commission.

Response: This information is provided as Part H, Attachment 4.

9. *Wind Curtailment (DOC IR No. 8, Docket No. E002/AA-23-153)*

Question: Provide forecasted and the past three calendar year actual MWh and $ curtailment for all PPAs. Provide actual MWh curtailed for the past three calendar years and forecasted MWh curtailed for Company-owned wind farms.

Response: This information is provided as Part G, Workpaper 6.

10. *Wind, Forecasted Wind Capacity Factors (DOC IR 11, Docket No. E002/AA-23-153)*

Question: For each wind facility included on our system (PPAs and Company-owned wind), provide the assumed capacity factor at the time the project or PPA was approved by the Commission and provide the actual capacity factor for each wind facility for the past three calendar years, and forecasted capacity factors for the current year and the new year's forecast. The Company notes that we do not have a compiled record of capacity factors for these PPAs assumed at the time of Commission approval.

Response: This information is provided as Part H, Attachment 5.

V. REPORTING IN COMPLIANCE WITH MINNESOTA RULES

This filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Policies and Actions
7825.2810 Annual Report of Automatic Adjustment Charges
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

A. 7825.2800 Annual Reports: Policies and Actions

Part D, Attachments 1-10 include information and supporting data in compliance with the following topics listed in Minn. Rule 7825.2800:

- Procurement Policies
- Dispatching Policies and Procedures
- Fuel Supply
- Conservation and Load Management Policy
- Other Actions

This information was also filed in the March 1, 2024 Annual Fuel Forecast True-Up Report, which included compliance items required to be filed in the Company's Annual Automatic Adjustment of Charges Report for the January-December 2023 period (Docket No. E999/AA-22-179). We will update Part D in our March 1, 2025 True-Up filing as necessary to reflect any changes between the 2024 forecast and actuals.

B. 7825.2810 Annual Report: Automatic Adjustment of Charges

Minn. Rule 7825.2810 requires the following information:

- Base Cost of Fuel
- Billing Adjustment Amounts Charged Customers for Each Month
- Total Cost of Fuel Delivered to Customers
- Revenue Collected from Customers for Energy Delivered
- Monthly Fuel Cost Charge

At this time, we are able to provide information about the Base Cost of Fuel below, and we have specified the Monthly Fuel Cost Charges as proposed in this filing. We provided the remainder of these requirements in our March 1, 2024 True-Up Filing.

1. Base Cost of Energy

The Commission's November 5, 2019 Order in Docket No. E999/CI-03-802 approved the Company's proposal to use fuel costs from the Company's latest "Annual Fuel Forecast" in some elements of future electric rate cases, and eliminate the base cost of energy rate from our Fuel Clause Rider tariff. The Company updated its tariff language in accordance with the Commission's Order.

New FAF Ratios were approved by the Commission in the July 17, 2023 Order in Docket No. E002/GR-21-630. These FAF Ratios are shown in Part A, Attachment 1.

2. *Monthly Fuel Cost Charges*

See Tables 1 and 2 and Part A, Attachment 1, page 2 of this Petition for the monthly fuel cost charges we propose to implement in 2025.

C. 7825.2830 Annual Five-Year Projection

The fuel cost forecast summarized per unit, cost and energy for the 2025 test year is provided in Part A, Attachments 1 through 3. The monthly projection of fuel cost by energy source for the 2025 test year is provided as Part B, Attachments 2 through 4.

The fuel cost forecast summarized per unit, cost and energy for the four years beyond the 2025 test year is provided in Part E, Attachments 1 through 3. The monthly projection of fuel cost by energy source for the four years beyond the 2025 test year is provided as Part E, Attachments 4 through 6.

D. 7825.2840 Annual Notice of Reports Availability

Minn. Rule 7825.2840 requires utilities to provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the utility's two previous general rate cases. In compliance with this Rule, the Company is providing notice to all intervenors in our 2015 and 2021 electric rate cases who have requested to remain on the docket service lists.

CONCLUSION

Xcel Energy respectfully requests the Commission approve our 2025 Annual Fuel Forecast, resulting proposed monthly fuel cost charges for the months of January-December 2025, and corresponding proposed tariff revision reflecting the monthly fuel cost charges.

Dated: May 1, 2024

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2025 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-24-___

PETITION

SUMMARY

Please take notice that on May 1, 2024 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of our 2025 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months of January-December 2025 in compliance with the Commission's December 17, 2017, December 12, 2018, June 12, 2019, and March 12, 2024 Orders in Docket No. E999/CI-03-802. This Petition also complies with Minn. Rule 7825.2830.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Valerie Means	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2025 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-24-___

NOTICE OF REPORT AVAILABILITY

On May 1, 2024, Northern States Power Company, doing business as Xcel Energy, filed a Petition with the Minnesota Public Utilities Commission which provided information in compliance with the following MPUC Rules:

7825.2800 Annual Reports; Policies & Actions
7825.2810 Annual Report; Automatic Adjustment Charges
7825.2830 Annual Five-Year Projection
7825.2840 Annual Notice of Reports Availability

The Petition primarily addresses the Company's fuel forecast and resulting monthly fuel rates for the 2025 calendar year, but also complies with additional fuel clause related reporting requirements under various Commission Orders.

The aforementioned report is available for public inspection at the MPUC offices, 121 East 7th Place, Suite 350 St. Paul, MN 55101-2147, on the Minnesota Department of Commerce edockets website (https://www.edockets.state.mn.us/EFiling) and upon written request to the following:

Xcel Energy
Regulatory Administration
414 Nicollet Mall – 401 7th Floor
Minneapolis, MN 55401

TRADE SECRET JUSTIFICATION:

Under Minnesota Stat. § 13.37, trade secret information is defined as including a compilation of government data that 1) was supplied by the affected individual or organization, 2) is subject of efforts by the individual or organization that are reasonable under the circumstances to maintain its secrecy, and 3) derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

The fuel supply, fuel cost, fuel cost forecast and wind curtailment information designated as Trade Secret in this Petition meets this definition for the following reasons:

1. This information meets the first criterion as it is submitted by Xcel Energy, which is an affected organization.

2. The information meets the second criterion in the statute because Xcel Energy makes extensive efforts to maintain the secrecy of this information. The information is not available outside of the Company except to (i) other parties to applicable contracts subject to the confidentiality and non-disclosure provisions contained in such contracts, and (ii) regulatory agencies under the confidentiality provisions of state or federal law.

3. The information meets the third criterion in the statute because the information has economic value to Xcel Energy, its customers, suppliers, and competitors. First, if suppliers knew the terms of Xcel Energy's electric and fuel supply and transportation contracts, they may be able to use this knowledge to fashion bids to Xcel Energy. While their bids may be competitive with existing contracts, they could be at a price higher than the best price the supplier can offer or the current market price. Second, suppliers will be reluctant to offer special favorable terms to Xcel Energy if they know other competitors or customers will gain knowledge of the terms and demand similar terms in the future. Third, competitors of Xcel Energy also purchase these services. These competitors may be able to leverage knowledge of Xcel Energy's costs to gain similar terms or may negotiate slightly better prices from the supplier. Any of these results would harm Xcel Energy and its customers. Because Xcel Energy competes for purchased energy, fuel and transportation services in a competitive marketplace, disclosure would directly harm Xcel Energy by making its delivered supply costs less competitive. The forecast of future fuel costs includes assumptions of future market prices for fuel not yet

procured under contract. This information would give future potential suppliers knowledge of Xcel Energy's forecast of fuel prices that may not be the actual market price when procurement bids are requested. This knowledge may directly affect the prices submitted under bid or renegotiated during contract renewal.

Contract confidentiality clauses in existing fuel supply and other applicable contracts require suppliers' authorization prior to the release of any information pertaining to contract terms and conditions. Suppliers limit the public disclosure of this information to maintain their competitive position in the marketplace. Fuel and transportation services are not purchased in an open, commoditized marketplace. Prices are the result of closed bidding or direct negotiations and are not publicly available.

Xcel Energy requests Trade Secret protection of this information to maintain the Company's competitive position in the marketplace. If our competitors knew our pricing information, they could use it to possibly extract advantageous terms from Xcel Energy or other suppliers, which would result in financial harm to Xcel Energy and its customers.

Part F and G Workpapers Trade Secret in Their Entirety

Part F, Workpapers 1 – 5 and Part G, Workpapers 3, 4, 5, 6, 7, and 8 provided with the Not Public version of this filing contain data classified as trade secret pursuant to Minn. Stat. §13.37, subd. 1(b) and are marked as "Not Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: The workpapers contain Confidential and Proprietary forecast modeling inputs from PLEXOS, including contract terms and forecasted market pricing.
2. **Authors:** The data is output from PLEXOS and prepared under the direction of Dave Horneck.
3. **Importance:** The workpapers contain competitively sensitive data related to modeling inputs and has economic value to Xcel Energy, its customers, suppliers, and competitors. The knowledge of such information could adversely impact future contract negotiations, potentially increasing costs for these services for our customers.
4. **Date the Information was Prepared**: The information was prepared in April 2024.

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Workpaper 4	Gas Pricing
Workpaper 5	MISO Charges

Part G: Fuel Forecast Workpapers and Supporting Data

Workpaper 1	Forecast Energy and Peak Demand Summary
Workpaper 2	Hydro Historical
Workpaper 3	Pricing for Hydro PPAs
Workpaper 4	Benson Recovery
Workpaper 5	NSP Solar Gardens Forecast
Workpaper 6	NSP Wind Curtailment
Workpaper 7	Forced Outage Calculation for Baseload and Intermediate Plants
Workpaper 8	Renewable*Connect Program

Part H: Recurring Information Requests

Attachment 1	Actual Annual Data Comparison
Attachment 2	MISO Costs
Attachment 3	Outages
Attachment 4	Congestion Costs
Attachment 5	Wind Capacity Factors

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company | Docket No. E002/AA-24-___
Electric Utility - State of Minnesota | 2025 Fuel Forecast Petition
Jan 2025 - Dec 2025 | *Protected Data is shaded.* | Part A, Attachment 1 - Page 1 of 3

Line #	*Costs in $1,000's*	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025	2025 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens (CSG)	$10,782	$16,976	$26,783	$25,145	$30,494	$33,913	$33,668	$29,702	$23,347	$17,026	$10,122	$6,500	$264,457
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total NSP System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($6,861)	($10,803)	($20,655)	($18,849)	($22,842)	($23,821)	($20,385)	($18,373)	($16,502)	($11,990)	($7,209)	($4,452)	($182,742)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect Flex (MTM)**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable*Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect Flex (MTM) MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													31,342,179
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect Flex (MTM) MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													26,922,097
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$6,861	$10,803	$20,655	$18,849	$22,842	$23,821	$20,385	$18,373	$16,502	$11,990	$7,209	$4,452	$182,742
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													$888,562
66														
67														
68	**Forecast MN FCA Cost in cents/kWh**													**3.300**
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													33.00

PROTECTED DATA ENDS]

Proposed 2025 Monthly Fuel Clause Charges ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.03244	$0.03241	$0.03193	$0.04055	$0.02548	$0.02439
February	$0.03454	$0.03451	$0.03399	$0.04319	$0.02712	$0.02596
March	$0.03584	$0.03580	$0.03527	$0.04482	$0.02813	$0.02692
April	$0.03879	$0.03876	$0.03817	$0.04851	$0.03045	$0.02915
May	$0.03667	$0.03664	$0.03609	$0.04585	$0.02879	$0.02756
June	$0.03682	$0.03679	$0.03624	$0.04606	$0.02890	$0.02766
July	$0.03519	$0.03516	$0.03463	$0.04403	$0.02761	$0.02643
August	$0.03388	$0.03385	$0.03334	$0.04238	$0.02658	$0.02544
September	$0.03212	$0.03209	$0.03160	$0.04017	$0.02521	$0.02413
October	$0.02970	$0.02967	$0.02923	$0.03714	$0.02331	$0.02232
November	$0.02863	$0.02860	$0.02817	$0.03581	$0.02247	$0.02151
December	$0.02899	$0.02896	$0.02853	$0.03625	$0.02275	$0.02178

Proposed 2025 Monthly Fuel Clause Charges ($/KWh)

	Commercial & Industrial General TOUService Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04209	$0.03394	$0.01671
February	$0.04483	$0.03614	$0.01776
March	$0.04652	$0.03750	$0.01841
April	$0.05035	$0.04059	$0.01994
May	$0.04759	$0.03837	$0.01886
June	$0.04781	$0.03853	$0.01891
July	$0.04571	$0.03683	$0.01805
August	$0.04400	$0.03545	$0.01739
September	$0.04170	$0.03361	$0.01649
October	$0.03855	$0.03108	$0.01527
November	$0.03717	$0.02996	$0.01471
December	$0.03763	$0.03033	$0.01489

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NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company | Docket No. E002/AA-24-___
Electric Utility - State of Minnesota | 2025 Fuel Forecast Petition
Monthly Fuel Clause Charge January 2025 - December 2025 | Part A, Attachment 1 - Page 3a of 3

Protected Data is shaded.

Month Fuel Cost Charges Applied to Customer Billing	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	12 Months
FORECASTED COST OF FUEL													
	[PROTECTED DATA BEGINS												
[1] Forecasted MN Cost in $1,000's													**$888,562**
[2] Forecasted Minn. Retail Sales Subject to FCC *													26,922,097
[3] Forecasted MN Cost in cents/kWh [1]/[2]*100													**3.300¢**
												PROTECTED DATA ENDS]	
Class FAF Ratio													
[4] Residential FAF Ratio	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192	1.0192
[5] C&I Non-Demand FAF Ratio	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183	1.0183
[6] C & I Demand Non-TOD FAF Ratio	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030	1.0030
[7] C & I Demand TOD On-Peak FAF Ratio	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746	1.2746
[8] C & I Demand TOD Off-Peak FAF Ratio	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001	0.8001
[9] Outdoor Lighting FAF Ratio	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659	0.7659
2023 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[10] Residential [3]*[4]													
[11] C & I Non-Demand [3]*[5]													
[12] C & I Demand Non-TOD [3]*[6]													
[13] C & I Demand TOD On-Peak [3]*[7]													
[14] C & I Demand TOD Off-Peak [3]*[8]													
[15] Outdoor Lighting [3]*[9]													
MN Retail MWh Subject to FCA *													
[16] Residential													
[17] C & I Non-Demand													
[18] C & I Demand Non-TOD													
[19] C & I Demand TOD On-Peak													
[20] C & I Demand TOD Off-Peak													
[21] Outdoor Lighting													
[22] Total													26,922,097
2024 Class Fuel Cost Revenues in $1,000's													
[23] Residential [10]*[16]/100													
[24] C & I Non-Demand [11]*[17]/100													
[25] C & I Demand Non-TOD [12]*[18]/100													
[26] C & I Demand TOD On-Peak [13]*[19]/100													
[27] C & I Demand TOD Off-Peak [14]*[20]/100													
[28] Outdoor Lighting [15]*[21]/100													
[29] Total [23]+[24]+[25}+[26]+[27]+[28]													$888,856
[30] **2024 Cost vs Revenue Diff in $1,000's** [1]-[29]													
[31] **2024 Cost vs Revenue Diff in $1,000's** [30]													
[32] **MN Retail MWh Subject to FCA *** [22]													
[33] **Monthly Class Ratio Adjustment** [31]/[32]*100													
													PROTECTED DATA ENDS]
2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[34] **Residential** [10]/100+[33]/100	**$0.03244**	**$0.03454**	**$0.03584**	**$0.03879**	**$0.03667**	**$0.03682**	**$0.03519**	**$0.03388**	**$0.03212**	**$0.02970**	**$0.02863**	**$0.02899**	
[35] **C & I Non-Demand** [11]/100+[33]/100	**$0.03241**	**$0.03451**	**$0.03580**	**$0.03876**	**$0.03664**	**$0.03679**	**$0.03516**	**$0.03385**	**$0.03209**	**$0.02967**	**$0.02860**	**$0.02896**	
[36] **C & I Demand Non-TOD** [12]/100+[33]/100	**$0.03193**	**$0.03399**	**$0.03527**	**$0.03817**	**$0.03609**	**$0.03624**	**$0.03463**	**$0.03334**	**$0.03160**	**$0.02923**	**$0.02817**	**$0.02853**	
[37] **C & I Demand TOD On-Peak** [13]/100+[33]/100	**$0.04055**	**$0.04319**	**$0.04482**	**$0.04851**	**$0.04585**	**$0.04606**	**$0.04403**	**$0.04238**	**$0.04017**	**$0.03714**	**$0.03581**	**$0.03625**	
[38] **C & I Demand TOD Off-Peak** [14]/100+[33]/100	**$0.02548**	**$0.02712**	**$0.02813**	**$0.03045**	**$0.02879**	**$0.02890**	**$0.02761**	**$0.02658**	**$0.02521**	**$0.02331**	**$0.02247**	**$0.02275**	
[39] **Outdoor Lighting** [15]/100+[33]/100	**$0.02439**	**$0.02596**	**$0.02692**	**$0.02915**	**$0.02756**	**$0.02766**	**$0.02643**	**$0.02544**	**$0.02413**	**$0.02232**	**$0.02151**	**$0.02178**	

* Excluded Renewable*Connect MWh

2024 Proposed Costs verses Revenues	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	12 Months
2023 Class Fuel Cost Revenues in $1,000's	**[PROTECTED DATA BEGINS**												
[40] Residential [34]*[16]													
[41] C & I Non-Demand [35]*[17]													
[42] C & I Demand Non-TOD [36]*[18]													
[43] C & I Demand TOD On-Peak [37]*[19]													
[44] C & I Demand TOD Off-Peak [38]*[20]													
[45] Outdoor Lighting [39]*[21]													
[46] Total [40]+[41]+[42}+[43]+[44]+[45]													$888,537
[47] Total Forecasted MN Costs [1]													$888,562
[48] **2023 Cost vs Revenue Diff in $1,000's** [47]-[46]													$25
													PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2025 - December 2025
C&I General Time of Use Service Pilot Program

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	Monthly Fuel Cost Charges Applied to Customer Billing	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	12 Months
	Forecasted Cost of Fuel													
		[PROTECTED DATA BEGINS												
[1]	Forecasted MN Cost in $1,000's													**$888,562**
[2]	Forecasted Minn. Retail Sales Subject to FCC *													26,922,097
[3]	**Forecasted MN Cost in cents/kWh** [1]/[2]*100													**3.300¢**
													PROTECTED DATA ENDS]	
	Class FAF Ratio													
[4]	C&I Demand General TOU Peak Ratio	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230	1.3230
[5]	C&I Demand General TOU Base Ratio	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665	1.0665
[6]	C&I Demand General TOU Off-Peak Ratio	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239	0.5239
	2024 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[7]	**C&I Demand General TOU Peak** [3]*[4]													
[8]	**C&I Demand General TOU Base** [3]*[5]													
[9]	**C&I Demand General TOU Off-Peak** [3]*[6]													
[10]	**Monthly Class Ratio Adjustment**													
														PROTECTED DATA ENDS]
	2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[11]	**C&I Demand Generl TOU Peak** [7]+[10]	**$0.04209**	**$0.04483**	**$0.04652**	**$0.05035**	**$0.04759**	**$0.04781**	**$0.04571**	**$0.04400**	**$0.04170**	**$0.03855**	**$0.03717**	**$0.03763**	
[12]	**C&I Demand General TOU Base** [8]+[12]	**$0.03394**	**$0.03614**	**$0.03750**	**$0.04059**	**$0.03837**	**$0.03853**	**$0.03683**	**$0.03545**	**$0.03361**	**$0.03108**	**$0.02996**	**$0.03033**	
[13]	**C&I Demand General TOU Off-Peak** [9]+[13]	**$0.01671**	**$0.01776**	**$0.01841**	**$0.01994**	**$0.01886**	**$0.01891**	**$0.01805**	**$0.01739**	**$0.01649**	**$0.01527**	**$0.01471**	**$0.01489**	

* Excluded Renewable*Connect MWh

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Northern States Power Company Docket No. E002/AA-24-___
Electric Utility - State of Minnesota 2025 Fuel Forecast Petition
Jan 2025 - Dec 2025 *Protected Data is shaded.* Part A - Attachment 2 - Page 1 of 1

Line #														
1	*Energy in GWhs*	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**	**2025 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	75.7	119.2	188.1	209.4	254.0	282.5	280.4	247.4	194.5	141.8	84.3	54.1	2,131.4
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable* Connect Flex (MTM) GWh**													
31	**Less Renewable* Connect LT GWh**													
32														
33	**Net System GWh**													42,465.0

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
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Northern States Power Company Docket No. E002/AA-24-___
Electric Utility - State of Minnesota 2025 Fuel Forecast Petition
Jan 2025 - Dec 2025 *Protected Data is shaded.* Part A - Attachment 3 - Page 1 of 1

Line #														
1	*$/MWh*	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**	**2025 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$142.42	$142.42	$142.42	$120.06	$120.06	$120.06	$120.06	$120.06	$120.06	$120.06	$120.06	$120.06	$124.08
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$90.63	$90.63	$109.83	$90.00	$89.93	$84.33	$72.69	$74.27	$84.86	$84.55	$85.51	$82.23	$85.74
30	**Less Renewable*Connect Pilot**													
31	**Less Renewable* Connect Flex (MTM)**													
32	**Less Renewable*Connect LT**													
33														
34	**Net System $/MWh**													$23.24

PROTECTED DATA ENDS]

2025
2025 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,559	3,851,840	78.93%
February	6,174	3,364,605	81.10%
March	5,992	3,572,028	80.12%
April	5,224	3,057,451	81.29%
May	6,837	3,362,394	66.10%
June	8,393	3,786,165	62.66%
July	9,034	4,354,677	64.79%
August	8,651	4,132,252	64.20%
September	7,555	3,426,409	62.99%
October	5,722	3,348,569	78.66%
November	5,863	3,301,963	78.22%
December	6,347	3,730,814	79.00%
Annual	**9,034**	**43,289,167**	**54.55%**

Redline

FUEL COST FACTORS (~~2024~~2025) T

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting	
January	$~~0.03088~~ 0.03244	$~~0.03085~~ 0.03241	$~~0.03039~~0.03193	$~~0.03860~~ 0.04055	$~~0.02426~~ 0.02548	$~~0.02323~~ 0.02439	R
February	$~~0.03377~~ 0.03454	$~~0.03374~~ 0.03451	$~~0.03323~~0.03399	$~~0.04221~~ 0.04319	$~~0.02652~~ 0.02712	$~~0.02539~~ 0.02596	
March	$~~0.03659~~ 0.03584	$~~0.03656~~ 0.03580	$~~0.03601~~0.03527	$~~0.04575~~ 0.04482	$~~0.02873~~ 0.02813	$~~0.02750~~ 0.02692	
April	$~~0.03563~~ 0.03879	$~~0.03560~~ 0.03876	$~~0.03507~~0.03817	$~~0.04454~~ 0.04851	$~~0.02798~~ 0.03045	$~~0.02679~~ 0.02915	
May	$~~0.03876~~ 0.03667	$~~0.03873~~ 0.03664	$~~0.03814~~0.03609	$~~0.04846~~ 0.04585	$~~0.03044~~ 0.02879	$~~0.02914~~ 0.02756	
June	$~~0.03653~~ 0.03682	$~~0.03649~~ 0.03679	$~~0.03595~~0.03624	$~~0.04567~~ 0.04606	$~~0.02868~~ 0.02890	$~~0.02746~~ 0.02766	
July	$~~0.03787~~ 0.03519	$~~0.03783~~ 0.03516	$~~0.03726~~0.03463	$~~0.04737~~ 0.04403	$~~0.02971~~ 0.02761	$~~0.02844~~ 0.02643	
August	$~~0.03665~~ 0.03388	$~~0.03662~~ 0.03385	$~~0.03607~~0.03334	$~~0.04584~~ 0.04238	$~~0.02877~~ 0.02658	$~~0.02753~~ 0.02544	
September	$~~0.03377~~ 0.03212	$~~0.03375~~ 0.03209	$~~0.03324~~0.03160	$~~0.04224~~ 0.04017	$~~0.02652~~ 0.02521	$~~0.02538~~ 0.02413	
October	$~~0.03208~~ 0.02970	$~~0.03204~~ 0.02967	$~~0.03156~~0.02923	$~~0.04011~~ 0.03714	$~~0.02518~~ 0.02331	$~~0.02410~~ 0.02232	
November	$~~0.02843~~ 0.02863	$~~0.02841~~ 0.02860	$~~0.02798~~0.02817	$~~0.03555~~ 0.03581	$~~0.02233~~ 0.02247	$~~0.02137~~ 0.02151	
December	$~~0.02666~~ 0.02899	$~~0.02664~~ 0.02896	$~~0.02623~~0.02853	$~~0.03334~~ 0.03625	$~~0.02094~~ 0.02275	$~~0.02004~~ 0.02178	R

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak	
January	$~~0.04006~~0.04209	$~~0.03231~~0.03394	$~~0.01592~~0.01671	R
February	$~~0.04381~~0.04483	$~~0.03533~~0.03614	$~~0.01738~~0.01776	
March	$~~0.04749~~0.04652	$~~0.03829~~0.03750	$~~0.01882~~0.01841	
April	$~~0.04624~~0.05035	$~~0.03728~~0.04059	$~~0.01834~~0.01994	
May	$~~0.05029~~0.04759	$~~0.04055~~0.03837	$~~0.01996~~0.01886	
June	$~~0.04740~~0.04781	$~~0.03822~~0.03853	$~~0.01880~~0.01891	
July	$~~0.04917~~0.04571	$~~0.03962~~0.03683	$~~0.01943~~0.01805	
August	$~~0.04759~~0.04400	$~~0.03835~~0.03545	$~~0.01883~~0.01739	~~I~~
September	$~~0.04384~~0.04170	$~~0.03535~~0.03361	$~~0.01736~~0.01649	~~I~~
October	$~~0.04163~~0.03855	$~~0.03356~~0.03108	$~~0.01649~~0.01527	~~I~~
November	$~~0.03690~~0.03717	$~~0.02975~~0.02996	$~~0.01463~~0.01471	
December	$~~0.03460~~0.03763	$~~0.02790~~0.03033	$~~0.01373~~0.01489	R

(Continued on Sheet No. 5-91.2)

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2025) T

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Off-Peak	Outdoor Lighting
January	$0.03244	$0.03241	$0.03193	$0.04055	$0.02548	$0.02439
February	$0.03454	$0.03451	$0.03399	$0.04319	$0.02712	$0.02596
March	$0.03584	$0.03580	$0.03527	$0.04482	$0.02813	$0.02692
April	$0.03879	$0.03876	$0.03817	$0.04851	$0.03045	$0.02915
May	$0.03667	$0.03664	$0.03609	$0.04585	$0.02879	$0.02756
June	$0.03682	$0.03679	$0.03624	$0.04606	$0.02890	$0.02766
July	$0.03519	$0.03516	$0.03463	$0.04403	$0.02761	$0.02643
August	$0.03388	$0.03385	$0.03334	$0.04238	$0.02658	$0.02544
September	$0.03212	$0.03209	$0.03160	$0.04017	$0.02521	$0.02413
October	$0.02970	$0.02967	$0.02923	$0.03714	$0.02331	$0.02232
November	$0.02863	$0.02860	$0.02817	$0.03581	$0.02247	$0.02151
December	$0.02899	$0.02896	$0.02853	$0.03625	$0.02275	$0.02178

R
R

Commercial & Industrial General TOU Service Pilot Program

Month	Peak	Base	Off-Peak
January	$0.04209	$0.03394	$0.01671
February	$0.04483	$0.03614	$0.01776
March	$0.04652	$0.03750	$0.01841
April	$0.05035	$0.04059	$0.01994
May	$0.04759	$0.03837	$0.01886
June	$0.04781	$0.03853	$0.01891
July	$0.04571	$0.03683	$0.01805
August	$0.04400	$0.03545	$0.01739
September	$0.04170	$0.03361	$0.01649
October	$0.03855	$0.03108	$0.01527
November	$0.03717	$0.02996	$0.01471
December	$0.03763	$0.03033	$0.01489

R
R

CURRENT PERIOD COST OF ENERGY
The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government, Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and Voluntary Renewable*Connect Program Rider (Long Term) kWh sales. Qualifying costs are the sum of the following:

(Continued on Sheet No. 5-91.2)

Methodology

PLEXOS® is built on a mathematical programming foundation that supports all the popular third-party commercial solver tools (CPLEX, Gurobi, MOSEK, Xpress-MP and others). A unique and compelling feature of the software is the dynamic problem formulation engine. This builds the mathematical representation of the task at hand, whether it's long-term capacity planning or short-term UC/ED, from scratch at runtime, adjusting the formulation of each element based on defined data and user settings. This creates the most efficient formulation possible and allows users to control the mathematical task's complexity.

PLEXOS® uses a single, consistent user interface and database for all study types from long-term, medium to short term. In all cases the approach used is to formulate and solve one or more stochastic (or deterministic) mixed integer programming problems.

The specific methodology used for selected key features is described in the following table:

Feature	Method	Notes
Security-constrained Unit Commitment/Economic Dispatch	Mixed integer programming	Full co-optimization with ancillary services. Heuristic rounding methods and linear relaxation also available as options
Expansion Planning	Mixed integer programming	Simultaneous generation and transmission optimal expansion over 20+ year timeframe fully integrated with mid and short-term simulations.
Network and Optimal Power Flow	Linearized DC-OPF	State-of-the-art linearized DC-OPF including losses produces solutions very close to AC-OPF. AC-PF ex-post computation of voltage and reactive power flows in development.
Hydro	Stochastic or Deterministic with Decomposition from mid to short term	Hydro with storage optimized in two-stages from medium term stochastic optimization to short-term with optimized release policies based on state-of-the-art future cost function method.
Pumped Storage	Full intermittent co-optimization	True optimization of pumped storage operation with user-definable timeframe e.g. day or week.
Wind/Solar/Other Renewable	Detailed and stochastic	Wind and solar generation with forecast uncertainty modeled as stochastic processes.

Market-leading Features

Energy Exemplar® invests heavily in research and development, led by the original developer Dr. Glenn Drayton and his Adelaide, Australia based development team. As a result, PLEXOS® leads the field in scope and depth of features. The following table outlines features that set PLEXOS® software apart from other competing tools.

Feature	Applications
Sub-hourly simulation e.g. 5-minute dispatch	RES,LMP,STO,DSR
Mixed integer programming for unit commitment	RES,OPT,SYS
Co-optimization of energy and ancillary services	RES,STO,DSR
Nodal transmission model	RES,LMP
Co-optimization of generation and optimal power flow with losses	RES,POL,LMP
Pumped storage optimization	RES,STO
Decomposition of long-term constraints (emission, fuel, hydro, etc)	OPT,IRP
Co-optimization of hydro-thermal dispatch	RES,STO
Cascading hydro network model	HYD
Stochastic optimization of hydro storage	HYD
Stochastic unit commitment	SYS
Long-term capacity expansion planning	CEP,IRP
Long-term integrated with mid and short-term simulations	CEP,MA,IRP
Chronological long and mid-term simulations	CEP,IRP
Multi-commodity market arbitrage (electric, fuel, AS, emissions)	OPT,IRP
CCGT as GT and HRSG components	MA
CHP with Heat Storage	MA
Fuel Stockpiles	FUE
Integrated gas-electric co-optimization	GAS,MA
Models of competition (Bertrand, Cournot)	POL,MA
Generic (user-defined) constraints and decision variables	POL,LMP,DSR
Synthetic stochastic series	HYD,RES
Support for high-performance computing	ADQ,RES,PAR
Choice of mathematical programming solver	-
Published benchmarks against ISO/RTO market scheduling software solutions	-
Interleaved Day-ahead/Hour-ahead/ Real-time market sequential simulations	RES

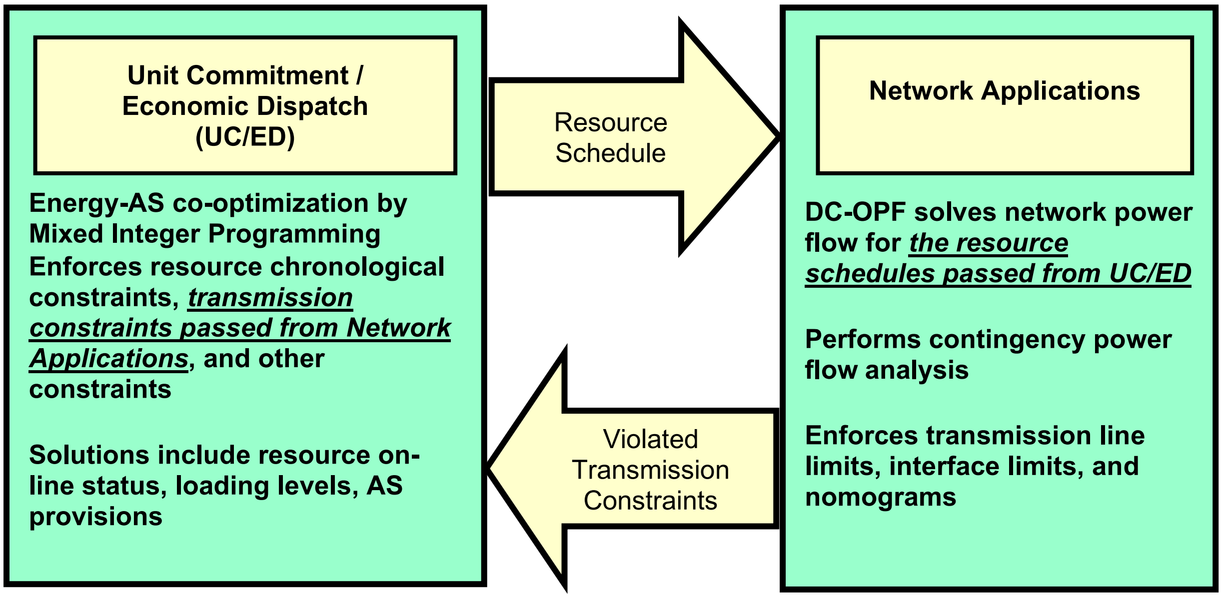
Key to Applications:

Acronym	Description
MA	Electric power market simulation and price forecasting
OPT	Asset portfolio optimization and valuation
CEP	Capacity expansion planning in electric and natural gas systems
LMP	Locational marginal price forecasting
GAS	Natural gas pipeline and storage simulation
RES	Renewable generation integration and flexible resource assessment
STO	Energy storage evaluation
DSR	Demand response valuation
POL	Public policy and interregional transmission planning
GAM	Market power analysis and competition indices
ADQ	Generation adequacy and system reliability calculations
IRP	Integrated resource planning
FUE	Fuel and emission planning
RSK	Risk analysis
HYD	Multi-stage stochastic hydro reservoir optimization
SYS	System operations and real time dispatch
SO	Deterministic, Monte Carlo, and stochastic optimization
DB	Common database for long and short-term simulations
PAR	Parallel and cluster computing

PLEXOS SCUC/ED algorithm

PLEXOS' security constrained unit commitment (SCUC) algorithm consists of two major logics: Unit Commitment using Mixed Integer Programming and Network Applications. The SCUC / ED simulation algorithm can be better described in the following figure. The same SCUC / ED algorithm is used by most ISO or RTO scheduling software (except that AC-OPF may be used by some ISO scheduling software).

Figure 0-1 PLEXOS Security-Constrained Unit Commitment and Economic Dispatch Algorithm



The unit commitment and economic dispatch (UC/ED) logic performs the Energy-AS co-optimization using Mixed Integer Programming enforcing all resource and operation constraints. The UC/ED logic commits and dispatch resources to balance the system energy demand and meet the system reserve requirements.

The resource schedules from the UC/ED are passed to the Network Applications logic. The Network Applications logic solves the DC-OPF to enforce the power flow limits and nomograms. The Network Applications logic also performs the contingency analysis if the contingencies are defined. If there are any transmission limit violations, these transmission limits are passed to the UC/ED logic for the re-run of UC/ED. The iteration continues until all transmission limit violations resolved. Thus the co-optimization solution of Energy-AS-DC-OPF is reached

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part B, Attachment 2 - Page 1 of 1

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2025

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2025 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood/Gas													
Bay Front 6	Wood/Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Inver Hills 1	Gas													
Inver Hills 1	Oil													
Inver Hills 3	Gas													
Inver Hills 3	Oil													
Inver Hills 4	Gas													
Inver Hills 4	Oil													
Inver Hills 6	Gas													
Inver Hills 6	Oil													
Inver Hills	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 6	Oil													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2025

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2025 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2024 04-10-24 09:02:37)	Jan 2025	Feb 2025	Mar 2025	Apr 2025	May 2025	Jun 2025	Jul 2025	Aug 2025	Sep 2025	Oct 2025	Nov 2025	Dec 2025
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

PROTECTED DATA ENDS]

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NOT-PUBLIC DATA HAS BEEN EXCISED

	Unit	Reason for Outage	Start Date	End Date	Duration (Days)
	[PROTECTED DATA BEGINS				
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
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21					
22					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

PROTECTED DATA ENDS]

	2019	2020	2021	2022	2023		5 Yr Average	ES Adder	Modeled
	[PROTECTED DATA BEGINS								
Monti									
PI1									
PI2									
SHC1									
SHC3									
King									
BD 5/2									
Highbridge									
Riverside									

PROTECTED DATA ENDS]

	Unit					MISO Rate
			[PROTECTED DATA BEGINS			
1	Angus Anson 2					
2	Angus Anson 3					
3	Angus Anson 4					
4	Black Dog 6					
5	Blue Lake 7					
6	Blue Lake 8					
7	Inver Hills 1					
8	Inver Hills 2					
9	Inver Hills 3					
10	Inver Hills 4					
11	Inver Hills 5					
12	Inver Hills 6					
13	Wheaton 1					
14	Wheaton 2					
15	Wheaton 3					
16	Wheaton 4					
17	Wheaton 6					

PROTECTED DATA ENDS]

Northern States Power
Electric Utility - State of Minnesota
Replacement Power Costs Estimate

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition

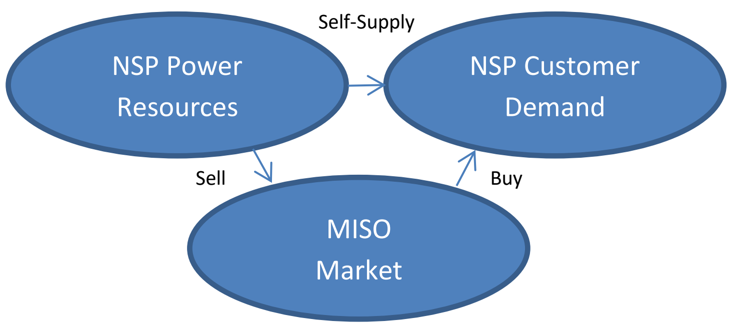
		Planned							Unplanned						
Unit	Type	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
		[PROTECTED DATA BEGINS													
Black Dog 25	NSP CC														
High Bridge 1x1	NSP CC														
High Bridge 2x1	NSP CC														
Riverside 1x1	NSP CC														
Riverside 2x1	NSP CC														
Allen S King	NSP Coal														
Sherburne 1	NSP Coal														
Sherburne 3	NSP Coal														
Monticello	NSP Nuclear														
Prairie Island 1	NSP Nuclear														
Prairie Island 2	NSP Nuclear														
Total															
Combined															

PROTECTED DATA ENDS]

MISO Hourly LMP Forecasting in the NSP Production Cost Model

Northern States Power (NSP) buys and sells energy through the MISO market. The energy price is determined by system-wide economic dispatch of power resources to meet customer demand. NSP is a net buyer from the market when energy prices are lower than the cost to serve customers from native generation and a net seller to the market when energy prices are higher than the cost to serve from native generation. Ultimately, the choice between self-supply and buying from (or selling to) MISO is determined by the market energy price. This is a simple and effective construct for modeling purposes, and is reflected in Figure 1.

Figure 1 – Model of NSP Interaction with the MISO Market



The modeled MISO energy price is best represented by the MINN.HUB day-ahead energy price. The MINN.HUB price is a weighted average of price nodes in the northwest region of the MISO market, inclusive of the entire NSP service territory. The day-ahead energy price is used because the NSP production cost model is set-up to predict interaction with the MISO day-ahead market. Further, the day-ahead market clears the vast majority of all energy transacted in MISO making it the most important market to model.

Hourly MINN.HUB LMP Forecast

Four years of historical data are analyzed quarterly using the least square regression model detailed below in order to update the coefficients $a, b,$ and c^M. The regression quantifies the historical relationship between the MINN.HUB Locational Marginal Price (LMP) and load (D_t), wind (W_t), and natural gas (P_d^{NG}). An additional model relates each hour of the day to monthly variations in daily peaks and troughs. The MINN.HUB energy price, or dependent variable, is correlated to the aforementioned price drivers, or independent variables, and applied to forecast price drivers in order to derive an hourly forecast of MINN.HUB prices. The correlation formula is as follows:

$$MISO_t = P_d^{NG}[a(NL_t)^3 + b(NL_t)^{-2} + c^M S_{1..24}^M] \quad (1)$$

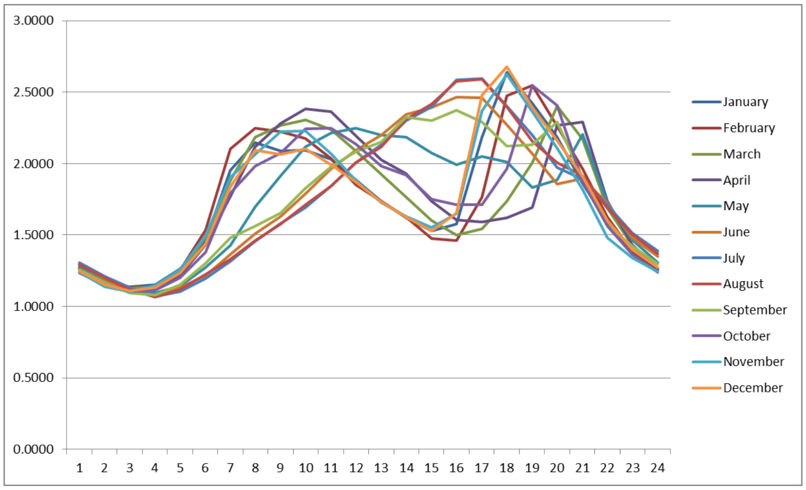
$$P_d^{NG} = Daily\ Natural\ Gas\ Price;\ NL_t = Hourly\ Net\ Load = D_t - W_t$$

$$D_t = Day\ Ahead\ Customer\ Demand;\ \ W_t = \sum_k Wind\ Energy\ DayAhead\ Award_t^k$$

$$S_{1..24}^M = Historic\ Daily\ Price\ Pattern\ by\ Month\ (M = 1,2, \dots ,12)$$

The historical daily price pattern ($S_{1..24}^M$) captures monthly changes to the daily price shape. For each month, average historical prices for each hour of the day are ranked from the highest average price hour to the lowest average price hour. An exponential relationship based on this rank is derived, creating a daily price pattern for each month. Example daily price patterns for each month are shown in Figure 2. For consistency, the historical daily price pattern is updated just prior to the least square regression analysis.

Figure 2 - Example Daily Price Pattern (12/31/2015 analysis)



Once the historical regression and daily price pattern analyses are complete, the hourly forecast of MINN.HUB LMPs can be updated using forecast hourly customer demand, hourly wind energy, and monthly natural gas prices. The load, wind, and natural gas price forecasts used in the PLEXOS modeling tool are used for the MINN.HUB energy price forecast such that the hourly LMP price forecast correlates to the modeled load, wind pattern, and gas price in any given database. The mathematical relationship established by the historical regression is applied to the forecast via the regression coefficients and historical daily price pattern by month.

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NOT-PUBLIC DATA HAS BEEN EXCISED

	Category	2025 Forecast	
	[PROTECTED DATA BEGINS		
1	Congestion		Part F, Workpaper 5
2	FTR		Part F, Workpaper 5
3	Incremental Transmission losses		Part F, Workpaper 5
4	RSG/RNU		Part F, Workpaper 5
5	ASM		Part F, Workpaper 5
6	**MISO Market Charges TOTAL**		line 24, Part A, Att 1, pg 1
7	MISO Market Purchases from PLEXOS		line 23, Part A, Att 1, pg 1
8	MISO Market Sales from PLEXOS		line 29, Part A, Att 1, pg 1
9	**Net MISO Day 2 and Day 3 costs and revenues**		Lines 6+7+8
	PROTECTED DATA ENDS]		

White Paper: Park Potential profiles for modeling wind and solar generation on the NSP System

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Introduction

This paper describes the process used to create Park Potential (PP) profiles of wind and solar generation for Xcel Energy's upper Midwest region.

Annual Expected Park Potential

The Company combined monthly generation and curtailment data to derive the monthly Park Potential for each renewable generation Commercial Pricing Node (CP Node) from January 2018 through December 2023. The monthly Park Potentials were summed on a rolling 12-month basis to derive 61 annual Park Potential values. The Company averaged the 61 annual values to determine the annual expected Park Potential value for each CP Node. For renewable generation without sufficient historic data, the most recent Energy Production Estimate (EPE) from pre-construction developer software or the Annual Committed Energy from the Purchase Power Agreement was used as the annual PP value.

Monthly allocation of annual Park Potential

For new wind plants, the pre-construction developer software uses 30 years' worth of meteorological weather reanalysis data to determine the expected monthly generation expressed as a percentage of the annual EPE. The Company used the average of the monthly percentages from new wind plants to allocate the CP Node annual Park Potential values to each calendar month. For solar plants, the Company calculated the ratio of monthly Park Potential relative to annual Park Potential for each month from the years 2018-2023. Table 1 shows the monthly allocations for wind and solar plants expressed as a percentage of the annual expected Park Potential.

Table 1
Monthly Percentage of Annual Wind and Solar Plant Park Potential

Month	Wind % Allocation	Solar % Allocation
January	9.1%	3.5%
February	8.2%	5.5%
March	9.1%	8.9%
April	9.4%	10.0%
May	9.1%	12.1%
June	7.7%	13.2%
July	6.3%	13.2%
August	6.1%	11.6%
September	7.7%	9.0%
October	9.1%	6.6%
November	9.2%	3.9%
December	9.0%	2.5%

<u>Hourly allocation of monthly Park Potential</u>

For most wind plants, the Company has wind speed data measured at the turbine anemometers[1]. The Company gathered hourly-averaged wind speed data from 2022 for each wind CP Node and used empirical power conversions specific to those CP Nodes to convert the hourly wind speed to hourly generation. The summed monthly generation for each CP Node was compared to the volume of generation derived from the monthly allocation of the annual Park Potential. A constant wind speed adjustment was made to each hour so that the sum of the hourly generation based on the hourly wind speed data matched the monthly allocation of the annual Park Potential.

For wind generation at CP Nodes without wind speed data, the Company generated a single empirical power conversion derived from the simple average of all wind speed data for each hour in 2021 and the paired sum-of-generation from all CP Nodes without wind speed data. For each of these CP Nodes, the Company calculated the pro rata ratio of the CP Node annual Park Potential relative to the sum of annual Park Potentials for all CP Nodes without wind speed data. A constant wind speed adjustment was applied to the system average wind speed profile for each month so that the resulting generation profile matched the monthly allocation of the sum of annual Park Potentials for all CP Nodes without wind speed data. Each CP Node

[1] The Company has turbine wind speed data for approximately 93% of Company-controlled wind generation capacity.

without wind speed data was assigned their pro-rata share of this hourly generation profile for each month.

For solar generation, the Company used hourly irradiance and generation data from 2022 for each solar plant and used empirical power conversions to convert the hourly irradiance to hourly generation. The summed monthly generation for each plant was compared to the volume of generation derived from the monthly allocation of the annual PP. An irradiance adjustment was made to each hour in a given month so that the sum of the hourly generation based on the hourly irradiance data matched the monthly allocation of the annual PP.

For plants without historic irradiance or generation data, the Company used 2022 hourly irradiance data for each plant location sourced from the National Solar Radiation DataBase (NSRDB) maintained by the National Renewable Energy Laboratory (NREL). The same process was used to derive the hourly generation profiles for these solar plants as for the existing solar plants in the Company's portfolio of renewable generation.

Wind Maintenance Adjustment

For new and repowered wind farms, an adjustment factor is included to account for warranty, preventative maintenance, daily faults, and other issues common with new wind farms in their first years of operation. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

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NOT-PUBLIC DATA HAS BEEN EXCISED

	Date Signed	COD	Termination	Term (yrs)	Counterparty	Hrs Available	MW	Energy Price	Capacity Price	Fuel Type	Not Firm?	Dispatchability	Price Escalation?	RPS/Renewable*Connect Assignment[1]
								[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS	
CC Calpine	3/11/2004	1/1/2006	8/31/2028	22	Mankato Energy Center LLC	All	375			Gas		Dispatchable		None
CC Calpine II	4/28/2015	6/1/2019	5/31/2039	20	Mankato Energy Center LLC	All	345			Gas		Dispatchable		None
CC LSPower	5/9/1994	10/1/1997	9/30/2027	30	LSP- Cottage Grove, L.P.	All	245.1			Gas		Dispatchable		None
CT Invenergy 1	4/1/2005	4/11/2008	5/31/2028	20	Invenergy Cannon Falls LLC	All	178.5			Oil/Gas		Dispatchable		None
CT Invenergy 2	4/1/2005	4/11/2008	5/31/2028	20	Invenergy Cannon Falls LLC	All	178.5			Oil/Gas		Dispatchable		None
DPC Flambeau	7/1/1963	7/1/1963	7/1/2052	Life of Plant	Dairyland Flambeau	All	1.2			Hydro		Must Take		None
Eau Galle	7/31/1991	8/1/1991	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	All	0.30			Hydro		Must Take		None
Hastings	9/10/1985	10/5/1987	6/30/2033	45	City of Hastings Hydro	All	4.0			Hydro		Must Take		None
Part 3	5/27/2010	5/1/2015	4/30/2025	10	Manitoba Hydro Electric Board	6am-10pm, Mon-Fri	Summer: 375, Winter: 325 (Summer = May thru October)			Hydro		Must Take		None
Part 4	5/27/2010	5/1/2021	4/30/2025	5	Manitoba Hydro Electric Board	6am-10pm, Mon-Fri	125			Hydro		Must Take		None
SAF	1/9/2007	12/19/2011	12/18/2031	20	SAF Hydroelectric, LLC	All	9.2			Hydro		Must Take		RPS
Solar Aurora	2/12/2015	12/31/2016	12/30/2036	20	Aurora Distributed Solar	All	100			Solar		Must Take		RPS
Solar Best Power International PV	12/1/2009	5/28/2010	5/27/2030	20	St. John's Solar	All	0.5			Solar		Must Take		RPS
Solar Best Power International PV II	5/11/2015	10/12/2015	10/11/2030	15	School Sisters of Notre Dame Solar Park)	All	0.72			Solar		Must Take		RPS
Solar Dragonfly	6/6/2017	9/11/2018	9/10/2033	15	Dragonfly Solar, LLC	All	0.8			Solar		Must Take		RPS
Solar Marshall	3/3/2015	1/09/2017	5/31/2042	25.5	Marshall Solar, LLC	All	62.25			Solar		Must Take		RPS
Solar North Star	3/6/2015	12/21/2016	12/20/2041	25	North Star Solar PV	All	100			Solar		Must Take		RPS
Solar Slayton	11/3/2010	1/14/2013	1/13/2033	20	Slayton Solar, LLC	All	1.66			Solar		Must Take		RPS
Solar Fillmore County Solar Project (6)	12/5/2022	Target 12/15/2024	18.5 Yrs from COD	18.5	Fillmore County Solar Project, LLC	All	30			Solar		Must Take		Renewable*Connect
Solar Louise Solar Generation Facility (6)	12/5/2022	Target 12/15/2024	18.5 Yrs from COD	18.5	Louise Solar Generation Facility, LLC	All	50			Solar		Must Take		Renewable*Connect
City of St. Cloud (New PPA)	6/12/2020	11/1/2021	5/31/2041	19.5	The City of St. Cloud	All	Summer: 8.1, Winter: 6.6 (Summer = May thru October)			Hydro		Must Take		None
Wind CBED Adams	10/27/2009	3/9/2011	3/8/2031	20	Adams Wind Generations, LLC	All	19.8			Wind		Must Take		RPS
Wind CBED Big Blue	6/1/2010	12/15/2012	12/14/2032	20	Big Blue Wind Farm, LLC	All	36			Wind		Must Take		RPS
Wind CBED Community Wind South	7/6/2011	12/26/2012	12/25/2032	20	Zephyr Wind, LLC	All	30.75			Wind		Must Take		RPS
Wind CBED Danielson	10/27/2009	3/11/2011	3/10/2031	20	Danielson Wind Farms, LLC	All	19.8			Wind		Must Take		RPS
Wind CBED Ewington (New Repower PPA) (4)	10/28/2020	6/30/2022	6/29/2047	25	Ewington Energy Systems, LLC	All	19.95			Wind		Must Take		RPS
Wind CBED Hilltop	12/12/2007	2/20/2009	2/19/2029	20	Hilltop Power	All	2			Wind		Must Take		RPS
Wind CBED Ridgewind	11/3/2008	1/13/2011	1/12/2031	20	Ridgewind Power Partners LLC	All	25.3			Wind		Must Take		RPS
Wind CBED Roseville	5/12/2009	8/9/2010	8/8/2030	20	Grant County Wind	All	20			Wind		Must Take		RPS
Wind CBED Uilk	11/26/2008	1/15/2010	1/14/2030	20	Uilk Wind Farm, LLC	All	4.5			Wind		Must Take		RPS
Wind CBED Valley View	9/26/2008	11/30/2011	11/29/2031	20	Valley View Transmission, LLC	All	10			Wind		Must Take		RPS
Wind CBED Winona	10/15/2009	10/27/2011	10/26/2031	20	Winona County Wind, LLC	All	1.5			Wind		Must Take		RPS
Wind CBED Woodstock	8/10/2009	6/24/2010	6/23/2030	20	Woodstock Municipal Wind, LLC	All	0.75			Wind		Must Take		RPS
Wind Eastridge	11/13/2003	5/1/2006	4/30/2026	20	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	All	10			Wind		Must Take		RPS
Wind Fenton	9/30/2005	11/13/2007	11/12/2032	25	Fenton Power Partners I, LLC	All	205.5			Wind		Must Take		RPS
Wind Garwin McNeilus	Various	Various	Various	20-25	Ashland, Bangladesh CS LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese CS, LLC,Elsinore Wind, ZumbroGarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian CS, LLC, McNeilus Windfarm LLC, Salvadoran CS LLC, SG (JCKD) Windfarm LLC, Asian CS, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC , Zumbro Windfarm LLC	All	36.75			Wind		Must Take		RPS/Windsource (2)
Wind Geronimo Odell	7/2/2013	7/29/2016	7/28/2036	20	Odell Wind, LLC	All	200			Wind		Must Take		RPS
Wind Lakota	3/26/1997	5/1/2004	4/30/2034	30	Northern Alternative Energy Lakota Ridge LLC	All	11.25			Wind		Must Take		None
Wind Moraine II	11/7/2008	2/18/2009	2/17/2029	10	Moraine Wind II LLC	All	49.5			Wind		Must Take		Renewable*Connect
Wind Norgaard	12/26/2003	5/11/2006	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	All	8.75			Wind		Must Take		RPS
Wind North Shaokatan	2/15/1999	11/1/2003	10/31/2033	30	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	All	13.53			Wind		Must Take		RPS
Wind Phase 2	9/6/1996	12/14/1998	12/13/2028	30	Lake Benton Power Partners LLC (LBI)	All	104.25			Wind		Must Take		RPS
Wind Prairie Rose	6/7/2011	12/11/2012	12/10/2032	20	Prairie Rose Wind, LLC	All	200			Wind		Must Take		RPS
Wind Ruthton	2/15/1999	1/23/2001	1/22/2031	30	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	All	15.84			Wind		Must Take		None

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

	Date Signed	COD	Termination	Term (yrs)	Counterparty	Hrs Available	MW	Energy Price	Capacity Price	Fuel Type	Not Firm?	Dispatchability	Price Escalation?	RPS/Renewable*Connect Assignment[1]
								[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS	
Wind Shaokatan	3/26/1997	5/1/2004	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	All	11.88			Wind		Must Take		RPS
Wind Source Cisco	9/29/2006	5/28/2008	5/27/2028	20	Cisco Wind Energy LLC	All	8			Wind		Must Take		Renewable*Connect
Wind Source Garwin McNeilus	5/1/2005	5/21/2003	4/30/2025	20	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	All	9.25			Wind		Must Take		Renewable*Connect
Wind Source JJN	5/20/2002	12/17/2004	12/16/2029	25	JJN Windfarm, LLC	All	1.5			Wind		Must Take		Renewable*Connect
Wind Source West Ridge	1/31/2002	12/28/2003	12/27/2028	25	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	All	9.5			Wind		Must Take		RPS/Windsource (2)
Wind Stahl	11/13/2003	1/1/2005	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	All	8.25			Wind		Must Take		RPS
Wind Tholen	11/17/2003	8/28/2005	8/27/2025	20	Tholen Transmission Projects	All	13.2			Wind		Must Take		RPS
Wind University of Minnesota	4/24/2011	10/26/2011	Evergreen		UMORE Park, LLC	All	2.5			Wind		Must Take		None
Wind Various	Various	Various	Various	30	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carlton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, Rock Ridge Windfarm LLC, Southridge Windfarm LLC, St.Olaf College, Windvest Windfarm LLC	All	16.34			Wind		Must Take		RPS
Wind Velva	5/10/2004	1/19/2006	1/18/2026	20	Velva Windfarm, LLC	All	11.88			Wind		Must Take		RPS
Wind Westridge	1/31/2002	12/28/2003	Various 2028	25	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	All	7.6			Wind		Must Take		RPS
Wind Woodstock (5)	9/19/1997	5/1/2004	4/30/2033	30	Woodstock Wind Farm, LLC	All	9.2			Wind		Must Take		RPS
Wind Crown Ridge	3/7/2017	1/10/2020	1/9/2045	25	Crowned Ridge Wind, LLC	All	200			Wind		Must Take		RPS
Wind Clean Energy	3/13/2017	12/19/2019	12/18/2039	20	Glen Ullin Energy Center, LLC	All	106.8			Wind		Must Take		RPS
Wind Dakota Range III	10/29/2018	4/29/2021	4/28/2033	12	DAKOTA RANGE III, LLC	All	153.6			Wind		Must Take		RPS
Wind Deuel Harvest PPA	11/25/2019	10/1/2021	9/30/2036	15	Deuel Harvest Wind Energy, LLC	All	100			Wind		Must Take		Renewable*Connect
Wind Heartland Divide 2 PPA	7/21/2020	4/11/2022	4/10/2047	25	Heartland Divide Wind II, LLC	All	200			Wind		Must Take		Renewable*Connect
									PROTECTED DATA ENDS]				PROTECTED DATA ENDS]	

Notes:

(1) "RPS" indicates compliance with the Renewable Portfolio Standards/Objectives of Minnesota, Wisconsin, North Dakota, and/or South Dakota.
"Renewable*Connect" indicates resource is used for the NSP green pricing program
"None" indicates that the generator owner retains the RECs and the resource is not used for compliance with any Renewable Portfolio Standard/Objectives or green pricing program
(2) The generation from this resource is allocated to RPS compliance and to Windsource. None of the RECs are used for both purposes.

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
1	Le Sueur	9/9/2015	0.036	9
2	Lincoln	4/25/2016	0.204	8
3	Ramsey	5/12/2016	0.125	19
4	Hennepin	8/22/2016	0.036	14
5	Chisago	12/14/2016	5	29
6	Dakota	12/14/2016	5	11
7	Chisago	12/15/2016	4	11
8	Carver	12/15/2016	5	10
9	Scott	12/19/2016	3	8
10	Dakota	12/20/2016	5	18
11	Stearns	12/21/2016	5	175
12	Dakota	12/22/2016	5	174
13	Stearns	1/4/2017	3	88
14	Stearns	1/5/2017	3	174
15	Goodhue	1/12/2017	4.86	30
16	Dakota	1/13/2017	5	41
17	Chisago	1/13/2017	3.888	102
18	Dakota	2/13/2017	5	79
19	Goodhue	2/13/2017	4	31
20	Carver	2/28/2017	4.86	13
21	Washington	3/10/2017	0.036	18
22	Wabasha	3/13/2017	3	116
23	Blue Earth	5/31/2017	3	116
24	Redwood	5/31/2017	3	138
25	Winona	5/31/2017	0.25	148
26	Rice	6/30/2017	5	158
27	Dodge	7/18/2017	5	184
28	Washington	7/18/2017	5	13
29	Olmsted	7/19/2017	5	98
30	Kandiyohi	8/14/2017	2	168
31	Pipestone	8/18/2017	2	189
32	Chisago	8/22/2017	3	31
33	Stearns	8/24/2017	2	190
34	Chippewa	8/29/2017	2	78
35	Dakota	8/31/2017	5	86
36	Pope	9/13/2017	5	183
37	Stearns	9/13/2017	2.188	199
38	Stearns	9/13/2017	4.86	210
39	Lincoln	9/14/2017	0.2	9
40	Sherburne	9/22/2017	5	183

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
41	Dodge	9/27/2017	4	19
42	Benton	9/29/2017	2	134
43	McLeod	10/25/2017	3	55
44	Chippewa	10/25/2017	3	209
45	Hennepin	10/25/2017	5	70
46	McLeod	10/26/2017	5	45
47	Pipestone	10/30/2017	5	73
48	Stearns	10/30/2017	3	8
49	Benton	10/30/2017	5	6
50	Wright	11/3/2017	5	8
51	Stearns	11/9/2017	5	67
52	Wright	11/13/2017	5	6
53	Stearns	11/16/2017	4	41
54	Nicollet	11/20/2017	5	56
55	Blue Earth	11/20/2017	5	125
56	Scott	11/30/2017	4.69	45
57	Scott	11/30/2017	0.7	60
58	Dakota	11/30/2017	2.7	71
59	Rice	11/30/2017	5	46
60	Stearns	12/13/2017	5	39
61	Chisago	12/13/2017	5	22
62	Carver	12/15/2017	5	56
63	Chisago	12/18/2017	5	126
64	Dodge	12/18/2017	5	225
65	Scott	12/20/2017	2.991	202
66	Carver	12/21/2017	4.361	203
67	Renville	12/28/2017	3	224
68	Washington	1/10/2018	5	23
69	Carver	1/16/2018	3	159
70	Le Sueur	1/18/2018	3	52
71	Dakota	1/23/2018	4.95	12
72	Wabasha	1/29/2018	4	9
73	Pipestone	1/31/2018	4.7	33
74	Sherburne	2/12/2018	3.25	10
75	Rice	2/14/2018	0.998	47
76	Le Sueur	2/23/2018	3	61
77	Carver	2/26/2018	1.996	65
78	Waseca	2/26/2018	5	17
79	Rice	2/28/2018	5	41
80	Le Sueur	2/28/2018	5	40

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
81	Washington	2/28/2018	4	142
82	Faribault	3/2/2018	1.84	26
83	Rice	3/2/2018	3	14
84	Steele	3/5/2018	3.4	33
85	Carver	3/6/2018	3	8
86	Chisago	3/13/2018	5	80
87	Carver	3/14/2018	0.998	110
88	Sherburne	3/14/2018	5	10
89	Pope	3/15/2018	5	48
90	Chippewa	3/25/2018	4	7
91	Benton	3/25/2018	2	61
92	Scott	3/28/2018	4.95	142
93	Goodhue	4/12/2018	0.8	294
94	Washington	4/13/2018	3	148
95	Pope	4/19/2018	3	35
96	Washington	4/20/2018	5	21
97	Goodhue	4/26/2018	0.998	40
98	Chisago	4/30/2018	3	35
99	Stearns	4/30/2018	5	50
100	Sherburne	4/30/2018	4	30
101	Goodhue	5/11/2018	1	39
102	Renville	5/16/2018	1	30
103	Renville	5/17/2018	1	28
104	Goodhue	5/22/2018	1	38
105	Blue Earth	5/30/2018	1	33
106	Steele	6/5/2018	1	51
107	Hennepin	6/6/2018	0.18	43
108	Lyon	6/15/2018	3	19
109	Rice	6/20/2018	1	46
110	Le Sueur	6/29/2018	3	54
111	Sherburne	6/29/2018	5	46
112	Watonwan	7/2/2018	0.25	34
113	Sherburne	7/13/2018	5	60
114	Washington	7/16/2018	2.5	64
115	Steele	7/18/2018	1	33
116	Goodhue	7/19/2018	5	23
117	Dakota	7/27/2018	5	24
118	Goodhue	7/30/2018	2	44
119	Chisago	8/1/2018	1	50
120	DOUGLAS	8/2/2018	5	42

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
121	Le Sueur	8/6/2018	5	56
122	Blue Earth	8/7/2018	3.54	18
123	Chisago	8/9/2018	5	35
124	Wright	8/14/2018	0.972	57
125	Benton	8/14/2018	4.95	1741
126	Carver	8/16/2018	4	1272
127	Wright	8/27/2018	5	270
128	Chisago	8/30/2018	1	603
129	Washington	9/4/2018	5	1028
130	Washington	9/7/2018	0.75	450
131	Goodhue	9/14/2018	1	460
132	Dakota	9/17/2018	0.75	763
133	Goodhue	9/19/2018	1	1111
134	Waseca	9/27/2018	1	491
135	Chisago	9/28/2018	1	73
136	Chisago	9/28/2018	1	1152
137	Hennepin	9/28/2018	0.32	33
138	Blue Earth	10/16/2018	5	36
139	Wright	10/17/2018	4	49
140	McLeod	10/25/2018	1	5
141	Waseca	10/25/2018	1	31
142	Washington	10/29/2018	4.875	23
143	Benton	10/30/2018	1	142
144	Waseca	11/1/2018	1	50
145	Chippewa	11/14/2018	1	277
146	Kandiyohi	11/14/2018	1	227
147	Pope	11/16/2018	1	494
148	Sherburne	11/16/2018	1	46
149	Chisago	11/26/2018	1	24
150	Chisago	11/27/2018	1	20
151	Wright	11/28/2018	5	55
152	Scott	11/28/2018	0.823	179
153	Hennepin	11/28/2018	0.527	416
154	Scott	11/28/2018	1	259
155	Chisago	11/28/2018	1	208
156	Chisago	11/28/2018	1	501
157	Chisago	11/29/2018	1	455
158	Sherburne	12/3/2018	5	198
159	Chisago	12/7/2018	1	299
160	Sherburne	12/10/2018	4.8	206

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
161	Chisago	12/11/2018	0.5	174
162	Stearns	12/17/2018	1	265
163	Benton	12/17/2018	1	37
164	Benton	12/17/2018	1	57
165	Chippewa	12/18/2018	1	45
166	Le Sueur	12/19/2018	1	168
167	Murray	12/20/2018	1	24
168	Murray	12/20/2018	1	50
169	Yellow Medicine	12/21/2018	5	66
170	Ramsey	1/8/2019	0.54	40
171	Dodge	1/9/2019	1	50
172	Hennepin	1/11/2019	5	60
173	Meeker	1/23/2019	0.76	50
174	Stearns	1/28/2019	0.324	706
175	Nicollet	1/31/2019	1	40
176	Waseca	2/13/2019	1	85
177	Chisago	2/27/2019	2	105
178	Stearns	3/4/2019	0.72	39
179	Stearns	3/4/2019	1	20
180	Blue Earth	3/5/2019	0.24	36
181	McLeod	3/12/2019	3	89
182	Washington	3/22/2019	1	99
183	Stearns	3/25/2019	1	90
184	Wabasha	3/26/2019	0.85	167
185	Pope	3/26/2019	1	33
186	Sherburne	3/28/2019	5	47
187	Pope	3/28/2019	1	6
188	Renville	3/29/2019	1	50
189	Goodhue	4/11/2019	5	27
190	Wright	4/15/2019	5	57
191	Stearns	4/16/2019	1	12
192	Chisago	4/22/2019	3	133
193	Washington	4/22/2019	1	17
194	Rice	4/30/2019	1	28
195	Carver	5/1/2019	1	50
196	Lyon	5/3/2019	1	20
197	Benton	5/13/2019	5	27
198	Dodge	5/15/2019	1	75
199	Dodge	5/15/2019	0.4	31
200	Kandiyohi	5/21/2019	1	674

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
201	Chisago	5/21/2019	1	27
202	Wright	5/31/2019	5	45
203	Stearns	6/3/2019	5	7
204	Dakota	6/7/2019	5	21
205	Dakota	6/7/2019	5	49
206	Sibley	6/14/2019	3.25	40
207	Stearns	6/18/2019	3	42
208	Freeborn	6/18/2019	0.25	50
209	Chisago	7/3/2019	1	9
210	Carver	7/22/2019	1	18
211	Scott	7/24/2019	0.598	237
212	Carver	7/25/2019	1	348
213	Sherburne	7/26/2019	3	76
214	Hennepin	7/30/2019	0.18	94
215	Sherburne	7/31/2019	0.996	90
216	Dakota	8/6/2019	1	282
217	Rice	8/8/2019	1	69
218	Scott	8/13/2019	1	84
219	Chisago	8/16/2019	0.998	133
220	Stearns	8/16/2019	1	198
221	Stearns	8/16/2019	1	153
222	Wabasha	8/20/2019	1	70
223	Wabasha	8/20/2019	1	132
224	Winona	8/21/2019	5	193
225	Winona	8/22/2019	1	45
226	Wabasha	8/22/2019	1	45
227	Winona	8/22/2019	1	270
228	Chippewa	8/26/2019	1	25
229	Carver	8/29/2019	1	226
230	McLeod	8/30/2019	1	61
231	Chisago	9/3/2019	1	45
232	Waseca	9/6/2019	1	23
233	Olmsted	9/9/2019	1	46
234	Pope	9/11/2019	1	22
235	Pope	9/11/2019	1	126
236	Hennepin	9/18/2019	0.96	18
237	Rice	9/18/2019	1	8
238	Blue Earth	9/24/2019	0.62	18
239	Goodhue	9/27/2019	4.4	125
240	Blue Earth	9/27/2019	0.62	17

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
241	Rice	10/9/2019	1	30
242	Stearns	10/23/2019	1	35
243	Stearns	10/25/2019	4.75	50
244	Sherburne	10/29/2019	1	77
245	Scott	10/30/2019	0.4	7
246	Waseca	11/18/2019	0.996	13
247	Sherburne	11/26/2019	1	101
248	Stearns	12/3/2019	1	15
249	Meeker	12/11/2019	1	9
250	Dakota	12/11/2019	1	9
251	DOUGLAS	12/11/2019	1	11
252	Meeker	12/13/2019	1	13
253	Rice	12/13/2019	1	5
254	Pope	12/16/2019	1	27
255	Stearns	12/16/2019	1	10
256	Nicollet	12/18/2019	1	140
257	Blue Earth	12/18/2019	1	7
258	McLeod	12/18/2019	1	25
259	Chisago	12/19/2019	1	8
260	Stearns	12/23/2019	1	49
261	Sherburne	12/23/2019	1	26
262	Sherburne	12/26/2019	1	12
263	Stearns	12/27/2019	1	7
264	DOUGLAS	12/27/2019	1	23
265	McLeod	12/27/2019	1	20
266	Renville	12/30/2019	1	6
267	Sherburne	12/30/2019	0.94	9
268	Goodhue	12/31/2019	0.59	104
269	Winona	1/3/2020	1	8
270	Winona	1/3/2020	1	13
271	Stearns	1/13/2020	1	6
272	Rice	1/14/2020	1	7
273	Dakota	1/15/2020	1	11
274	Meeker	1/17/2020	1	154
275	Winona	2/12/2020	1	148
276	Goodhue	2/13/2020	1	11
277	Pope	2/17/2020	1	24
278	Hennepin	2/17/2020	0.29	10
279	Rice	2/20/2020	1	10
280	Goodhue	2/26/2020	1	18

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
281	Pope	2/26/2020	1	10
282	Waseca	2/27/2020	1	86
283	Goodhue	2/28/2020	1	50
284	Goodhue	2/28/2020	1	7
285	Sherburne	2/28/2020	1	12
286	Waseca	3/4/2020	1	21
287	Washington	3/9/2020	3	11
288	Goodhue	3/9/2020	1	9
289	Rice	3/20/2020	1	6
290	Sibley	3/26/2020	1	75
291	Dakota	3/26/2020	1	19
292	Sibley	4/3/2020	1	10
293	Olmsted	4/3/2020	1	24
294	Dodge	4/7/2020	1	38
295	DOUGLAS	4/9/2020	1	125
296	Olmsted	4/13/2020	1	13
297	Olmsted	4/16/2020	1	14
298	Rice	4/24/2020	0.96	22
299	Scott	4/27/2020	3	12
300	Rice	4/27/2020	1	9
301	Goodhue	4/30/2020	1	16
302	Chisago	5/19/2020	1	21
303	Benton	5/20/2020	1	117
304	Stearns	5/21/2020	1	389
305	Dodge	5/21/2020	1	18
306	Carver	5/28/2020	1	17
307	Pope	5/30/2020	1	36
308	Dakota	6/2/2020	1	151
309	Dakota	6/4/2020	1	62
310	Waseca	6/16/2020	1	10
311	Rice	6/17/2020	2	11
312	Winona	6/24/2020	1	12
313	Winona	6/24/2020	1	121
314	Benton	7/10/2020	1	29
315	Rice	7/13/2020	5	86
316	Rice	7/20/2020	4	10
317	McLeod	7/20/2020	4	186
318	Nicollet	7/30/2020	1	25
319	Goodhue	7/30/2020	1	48
320	Stearns	7/31/2020	1	12

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
321	Wright	7/31/2020	1	14
322	Le Sueur	7/31/2020	1	77
323	Sherburne	7/31/2020	1	11
324	Goodhue	8/18/2020	1	240
325	Sherburne	9/1/2020	1	96
326	Redwood	9/14/2020	0.86	61
327	Chisago	9/14/2020	1	10
328	Waseca	9/15/2020	1	8
329	Chippewa	9/16/2020	1	188
330	Redwood	9/16/2020	1	152
331	Waseca	9/21/2020	1	6
332	Steele	9/22/2020	1	402
333	Nicollet	9/22/2020	1	16
334	Washington	9/28/2020	1	10
335	Redwood	9/28/2020	1	14
336	Freeborn	9/29/2020	1	6
337	Wright	10/1/2020	1	141
338	Dodge	10/6/2020	1	15
339	Dakota	10/6/2020	1	8
340	Clay	10/8/2020	1	201
341	Clay	10/8/2020	1	16
342	Clay	10/8/2020	1	176
343	Clay	10/8/2020	1	10
344	Nicollet	10/8/2020	1	198
345	Benton	10/14/2020	1	42
346	Rice	10/15/2020	0.7	167
347	Kandiyohi	10/19/2020	1	232
348	Kandiyohi	10/19/2020	1	16
349	Washington	10/20/2020	1	222
350	Clay	10/21/2020	1	177
351	Goodhue	10/26/2020	1	17
352	Waseca	10/27/2020	1	177
353	Renville	10/29/2020	1	38
354	Freeborn	10/30/2020	1	218
355	Chippewa	10/30/2020	1	11
356	Benton	11/3/2020	1	13
357	Dakota	11/4/2020	1	8
358	Goodhue	11/5/2020	1	26
359	Dodge	11/9/2020	1	186
360	Olmsted	11/9/2020	1	240

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
361	Sherburne	11/10/2020	1	15
362	Dodge	11/16/2020	1	165
363	Rice	11/19/2020	1	10
364	Goodhue	11/19/2020	1	235
365	Dodge	11/23/2020	1	20
366	Winona	11/30/2020	1	205
367	Stearns	12/1/2020	1	28
368	Renville	12/4/2020	1	198
369	McLeod	12/4/2020	1	27
370	Lyon	12/7/2020	1	34
371	Stearns	12/9/2020	1	7
372	Chisago	12/9/2020	1	9
373	Carver	12/10/2020	1	25
374	Chisago	12/11/2020	1	10
375	Pope	12/14/2020	1	12
376	Pope	12/14/2020	1	16
377	Stearns	12/16/2020	1	22
378	Nicollet	12/17/2020	1	8
379	Pope	12/21/2020	1	26
380	Rice	12/21/2020	1	14
381	Pope	12/28/2020	1	22
382	McLeod	12/30/2020	1	30
383	Dodge	1/4/2021	1	54
384	Dodge	1/4/2021	1	9
385	Waseca	1/6/2021	1	39
386	Le Sueur	1/28/2021	1	32
387	Kandiyohi	2/2/2021	1	29
388	Blue Earth	3/2/2021	1	7
389	Stearns	3/22/2021	0.86	8
390	Rice	3/23/2021	0.83	10
391	Rice	3/25/2021	1	36
392	Redwood	3/31/2021	1	14
393	Redwood	3/31/2021	0.86	23
394	Waseca	4/7/2021	1	37
395	Benton	4/21/2021	1	94
396	Benton	4/22/2021	1	9
397	Sherburne	6/2/2021	1	12
398	Washington	6/8/2021	1	30
399	Steele	6/16/2021	1	7
400	Rice	7/9/2021	1	11

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
401	Wright	7/13/2021	4	19
402	Dodge	7/13/2021	0.78	11
403	Pope	7/20/2021	1	10
404	Renville	7/20/2021	1	12
405	Renville	7/21/2021	1	11
406	McLeod	7/21/2021	1	15
407	Chisago	7/21/2021	1	31
408	Chisago	8/3/2021	1	6
409	Chisago	8/3/2021	1	24
410	Pipestone	8/5/2021	1	13
411	Goodhue	8/13/2021	1	12
412	Benton	8/19/2021	0.7	10
413	Pope	9/1/2021	1	22
414	Le Sueur	9/2/2021	1	10
415	Pope	9/23/2021	1	8
416	Goodhue	9/28/2021	1	14
417	Le Sueur	9/29/2021	1	25
418	McLeod	10/12/2021	1	14
419	Le Sueur	10/22/2021	1	20
420	Blue Earth	11/30/2021	1	14
421	Renville	11/30/2021	1	11
422	Goodhue	11/30/2021	1	13
423	Chisago	12/8/2021	1	15
424	Chisago	12/8/2021	1	10
425	Chisago	12/16/2021	1	27
426	Wright	12/22/2021	1	14
427	Nicollet	2/16/2022	1	8
428	Waseca	3/10/2022	1	12
429	Waseca	4/20/2022	1	9
430	Yellow Medicine	4/28/2022	1	9
431	Renville	5/12/2022	1	25
432	Wabasha	5/31/2022	1	9
433	Blue Earth	6/1/2022	1	14
434	Winona	6/9/2022	1	22
435	Blue Earth	6/9/2022	1	8
436	Benton	6/10/2022	1	21
437	McLeod	8/5/2022	0.427	7
438	Dodge	8/11/2022	1	10
439	Redwood	8/24/2022	1	10
440	Dodge	8/26/2022	0.48	17

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
441	Chisago	8/31/2022	1	9
442	Lyon	9/8/2022	1	10
443	Dodge	9/9/2022	1	13
444	McLeod	9/28/2022	1	11
445	Renville	10/13/2022	1	9
446	Hennepin	11/10/2022	0.125	26
447	Renville	11/29/2022	1	9
448	Lyon	12/5/2022	1	25
449	Chippewa	12/6/2022	1	19
450	Murray	12/8/2022	1	17
451	DOUGLAS	12/9/2022	0.453	11
452	Ramsey	12/9/2022	0.25036	9
453	Le Sueur	12/9/2022	1	10
454	Sherburne	12/12/2022	1	14
455	Chippewa	12/13/2022	1	10
456	Sibley	12/14/2022	1	10
457	Renville	12/16/2022	1	9
458	Blue Earth	12/19/2022	1	9
459	Renville	12/19/2022	1	7
460	Wabasha	12/20/2022	1	10
461	Renville	12/20/2022	1	9
462	Goodhue	12/22/2022	1	20
463	Winona	12/28/2022	1	10
464	Renville	1/10/2023	1	9
465	Sibley	1/12/2023	1	14
466	Olmsted	2/21/2023	1	10
467	Chisago	3/28/2023	1	11
468	Chisago	5/1/2023	1	8
469	Wright	5/30/2023	1	9
470	Waseca	6/9/2023	1	7
471	Stearns	6/13/2023	1	10
472	Yellow Medicine	6/15/2023	1	11
473	Steele	6/19/2023	1	19
474	McLeod	6/19/2023	1	35
475	Renville	6/20/2023	1	42
476	Carver	6/21/2023	1	13
477	Nicollet	6/26/2023	1	7
478	Sibley	6/26/2023	0.96	7
479	Meeker	6/28/2023	1	10
480	Sherburne	7/19/2023	1	14

Number	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2023)
481	Blue Earth	9/6/2023	1	14
482	Lyon	9/13/2023	1	7
483	Blue Earth	9/14/2023	1	9
484	Pope	9/15/2023	1	11
485	Stearns	9/27/2023	1	12
486	Wabasha	10/25/2023	1	12
487	Wabasha	10/25/2023	0.999	8
488	Winona	10/25/2023	0.999	10
489	McLeod	10/30/2023	0.999	27
490	Goodhue	11/6/2023	0.999	8
491	Renville	11/15/2023	0.88	15
492	Chippewa	11/21/2023	1	14
493	Stearns	11/22/2023	1	112
494	Chisago	11/30/2023	1	8
495	Chippewa	12/4/2023	0.999	0
496	Chisago	12/18/2023	0.8	0
497	Blue Earth	12/18/2023	0.999	0
498	Blue Earth	12/19/2023	0.6216	0
499	Rice	12/20/2023	0.999	0
500	Sherburne	12/20/2023	0.999	0
501	Renville	12/21/2023	0.999	0
502	Washington	12/21/2023	0.999999	0
503	Renville	12/27/2023	0.999	0

* Data represents subscriptions through November. Projects completed in December had yet to receive bill credits are therefore are not yet counted here.

XCEL ENERGY, INC.
NSP PEAK DEMAND AND ELECTRIC CONSUMPTION FORECAST

Forecast Methodology

Overall Methodological Framework

The NSP System serves five jurisdictions. Minnesota, North Dakota, and South Dakota are served by Northern States Power Company, a Minnesota corporation (NSPM). Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The NSPM and NSPW Systems operate as an integrated system. Each class in each jurisdiction is modeled using econometric regression analysis or a historical average:

1. ***Econometric Analysis*** – Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:
    a. Residential without Space Heating;
    b. Residential with Space Heating;
    c. Small Commercial and Industrial;
    d. Large Commercial and Industrial (NSPM);
    e. Public Street and Highway Lighting (Minnesota);
    f. Other Sales to Public Authorities (Minnesota);
    g. Total System MW Demand Forecast.

   Inputs to these models include: economic and demographic series specific to the jurisdiction being modeled, weather variables (Heating Degree Day or "HDD" and Temperature-Humidity Index or "THI"), class customer counts, and binary variables. The historical sales series for NSPM are adjusted to remove the effects of DSM and DG Solar prior to modeling, and the resulting forecast series are then adjusted to include these effects. Sales are also adjusted to include the predicted impacts of EV adoption, BE, and new or lost LCI loads.

2. ***Historical Average*** is used for "Other" MWh sales sectors, which includes Public Street and Highway Lighting (all states except Minnesota), Other Sales to Public Authorities (Michigan, North Dakota, and Wisconsin), Interdepartmental (Michigan, Minnesota, and Wisconsin), and Large Commercial and Industrial (Michigan and Wisconsin).

3. ***Line Loss Calculation -*** since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed by modeling actual historical loss factors and estimating losses for the first forecast year (2024). These factors are held constant over the forecast period. Native energy requirements at the generator are calculated by grossing the sales forecast at meter for line losses using a loss factor specific to each jurisdiction.

4. **Peak forecasting** - The peak forecast methodology was recently updated to better account for the potential peak shifting due to future adoption of Distributed Solar Generation (DG Solar), managed and unmanaged Electric Vehicle (EV) charging, and Beneficial Electrification (BE). These technologies will gradually change the overall NSP load shape and shift the peak hour later in the day or into the early morning due to managed EV charging. The prior monthly peak modeling approach could not

account for time shifting; therefore, the static assumption would be that NSP will continue to peak at the same time as the historical series being modeled.

The new "8760" peak modeling approach uses Metrix LT to construct and forecast value for each hour of the forecast timeframe. Base energy, EV, BE, DG Solar, Large CI Data Centers, and Energy Efficiency hourly profiles are scaled using monthly energy assumptions for each specific component and on a state-by-state basis[1]. All component curves are then aggregated, and the maximum hourly load by month is calculated. The resulting peaks largely align with the Company's old monthly modeling process for the first few years of the forecast timeframe. However, adoption of rooftop solar generation eventually pushes summer peaks later into the evening, and increased EV penetration with charge management programs moves peaks to 1 AM by the early 2040s.

Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

Modeling Data

Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimates are added to the net peak demand to derive the base peak demand.

Monthly weather data is collected for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire metropolitan areas. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically, they are accessed from IHS Markit, and reflect the most recent values of those series at the time of modeling.

[1] The Base energy curve is also scaled to include a Base monthly peak demand outlook that assumes no new technologies and no change in customer behavior from the present.

Demand-Side Management Programs

The Company sponsors demand-side management ("DSM") programs in the Minnesota and South Dakota jurisdictions. There are no Company-sponsored DSM programs in the North Dakota, Michigan, or Wisconsin jurisdictions. For Minnesota and South Dakota, the regression model results for the Residential and Commercial and Industrial classes are reduced to account for the expected impacts of DSM programs.

The DSM methodology utilizes a transparent method for projecting the impacts of energy efficiency and load management on sales forecasts. There are three distinct steps to this process:

- Collect and calculate historical and current effects of DSM on observed sales;
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales to show hypothetical case without DSM);
- Adjust the forecast to show the impact of all planned DSM in future years.

The first step involves collecting data involving any measure that would cause an impact on the time period utilized in the sales forecast. In the 2024V1 modeling, the Company used the time period from 2009 to December 2023 and therefore the historical DSM would include any measure that results in decreased sales in any (or all) years from 2009 through December 2023. Since the vast majority of DSM measures have a lifetime greater than one year (exceptions include but are not limited to behavioral energy savings programs), the impact on sales will include the year that a measure is installed as well as any years that follow until the measure has reached the end of its useful life. For example, a residential lighting measure that was installed in 2008 and has a life of 6 years will result in a sales reduction from 2008 to 2013 (6 full calendar years). Though a measure may be installed in June of 2008 and would persist until May of 2013, the Company believes that the simplifying case in which all measures are installed for the entire calendar year is sufficient.

Due to the wide variation of measures available to customers, the Company sums the savings for each year by DSM program to optimize the level of detail and depth of history included in the model. Achievement data are from the approved Conservation Improvement Program (CIP) Status Reports filed annually for each year since 1996.

Adjustments for distributed solar generation

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. Impacts of customer sited behind-the-meter solar installations on the NSP system were extracted from this forecast and used to develop adjustments to reduce the class level sales for Minnesota and the NSP System peak demand forecast.

Xcel has calculated and metered the historical impact of distributed solar generation on customer sales and peak demands.

Once the total impact of DSM in effect and distributed solar generation is calculated for each year, a hypothetical sales data set is created. This series consists of the observed sales from 2009 through December 2023 plus the effective DSM calculated for all DSM measures installed in that year as well is achieved savings from programs in prior years that are still within the useful measure life, plus the historical distributed solar generation.

In the second step, the hypothetical sales data is used to generate a sales forecast that has entirely excluded the impacts of Company-sponsored DSM and distributed solar generation. It is important to note that customer-initiated DSM or DSM due to codes and standards (naturally occurring DSM) is not calculated as part of the CIP. The methodology to account for codes and standards changes is described below.

In the third step, once the sales forecast based on hypothetical sales has been generated, the Company adjusts the forecast to account for future DSM and future distributed solar generation. The forecast of future distributed solar generation is developed by Xcel Energy's Load Research Department. A monthly forecast of the impact of new DSM programs (excluding Saver's Switch) is developed by Xcel Energy's DSM Strategy and Policy Department. The future DSM sales volumes are combined with the continuing impacts of historical DSM measures and future solar generation and used to reduce the class level sales forecasts that result from the regression modeling process to determine the DSM and solar-adjusted sales. Impacts from all program installations through December 2023 are assumed to be imbedded in the historical data, so only new program installations and the continuing impact of historical programs are included in the DSM-solar generation adjustment. The source for Company-sponsored DSM adjustments is based on the CIP Plan in effect at the time of the forecast.

The Company's Saver's Switch program results in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

Data Adjustments and Assumptions

1. Weather Adjustments. Xcel Energy adjusts calendar month weather data to reflect billing month schedules before using the series to model monthly billing cycle sales.

2. Demand Forecast Wholesale Adjustment. An adjustment to account for terminating firm wholesale customer contracts was incorporated into the development of the peak demand forecast. Estimated historical coincident peak demand and energy for all firm wholesale customers were removed from the regression model data to create a consistent data series for retail demand and energy.

3. The sales and peak demand series were adjusted to account for recent or planned future changes in production and/or customer owned generation for several large customers.

4. Electric Vehicle Adjustments - the penetration of electric vehicles in Xcel Energy's service territory has been increasing over the past few years and is expected to continue increasing. Because this trend of increasing electric vehicle penetration is expected to continue, the Residential sales forecasts have been adjusted for to account for future electricity usage from home charging of electric vehicles. In addition, the Small Commercial and Industrial and Large Commercial and Industrial sales forecasts have been adjusted to account for future electricity usage from the charging of medium-duty and heavy-duty electric vehicles.

Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and practical one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Markit, and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Weather Assumption. Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 2003-2023. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

3. Loss Factor Assumptions. The loss factors are used to convert the at meter sales forecast to an at generator energy requirements figure. Xcel Energy uses regression modeling to analyze line losses for each jurisdiction and then projects a typical forecast year's loss factor.

Docket or Rule	Order Date	Rule or Order Point	Description	May 1, 2024 Annual Forecast of Rates	March 1, 2027 Annual True-Up Filing
Rule 7825.2800	NA	All public utilities shall file annually on September 1 of each year the procurement policies for selecting sources of fuel and energy purchased, dispatching policies, if applicable, and a summary of actions taken to minimize cost including conservation actions for gas utilities.	Policies and Actions: Fuel Procurement	Part D, Attachment 1	Part D, Attachment 1
			Nuclear Fuel Component of Service	Part D, Attachment 2	Part D, Attachment 2
			Coal Contracts	Part D, Attachment 3	Part D, Attachment 3
			Transportation & Related Services Contracts	Part D, Attachment 4	Part D, Attachment 4
			Wood and RDF Contracts	Part D, Attachment 5	Part D, Attachment 5
			Cost Changes	Part D, Attachment 6	Part D, Attachment 6
			Policies and Actions: Dispatching Policies and Procedures	Part D, Attachment 7	Part D, Attachment 7
			Policies and Actions: Fuel Supply	Part D, Attachment 8	Part D, Attachment 8
			Policies and Actions: Conservation and Load Management Policy	Part D, Attachment 9	Part D, Attachment 9
			Policies and Actions: Other Actions to Minimize Costs	Part D, Attachment 10	Part D, Attachment 10
Rule 7825.2810; E,G999/AA-04-1279	December 7, 2005	A. the commission-approved base cost of fuel or gas as defined by part 7825.2400, subpart 4 or 4a;	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Part A, Attachment 1 and discussed in Petition	Report Narrative
Rule 7825.2810; E,G999/AA-04-1279		B. billing adjustment amounts, such as Kwh, Mcf, Ccf, or Btu, charged customers for each type of energy cost, such as nuclear, coal, purchased power, purchased gas by major component, peak shaving gas, or manufactured gas;	Annual Report of Automatic Adjustment Charges: Billing Adjustment Amounts Charged to Customers for Each Type of Energy Cost	Discussed in Petition	Part A
Rule 7825.2810; E,G999/AA-04-1279		D. the total cost of fuel or gas delivered to customers including, for gas utilities, the cost of supply-related services;	Annual Report of Automatic Adjustment Charges: Total Cost of Fuel Delivered to Customers	Discussed in Petition	Part A
Rule 7825.2810; E,G999/AA-04-1279		E. the revenues collected from customers for energy delivered;	Annual Report of Automatic Adjustment Charges: Revenue Collected from Customers for Energy Delivered	Discussed in Petition	Part A
Rule 7825.2810; E,G999/AA-04-1279		F. billing adjustments, supplier refunds, and any refunds credited to customers.	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Part A, Attachment 1 and discussed in Petition	Part A, Attachment 4
Rule 7825.2820 Rule variance approved in E999/CI-03-802	NA	By September 1 of each year, all gas and electric utilities shall submit to the commission an independent auditor's report evaluating accounting for automatic adjustments for the prior year commencing July 1 and ending June 30 or any other year if requested by the utility and approved by the commission. The commission shall approve the request unless it finds that to do so would seriously affect the administration of the automatic adjustment reporting program.	Memo Engaging Auditor	NA	Part E, Attachment 1
			Independent Auditor’s Report	NA	Part E, Attachment 2
Rule 7825.2830 Rule variance approved in E999/CI-03-802	NA	By September 1 of each year, electric utilities shall submit to the commission a five-year projection of fuel costs by energy source by month for the first two years and on an annual basis thereafter.	5-Year Fuel Cost Forecast – Per Unit Summary	Part A, Attachment 1 Part E, Attachment 1	NA
			5-Year Fuel Cost Forecast – Cost Summary	Part A, Attachment 2 Part E, Attachment 2	NA
			5-Year Fuel Cost Forecast – Energy Summary	Part A, Attachment 3 Part E, Attachment 3	NA
			Fossil Fuel Costs	Part B, Attachment 2	NA
			Coal Burn Expenses	Part B, Attachment 3	NA
			Nuclear Fuel Expenses	Part B, Attachment 4	NA
			Peak Demand and Energy Requirements	Part A, Attachment 4 Part E, Attachment 4	NA
			Estimated Load Management Impact	Part E, Attachment 5	NA
Rule 7825.2840	NA	By September 1 of each year, all gas and electric utilities shall provide notice of the availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the previous two general rate cases.	Notice of Reports Availability	Addendum to Petition	Part F, Attachment 7
E002/M-01-1953 and E,G/999-AA-02-950	March 20, 2002	Approved the Company’s proposed method to separate, for accounting purposes, the costs and effects of financial instruments purchased to meet the needs of retail electric or natural gas ratepayers from the financial instruments purchased to mitigate price risk in the Company’s non-jurisdictional wholesale electric sales activity.	Natural Gas Financial Instruments	NA	Report Narrative Part E, Attachments 1 and 2
E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85	July 17, 2002; October 4, 2004; December 27, 2022	Summarize curtailment events in its annual automatic adjustment (AAA) report; require Xcel to identify in its monthly fuel adjustment report the date, length, cost to ratepayers, and reason for each Voluntary Curtailment, all such events should be summarized in the Company's annual automatic adjustment (AAA) report.	Wind Curtailment Summary	NA	Part C, Attachment 2
E,G999/AA-04-1279	April 4, 2006	Track curtailments and curtailment payments that result from a lack of transmission capacity and report annually with Xcel's AAA information.	Wind Curtailment Report Narrative	Discussed in Petition Part G, Workpaper 6	Part C, Attachment 1
E002/M-08-1098	January 29, 2009	Xcel shall report in its annual automatic adjustment reports whether Xcel obtains any revenue from any source as result of the REPA and to itemize any such revenues by source and amount.	KODA PPA	NA	Part F, Attachment 1
E002/M-13-867	September 17, 2014	Commission directed the Company to “include information about its bill credits, as reported in its Annual Compliance Report in this docket, in the Company’s annual FCA Annual Automatic Adjustment (AAA) Report, reflecting the same time period covered by the AAA report.	Community Solar Gardens	Discussed in Petition Part B, Attachment 12 Part G, Workpaper 5	Part C, Attachments 8, 9, 10 Report Narrative
E999/AA-15-611	July 21, 2017	All electric utilities shall identify all dockets in which the Commission has granted rule variances to a utility’s FCA (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA).	FCA Rule Variance Dockets	Discussed in Petition Part C, Attachment 2	Part F, Attachment 4
E002/M-17-532	February 1, 2018	Letter whereby Xcel committed to provide the Commission with additional supporting information about the interim costs associated with the HERC PPA.	HERC	NA	Part F, Attachment 1
E002/M-04-1970 E,G999/AA-06-1208 E002/GR-05-1428	December 20, 2006	Each utility shall file as part of its electric AAA report certain additional information regarding its plans with respect to acquiring fuel and purchased energy.	Summary of key factors affecting costs in the forecast, and plan for acquiring fuel and purchased energy.	Discussed in Petition	NA

Docket or Rule	Order Date	Rule or Order Point	Description	May 1, 2024 Annual Forecast of Rates	March 1, 2027 Annual True-Up Filing
E002/M-04-1970 E,G999/AA-06-1208	February 6, 2008	All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall provide information requested by the Department in docket E,G-999/AA-07-1130 according to the spreadsheet attached to the 2007 Report pertaining to MISO Day 2 charges, one for every month in the AAA period and as a summary of MISO Day 2 charges for the entire AAA period, for a total of 13 pages in each utility's AAA filing.	Monthly MISO Day 2 charges and allocation	Discussed in Petition Part B, Attachment 9 Part F, Workpaper 5	Part B
E002/00-257, *et al.* E999/AA-11-792	May 9, 2002 August 16, 2013	Report, as part of its Annual Automatic Adjustment of Charges report (AAA) tiled under Minnesota Rules part 7825 2800, the following : a) The Schedule 10 administrative charges paid to the MISO under the MISO tariff, and b) Any amount of MISO administrative charge deterred by the MISO for later recovery.	Schedule 10 Administrative Charge Paid to MISO	NA	Part B, Attachment 1
E002/M-08-528	August 23, 2010	The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 et seq., including the annual filing required thereunder.	Annual and Daily Ancillary Services market charges and summary	NA	Part B
E,G999/AA-06-1208	February 6, 2008	All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.	Generation facilities maintenance expenses	NA	Part C, Attachment 6
E999/AA-08-995	March 15, 2010	All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages.	Contractor and supplier performance	NA	Part C, Attachment 3
E999/AA-09-961 E999/AA-10-884	April 6, 2012	Xcel shall report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the 6 IOUs shall clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.	Offsetting Revenues and/or compensation Received by IOUs	NA	Part F, Attachment 1
E999/AA-08-995 E999/AA-10-884	April 6, 2012	The Commission requests Xcel to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requests the companies to discuss amongst themselves whether and what kind of information sharing would be beneficial. The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E-999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.	Handling of forced outages	NA	Part C, Attachments 3, 4, 5
E999/AA-09-961 E999/AA-10-884	April 6, 2012	Xcel shall provide footnotes in future monthly FCA filings and future AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis.	Unusual Adjustments over $500,000	NA	Part F, Attachment 3
E999/AA-18-373	November 13, 2019	Xcel shall identify and include error reports in future AAA filings and annual FCA true-up filings under the new FCA reform process.			
E002/M-15-985	February 27, 2017	Xcel shall provide in its Annual Automatic Adjustment reports a separate section discussing the pilot programs' impact on non-participants and the effectiveness of the neutrality charge to address any cost shift between participants and nonparticipants.	Renewable*Connect Neutrality	Discussed in Petition Part G, Workpaper 8	Part F, Attachment 2
E002/AA-23-153	November 9, 2023	Required Xcel Energy to report on the prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition.	Prudency of unplanned outages	NA	Part C, Attachment 4
E002/AA-23-153	November 9, 2023	Required Xcel Energy to provide the following in its next FCA true-up petition: a. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors after curtailment. b. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors if no curtailment had occurred	Wind capacity factors and curtailment	NA	Part C, Attachment 2b
E999/CI-03-802	March 14, 2024	Ordered the utilities in their future initial FCA filings, to incorporate answers to the recurring information requests, including the most recent three-year average of actual annual data compared to forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages and a comparison of the actual winter energy purchase amounts to the forecast amounts, with an explanation of a variance of five percent or greater.	Recurring Information Requests	Discussed in Petition; Part H, Attachments 1-5; Part G Workpaper 6	TBD

The Commission's July 21, 2017 Order in Docket No. E999/AA-15-611 requires electric utilities to identify all dockets in which the Commission has granted rule variances to a utility's Fuel Clause Adjustment (such as those authorizing true-up provisions, those allowing costs of purchased power adjustments to flow through the FCA, and those allowing MISO costs and revenues to be included in the FCA). The variances and dockets pertaining to the 2024 Fuel Forecast True-Up reporting period are listed below.

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, E,G002/M-97-985, E002/M-17-530, E002/M-17-531, E002/M-17-532, E002/M-17-551, and E002/M-17-694
- Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017, June 12, 2019, and November 5, 2019
- 2021 Fuel Forecast and Factors – E002/AA-20-417, Order dated July 5, 2022, and Compliance Filing dated November 17, 2023
- 2022 Fuel Forecast and Factors– E002/AA-21-295, Order dated June 30, 2023
- 2023 Fuel Forecast and Factors – E002/AA-22-179, Order dated December 5, 2022, Rate Adjustment filing dated May 21, 2023, and Rate Adjustment filing dated November 21, 2023
- 2024 Fuel Forecast and Factors – E002/AA-23-153, Order dated November 9, 2023 in reference to Jurisdictional Allocation

For the 12 months ending December 31, 2024, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, renewable energy purchase agreements, Windsource exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
    - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
    - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009

  - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
  - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009
  - Best Power, LLC, Amendment approved in E002/M-14-490, Order dated September 8, 2014
  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
  - Big Blue, LLC, Amendment approved in E002/M-13-1002, Order dated February 27, 2014.
  - Hilltop, E002/M-08-47, Notice of Approval dated February 15, 2008
  - Valley View, E002/M-08-1235, Order dated March 9, 2009
  - Ridgewind, E002/M-08-1428, Notice of Approval dated January 2, 2009
  - Moraine II, Amendment approved in E002/M-19-58, Order dated March 25, 2019
  - Ewington Energy Systems LLC, E002/M-06-1472, Notice of Approval dated November 30, 2006
  - Uilk Wind Farm, LLC, E002/M-08-1502, Notice of Approval dated February 6, 2009
  - Prairie Rose Wind, LLC, E002/M-11-713, Order dated December 28, 2011
  - Diamond K Dairy, E002/M-10-486, Order dated August 26, 2010
  - School Sisters, E002/M-15-619, Order dated September 14, 2015
  - Aurora Solar, E002/M-15-330, Order dated August 2, 2015
  - Marshall and NorthStar Solar, E002/M-14-162, Order dated March 24, 2015
  - Slayton Solar, E002/M-11-490, Order dated September 14, 2011
  - Dragonfly Solar, E002/M-17-561, Order dated October 12, 2017
  - University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
  - Crowned Ridge and Clean Energy #1 – E002/M-16-777, Order dated September 1, 2017
  - Dakota Range III – E002/M-18-765, Order dated July 19, 2019
  - St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177, Order dated June 21, 2010
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648
- Community Solar Gardens Program – E002/M-13-867
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33

- Renewable*Connect – Docket Nos. E002/M-19-33 and E002/M-21-222, Order dated May 18, 2023
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- General Time of Use Service – E002/M-20-86, Order dated February 1, 2023
- Acquisition of Community Wind North and Jeffers Wind Facilities – E002/PA-18-777, Order dated December 3, 2019
- Becker Land Sale – E002/PA-23-110, Order dated April 12, 2023
- Red Wing Land Sale – E002/PA-23-118, Order dated May 2, 2023

FUEL PROCUREMENT POLICIES

A. Coal

Xcel Energy's coal procurement policy provides that coal and transportation services will be purchased at the lowest reasonable cost within the constraints of environmental regulations, supply reliability, operational compatibility, and consistency with Xcel Energy's inventory needs. The Company obtains its coal through a combination of long- and short-term contracts, including spot coal markets. A listing of current coal supply and transportation contracts and cost changes is shown on Part D, Attachments 3, 4 and 6.

Formal analysis of coal supply requirements for future years is performed on a regular basis. This multi-year analysis generally leads to solicitations for offers to supply unfulfilled requirements and/or bids to purchase coal. The solicitation process typically leads to purchases to fill the targeted percentages of near-term requirements based on a layered approach that varies from station to station. For example, purchases for the King Station are targeted at **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] When the transaction terms are attractive, Xcel Energy may fill different proportions of its future requirements. Xcel Energy continually reviews the current year's coal consumption to determine changes in coal requirements caused by such variables as weather, transportation availability, outage schedule revisions, capacity factors, and alternative electric sources. If there is an imbalance during an operational year between purchased coal supplies and station requirements, the additional fuel supply need is then corrected through such means as purchases based on spot coal market and transportation conditions at that time. Xcel Energy also monitors future years' needs on a continual basis.

The coal procurement strategy addresses the risk of supply interruption and exposure to market price fluctuations. Supply interruption can result from mine and/or transportation failures. Supply diversification is used to minimize the risk of mine failures and enhance market competition. Multiple suppliers are pre-qualified for each plant. Also, new contracts for coal supply generally do not include a specific destination, which allows coal to be moved to the generating facility where it is most needed. Supply interruptions resulting from transportation failures have been minimized through plant-specific inventory targets. When transportation performance degrades, the Company initiates close contact with our rail providers at all management levels to improve and restore service levels. Where necessary, other communication channels may be explored to exert all possible pressure to improve transportation service. **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

Fuel transportation service contracts are executed for various multiyear terms depending on market conditions, anticipated future market conditions, and plant delivery requirements. Proposed rates are vetted internally and externally through consultants and are compared to peers in the market to ensure price competitiveness. The final agreements for transportation of fuels may include minimum tonnage requirements.

B. Nuclear

The spot market price for uranium started 2024 at $91.00 per pound, which is an increase of $43.25 as compared to the beginning of 2023. During the early part of the first quarter of 2024, the spot market price has ranged from $91.00 per pound to a high of $106.00 per pound in January. This market volatility is mainly due to geopolitical pressures, transportation challenges, and the potential for disruption of supply from Russia.

Overall spot market volume declined in 2023. Spot market volumes were volatile from month to month. The largest increases were in the January and September timeframes. Term contracting has continued to trend higher in 2023. Term contracting volumes rose about 2.4 percent in 2023. The 2023 term contracting volume is the highest since 2012. Continued strength in reported long-term market prices, which have risen to $68.00 per pound in December of 2023 from $51.00 per pound in December of 2022 and $32 per pound in July of 2021, has resulted in several uranium mine operators announcing restarts of existing mines. While forecasted levels of uranium production have increased, continued growth in forecasted global demand has also increased. The world's forecasted uncovered requirements of 107.1 million pounds in 2030 rises to 226.1 million pounds by 2040 as new nuclear plants are completed and existing nuclear plants in Japan are being restarted. Throughout 2024 and continuing into 2025, uranium security of supply issues remain of concern as the impact of supply chain and transportation challenges due to geopolitical pressures and Russia's on-going war in the Ukraine. Differences between supply and demand is projected to be covered by end user inventories in 2024. Spot market volume estimated at 57 million pounds of U_3O_8 for 2023 is below the 61.5 million pounds of U_3O_8 reported for 2022. Spot market volumes in 2024 are predicted to range from 43 to 86 million pounds of U_3O_8. Spot market prices for 2024 through 2026 are projected to increase at an average annual rate of about 14.1 percent from 2023. The current market analysis forecasts global supply and inventories meeting demand until 2024, with a small supply deficit projected in 2024 (1.2 million pounds) and an oversupply projected in 2025 (9 million pounds). The current market analysis forecasts a global supply deficit relative to projected demand of between 1.3 million to 13 million pounds in the years 2026 through 2029, but will continue to be dependent on the willingness of suppliers to bring new supply into the market.

The potential of western sanctions against Russia and pending legislation banning importation of enriched uranium from Russia continue to provide uncertainty with regard to price impacts or supply interruptions. Numerous U.S. utilities have contracted for supply of enriched uranium from Russia beyond 2023. If sanctions or a legislative ban on imports impact the supply of enriched uranium from Russia to customers in the U.S. or EU, either directly (or indirectly through sanctions on the banking infrastructure), the price of uranium could continue to be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

C. Natural Gas

In contracting for natural gas, a combination of baseload purchases, daily spot purchases, and storage are utilized to meet the portfolio requirements. The basic premise is that base load purchases are used to approximately meet the minimum daily portfolio requirements, and the incremental burns above the minimum requirements are met using a combination of daily spot purchases and storage.

D. Woody Biomass

Xcel Energy establishes woody biomass supply contracts with a diverse group of suppliers. Sources of woody biomass include waste products from lumber mills and wood products industries, chipped bark and limbs from municipal tree trimming operations, chipped slash from logging operations, chipped pallets and demolition debris diverted from landfills, as well as shredded creosote-treated railroad ties. All wood fuel is chipped to sizing specifications and delivered by truck to the plants. There are currently between 25 and 30 suppliers that provide wood fuel to two plants. Our practice has been to establish long-term relationships with a select group of local suppliers. The criteria for selection of suppliers are: 1) dependable supply, 2) consistent quality, and 3) reasonable pricing. By ensuring that these suppliers sustain viable small businesses, we in turn can be reasonably confident that we will receive consistent supplies of wood fuel to our plants. Contracts are typically executed with terms from 1 to 5 years. See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. We have been able to maintain biomass pricing for our power plants below pulpwood industry prices to avoid potential competition for woody biomass with the pulp and paper industry.

E. Refuse-Derived Fuel (RDF)

Xcel Energy has established five contracts for the supply of refuse-derived fuel (RDF) for three power plants (Red Wing and Wilmarth, Minnesota, and French Island, Wisconsin). See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of cost changes. Four of the contracts provide for the delivery of processed RDF to two of the plants. Xcel Energy also has a service agreement with La Crosse County, Wisconsin, which provides for the processing of municipal solid waste (MSW) into RDF and combustion of the RDF at the French Island facility in LaCrosse. Almost all of the county's MSW is processed and disposed at the Xcel Energy facility, with the exception of materials recovered for recycling, and non-combustible or non-recoverable materials and ash byproducts which are disposed in the County's landfill.

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PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of January through December 2023

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
	[PROTECTED DATA BEGINS			
1				
2				
3				
4				
5				
6				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
7				
8				
9				
10				
11				
12				
13				
14				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
15				
16				
17				
18				
19				
20				
				PROTECTED DATA ENDS]

Coal Contracts

	Supplier & Corporate Headquarters Location	**Description of Fuel or Services**	**Quantity or Volume (million tons/year)**	**Contract Expiration Date**
[PROTECTED DATA BEGINS				
1				
2				
4				
5				
6				
7				
8				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
				PROTECTED DATA ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
1				
2				
3				
4				
5				
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Cost Changes – January 1, 2022 to January 1, 2023

	Contract	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

Cost Changes – January 1, 2022 to January 1, 2023

	Contract*	Percent Change
[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS		
		PROTECTED DATA ENDS]

*The majority of wood contracts are renewed with similar terms on an annual basis. The cost change represented is the related contract price on January 1, 2023 compared to the contract price on January 1, 2024.

DISPATCHING POLICIES AND PROCEDURES

The goal for Xcel Energy's dispatching policies and procedures is to provide our native load customers with low-priced reliable electric energy services. This goal is achieved primarily by closely monitoring our load and managing our generation system and purchased energy resources to provide the most economic loading of our own generation units in conjunction with leveraging the competitive wholesale energy and fuel markets. We discuss the Company's policies about self-commitment and self-scheduling of plants in our March 1 annual report filed in Docket No. E999/CI-19-704.

Xcel Energy devotes significant resources to managing our participation in MISO's wholesale energy market, which began operation on April 1, 2005 and increased functions on January 6, 2009. The MISO market altered the method by which we optimize our resources on behalf of our ratepayers, since all resources and load must be scheduled and cleared through MISO's Day Ahead and Real Time markets. However, this change has not altered our overarching goal of reliably providing our customers with the lowest possible energy cost. The Company continues to purchase energy in the the MISO Day Ahead and Real Time markets whenever the market price of purchased energy is below our avoided cost of production. Additionally, we continue to work with MISO to coordinate our efforts to obtain maximum value of our generation and purchased resources for customers.

The Company uses MISO Ancillary Services Market to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers.

Another component of the Company's dispatching policy is forecasting how much wind will be on the system at a given time. The Company developed a wind generation forecasting tool in partnership with the National Center for Atmospheric Research. Xcel Energy uses this tool to forecast output from all NSP system wind farms, resulting in a reduction of wind forecast error. Similarly, Xcel Energy uses a solar forecast developed in conjunction with Global Weather Corporation (GWC) to estimate production from NSP system solar facilities. Reductions in forecast error translate directly into a long term decrease in fuel and purchased power costs because improved forecast for renewable energy reduces the need for excessive commitment of thermal resources.

In summary, Xcel Energy's dispatching policies and procedures, while focused on reliable service, are influenced by a goal of lowest cost in an uncertain environment.

Based on the best available information and analytical tools, Xcel Energy attempts to optimally offer our generation units to both minimize energy costs and mitigate the risks of higher than expected costs. These efforts include dispatching practices aimed at controlling wind curtailment costs. Given the potential uncertainties regarding load, generation plant availability, transmission limitations, and wholesale market prices, this requires continual analysis and rapid response to changing conditions, both on an expected (day ahead) and real-time basis.

FUEL SUPPLY

a. Nuclear Fuel

1. Nuclear fuel costs are economically competitive. The average total fuel cost at Prairie Island and Monticello was approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** mills/kWh in 2023.

2. **[PROTECTED DATA BEGINS BEGINS PROTECTED DATA ENDS]** have been managed to ensure security of supply and take advantage of market opportunities.

3. One contract was executed in **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

b. Fossil Fuel

1. Public documents released by the U.S. Energy Information Agency report average coal costs for utility consumption delivered in the U.S. was $2.36/MMBtu during 2022. (https://www.eia.gov/electricity/annual/html/epa_07_01.html) During this same period, Northern States Power Company – Minnesota's average delivered coal cost was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. NSP's average delivered coal cost for 2021 was **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

2. NSP has re-emphasized its program to review or modify, as appropriate, coal procurement strategy **[PROTECTED DATA BEGINS**

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3. NSP maintained contract supplies, satisfied generation coal requirements, and produced fuel expense reductions.

4. Xcel Energy Services, Inc. negotiates terms with existing major coal suppliers on behalf of NSP **[PROTECTED DATA BEGINS**

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c. MISO Energy Charges

The Company actively checks, investigates, and disputes (when appropriate) calculations and the charges billed by MISO in the Day 2 energy market. From January through December 2023, the Company submitted three disputes for operating days in 2023.

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2023	2023-03	3/2/2023	$11,350.13	$0.00	$0.00	$11,350.13
2023	2023-08	8/4/2023	$0.00	$2,500,000.00	$0.00	$2,500,000.00
2023	2023-08	8/4/2023	$0.00	$2,500,000.00	$0.00	$2,500,000.00
TOTAL			$11,350.13	$5,000,000.00	$0.00	$5,011,350.13

The total dollar amount disputed in the 2023 reporting period was $5,011,350.13, which is more than the 2022 reporting period of $1,916,558.13. There were three disputes, one was granted and two were denied. We note that the Company is currently addressing the two disputed items related to Cannon Falls with FERC. All other discrepancies not requiring a formal dispute are identified during our daily checkout process and generally resolved through the normal settlement process.

ENERGY CONSERVATION AND OPTMIZATION PROGRAM

Xcel Energy's Energy Conservation and Optimization Program (ECO) is designed to help our customers use energy wisely. The Company has developed more than 40 commercial and residential programs with the intent of providing customers the opportunity to lower their energy consumption and overall energy bills. As part of this portfolio, the Company has several electric load management programs available to customers including rate discounts for reducing electric loads on days with peak demand for electricity or rebates for participation in control events utilizing a smart thermostat.

Minn. Stat. §§ 216B.2401 and 216B.241 require certain Minnesota utilities, including Xcel Energy's electric utility, to invest in cost-effective conservation improvements through ECO. ECO programs are subject to regulation by the Minnesota Department of Commerce (Department). Currently, the Company offers a wide variety of programs that assist customers in implementing energy efficiency, load management, and efficient fuel switching measures, ranging from rebates for high efficiency equipment to home energy squad visits. By conserving energy (i.e. using less of it) and varying loads (i.e. interrupting a constant demand to lessen the peak kilowatt impact), customers will experience an overall reduction in their utility bills. Both methods mitigate the Company's power producing and purchasing needs. Moreover, both are considered in the Company's integrated resource planning process.

The Company is required to file with the Department every three years, an ECO Triennial Plan detailing our goals, budgets and cost-effectiveness analyses for the next planning cycle. A detailed description and analysis of the Company's electric conservation policy and programs may be found in the Company's current 2024-2026 ECO Triennial Plan,[1] which was filed on June 29, 2023 and approved on December 1, 2023.[2]

On April 1 of each year, the Company is required to file with the Department an annual Status Report, which details the cost-effectiveness and spending for the prior year's program. The Deputy Commissioner issued approval of the Company's 2022 Status Report on July 6, 2023.[3]

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[1] Minn.Stat. §216B.241 was adjusted in 2021 to enact changes to the Conservation Improvement Plan to modernize its scope to include additional load management technologies and beneficial electrification. This change is under the Energy Conservation and Optimization Act or ECO.
[2] Docket No. E,G002/CIP-23-92
[3] Docket No. E,G002/CIP-20-473

OTHER ACTIONS TO MINIMIZE COSTS

The Company continues to actively represent the interests of its Minnesota electric customers before national regulatory agencies to minimize the cost of wholesale electric supplies and third party transmission services to be recovered from Minnesota retail electric customers. The Company does this as an individual intervenor, through intervenor groups such as the MISO Transmission Owners (TOs), and through its membership in the Edison Electric Institute (EEI), which actively represents its members in major policy proceedings such as Federal Energy Regulatory Commission (FERC) rulemakings.

1. PARTICIPATION IN THE MISO TRANSMISSION OWNERS COMMITTEE

Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW) are transmission-owning members of MISO. NSPM and NSPW (jointly, the NSP Companies)[1] participate in the MISO Transmission Owning Committee (TOC). Not all MISO transmission-owning companies participate in the TOC.

The MISO TOC members jointly intervene in numerous FERC and other proceedings. The MISO TOC members own a substantial portion of the transmission facilities subject to MISO functional control, representing approximately two-thirds of all load in the MISO footprint. Other Minnesota entities that are MISO TOC members include Great River Energy, Minnesota Power, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, ITC Midwest, LLC, Minnesota Municipal Power Agency, and Central Minnesota Municipal Power Agency. NSPM is also a participant on the Transmission Owners Tariff Working Group, which makes recommendations to the TOC on certain rate and revenue distribution changes pursuant to the MISO Transmission Owners Agreement (TOA). Xcel Energy representatives also participate in all other MISO committees, such as the Market Sub-Committee, Planning Advisory Committee, Reliability Sub-Committee and Regional Criteria and Benefits Working Group. These committees are critical to ensuring the development of transmission system additions that achieve maximum efficiency benefits.

[1] The Company and NSPW are jointly referred to as the "NSP Companies," and their integrated electric generation and transmission system is referred to as the "NSP System."

2. SIGNIFICANT MISO DEVELOPMENTS/ACTIONS

The Company has been active in a number of proceedings before the FERC. To the extent the Department or the Commission or another stakeholder desires information related to specific proceedings, the Company will provide the additional information upon request.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #														
1	*Costs in $1,000's*	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	2026 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$9,906	$15,597	$24,606	$26,875	$32,591	$36,245	$35,984	$31,745	$24,953	$18,197	$10,818	$6,948	$274,465
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($5,383)	($8,491)	($17,059)	($19,589)	($23,925)	($24,281)	($19,818)	($18,232)	($16,497)	($12,220)	($7,441)	($4,506)	($177,443)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable Connect Pilot MWh Sales**													
46	**Less Renewable Connect MTM MWh Sales**													
47	**Less Renewable Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Juris. MWh Sales**													
54														
55	**Less Renewable Connect Pilot MWh Sales**													
56	**Less Renewable Connect MTM MWh Sales**													
57	**Less Renewable Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$5,383	$8,491	$17,060	$19,589	$23,925	$24,281	$19,818	$18,232	$16,497	$12,220	$7,441	$4,506	$177,443
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													
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67														
68	**Forecast MN FCA Cost in cents/kWh**													
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*Costs in $1,000's*	1/1/2027	2/1/2027	3/1/2027	4/1/2027	5/1/2027	6/1/2027	7/1/2027	8/1/2027	9/1/2027	10/1/2027	11/1/2027	12/1/2027	2027 Total
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$10,356	$16,304	$25,722	$29,151	$35,352	$39,315	$39,031	$34,433	$27,066	$19,738	$11,735	$7,536	$295,739
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($6,254)	($10,040)	($16,832)	($19,716)	($23,918)	($23,910)	($17,749)	($16,175)	($16,250)	($12,443)	($7,565)	($4,794)	($175,644)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable Connect Costs**													PROTECTED DATA ENDS]
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable Connect Pilot MWh Sales**													
46	**Less Renewable Connect MTM MWh Sales**													
47	**Less Renewable Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Juris. MWh Sales**													
54														
55	**Less Renewable Connect Pilot MWh Sales**													
56	**Less Renewable Connect MTM MWh Sales**													
57	**Less Renewable Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													
66														
67														
68	**Forecast MN FCA Cost in cents/kWh**													
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*Costs in $1,000's*	1/1/2028	2/1/2028	3/1/2028	4/1/2028	5/1/2028	6/1/2028	7/1/2028	8/1/2028	9/1/2028	10/1/2028	11/1/2028	12/1/2028	2028 Total
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$11,190	$18,722	$27,794	$31,559	$38,272	$42,563	$42,256	$37,278	$29,302	$21,368	$12,704	$8,159	$321,166
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($5,929)	($11,414)	($17,744)	($22,343)	($27,167)	($27,953)	($20,719)	($18,408)	($18,980)	($14,865)	($8,963)	($5,480)	($199,966)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable Connect Costs**													PROTECTED DATA ENDS]
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable Connect Pilot MWh Sales**													
46	**Less Renewable Connect MTM MWh Sales**													
47	**Less Renewable Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Juris. MWh Sales**													
54														
55	**Less Renewable Connect Pilot MWh Sales**													
56	**Less Renewable Connect MTM MWh Sales**													
57	**Less Renewable Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													
66														
67														
68	**Forecast MN FCA Cost in cents/kWh**													
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*Costs in $1,000's*	1/1/2029	2/1/2029	3/1/2029	4/1/2029	5/1/2029	6/1/2029	7/1/2029	8/1/2029	9/1/2029	10/1/2029	11/1/2029	12/1/2029	2029 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$12,073	$19,008	$29,988	$34,024	$41,261	$45,887	$45,556	$40,190	$31,591	$23,037	$13,696	$8,796	$345,107
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($6,396)	($12,059)	($20,233)	($25,742)	($31,217)	($32,713)	($25,009)	($21,180)	($21,870)	($17,083)	($9,894)	($6,128)	($229,525)
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable Connect Costs**													**PROTECTED DATA ENDS]**
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable Connect Pilot MWh Sales**													
46	**Less Renewable Connect MTM MWh Sales**													
47	**Less Renewable Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Juris. MWh Sales**													
54														
55	**Less Renewable Connect Pilot MWh Sales**													
56	**Less Renewable Connect MTM MWh Sales**													
57	**Less Renewable Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**													
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													
66														
67														
68	**Forecast MN FCA Cost in cents/kWh**													
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													

Northern States Power Company
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Line #	*Energy in GWhs*	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	2026 Total
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	82.5	129.9	205.0	228.3	276.8	307.8	305.6	269.6	211.9	154.6	91.9	59.0	2,322.9
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable Connect Pilot GWh**													
30	**Less Renewable Connect MTM GWh**													
31	**Less Renewable Connect LT GWh**													
32														
33	**Net System GWh**													

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #		1/1/2027	2/1/2027	3/1/2027	4/1/2027	5/1/2027	6/1/2027	7/1/2027	8/1/2027	9/1/2027	10/1/2027	11/1/2027	12/1/2027	2027 Total
1	*Energy in GWhs*													
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens													
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable Connect Pilot GWh**													
30	**Less Renewable Connect MTM GWh**													
31	**Less Renewable Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #														
1	*Energy in GWhs*	**1/1/2028**	**2/1/2028**	**3/1/2028**	**4/1/2028**	**5/1/2028**	**6/1/2028**	**7/1/2028**	**8/1/2028**	**9/1/2028**	**10/1/2028**	**11/1/2028**	**12/1/2028**	**2028 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens													
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable Connect Pilot GWh**													
30	**Less Renewable Connect MTM GWh**													
31	**Less Renewable Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*Energy in GWhs*	1/1/2029	2/1/2029	3/1/2029	4/1/2029	5/1/2029	6/1/2029	7/1/2029	8/1/2029	9/1/2029	10/1/2029	11/1/2029	12/1/2029	2029 Total
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens													
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable Connect Pilot GWh**													
30	**Less Renewable Connect MTM GWh**													
31	**Less Renewable Connect LT GWh**													
32														
33	**Net System GWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*$/MWh*	1/1/2026	2/1/2026	3/1/2026	4/1/2026	5/1/2026	6/1/2026	7/1/2026	8/1/2026	9/1/2026	10/1/2026	11/1/2026	12/1/2026	2026 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$120.06	$120.06	$120.06	$117.74	$117.74	$117.74	$117.74	$117.74	$117.74	$117.74	$117.74	$117.74	$118.16
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #														
1	*$/MWh*	1/1/2027	2/1/2027	3/1/2027	4/1/2027	5/1/2027	6/1/2027	7/1/2027	8/1/2027	9/1/2027	10/1/2027	11/1/2027	12/1/2027	2027 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$117.74	$117.74	$117.74	$119.81	$119.81	$119.81	$119.81	$119.81	$119.81	$119.81	$119.81	$119.81	$119.44
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	*$/MWh*	1/1/2028	2/1/2028	3/1/2028	4/1/2028	5/1/2028	6/1/2028	7/1/2028	8/1/2028	9/1/2028	10/1/2028	11/1/2028	12/1/2028	2028 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$119.81	$119.81	$119.81	$122.15	$122.15	$122.15	$122.15	$122.15	$122.15	$122.15	$122.15	$122.15	$121.72
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2026 - Dec 2029

Line #	$/MWh	1/1/2029	2/1/2029	3/1/2029	4/1/2029	5/1/2029	6/1/2029	7/1/2029	8/1/2029	9/1/2029	10/1/2029	11/1/2029	12/1/2029	2029 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$122.15	$122.15	$122.15	$124.44	$124.44	$124.44	$124.44	$124.44	$124.44	$124.44	$124.44	$124.44	$124.03
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**													
30	**Renewable Connect Pilot**													
31	**Renewable Connect MTM**													
32	**Renewable Connect LT**													
33														
34	**Net System $/MWh**													

PROTECTED DATA ENDS]

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Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2026

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood/Gas													
Bay Front 6	Wood/Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Inver Hills 1	Gas													
Inver Hills 1	Oil													
Inver Hills 2	Gas													
Inver Hills 2	Oil													
Inver Hills 3	Gas													
Inver Hills 3	Oil													
Inver Hills 4	Gas													
Inver Hills 4	Oil													
Inver Hills 5	Gas													
Inver Hills 5	Oil													
Inver Hills 6	Gas													
Inver Hills 6	Oil													
Inver Hills	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2027

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2027 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood/Gas													
Bay Front 6	Wood/Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC LSPower	Gas													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
Willmarth 1	Gas													
Willmarth 1	RDF													
Willmarth 2	Gas													
Willmarth 2	RDF													
Wilmarth	AVG COST													
System MN	AVG COST													

PROTECTED DATA ENDS]

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Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2028

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2028 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood/Gas													
Bay Front 6	Wood/Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC MEC I	Gas													
CC MEC II	Gas													
MEC	AVG COST													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Lyon County	Gas													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
System MN	AVG COST													

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part E, Attachment 4 - Page 4 of 4

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2029

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2029 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Bay Front 5	Wood/Gas													
Bay Front 6	Wood/Gas													
Bay Front	AVG COST													
Black Dog 25	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake 9 Recip	Gas													
Blue Lake 9 Recip	Oil													
Blue Lake	AVG COST													
CC MEC I	Gas													
Fargo	Gas													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
High Bridge 1x1	Gas													
High Bridge 2x1	Gas													
High Bridge	AVG COST													
Lyon County	Gas													
Riverside 1x1	Gas													
Riverside 2x1	Gas													
Riverside	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Wheaton 7	Gas													
Wheaton 8 Recip	Gas													
Wheaton 8 Recip	Oil													
Wheaton	AVG COST													
System MN	AVG COST													
														PROTECTED DATA ENDS]

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part E, Attachment 5 - Page 1 of 4

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2026

[PROTECTED DATA BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2026 Total AVG
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 1	Coal WY Sherburne County													
Sherburne 1	Oil													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

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Northern States Power Company
Electric Operations - State of Minnesota

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part E, Attachment 5 - Page 2 of 4

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2027

Unit	**Fuel**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**2027 Total AVG**
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2028

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2028 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													

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Northern States Power Company
Electric Operations - State of Minnesota

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2029

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2029 Total AVG
		[PROTECTED DATA BEGINS												
Allen S King	Coal													
Allen S King	Gas													
Allen S King	AVG COST													
Sherburne 3	Coal WY Sherburne County													
Sherburne 3	Oil													
Sherburne	AVG COST													
Coal	AVG COST													
														PROTECTED DATA ENDS]

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Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part E, Attachment 6 - Page 1 of 4

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2024 04-10-24 09:02:37)	Jan 2026	Feb 2026	Mar 2026	Apr 2026	May 2026	Jun 2026	Jul 2026	Aug 2026	Sep 2026	Oct 2026	Nov 2026	Dec 2026
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

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Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

Docket No. E002/AA-24-___
2025 Fuel Forecast Petition
Part E, Attachment 6 - Page 2 of 4

[PROTECTED DATA BEGINS

Item ID	Item Description (Q1-2024 04-10-24 09:02:37)	Jan 2027	Feb 2027	Mar 2027	Apr 2027	May 2027	Jun 2027	Jul 2027	Aug 2027	Sep 2027	Oct 2027	Nov 2027	Dec 2027
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PROTECTED DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Nuclear Fuel Expense (Units noted in row)

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PROTECTED DATA ENDS]

2026
2026 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,609	3,901,376	79.35%
February	6,261	3,413,421	81.13%
March	6,098	3,633,127	80.08%
April	5,318	3,121,385	81.52%
May	6,938	3,432,218	66.50%
June	8,503	3,860,981	63.07%
July	9,157	4,446,696	65.27%
August	8,800	4,234,281	64.67%
September	7,695	3,535,022	63.80%
October	5,958	3,474,467	78.38%
November	6,063	3,435,365	78.69%
December	6,578	3,885,658	79.39%
Annual	**9,157**	**44,373,999**	**55.32%**

2027
2027 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,861	4,060,695	79.54%
February	6,532	3,579,693	78.73%
March	6,379	3,815,927	80.40%
April	5,554	3,311,425	82.81%
May	7,217	3,637,126	67.73%
June	8,800	4,077,071	64.35%
July	9,501	4,690,449	66.35%
August	9,151	4,489,102	65.93%
September	8,081	3,812,662	65.53%
October	6,408	3,779,155	79.27%
November	6,539	3,763,683	79.94%
December	7,084	4,242,046	80.48%
Annual	**9,501**	**47,259,034**	**56.78%**

2028
2028 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	7,446	4,449,574	80.32%
February	7,132	3,982,824	80.24%
March	6,961	4,221,462	81.51%
April	6,192	3,731,473	83.69%
May	7,807	4,066,598	70.02%
June	9,430	4,532,688	66.76%
July	10,125	5,123,900	68.02%
August	9,704	4,882,580	67.63%
September	8,619	4,177,456	67.32%
October	6,903	4,113,655	80.10%
November	7,049	4,080,963	80.41%
December	7,531	4,535,967	80.96%
Annual	**10,125**	**51,899,138**	**58.51%**

2029
2029 Electric Production Forecast
Peak Demand and Energy Requirements

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	7,739	4,674,537	81.19%
February	7,435	4,142,447	80.05%
March	7,231	4,369,200	81.22%
April	6,423	3,851,376	83.28%
May	7,943	4,166,915	70.51%
June	9,554	4,602,819	66.91%
July	10,230	5,191,924	68.21%
August	9,772	4,931,605	67.83%
September	8,695	4,232,643	67.61%
October	6,939	4,173,298	80.84%
November	7,106	4,138,979	80.89%
December	7,635	4,590,782	80.82%
Annual	**10,230**	**53,066,525**	**59.21%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2024	9,023	1,020	8,002
2025	9,034	1,034	7,999
2026	9,157	1,048	8,109
2027	9,501	1,057	8,444
2028	10,125	1,062	9,063
2029	10,230	1,066	9,164

Part F: Modeling and Market Workpapers and Supporting Data
Part F consists of workpapers that are being submitted as live files.

Workpaper 1	PLEXOS Inputs
Workpaper 2	PLEXOS Output
Workpaper 3	Coal Pricing
Workpaper 4	Gas Pricing
Workpaper 5	MISO Charges

Part G: Fuel Forecast Workpapers and Supporting Data
Part G consists of workpapers that are being submitted as live files.

Workpaper 1	Forecast Energy and Peak Demand Summary
Workpaper 2	Hydro Historical
Workpaper 3	Pricing for Hydro PPAs
Workpaper 4	Benson Recovery
Workpaper 5	NSP Solar Gardens Forecast
Workpaper 6	NSP Wind Curtailment
Workpaper 7	Forced Outage Calculation for Baseload and Intermediate Plants
Workpaper 8	Renewable*Connect Program

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
2025 Forecast, 2021-2023 Actual Fuel, Purchased Power and Other Costs

Line #		2025			2021			2022			2023			2021 - 2023 Average		
1	*Costs in $1,000's*	Costs	GWh	$/MWh	Costs	GWh	$/MWh	Costs	GWh	$/MWh	Costs	GWh	$/MWh	Costs	GWh	$/MWh
2																
3	**Own Generation**	*Protected Data is shaded.*														
4	Fossil Fuel	**[PROTECTED DATA BEGINS**														
5	Coal				$197,754	9,265.0	$21.34	$242,848	9,523.9	$25.50	$174,754	6,451.3	$27.09	$205,119	8,413.4	$24.38
6	Wood/RDF				$9,155	533.8	$17.15	$9,781	513.5	$19.05	$9,693	505.5	$19.18	$9,543	517.6	$18.44
7	Natural Gas CC				$195,504	6,100.6	$32.05	$217,122	3,852.6	$56.36	$169,158	6,357.5	$26.61	$193,928	5,436.9	$35.67
8	Natural Gas & Oil CT				$49,824	842.6	$59.13	$46,559	528.5	$88.10	$36,196	827.8	$43.73	$44,193	733.0	$60.29
9	Subtotal				$452,237	16,742.1	$27.01	$516,310	14,418.5	$35.81	$389,801	14,142.1	$27.56	$452,783	15,100.9	$29.98
10																
11	Hydro				$0	861.1	$0.00	$0	848.0	$0.00	$0	834.3	$0.00	$0	847.8	$0.00
12	Solar										$0					
13	Wind				$0	7,264.3	$0.00	$0	9,361.3	$0.00	$0	9,238.5	$0.00	$0	8,621.4	$0.00
14																
15	Nuclear Fuel				$111,253	14,068.5	$7.91	$117,174	14,696.2	$7.97	$95,337	11,927.7	$7.99	$107,921	13,564.1	$7.96
16																
17	**Purchased Energy**															
18	LT Purchased Energy (Gas)				$146,232	4,032.0	$36.27	$155,586	2,494.9	$62.36	$135,913	4,345.2	$31.28	$145,911	3,624.0	$40.26
19	LT Purchased Energy (Solar)				$42,905	608.9	$70.47	$48,633	787.9	$61.73	$48,841	731.4	$66.78	$46,793	709.4	$65.96
20	Community Solar*Gardens (CSG)	$264,457	2,131.4	$124.08	$183,652	1,455.6	$126.17	$184,030	1,403.5	$131.12	$206,275	1,531.1	$134.72	$191,319	1,463.4	$130.73
21	LT Purchased Energy (Wind)				$194,087	5,007.6	$38.76	$244,613	6,470.0	$37.81	$208,370	5,609.5	$37.15	$215,690	5,695.7	$37.87
22	LT Purchased Energy (Other)				$176,450	2,138.6	$82.51	$190,665	2,219.6	$85.90	$186,040	2,259.5	$82.34	$184,385	2,205.9	$83.59
23	ST Market Purchases				$85,141	2,085.8	$40.82	$146,773	2,770.6	$52.98	$94,895	2,365.4	$40.12	$108,936	2,407.3	$45.25
24	MISO Market Charges				$229,886			$239,474			$148,146			$205,835		
25	Subtotal				$1,058,353	15,328.4	$69.05	$1,209,774	16,146.5	$74.92	$1,028,480	16,842.1	$61.07	$1,098,869	16,105.6	$68.23
26																
27	**Total NSP System Costs**				$1,621,843	54,264.3	$29.89	$1,843,257	55,470.5	$33.23	$1,513,618	52,984.6	$28.57	$1,659,573	54,239.8	$30.60
28																
29	**Less Sales Revenue**				($437,200)	(12,659.8)	$34.53	($564,368)	(13,721.3)	$41.13	($282,329)	(11,711.8)	$24.11	($427,966)	(12,697.7)	$33.70
30	**Less Solar Gardens - Above Market Cost**	(182,742)			($110,745)			($99,903)			($155,166)			($121,938)		
31	**Less Renewable*Connect Pilot**				($6,190)	(177.8)	$34.82	($6,291)	(183.2)	$34.33	($6,739)	(189.9)	$35.49	($6,407)	(183.6)	$34.89
32	**Less Renewable*Connect MTM**				($12,169)	(440.6)	$27.62	($18,190)	(493.3)	$36.87	($16,858)	(539.6)	$31.24	($15,739)	(491.1)	$32.05
33	**Less Renewable*Connect LT**															
34																
35	**NSP Net System Costs Excluded CSG Above Market**			$23.24	$1,055,539	40,986.2	$25.75	$1,154,506	41,072.7	$28.11	$1,052,526	40,543.2	$25.96	$1,087,524	40,867.4	$26.61
36	**& Renewable*Connect Costs**			**PROTECTED DATA ENDS]**												
37																

Northern States Power Company
Electric Utility - State of Minnesota
2025 Forecast Fuel, Purchased Power and Other Costs

Line #		2025			2023			
1	*Costs in $1,000's*	Costs	GWh	$/MWh	Costs	GWh	$/MWh	
2								
3	**Own Generation**	*Protected Data is shaded.*						2023 Delta and key drivers
4	Fossil Fuel	**[PROTECTED DATA BEGINS**						**[PROTECTED DATA BEGINS**
5	Coal				$174,754	6,451.3	$27.09	
6	Wood/RDF				$9,693	505.5	$19.18	
7	Natural Gas CC				$169,158	6,357.5	$26.61	
8	Natural Gas & Oil CT				$36,196	827.8	$43.73	
9	Subtotal				$389,801	14,142.1	$27.56	
10								
11	Hydro				$0	834.3	$0.00	
12	Solar				$0			
13	Wind				$0	9,238.5	$0.00	
14								
15	Nuclear Fuel				$95,337	11,927.7	$7.99	
16								
17	**Purchased Energy**							
18	LT Purchased Energy (Gas)				$135,913	4,345.2	$31.28	
19	LT Purchased Energy (Solar)				$48,841	731.4	$66.78	
20	Community Solar*Gardens (CSG)	$264,457	2,131.4	$124.08	$206,275	1,531.1	$134.72	-7.9% Lower solar rate due to ARR customer conversion to VOS per Commission order
21	LT Purchased Energy (Wind)				$208,370	5,609.5	$37.15	
22	LT Purchased Energy (Other)				$186,040	2,259.5	$82.34	
23	ST Market Purchases				$94,895	2,365.4	$40.12	
24	MISO Market Charges				$148,146			
25	Subtotal				$1,028,480	16,842.1	$61.07	
26								
27	**Total NSP System Costs**				$1,513,618	52,984.6	$28.57	
28								
29	**Less Sales Revenue**				($282,329)	(11,711.8)	$24.11	
30	**Less Solar Gardens - Above Market Cost**	(182,742)			($155,166)			
31	**Less Renewable*Connect Pilot**				($6,739)	(189.9)	$35.49	
32	**Less Renewable*Connect MTM**				($16,858)	(539.6)	$31.24	
33	**Less Renewable*Connect LT**							
34								
35	**NSP Net System Costs Excluded CSG Above Market**			$23.24	$1,052,526	40,543.2	$25.96	
36	**& Renewable*Connect Costs**			**PROTECTED DATA ENDS]**				**PROTECTED DATA ENDS]**
37								

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Northern States Power Company
Electric Utility - State of Minnesota
2025 Forecast Fuel, Purchased Power and Other Costs

Line #		2024			2021 - 2023 Average			
1	*Costs in $1,000's*	Costs	GWh	$/MWh	Costs	GWh	$/MWh	
2								
3	**Own Generation**	*Protected Data is shaded.*						3 Yr Avg Delta and key drivers
4	Fossil Fuel	**[PROTECTED DATA BEGINS**						**[PROTECTED DATA BEGINS**
5	Coal				$205,119	8,413.4	$24.38	
6	Wood/RDF				$9,543	517.6	$18.44	
7	Natural Gas CC				$193,928	5,436.9	$35.67	
8	Natural Gas & Oil CT				$44,193	733.0	$60.29	
9	Subtotal				$452,783	15,100.9	$29.98	
10								
11	Hydro				$0	847.8	$0.00	
12	Solar				$0	-		
13	Wind				$0	8,621.4	$0.00	
14								
15	Nuclear Fuel				$107,921	13,564.1	$7.96	
16								
17	**Purchased Energy**							
18	LT Purchased Energy (Gas)				$145,911	3,624.0	$40.26	
19	LT Purchased Energy (Solar)				$46,793	709.4	$65.96	
20	Community Solar*Gardens (CSG)	$264,457	2,131.4	$124.08	$191,319	1,463.4	$130.73	-5.1% Lower solar rate due to ARR customer conversion to VOS per Commission order
21	LT Purchased Energy (Wind)				$215,690	5,695.7	$37.87	
22	LT Purchased Energy (Other)				$184,385	2,205.9	$83.59	
23	ST Market Purchases				$108,936	2,407.3	$45.25	
24	MISO Market Charges				$205,835			
25	Subtotal				$1,098,869	16,105.6	$68.23	
26								
27	**Total NSP System Costs**				$1,659,573	54,239.8	$30.60	
28								
29	**Less Sales Revenue**				($427,966)	(12,697.7)	$33.70	
30	**Less Solar Gardens - Above Market Cost**	(182,742)			($121,938)			
31	**Less Renewable*Connect Pilot**				($6,407)	(183.6)	$34.89	
32	**Less Renewable*Connect MTM**				($15,739)	(491.1)	$32.05	
33	**Less Renewable*Connect LT**							
34								
35	**NSP Net System Costs Excluded CSG Above Market**			$23.24	$1,087,524	40,867.4	$26.61	
36	**& Renewable*Connect Costs**			**PROTECTED DATA ENDS]**				
37								

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2025

Protected Data is shaded.

Line #														
1	*Costs in $1,000's*	**1/1/2025**	**2/1/2025**	**3/1/2025**	**4/1/2025**	**5/1/2025**	**6/1/2025**	**7/1/2025**	**8/1/2025**	**9/1/2025**	**10/1/2025**	**11/1/2025**	**12/1/2025**	**2025 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens (CSG)	$10,782	$16,976	$26,783	$25,145	$30,494	$33,913	$33,668	$29,702	$23,347	$17,026	$10,122	$6,500	$264,457
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total NSP System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($6,861)	($10,803)	($20,655)	($18,849)	($22,842)	($23,821)	($20,385)	($18,373)	($16,502)	($11,990)	($7,209)	($4,452)	($182,742)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect Flex (MTM)**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable*Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect Flex (MTM) MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													31,342,179
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect Flex (MTM) MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													26,922,097
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$6,861	$10,803	$20,655	$18,849	$22,842	$23,821	$20,385	$18,373	$16,502	$11,990	$7,209	$4,452	$182,742
63	**Benson Buyout Cost**													
64														
65	**Forecast MN FCA Costs**													$888,562
66														
67														
68	**Forecast MN FCA Cost in cents/kWh**													**3.300**
69														
70														
71	**Forecast MN FCA Cost in $/MWh**													33.00

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Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2025

Protected Data is shaded.

Line #	*Energy in GWhs*	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025	11/1/2025	12/1/2025	2025 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	75.7	119.2	188.1	209.4	254.0	282.5	280.4	247.4	194.5	141.8	84.3	54.1	2,131.4
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable* Connect Flex (MTM) GWh**													
31	**Less Renewable* Connect LT GWh**													
32														
33	**Net System GWh**													42,465.0

PROTECTED DATA ENDS]

Actual Price

	Ventura		Ventura		Ventura	Initial Filing 2/28/2024	Ventura	
1/1/2021	$2.50	1/1/2022	$4.38	1/1/2023	$3.62	1/1/2025	$5.94	
2/1/2021	$32.73	2/1/2022	$4.55	2/1/2023	$2.31	2/1/2025	$5.84	
3/1/2021	$2.37	3/1/2022	$4.48	3/1/2023	$2.36	3/1/2025	$3.27	
4/1/2021	$2.47	4/1/2022	$6.29	4/1/2023	$1.93	4/1/2025	$2.84	
5/1/2021	$2.69	5/1/2022	$7.59	5/1/2023	$1.85	5/1/2025	$2.82	
6/1/2021	$3.05	6/1/2022	$7.24	6/1/2023	$2.00	6/1/2025	$2.94	
7/1/2021	$3.54	7/1/2022	$6.72	7/1/2023	$2.25	7/1/2025	$3.11	
8/1/2021	$3.83	8/1/2022	$8.17	8/1/2023	$2.28	8/1/2025	$3.12	
9/1/2021	$4.69	9/1/2022	$6.88	9/1/2023	$2.21	9/1/2025	$2.92	
10/1/2021	$5.21	10/1/2022	$5.00	10/1/2023	$2.26	10/1/2025	$2.94	
11/1/2021	$4.85	11/1/2022	$5.01	11/1/2023	$2.37	11/1/2025	$3.80	
12/1/2021	$3.60	12/1/2022	$6.81	12/1/2023	$2.06	12/1/2025	$4.93	
	$5.96		$6.09		$2.29		$3.71	$1.41
					$4.78		$3.71	-$1.08

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	On	Off	Avg		On	Off	Avg		On	Off	Avg
1/1/2021	$23.41	$20.05	$21.57	1/1/2022	$43.27	$33.58	$37.95	1/1/2023	$33.60	$26.82	$30.03
2/1/2021	$97.54	$48.34	$71.77	2/1/2022	$43.03	$34.06	$38.34	2/1/2023	$23.34	$18.02	$20.55
3/1/2021	$21.74	$14.83	$18.25	3/1/2022	$35.54	$31.06	$33.28	3/1/2023	$28.62	$22.72	$25.64
4/1/2021	$28.88	$22.36	$25.55	4/1/2022	$50.75	$37.32	$43.59	4/1/2023	$27.57	$19.19	$22.91
5/1/2021	$28.65	$22.22	$25.13	5/1/2022	$60.16	$38.09	$48.53	5/1/2023	$30.98	$16.29	$23.56
6/1/2021	$49.52	$26.93	$37.97	6/1/2022	$66.04	$38.26	$51.84	6/1/2023	$43.90	$21.09	$32.24
7/1/2021	$46.92	$30.08	$38.05	7/1/2022	$71.84	$44.35	$56.77	7/1/2023	$45.03	$26.54	$34.89
8/1/2021	$46.11	$28.86	$37.02	8/1/2022	$83.37	$49.33	$66.16	8/1/2023	$46.39	$25.27	$35.72
9/1/2021	$45.91	$32.92	$39.27	9/1/2022	$69.59	$40.93	$54.94	9/1/2023	$34.08	$24.71	$29.08
10/1/2021	$60.81	$47.00	$53.24	10/1/2022	$50.36	$31.66	$40.10	10/1/2023	$35.95	$23.80	$29.55
11/1/2021	$51.42	$38.16	$44.64	11/1/2022	$36.71	$23.59	$30.00	11/1/2023	$35.14	$25.66	$30.30
12/1/2021	$45.28	$32.18	$38.66	12/1/2022	$47.13	$34.96	$40.72	12/1/2023	$30.73	$23.28	$26.65
	$45.52	$30.33	$37.59		$54.82	$36.43	$45.19		$34.61	$22.78	$28.43
											$37.07

[PROTECTED DATA BEGINS

Initial Filing 2/28/2024	On	Off	Avg
1/1/2025			
2/1/2025			
3/1/2025			
4/1/2025			
5/1/2025			
6/1/2025			
7/1/2025			
8/1/2025			
9/1/2025			
10/1/2025			
11/1/2025			
12/1/2025			

PROTECTED DATA ENDS]

Question:
Topic: MISO Costs and Revenues
Reference(s): Part A, Attachment 1, page 1 of 3
a. Please explain in detail where Xcel's forecasted 2024 total MISO Day 2 (energy market) and MISO Day 3 (ancillary services market) costs and revenues are reflected on the above referenced attachment.
b. Please provide Xcel's comparable total forecasted 2024 net MISO Day 2 and net MISO Day 3 costs and revenues reflected in the above referenced attachment.
c. Please provide Xcel's actual net MISO Day 2 and MISO Day 3 costs and revenues for calendar years 2020, 2021, and 2022.

a. MISO Day 2 and Day 3 costs and revenues are shown at lines 23, 24, and 29 of Part A, Attachment 1, pg 1 (See calculation in part b, below)

b.

2025 Test Year MISO Forecast	**[PROTECTED DATA BEGINS**	
MISO Market Charges TOTAL		line 24, Part A, Att 1, pg 1; detail in Part F, Workpaper 5
MISO Market Purchases from PLEXOS		line 23, Part A, Att 1, pg 1
MISO Market Sales from PLEXOS		line 29, Part A, Att 1, pg 1
Net MISO Day 2 and Day 3 costs and revenues		
	PROTECTED DATA ENDS]	

c. Actual MISO Day 2 and Day 3 costs and revenues

	Day 2	Day 3 / ASM	Total
2021	$ (153,735,316.84)	$ 35,849,420.45	$ (117,885,896.39)
2022	$ (319,521,287.98)	$ 42,468,105.37	$ (277,053,182.61)
2023	$ (48,715,487.96)	$ 36,372,570.01	$ (12,342,917.95)

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	Planned									Unplanned							
Unit	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Change in Energy Cost Due to Outages ($)		Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh		Outage MWh	Replacement Cost ($)	Unit Cost ($)	Change in Energy Cost Due to Outages ($)		Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
	[PROTECTED DATA BEGINS																
Total 2021																	
Total 2022																	
Total 2023																	
3 Year Average																	
Total 2025 Test Year																	

	Total Outage MWh		Total Outage Energy Costs	
Total 2021				
Total 2022				
Total 2023				
3 Year Average				
Total 2025 Test Year				
Delta - 2025 vs. 2023		(1)		(3)
Delta - 2025 vs 3 Year Avg		(2)		(4)

PROTECTED DATA ENDS]

(1) Forecast outages for 2025 are more than 5% lower than 2023 mainly due to: planned maintenance at Sherco 3, retirement of Sherco 2, and extended outages at Prairie Island in 2023.
(2) Forecast outages for 2025 are more than 5% lower than the 3-year average mainly due to: retirement of Sherco 2, extended outages at Prairie Island in 2023, and seasonal operations at King.
(3) Forecast outage costs for 2025 are more than 5% lower than 2023 mainly due to lower forecast outage volume as explained in note (1).
(4) Forecast outage costs for 2025 are more than 5% lower than the 3-year average due to lower forecast outage volume as explained in note (2) and lower forecasted LMP compared to the 3-year average LMP.

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	Category	2021 Actual	2022 Actual	2023 Actual	2024 Approved	2025 Forecast
	[PROTECTED DATA BEGINS					
1	Congestion					

PROTECTED DATA ENDS]

Parent Name	Collection	Child Name	Category		Reply 2024	Test Year 2025
					[PROTECTED DATA BEGINS	
System	Generator	Wind Blazing Star I	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Blazing Star II	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Borders	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Borders Repower	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Community North	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Courtenay	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Crowned Ridge BOT	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Dakota Range	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Foxtail	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Freeborn	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Grand Meadow	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Jeffers	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Lake Benton BOT	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Mower County	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Nobles	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Northern CV	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Northern RA	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Pleasant Valley	NSP Wind	Capacity Factor (%)		
System	Generator	Wind Pleasant Valley Repower	NSP Wind	Capacity Factor (%)		
System	Generator	Wind CBED Adams	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Danielson	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Ewington	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Hilltop	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Ridgewind	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Roseville	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Uilk	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Valley View	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Winona	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Woodstock	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Deuel Harvest PPA	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Eastridge	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Garwin McNeilus	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Heartland Divide 2 PPA	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Lakota	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Norgaard	PPA Wind	Capacity Factor (%)		
System	Generator	Wind North Shaokatan	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Phase 2	PPA Wind	Capacity Factor (%)		
System	Generator	Wind PRC Windshare	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Ruthton	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Shaokatan	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Source Cisco	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Source Garwin McNeilus	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Source JJN	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Source West Ridge	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Stahl	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Tholen	PPA Wind	Capacity Factor (%)		
System	Generator	Wind UMORE Park	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Various	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Velva	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Westridge	PPA Wind	Capacity Factor (%)		
System	Generator	Wind Woodstock	PPA Wind	Capacity Factor (%)		
System	Generator	Wind CBED Big Blue	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind CBED Community Wind South	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Clean Energy1 PPA	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Crowned Ridge PPA	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Dakota Range III PPA	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Fenton	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Geronimo Odell	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Minn Dakota	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Moraine II	PPA Wind Curtailable	Capacity Factor (%)		
System	Generator	Wind Prairie Rose	PPA Wind Curtailable	Capacity Factor (%)		
					PROTECTED DATA ENDS]	

Company-Owned Wind Capacity Factors

Capacity Factors based on:	**Assumed at Acquisition**	**Actual Generation**				**Actual Generation + Curtailment Estimate**			
Wind Farm Name	**[PROTECTED DATA BEGINS**	**2020**	**2021**	**2022**	**2023**	**2020**	**2021**	**2022**	**2023**
Blazing Star 1			46.0	52.2	46.1		46.5	52.6	46.5
Blazing Star 2			42.3	51.1	46.6		43.1	51.7	46.9
Borders		51.2	48.3	50.6	44.4	51.6	48.3	51.4	44.7
Community Wind North			45.9	52.4	47.3		46.3	52.4	47.3
Courtenay		40.0	42.5	46.6	39.6	40.2	43.0	46.9	39.9
Crowned Ridge 2			47.0	50.4	44.3		49.9	55.6	48.6
Dakota Range 1 & 2				43.5	36.0			45.9	37.6
Foxtail		46.7	47.3	42.4	44.0	47.5	50.7	51.3	48.7
Freeborn				45.1	43.1			50.7	43.5
Grand Meadow		25.6	24.6	29.1		33.7	31.8	30.7	
Grand Meadow Repower (Ben Fowke)					37.2				38.3
Jeffers			45.0	54.3	49.8		47.5	54.9	49.9
Lake Benton 2		51.7	50.3	51.8	49.1	51.9	52.4	52.3	51.0
Mower				40.8	36.5			41.2	36.7
Nobles		38.1	19.6	23.9		38.5	37.5	38.7	
Nobles Repower					42.6				44.2
Northern Wind					39.9				41.9
Pleasant Valley		45.0	40.4	49.5	42.6	45.6	42.7	49.6	43.0
Rock Aetna			PPA Wind		45.3				46.3
	PROTECTED DATA ENDS]								

Note: The capacity factor (CF) provided is what Xcel Energy considers the "Design" CF, which uses the site interconnection injection limit in the denominator as opposed to the gross turbine capacity or the net capacity at the point of interconnect. Since we provided similar data in our response to Information Request No. DOC-11 in Docket No. E002/AA-23-153 on May 26, 2023, the actual values from past periods have been updated to match this methodology.

PPA Capacity Factors (CF) 2020-2023

PPA	Counterparty	MW	Actual 2020 CF	Actual 2021 CF	Actual 2022 CF	Actual 2023 CF
			[PROTECTED DATA BEGINS			
Wind CBED Adams	Adams Wind Generations, LLC	19.8				
Wind CBED Big Blue	Big Blue Wind Farm, LLC	36				
Wind CBED Community Wind South	Zephyr Wind, LLC	30				
Wind CBED Danielson	Danielson Wind Farms, LLC	19.8				
Wind CBED Ewington	Ewington Energy Systems, LLC	19.95				
Wind CBED Hilltop	Hilltop Power	2				
Wind CBED Jeffers	Jeffers Wind 20 LLC	50				
Wind CBED Ridgewind	Ridgewind Power Partners LLC	25.3				
Wind CBED Roseville	Grant County Wind	20				
Wind CBED Uilk	Uilk Wind Farm, LLC	4.5				
Wind CBED Valley View	Valley View Transmission, LLC	10				
Wind CBED Winona	Winona County Wind, LLC	1.5				
Wind CBED Woodstock	Woodstock Municipal Wind, LLC	0.75				
Wind Clean Energy	ALLETE Clean Energy, Inc. (Glen Ullin)	106.08				
Wind Community Wind North	North Wind Turbines LLC North Community Turbines LLC	30				
Wind Crown Ridge	Crowned Ridge Wind, LLC	200				
Wind Dakota Range III	DAKOTA RANGE III, LLC	153.6				
Wind Deuel Harvest Wind Energy LLC	Deuel Harvest Wind Energy LLC	300				
Wind Eastridge	Bendwind, LLC DeGreeff DP, LLC DeGreeffpa LLC Groen Wind LLC Hillcrest Wind LLC LarswindLLC Sierra Wind LLC TAIR Windfarm LLC	10				
Wind Fenton	Fenton Power Partners I, LLC	205.5				
Wind FPL	FPL Energy Mower County, LLC	98.9				
Wind Garwin McNeilus	Bangladesh Children's Support LLC, Brandon Wind LLC, BT Windfarm LLC, Burmese Children's Support, LLC, GarMar Foundation I, LLC/ REAP I, Gar Mar Wind I, LLC, GM Windfarm LLC, Henslin Creek LLC, Indian Children's Support, LLC, McNeilus Windfarm LLC, Salvadoran Children's Support , SG (JCKD) Windfarm LLC, Southeast Asian Children's Support, LLC, Triton Wind LLC, Wasioja Wind LLC, Wilhelm Wind LLC	27.5				
Wind Geronimo Odell	Odell Wind, LLC	200				
Wind Heartland Divide	Heartland Divide Wind II, LLC	200.04				
Wind Lakota	Northern Alternative Energy Lakota Ridge LLC	11.25				
Wind Minn Dakota	MinnDakota Wind LLC	150				
Wind Moraine II	Moraine Wind II LLC	49.5				
Wind Norgaard	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	8.75				
Wind North Shaokatan	Autumn Hills LLC, Jack River LLC,Jessica Mills LLC, Julia Hills LLC, Sun River LLC, Tsar Nicholas, LLC	13.53				
Wind Phase 2	Lake Benton Power Partners LLC (LBI)	105.75				
Wind Phase 4	Chanarambie Power Partners, LLC	85.5				
Wind PRC Windshare	Rock Ridge, South Ridge and Windvest	5.4				
Wind Prairie Rose	Prairie Rose Wind, LLC	200				
Wind Ruthton	Ruthton Ridge LLC, Florence Hills LLC,Hadley Ridge LLC,Hope Creek LLC, Soliloquy Ridge LLC, Spartan Hills LLC,Twin Lake Hills LL, Winter's Spawn LLC	15.84				
Wind Shaokatan	Northern Alternative Enrgy Shakotan Hills LLC	11.88				
Wind Source Cisco	Cisco Wind Energy LLC	8				
Wind Source Garwin McNeilus	Ashland Windfarm LLC, Elsinore Wind LLC, Gar Mar Foundation II / REAP II, Grant Windfarm LLC, Zumbro Windfarm	9.25				
Wind Source JJN	JJN Windfarm, LLC	1.5				
Wind Source MinWind	Minwind III -IX, LLC	11.55				
Wind Source West Ridge	Westridge Windfarm LLC, Tofteland Windfarm LLC, TG Windfarm LLC, CG Windfarm LLC, , Fey Windfarm LLC,	9.5				
Wind Stahl	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC, Carstensen Wind, LLC	8.25				
Wind Tholen	Tholen Transmission Projects	13.2				
Wind University of Minnesota	UMORE Park, LLC	2.5				
Wind Various	Agassiz Beach LLC, Metro Wind LLC, Shanes Wind Farm LLC, Carleton College LLC,Kas Brothers Wind LLC, Ed Olsen Wind LLC, St.Olaf College	10.94				
Wind Velva	Velva Windfarm, LLC	11.88				
Wind Viking	Buffalo Ridge Wind Farm LLC, Moulton Heights Wind Power Project LLC, Muncie Power Partners LLC, North Ridge Wind Farm LLC, Vandy South Project, Viking Wind Farm LLC, Vindy Power Partners LLC, Wilson-West Windfarm LLC	12				
Wind Westridge	K-Brink Wind Farm, LLC Bisson Windfarm LLC, Boeve Windfarm LLC, Windcurrents Windfarm, LLC	7.6				
Wind Woodstock	Woodstock Wind Farm, LLC	10.2				

PROTECTED DATA ENDS]

(1) Facility was not in commercial operation
(2) PPAs terminated and facility purchased by NSP
(3) Did not operate
(4) Repowered

CERTIFICATE OF SERVICE

I, Christine Schwartz, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

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

<u>xx</u> electronic filing

Docket No. **E002/AA-24-___**
E002/GR-15-826
E002/GR-21-630
MISCELLANEOUS ELECTRIC

Dated this 1st day of May 2024

/s/
____
Christine Schwartz
Regulatory Administrator

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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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