COMMERCE DEPARTMENT

June 30, 2025 **PUBLIC DOCUMENT**

Will Seuffert
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E002/AA-25-63

Dear Mr. Seuffert:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce (Department) in the following matter:

> *Petition of Northern States Power Company for Approval of the 2026 Annual Fuel Forecast and Monthly Fuel Cost Charges.*

The Petition was filed by Northern States Power Company, doing business as Xcel Energy (Xcel or the Company) on May 1, 2025, with Petition Errata filed on May 16, 2025.

The Department recommends approval of Xcel's initial forecast subject to Xcel providing additional information in reply comments. The Department will provide final recommendations to the Minnesota Public Utilities Commission (Commission) after reviewing Xcel's reply comments providing the additional information and Xcel's updated forecast. The Department is available to answer any questions the Commission may have in this matter.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

CN/JM/ad
Attachment

Before the Minnesota Public Utilities Commission

PUBLIC Comments of the Minnesota Department of Commerce

Docket No. E002/AA-25-63

I. INTRODUCTION

On May 1, 2025, Xcel filed a Petition with its 2026 Fuel Clause Rider (also known as the Fuel Clause Adjustment or FCA)[1] forecast and proposed 2026 monthly fuel charges, to comply with the requirements of the Minnesota Public Utilities Commission's (Commission) Orders[2] in Docket No. E999/CI-03-802. Based on its forecasted revenue requirements and sales, Xcel requests approval of monthly fuel charges in 2026, subject to true-up, as shown in Xcel's Tables 1 and 2 as well as Part A, Attachments 1 and 5 of the Petition. Xcel's proposed rates reflect a proposed recovery of $832 million in total 2026 Minnesota forecasted net fuel costs, which equate to $30.33/MWh on average.[3]

Xcel proposes to implement the monthly rate changes on the first day of each month for the 12 months beginning January 1, 2026. To provide customers 30 days' notice of the January 1, 2026 rate, Xcel requests that an Order be issued in this docket by November 30, 2025 as established in Appendix A of the June 12, 2019 Order in Docket No. E999/CI-03-802. Xcel's notice will consist of updating its rider webpage with the full year of monthly fuel cost charges by December 1, 2025, or upon approval by the Commission if approval is not received prior to December 1. In addition, Xcel will update the FCA 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.

As with prior FCA petitions (since 2015), Xcel used the PLEXOS software to model the power supply system and forecast FCA costs.[4] PLEXOS simulates Xcel's power supply costs and revenues on an hourly basis by estimating how Xcel's resources may be dispatched to meet the hourly load requirement at the lowest costs.

The Minnesota Department of Commerce, Division of Energy Resources (Department) reviews Xcel's Petition and provides background information below.

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[1] In the Matter of the Petition of Northern States Power Company for Approval of the 2026 Annual Fuel Forecast and Monthly Fuel Charges, Petition, Xcel Energy, May 1, 2025, Docket No. E002/AA-25-63, (eDockets) 20255-218511-01

[2] December 19, 2017 Order, December 12, 2018 Order, June 12, 2019 Order, and March 12, 2024 Order. The Department reviews these orders in the background section of these comments.

[3] Petition, page 13, Table 3.

[4] Petition, pages 2 and 5-11. See also Part B, Attachments 1 and 8.

II. PROCEDURAL BACKGROUND

A. FUEL CLAUSE STATUTE

Minn. Stat. § 216B.16, subd. 7, the Fuel Clause Statute, authorizes the Commission to allow a public utility to automatically adjust charges for the cost of certain fuel, energy, and wholesale costs, referred to generally as "fuel." Specifically, the Fuel Clause Statute states:

> Notwithstanding any other provision of this chapter, the commission may permit a public utility to file rate schedules containing provisions for the automatic adjustment of charges for public utility service in direct relation to changes in:
>
> (1) federally regulated wholesale rates for energy delivered through interstate facilities;
> (2) direct costs for natural gas delivered;
> (3) costs for fuel used in generation of electricity or the manufacture of gas; or
> (4) prudent costs incurred by a public utility for sorbents, reagents, or chemicals used to control emissions from an electric generation facility, provided that these costs are not recovered elsewhere in rates. The utility must track and report annually the volumes and costs of sorbents, reagents, or chemicals using separate accounts by generating plant.

B. FUEL CLAUSE RIDER

Section No. 5, Sheet No. 91 of Xcel's Minnesota rate book provides the rates, terms, and conditions of the Fuel Clause Rider. The tariff states that the rate for each service category is the sum of the Current Period Cost of Energy per kWh multiplied by the applicable Fuel Adjustment Factor (FAF) ratio, and the applicable Energy Cost True-up Factor. The FAF ratio is the class cost ratio multiplied by the time of day (TOD) ratio. The Current Period Cost of Energy is defined as the qualifying costs, forecasted to be incurred during the calendar month. Qualifying costs are the sum of the following:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.
2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.
3. All MISO (Midcontinent Independent System Operator) costs and revenues authorized by the Commission to flow through the FCA and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.
5. The energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, and the net cost of energy (and capacity if purchased on an energy output basis) purchases from any qualifying facility using wind energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis.
6. Capacity costs associated with such purchased power contracts, which are in excess of 100 kW and commenced after the date of the Commission's final order in Docket No. E002/GR-05-1428, shall be excluded from Fuel Cost Charge recovery.
7. Less the fuel-related costs recovered through intersystem sales.
8. Less purchased power costs for the Renewable*Connect, Renewable*Connect Government pilot programs, the Voluntary Renewable*Connect Program Rider (Renewable*Connect Flex), and the Voluntary Renewable*Connect Program Rider (Long Term) as recorded in FERC account 555.
9. Less neutrality charge cost recovery for the Renewable*Connect and Renewable*Connect Government pilot programs.
10. Less asset based margins from intersystem sales of excess generation and ancillary services. Asset based margins are defined as sales revenues less the sum of fuel and energy costs (including costs associated with MISO Day 2 markets that are booked to FERC Account 555) and any additional transmission costs incurred that are required to make such sales.

C. FUEL CLAUSE REFORM – DOCKET NO. E999/CI-03-802

Electric utilities in Minnesota follow an annual process to adjust their FCA rates. However, prior to 2020, utilities would adjust their FCA rates monthly to reflect, on a per-kWh (kilowatt-hour) basis, deviations from the base cost of energy established in the utility's most recent general rate case; and file monthly and annual reports to be reviewed for accuracy and prudence. In 2003, the Commission initiated an investigation in Docket No. E999/CI-03-802, the Fuel Clause Investigation Docket, to explore possible changes to the FCA. The Commission invited stakeholders to comment on the FCA's purpose, structure, rationale, and relevance.

The Department provides an overview of the move to an annual process below.

C.1. December 19, 2017 Order

On December 19, 2017, Commission issued an order in the Fuel Clause Investigation Docket, requiring utilities to move towards an annual fuel clause adjustment process with the following requirements.

- The Commission will set recovery of the utility's fuel, power purchase agreements, and other related costs (fuel rates) in a rate case or an annual fuel clause adjustment filing unless a utility can show a significant unforeseen impact.
- Each electric utility will publish the monthly fuel rates in advance of each year to give customers notice of the next year's monthly electric fuel rates.
- The monthly fuel clause adjustment will not operate – each electric utility will charge an approved monthly rate.
- Utilities will be allowed to track any changes in $/MWh (megawatt-hour) fuel costs that occur over the year and there will be no carrying charge on the tracker.
- Annually, each electric utility will report actual $/MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the fuel rates set by the Commission with annual revenues based on actual costs for the year.
- **Each electric utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections.** If annual revenues collected ($/MWh) are higher than total actual costs, the utility must refund the over-collection through a true-up mechanism. If annual revenues collected are lower than total actual costs), the utility must show why it is reasonable to charge the higher costs (under-collections) to ratepayers through a true-up mechanism.
- Each utility must file proposed fuel rates outside of a general rate case. If the proposed fuel rates are different from the rates set in a utility's most recent miscellaneous rate docket that coincides with a rate case, the utility must fully explain the basis for any difference. These filings should include complete documentation supporting the proposed fuel rates, including each power purchase agreement (PPA), 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.
- Each utility must file a lessons-learned report at the end of three years to assess the new process.

C.2. December 12, 2018 Order

On December 12, 2018, the Commission issued another order in the Fuel Clause Investigation Docket, modifying certain aspects of and adding to the FCA reform approved in the December 19, 2017 order. In particular, the December 12, 2018 order disposed as follows:

- The implementation date for the new fuel clause adjustment process is January 1, 2020.
- Beginning January 1, 2020, until the end of the pilot or as otherwise ordered, the FCA process shall follow the calendar year, and the annual fuel clause adjustment true-up compliance filings shall be filed by March 1 of the year following the relevant calendar year.
- Monthly automatic adjustment filings shall be discontinued once the new fuel clause adjustment process is implemented.
- Each utility shall file its annual fuel clause adjustment report in a separate docket.
- All changes approved in this docket shall remain in effect indefinitely.
- Before the lessons-learned reports are filed three years after implementation of the new FCA process, parties will discuss what information will be included in those reports.

C.3. June 12, 20219 Order

On June 12, 2019 the Commission issued its final main order in the Fuel Clause Investigation docket, providing additional details to finalize FCA reform. Specifically, the June 12, 2019 order approved, among other things:

- Variances to Minnesota Rules 7825.2800 through 7825.2840 to accommodate the new FCA process by modifying the filing deadlines contained in these rules.
- A threshold of plus or minus 5% of all FCA costs and revenues to determine whether an event qualifies as a significant, unforeseen impact that may justify an adjustment to the approved fuel rates. Utilities are permitted to implement revised rates following a 30-day notice period, subject to a full refund, if no party objects to the revised rates.
- Tracking under- or over-recovered FCA costs as regulatory assets or liabilities, respectively, using FERC Account 182.3.
- Information requirements for the annual forecast and true-up filings for all electric utilities, including the reporting requirement changes outlined in Attachments 1, 2, and 3 of the March 1, 2019 joint comments[5] in Docket No. E999/CI-03-802 and the requirement that the annual true-up filings include a complete analysis and discussion of the consequences of self-commitment and self-scheduling of their generators, including the annual difference between production costs and corresponding prevailing market prices.

[5] In the March 1, 2019 joint comments, Attachment 3 corresponds to Xcel.

- Tariff changes reflected in Attachments 4, 5, and 6 of the March 1, 2019 joint comments[6] in Docket No. E999/CI-03-802.
- Discontinuation of Xcel's reporting of Part H, Section 4 narrative and Schedule 1 (transformers); Part I (MISO Day 1); Part J, Section 5, Schedules 1, 3-6 (MISO Day 2); Part K, Section 5, Schedule 3 (transformer maintenance); Part K, Section 4, Schedule 3 (designated resource planning for MISO).
- A procedural schedule, as shown in Appendix A of the order.

C.4. Procedural Schedule

The Appendix A procedural schedule for the forecasted rates relating to the instant petition is below.

2025 May 1	Utilities submit 2026 forecast and rates
2025 June 30	Review & initial comments by consumer advocates of 2026 rates
2025 July 31	Utility reply comments on 2026 rates (forecast inputs updated)
2025 Aug. 30	Response by consumer advocates for 2026 rates
2025 Nov. 30	Commission's order on 2026 rates
2025 Dec. 1	Publication of 2026 rates
2026 Jan. 1	Implement 2026 rates

The 2025 FCA rates will then be trued up to actuals under the following schedule, also from Appendix A:

2027 Mar. 1	Utilities submit 2025 true-up petition
2027 Apr. 15	Review and initial comments by consumer advocates of 2025 true-up
2027 May 1	Utility reply comments for 2025 true-up
2027 May 15	Response by consumer advocates for 2025 true-up
2027 Aug. 1	Commission's order for 2025 true-up
2027 Sep. 1	Implement 2025 true-up

D. XCEL ANNUAL FCA HISTORY

The Department summarizes Xcel's history under the annual (post-reform) FCA process below. The Department also provides Department Table 1 below, showing Xcel's approved forecasts and costs in each year, with a comparison to this year's 2026 forecast.

[6] In the March 1, 2019 joint comments, Attachment 6 corresponds to Xcel and reflects the Company's current FCA Rate Schedule, Section 5, Sheet Nos. 91.0 – 91.3, as approved by the Commission's June 12, 2019 Order in Docket No. E-999/CI-03-802 (Part A, Attachment 9 to the instant Petition is the proposed nineteenth revision of the Company's FCA tariff).

Department Table 1
Xcel Minnesota Net FCA Costs: 2021-2026

Year	Docket	Forecasted Cost	Actual Cost	Forecast Unit Cost	Actual Unit Cost	Actual Recoveries	Over/(Under) Recovery
		$ millions		$/MWh		$ millions	
2021	20-417	749.7	894.1	27.78	31.71	812.3	(81.8)
2022	21-295	849.4	950.2	31.47	33.55	954.0	3.8
2023	22-179	1,069.2	935.3	38.96	33.44	1061.3	126.0
2024	23-153[7]	1,022.7	894.7	38.10	33.42	1019.4	124.7
2025	24-63	891.2	TBD	33.27	TBD	TBD	TBD
2026	25-63	832.1*	TBD	30.33	TBD	TBD	TBD

*Instant petition (not yet approved) – see page 13, Table 3.

D.1. 2021 FCA (20-417)

On May 1, 2020, Xcel filed its 2021 forecast petition, in Docket No. E002/AA-20-417.[8]
On December 22, 2020 the Commission issued an order approving Xcel's 2021 forecast. The approved forecasted FCA costs for 2021 were $749.7 million or $27.78/MWh.[9] In addition, the December 22, 2020 order required Xcel in its 2022 true-up filing and future filings, to identify the number and MWhs of planned outages that were originally classified as unplanned.

On August 27, 2021, Xcel filed a petition requesting to increase its monthly fuel rate for October through December 2021 for an unrecovered balance of $25.2 million.[10]

On September 24, 2021, the Department filed a letter supporting Xcel's proposal to recover $25.2 million.[11]

On March 1, 2022, Xcel submitted its 2021 true-up petition, requesting approval of 2021 actual FCA expenses of $894.1 million, $144.3 million higher than the approved forecast of $749.7 million.[12] On a

[7] The total actual costs and actual unit costs are derived from Docket 25-153 True-up Filing, excluding Mid-year adjustment refund ($30.5 million), Nuclear PTCs ($175.6 million), and Sherco 3 2011 Refund ($48 million) (eDocket) 20254-217695-01.
[8] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Petition, Xcel Energy, May 1, 2020, Docket No. E002/AA-20-417, (eDockets) 20205-162826-08.
[9] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, December 22, 2020, Docket No. E002/AA-20-417, (eDockets) 20205-162826-08.
[10] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2021 Forecast Period, Xcel Energy, August 27, 2021, Docket No. E002/AA-20-417, (eDockets) 20218-177503-01.
[11] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Letter, Minnesota Department of Commerce, September 24, 2021, Docket No. E002/AA-20-417, (eDockets) 20219-178245-01.
[12] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Annual True-Up Compliance Report, Xcel Energy, March 1, 2022, Docket No. E002/AA-20-417, (eDockets) 20223-183343-01.

unit cost basis, Xcel's requested 2021 actual FCA costs were $31.71/MWh versus $27.78/MWh forecasted. Xcel collected $812.3 million in 2021 FCA revenues leading to a $81.8 million under-recovery.

On July 5, 2022, the Commission issued an order approving Xcel's 2021 true-up.[13]

Xcel is recovering the $81.0 million through increased FCA charges over the 12 months beginning September 2022.[14]

D.2. 2022 FCA (21-295)

On April 30, 2021, Xcel filed its 2022 forecast petition, in Docket No. E002/AA-21-295.[15]

On December 2, 2021 the Commission issued an order approving Xcel's 2022 forecast. The approved forecasted FCA costs for 2022 were $849.4 million or $31.47/MWh.[16] In addition, the December 2, 2021 order required Xcel Energy, in its 2023 true-up filing, to (a) identify the number and MWhs of planned outages that were originally classified as unplanned, and (b) to file a request to modify the approved fuel rate as soon as practicable, if during 2022 Xcel Energy experiences an impact on all FCA costs and revenues of plus or minus 5% or larger. Xcel Energy will then be required to implement the revised rates, subject to a full refund, following a 30-day notice period, if no party objects to the revised rates.

On May 19, 2022, Xcel made a compliance filing proposing to increase its monthly fuel forecast charges by $61 million for the second-half of 2022.[17] The filing was unopposed.

On June 27, 2022, Xcel submitted a compliance filing with the increased FCA rates as requested in the May 19, 2022 filing.[18]

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[13] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, July 5, 2022, Docket No. E002/AA-20-417, (eDockets) 20227-187192-01.
[14] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2021 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing, Xcel Energy, July 13, 2022, Docket No. E002/AA-20-417, (eDockets) 20227-187381-01.
[15] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Petition, Xcel Energy, April 30, 2021, Docket No. E002/AA-21-295, (eDockets) 20214-173731-02.
[16] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, December 2, 2021, Docket No. E002/AA-21-295, (eDockets) 202112-180345-01.
[17] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 202Forecast Period, Xcel Energy, May 19, 2022, Docket No. E002/AA-21-295, (eDockets) 20225-185907-01.
[18] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing, Xcel Energy, June 27, 2022, Docket No. E002/AA-21-295, (eDockets) 20226-186886-01.

On March 1, 2023, Xcel submitted its 2022 true-up petition, requesting approval of 2022 actual FCA expenses of $950.2 million, $100.8 million higher than the approved forecast of $849.4 million.[19] On a unit cost basis, Xcel's requested 2022 actual FCA costs were $33.55/MWh versus $31.47/MWh forecasted. Xcel collected $954.0 million in 2022 FCA revenues leading to a $3.8 million over-recovery.

On June 30, 2023, the Commission issued an Order approving Xcel's 2021 true-up.[20]

Xcel refunded $3.8 million to ratepayers through a one-time decrease in FCA charges in September 2023.[21]

D.3. 2023 FCA (22-179)

On May 2, 2022, Xcel filed its 2023 forecast petition, in Docket No. E002/AA-22-179.[22]

On December 5, 2022 the Commission issued an order approving Xcel's 2023 forecast. The approved forecasted FCA costs for 2023 were $1,069.2 million or $38.96/MWh.[23]

On May 19, 2023, Xcel submitted a compliance filing proposing to reduce the 2023 forecast by $30 million.[24] Xcel also proposed reducing 2023 FCA rates to recover $10 million less in each of July, August, and September, to reflect this lower forecast. This update was *de facto* approved, as no party objected during the 30-day notice period established under the FCA process. Xcel submitted another rate adjustment proposal on November 21, 2023 to reduce FCA rates by $5 million per month from January-August 2024.[25] That proposal was likewise *de facto* approved.

On March 1, 2024, Xcel submitted its 2023 true-up petition proposing to refund an additional $86 million from April to December 2024, which Xcel implemented on April 1, 2024.[26]

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[19] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Annual True-Up Compliance Report, Xcel Energy, March 1, 2023, Docket No. E002/AA-21-295, (eDockets) 20233-193561-01.
[20] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, June 30, 2023, Docket No. E002/AA-21-295, (eDockets) 20236-197088-01.
[21] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing, Xcel Energy, July 10, 2023, Docket No. E002/AA-21-295, (eDockets) 20237-197344-01.
[22] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges, Petition, Xcel Energy, May 5, 2022, Docket No. E002/AA-22-179, (eDockets) 20225-185476-01.
[23] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, December 5, 2022, Docket No. E002/AA-22-179, (eDockets) 202212-191109-01.
[24] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2023 Forecast Period, Xcel Energy, May 19, 2023, Docket No. E002/AA-22-179, (eDockets) 20235-196011-01.
[25] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2023 Forecast Period, Xcel Energy, November 21, 2023, Docket No. E002/AA-22-179, (eDockets) 202311-200652-02.
[26] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2023 Annual Fuel Forecast and

D.4. 2024 FCA (23-153)

On May 1, 2023, Xcel filed its 2024 forecast petition, in Docket No. E002/AA-23-153. [27] On November 9, 2023, the Commission approved Xcel's 2024 forecast petition and revised adjustment factors as reflected in Xcel's October 23, 2023 filing, subject to true-up.[28] In addition, the Commission required Xcel to report in future FCA true-ups, on the:

- Assumed versus actual wind capacity factors for the true-up year and three prior years, with and without curtailment, for each Xcel-owned wind facility; and
- Prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition.

On November 17, 2023, Xcel submitted a compliance filing with FCA rates to be implemented on January 1, 2024.[29]

On September 30, 2024, Xcel submitted a compliance filing proposing to refund ratepayers $30.5 million for over-collected fuel costs beginning November 1, 2024.[30] This update was *de facto* approved, as no party objected during the 30-day notice period established under the FCA process.

On March 3, 2025, Xcel submitted the 2024 true-up petition for 2025, proposing to refund to customers an additional $94.2 million in fuel cost over-collection, $176 million of nuclear production tax credit transactions, and $48 million related to Sherco Unit 3 outage replacement power costs, for a total proposed refund to customers of $318 million.[31]

D.5. 2025 FCA (24-63)

On May 1, 2024, Xcel filed its 2025 forecast petition, in Docket No. E002/AA-24-63 requesting approval of its 2025 FCA forecast and rates, subject to true-up.[32]

Monthly Fuel Cost Charges, Annual True-Up Compliance Filing, Xcel Energy, March 1, 2024, Docket No. E002/AA-22-179, (eDockets) 20243-204018-01.

[27] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges, Petition, Xcel Energy, May 1, 2023, Docket No. E002/AA-23-153, (eDockets) 20235-195484-01.

[28] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Public Utilities Commission, November 9, 2023, Docket No. E002/AA-23-153, (eDockets) 202311-200373-01.

[29] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing, Xcel Energy, November 17, 2023, Docket No. E002/AA-23-153, (eDockets) 202311-200577-01.

[30] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges, Compliance Filing – Rate Adjustment Proposal to Monthly Fuel Cost Charges for the 2024 Forecast Period, Xcel Energy, September 30, 2024, Docket No. E002/AA-23-153, (eDockets) 20249-210591-01.

[31] In the Matter of the Petition of Northern States Power Company for Approval of the 2024 Annual Fuel Forecast and Monthly Fuel Charges, Petition, Xcel Energy, March 3, 2025, Docket No. E002/AA-23-153, (eDockets) 20253-215976-01.

[32] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges, Petition, Xcel Energy, May 1, 2024, Docket No. E002/AA-24-63, (eDockets) 20245-206297-02.

On November 8, 2024, the Commission issued an Order authorizing Xcel to implement its 2025 FCA Forecast, based on revised forecasted sales of 26,788,077 MWh and revised forecasted costs of $891,200,000, for the Minnesota jurisdiction.[33] The Commission also required Xcel to provide calculations of proposed net cost of generation rate as an attachment in the fuel forecast dockets, in addition to approving various other forecast-related items including land sale gains and credits, Community Solar Gardens forecast and generation rate, net cost of generation rate, Tariff Sheet language changes, and biomass buyout costs.

On November 18, 2024, Xcel submitted a compliance filing with updated FCA rates to be implemented on January 1, 2025.44

D.6. 2026 FCA (25-63)

On May 1, 2025, Xcel filed the current Petition requesting approval of its 2026 FCA forecast and rates, subject to true-up.

III. DEPARTMENT ANALYSIS

The Department analyzes Xcel's 2026 FCA petition and reviews individual components of Xcel's actual 2026 FCA costs below.

A. REPORTING REQUIREMENTS

The Commission's June 12, 2019 order in Docket No. E999/CI-03-802, order point 7, approved Xcel's reporting requirements for the forecast and true-up petitions as provided in Attachment 3 of the Department's March 1, 2019 joint comments[34]. Xcel provided a compliance matrix in Part C, Attachment 1 of the instant petition. The Department verified the Company provided the required information as follows.

Policies and Actions (Minnesota Rules 7825.2800):
Page 20 and Part D, Attachments 1-10 of the instant petition.

Base Cost of Fuel (Minnesota Rules 7825.2810):
Pages 24-25 and Part A, Attachment 1 of the instant petition.

Billing Adjustment Amounts Charge to Customers by Each Type of Energy Cost (Minnesota Rules 7825.2810):
Page 4 – Tables 1-2 and Part A, Attachment 1 of the instant petition.

[33] In the Matter of the Petition of Northern Sates Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges, Order, Minnesota Department of Commerce, November 8, 2024, Docket No. E002/AA-24-63, (eDockets) 202411-211745-01.

[34] Joint Comments of the Electric Utilities (Minnesota Power, OtterTail Power and Xcel Energy) and Consumer Advocates (Minnesota Department of Commerce – Division of Energy Resources, Minnesota Office of Attorney General – Residential Utilities and Antitrust Division, Minnesota Chamber of Commerce, and Minnesota Large Industrial Group) (eDocket) 20193-150778-01.

Total Cost of Fuel Delivered to Customers (Minnesota Rules 7825.2810)
On page 25, Xcel stated it will provide this information in its 2026 true-up petition.

Revenue Collected from Customers for Energy Delivered (Minnesota Rules 7825.2810)
On page 25, Xcel stated it will provide this information in its 2026 true-up petition.

Monthly Fuel Clause Adjustments (Minnesota Rules 7825.2810)
Part A, Attachment 1 of the instant petition.

Annual Five-Year Fuel Cost Forecast (Minnesota Rules 7825.2830):
Page 26 and Part A, Attachments 1-3, and Part E, Attachments 1-3 of the instant petition.

Fossil Fuel Costs, Coal Burn Expenses, and Nuclear Fuel Expenses (Minnesota Rules 7825.2830):
Part B, Attachments 2-4 of the instant petition.

Peak Demand and Energy Requirements (Minnesota Rules 7825.2830):
Part A, Attachment 4 and Part E, Attachment 4 of the instant petition.

Estimated Load Management Impact (Minnesota Rules 7825.2830):
Part E, Attachment 5 of the instant petition.

Wind Curtailment Report Narrative (projected wind curtailment costs) (Docket No. AA-04-1279, Order issued April 4, 2006):
Pages 6 and 9; Part B, Attachment 10; and Part G, Workpaper 6 of the instant petition.[35]

Community Solar Gardens (Docket No. M-13-867):
Page 9; Part B, Attachment 12; and Part G, Workpaper 5 of the instant petition.

FCA Rule Variance Dockets (Docket No. AA-15-611):
Page 20 and Part C, Attachment 2 of the instant petition.

MISO Day 2 and Day 3 Charges & Allocation (Docket Nos. AA-07-1130, M-08-528, and AA-19-293):
Page 19; Part A, Attachments 1-3; Part B, Attachment 8; and Part F, Workpaper 5 of the instant petition.

Notice of Report Availability (Minnesota Rules 7825.2840):
Pages 1 and 26 and Addendum to the instant petition.

[35] Xcel provides a full wind curtailment narrative in its true-up petitions.

Renewable*Connect Neutrality (Docket No. M-15-985):
Pages 11 and Part G, Workpaper 8 of the instant petition.

Plant Outage Summary (Docket AA-06-1208):
Pages 6-8; Part B, Attachments 5-7; and Part G, Workpaper 7 of the instant petition.

Moraine II, PPA (Docket M-08-1487):
Part B, Attachment 11 (page 2 of 2) and Part C, Attachment 2, page 2 of 3 of instant petition.

Monthly MISO Day 2 Charges and Allocations (Docket AA-07-1130):
Pages 10-11,16-20, Part B, Attachment 8; and Part F, Workpaper 5 of the instant petition.

Prospective Asset and Non-Asset Based Margin Sharing (Docket No. GR-10-971):
Pages 10, 13, 16-17, and 21-22 of the instant petition.

Saver's Switch Discount (Docket No. M-01-46):
In Part B, Attachment 13, page 4 of 5, Xcel stated its 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.

Self-Scheduling Reporting (Docket Nos. AA-17-492, AA-18-373, and CI-19-704):
Part D, Attachment 7 of the instant petition.

Compliance and Reporting Requirements Summary:
Based on our review, the Department recommends the Commission accept Xcel's compliance filings
and reporting requirements.

B. SALES FORECAST

The PLEXOS simulation estimates the hourly load requirement based on the most recent forecast of monthly energy and monthly peak demands developed by the Company's Sales Energy & Demand Forecasting Group. Xcel summarizes its sales in Part G, Workpaper 1 and describes the forecasting process in detail in Part B, Attachment 13.[36] Key input assumptions used to develop the PLEXOS forecast are provided in Part F, Workpaper 1.

[36] As stated in Part B, Attachment 13: "The NSP System serves five jurisdictions. Minnesota, North Dakota and South Dakota are served by Northern States Power Company (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."

The Department reviewed Xcel's 2025 sales forecast information provided in Parts B, F, and G of the Petition. A summary of Xcel's net system sales and production levels for its 2026 forecast, 2025 forecast, 2022-2024 actuals, and 2022-2024 average is provided in Table 2 below:

Department Table 2
Xcel's Energy Sales Forecasts (GWh)[37]

Item	2026	2025	2024	2023	2022	Avg
	Forecast		Actuals			
Net System Generation	42,959	42,465	39,451	40,543	41,073	40,356
Net System Sales	40,191	38,242	37,847	39,260	39,687	38,931
Net NSPM System Sales	31,884	31,342	31,121	32,372	32,722	32,072
Net MN Sales	27,434	26,788	26,774	27,972	28,318	27,688

As shown above, Xcel's 2026 Minnesota sales forecast is slightly above its 2025 sales forecast and slightly below the three-year average of actual sales for 2022-2024. The Department concludes Xcel's 2026 sales forecast appears reasonable, given Xcel is using the same methods as in prior proceedings and the forecast is within the range of prior years. As a result, the Department recommends the Commission accept Xcel's 2026 forecasted sales in this proceeding to set FCA rates for 2026 and notes Xcel's FCA revenues and costs are subject to true-up in the 2026 true-up petition to be filed in 2027. Finally, the Department's recommendations in this docket should not be used in Xcel's future rate cases or other rate proceedings, where a more thorough review of the sales forecast will occur.

C. FCA COST SUMMARY

Xcel's forecasted 2026 FCA cost summary is provided in Part A, Attachment 1 of the current Petition. The summary includes: costs for fuel for Company-owned generation facilities, long-term PPAs, short-term market purchases from MISO; less sales revenues received from MISO for asset-based sales and costs for Renewable*Connect programs.

Once Xcel determines its forecasted 2026 FCA on a total system level, Xcel assigns Minnesota its jurisdictional share of these costs based on its pro-rata share of megawatt-hours. Minnesota-specific adjustments are then added for Community Solar Garden – Above Market Costs (CSG-AMC) and biomass buyouts to determine Minnesota's forecasted net 2026 FCA costs.

For the record, the Department notes it is the Company's responsibility to properly identify and forecast all charges it intends to recover through the FCA process. Absent this responsibility, the Department notes electric utilities may have little incentive to accurately include and forecast all costs they intend to recover, which could limit the benefits of the forecast and true-up processes. Furthermore, poorly supported forecasts and/or true-up filings will likely lead to delays in the regulatory process or recommendations by Consumer Advocates of disallowance of costs.

[37] Part H, Attachment 7 (excludes Windsource and Renewable*Connect).

Part H, Attachment 1 of the Petition provided Xcel's actual and average FCA costs for 2022-2024 on a similar basis to its forecasted 2026 FCA costs provided in Part A, Attachment 1 of the instant petition. Department Table 3 below summarizes Xcel's FCA costs for its 2026 forecast, 2025 forecast, 2022-2024 actuals, and 2022-2024 average.

Department Table 3
Xcel's Forecasted 2024 FCA Cost Summary (in $1,000's)

			2026 Forecast*	2025 Forecast**	2024 Actuals*	2023 Actuals*	2022 Actuals*	2022-24 Avg. Actuals*
1	Own Generation	$	[TRADE SECRET DATA HAS BEEN EXCISED]		$ 456,768	$ 485,138	$ 633,483	$ 525,130
2	+ LT Purchased Energy	$			$ 588,576	$ 579,164	$ 639,497	$ 602,412
3	+ LT CSG Energy	$	$ 258,674	$ 264,457	$ 222,637	$ 206,275	$ 184,030	$ 204,314
4	+ MISO Market Charges		[TRADE SECRET DATA HAS BEEN EXCISED]		$ 169,317	$ 148,146	$ 239,474	$ 185,646
5	+ ST Market Purchases	$			$ 73,226	$ 94,895	$ 146,773	$ 104,964
6	= Total NSP System Costs	$			$ 1,510,524	$ 1,513,618	$ 1,843,257	$ 1,622,466
7	- Asset-Based Sales Revenues	$			$ (309,911)	$ (282,329)	$ (564,368)	$ (385,536)
8	- CSG-AMC	$	$ (163,405)	$ (184,921)	$ (180,137)	$ (155,166)	$ (99,903)	$ (145,069)
9	- RC Pilot	$	[TRADE SECRET DATA HAS BEEN EXCISED]		$ (6,791)	$ (6,739)	$ (6,291)	$ (6,607)
10	- RC MTM	$			$ (27,003)	$ (16,858)	$ (18,190)	$ (20,683)
11	- RC LT	$			$ -	$ -	$ -	$ -
12	= Net System FCA Costs	$			$ 986,682	$ 1,052,526	$ 1,154,506	$ 1,064,571
13	Net System Sales	MWh	40,190,819	38,242,162	37,846,946	39,260,332	39,686,566	38,931,281
14	**Net System FCA Unit Costs**	$/MWh	[TRADE SECRET DATA HAS BEEN EXCISED]		**$26.07**	**$26.81**	**$29.09**	**$27.34**
15	Net MN Sales	MWh	27,434,341	26,788,077	26,774,079	27,971,766	28,318,349	27,688,065
16	MN FCA Costs	$	[TRADE SECRET DATA HAS BEEN EXCISED]		$ 702,990	$ 753,515	$ 824,270	$ 760,258
17	+ CSG-AMC	$	$ 163,405	$ 184,921	$ 180,010	$ 155,061	$ 99,883	$ 144,985
18	+ Laurentian Buyout	$			$ -	$ -	$ 13,062	$ 4,354
19	+ Benson Buyout	$	[TRADE SECRET DATA HAS BEEN EXCISED]		$ 8,938	$ 22,412	$ 9,844	$ 13,731
20	- Nuclear PTCs	$			$ (175,612)			
21	- Sherco 3 Outage	$			$ (47,957)			
22	+ Other adjustments	$			$ 2,751	$ 4,349	$ 3,162	$ 3,421
23	Net MN FCA Costs	$	$ 832,139	$ 891,200	$ 671,120	$ 935,337	$ 950,221	$ 852,226
24	**Net MN FCA Unit Costs**	$/MWh	**$30.33**	**$33.27**	**$25.07**	**$33.44**	**$33.55**	**$30.78**
25	**MN FCA Premium Unit Costs*** **	$/MWh	[TRADE SECRET DATA HAS BEEN EXCISED]		**-$1.00**	**$6.63**	**$4.46**	**$3.43**

* Part H, Att. 1 & 7
** 7/31/24 Reply Comments in Docket No. E002/AA-24-163, Attachment A.
*** The costs of CSGs and biomass buyout costs are both solely assigned to the Minnesota jurisdiction.

For 2026, Xcel forecasts its net system FCA costs (line 12) to **[TRADE SECRET DATA HAS BEEN EXCISED]** than prior years.

Xcel forecasts that Minnesota customers will continue to **[TRADE SECRET DATA HAS BEEN EXCISED]** (Lines 24 & 25) relative to net system costs (Line 14). This divergence between the trends in FCA rates Xcel charges to its Minnesota customers compared to customers in North Dakota and South Dakota is significant due to only Minnesota ratepayers paying for costs of community solar gardens in Minnesota that are above market costs (CSG-AMC) (line 17).

As an overall note, simply analyzing cost variances by category in dollars does not account for the changing nature of Xcel's generation fleet, which continues to rely more on renewables and less on fossil fuels. To provide a more granular review, the Department provides its analysis of Xcel's FCA costs by category in the following sections.

D. OWNED GENERATION

Department Table 4 summarizes Xcel's forecasted 2026 and prior year FCA costs for Company-owned generation by fuel type in dollars and dollars per MWh. The Department discusses each fuel category for owned generation below.

Department Table 4
Company-Owned Generation FCA Costs

		Forecast		Actuals			
		2026	2025	2024	2023	2022	Avg
Fuel	**Unit**						
Coal	$000s			$ 139,293	$ 174,754	$ 242,848	$ 185,632
	GWh			5,513	6,451	9,524	7,163
	$/MWh			**$25.27**	**$27.09**	**$25.50**	**$25.92**
Wood/ RDF	$000s			$ 8,731	$ 9,693	$ 9,781	$ 9,402
	GWh			473	505	513	497
	$/MWh			**$18.46**	**$19.18**	**$19.05**	**$18.91**
Natural Gas CC	$000s			$ 169,165	$ 169,158	$ 217,122	$ 185,148
	GWh			7,696	6,357	3,853	5,969
	$/MWh	**[TRADE SECRET DATA HAS BEEN EXCISED]**		**$21.98**	**$26.61**	**$56.36**	**$31.02**
Nat. Gas & Oil CT	$000s			$ 34,970	$ 36,196	$ 46,559	$ 39,242
	GWh			1,125	828	528	827
	$/MWh			**$31.10**	**$43.73**	**$88.10**	**$47.45**
Nuclear	$000s			$ 104,608	$ 95,337	$ 117,174	$ 105,706
	GWh			11,956	11,928	14,696	12,860
	$/MWh			**$8.75**	**$7.99**	**$7.97**	**$8.22**
Total	$000s			$ 456,768	$ 485,138	$ 633,483	$ 525,130
	GWh			26,763	26,070	29,115	27,316
	$/MWh			**$17.07**	**$18.61**	**$21.76**	**$19.22**

Sources:
2026 Forecast and 2022-2024 Actuals: Part H, Att. 1, IR 7a (DOC Att. 6, page 3)
2025 Forecast: Xcel's 7/31/24 Reply Comments in Docket No. E002/AA-24-63, Attachments A (page 1), B, C

D.1. Owned Gas

Xcel forecasts natural gas unit costs to **[TRADE SECRET DATA HAS BEEN EXCISED]** following the recent increase in natural gas prices[38]**.** Xcel-owned natural gas generation in megawatt-hours is forecasted to **[TRADE SECRET DATA HAS BEEN EXCISED]** relative to historical levels. Xcel stated that it is forecasting higher than average natural gas combined-cycle generation due to higher forecast natural gas prices, the retirement of Sherco 2, and lower forecast generation from other PPAs (primarily Manitoba Hydro) as discussed on pages 15-16 of the petition.[39] Combining the forecasted trends in unit costs and generation, Xcel forecasts total fuel costs for owned gas generation to **[TRADE SECRET DATA HAS BEEN EXCISED]**.

D.2. OWNED COAL

Xcel forecasts 2026 coal generation to **[TRADE SECRET DATA HAS BEEN EXCISED]**. Other than Sherco 2 retiring in 2023, the secondary driver to lower forecast coal generation in 2026 is **[TRADE SECRET DATA HAS BEEN EXCISED]** in 2026.[40] Xcel forecasts coal and rail prices to be **[TRADE SECRET DATA HAS BEEN EXCISED]** than 2022-2024 on average.[41] Combined, Xcel forecasts 2025 total coal FCA costs to be the **[TRADE SECRET DATA HAS BEEN EXCISED]**.

D.3. Owned Nuclear

D.3.1. Nuclear Overall

Xcel forecasts 2026 nuclear fuel costs to be **[TRADE SECRET DATA HAS BEEN EXCISED]** than 2022-24 on average due to forecasted unit costs being **[TRADE SECRET DATA HAS BEEN EXCISED]**. Xcel's forecasted change in nuclear unit costs is attributed to the nuclear fuel price factors mentioned in Part D, Attachment 1 (pages 2-3) of the Petition. The Petition also provides support for nuclear fuel pricing in Part B, Attachment 4, and Part D, Attachment 2. Further details regarding fuel supply can be found in Part D, Attachment 8.

D.3.2. Nuclear Production Tax Credits.

In August 2022, the Inflation Reduction Act (IRA) became law and created a new production tax credit (PTC) for qualified nuclear facilities available for electricity produced and sold between 2024 and 2031.[42] Starting in 2024, nuclear facilities will be eligible for a base credit of 0.3 cents per kilowatt-hour (kWh) generated by existing facilities, which can increase to a maximum of 1.5 cents per kWh if specific requirements are met. The credits' value will be determined on a sliding scale based on the revenue generated by nuclear facilities, measured based on the LMP of energy, with the credit value decreasing as the LMP increases.

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[38] Petition, Part H WP-1, IR 7b and IR 7c (DOC Att. 6, page 4 and 5)
[39] Xcel's response to DOC IR 3. (b).
[40] Petition, page 6, 7, and Xcel's response to DOC IR 3. (b).
[41] Petition, Part H WP-1, IR 7a. (DOC Att. 6, page 3)
[42] https://energycommunities.gov/funding-opportunity/zero-emission-nuclear-power-production-credit-26-u-s-code-%C2%A4-45u/.

On July 23, 2023, the Commission issued an Order in Docket No. E002/GR-21-630 approving Xcel's proposal to pass-through nuclear PTCs to ratepayers in the FCA (Order Point 113).[43]

Xcel first reported the nuclear PTCs amount in its 2024 FCA true-up filing (Docket No. E002/AA-23-153). The Minnesota allocated value of the nuclear PTCs for 2024 is $175.8 million, inclusive of transaction costs. For the 2026 FCA forecast, the Company reports the estimated nuclear PTCs value for Minnesota ratepayers is **[TRADE SECRET DATA HAS BEEN EXCISED].** In response to the Department's IR related to nuclear PTCs, Xcel provided updated projections for nuclear PTCs for the 2024-2026 period. The Company explained that the significant reduction in forecasted nuclear PTCs compared to 2024 is attributable to higher annual gross receipts and an increased forecast for the LMP.[44]

The Department concludes Xcel has reasonably explained the discrepancy between actual and forecasted nuclear PTC production. However, since the Company has indicated its expectation to sell all the nuclear PTCs,[45] the Department requests Xcel provide in reply comments an analysis of the costs and benefits of transferring versus not transferring these credits. The Department does not have any objections to Xcel's forecasted 2026 Minnesota allocated value of nuclear PTCs, but intends to continue monitoring Xcel's actual nuclear PTCs in future FCA filings.

D.4. Owned Wood.

Xcel forecasts 2026 wood fuel costs to be **[TRADE SECRET DATA HAS BEEN EXCISED]**. This result is a combination of Xcel forecasting wood generation to **[TRADE SECRET DATA HAS BEEN EXCISED],** and Xcel forecasting wood unit costs to **[TRADE SECRET DATA HAS BEEN EXCISED]** due to higher wood/RDF fuel prices.[46]

D.5. Owned Generation Overall

Overall, Xcel's total forecasted 2026 FCA costs for Company-owned generation is **[TRADE SECRET DATA HAS BEEN EXCISED]** compared to 2025 forecast and 2022-2024, as shown in Department Table 4 above. Based on our review and the explanations Xcel provided, the Department concludes Xcel's forecasted 2026 fuel costs for Company-owned generating units appear reasonable for the purposes of establishing forecasted 2026 FCA rates. As a result, the Department recommends the Commission accept Xcel's forecasted 2026 fuel costs for Company-owned generation for the purpose of setting initial 2026 FCA rates in this proceeding, subject to the subsequent true-up.

[43] See also: 3/31/23 Administrative Law Judge Report in 21-630, Findings 127-130 (pages 23-24) and 11/8/22 Halama Rebuttal, pages 57-58.
[44] Xcel response to the Department's IR 2.
[45] Petition, Page 14.
[46] Petition, Part H WP-1, IR 7c (DOC Att. 6, page 5).

E. LONG-TERM POWER PURCHASE AGREEMENTS.

Department Table 5 below provides a breakout of Xcel's forecasted and historical costs and energy for long-term power purchase agreements (PPAs). Xcel's long-term power purchases come from gas, solar, wind, other, and CSGs. The petition lists individual PPAs in Part B, Attachment 11.

Department Table 5
Long-Term Purchased Energy FCA Costs

		Forecast		Actuals			
Fuel	**Unit**	**2026**	**2025**	**2024**	**2023**	**2022**	**Avg**
CSG	$000s	$ 258,674	$ 264,458	$ 222,637	$ 206,275	$ 184,030	$ 204,314
	GWh	2,081	2,131	1,586	1,531	1,404	1,507
	$/MWh	**$124.29**	**$124.08**	**$140.34**	**$134.72**	**$131.12**	**$135.57**
Gas	$000s	[TRADE SECRET DATA HAS BEEN EXCISED]		$ 118,274	$ 135,913	$ 155,586	$ 136,591
	GWh			4,779	4,345	2,495	3,873
	$/MWh			**$24.75**	**$31.28**	**$62.36**	**$35.27**
Solar	$000s			$ 55,139	$ 48,841	$ 48,633	$ 50,871
	GWh			848	731	788	789
	$/MWh			**$65.04**	**$66.78**	**$61.73**	**$64.48**
Wind	$000s			$ 224,133	$ 208,370	$ 244,613	$ 225,705
	GWh			5,772	5,610	6,470	5,950
	$/MWh			**$38.83**	**$37.15**	**$37.81**	**$37.93**
Other	$000s			$ 191,029	$ 186,040	$ 190,665	$ 189,245
	GWh			2,288	2,259	2,220	2,256
	$/MWh			**$83.49**	**$82.34**	**$85.90**	**$83.90**
Total	$000s			$ 811,213	$ 785,439	$ 823,527	$ 806,726
	GWh			15,273	14,477	13,376	14,375
	$/MWh			**$53.11**	**$54.26**	**$61.57**	**$56.12**

Sources:
2026 Forecast and 2022-24 Actuals: Part H, Att. 1
2025 Forecast: Xcel's 7/31/24 Reply Comments in Docket No. E002/AA-24-63, Attachments A (page 1), B, C

E.1. Gas PPAs

Overall, in 2026, Xcel is expecting to purchase **[TRADE SECRET DATA HAS BEEN EXCISED]** of gas-fired electricity as in 2022-2004 on average and as forecast for 2025. Xcel forecasts the price per MWh for purchased gas to be **[TRADE SECRET DATA HAS BEEN EXCISED]** than 2025's forecasts.

E.2. Solar PPAs (NON-CSG)

For solar PPAs (non-CSG), Xcel forecasts a **[TRADE SECRET DATA HAS BEEN EXCISED]** compared to the forecasted 2025, and **[TRADE SECRET DATA HAS BEEN EXCISED]** relative to the 2022-2024 average. Xcel forecasts solar PPA unit cost to be **[TRADE SECRET DATA HAS BEEN EXCISED]** relative to the 2022-2024 average, but **[TRADE SECRET DATA HAS BEEN EXCISED]** than 2025 forecast**,** due to new solar projects coming online.[47] The result is that overall solar PPA costs are forecasted to be **[TRADE SECRET DATA HAS BEEN EXCISED]** from prior years.

E.3. Wind PPAs

Forecasted wind PPA prices for 2026 are **[TRADE SECRET DATA HAS BEEN EXCISED]** relative to prior years. Wind energy purchased and dollars spent on wind PPAs are **[TRADE SECRET DATA HAS BEEN EXCISED].**

E.4. Community Solar Garden PPAs

For Community Solar Gardens, Xcel forecasts 2026 costs to increase by 27% relative to 2022-2024 averages. However, Xcel expects costs to decrease by 2% relative to the forecast for 2025. The forecasted decrease relative to 2025 is due to a forecasted decrease in the Applicable Retail Rate (ARR) and ARR MWh. As noted in Xcel's petition on page 17, the above market costs of Community Solar Gardens are directly assigned to Minnesota customers. Xcel provides supporting documentation for its solar garden assumptions in Part B, Attachment 12, and Part G, Workpaper 5.

[47] Petition, Part H WP-1, IR 7b, and IR 7c (DOC Att. 6, Page 5 and 6).

Department Table 6[48]
Xcel CSG Forecast

Item	CSG Type	2026	2025	2024	2023	2022
		Forecast		Actuals		
Cost ($000s)	ARR (Legacy)	$ 169,105	$ 179,666	$ 177,223	$ 164,781	$ 155,560
	VOS (Legacy)	$ 62,293	$ 84,801	$ 45,180	$ 38,956	$ 28,452
	Non-Legacy	$ 27,323	$ -	$ 2,553	$ -	$ -
	Total	**$ 258,721**	**$ 264,467**	**$ 224,956**	**$ 203,737**	**$ 184,012**
MWh	ARR (Legacy)	1,309,860	1,283,859	1,137,792	1,129,769	1,117,684
	VOS (Legacy)	582,160	846,836	427,761	373,943	277,494
	Non-Legacy	189,585	0	40,919	0	0
	Total	**2,081,605**	**2,130,695**	**1,606,472**	**1,503,712**	**1,395,178**
Cost per MWh	ARR (Legacy)	$ 129.10	$ 139.94	$ 155.76	$ 145.85	$ 139.18
	VOS (Legacy)	$ 107.00	$ 100.14	$ 105.62	$ 104.18	$ 102.53
	Non-Legacy	$ 144.12	n/a	$ 62.39	n/a	n/a
	Total	**$ 124.29**	**$ 124.12**	**$ 140.03**	**$ 135.49**	**$ 131.89**

E.5. Other PPAs

The final category in Xcel's long-term PPAs is "Other," which consists of PPAs that do not fit within one of the prior four categories.[49] Xcel forecasts costs for this category to **[TRADE SECRET DATA HAS BEEN EXCISED]** relative to prior years due to the new contracts of PPAs with St. Paul Cogeneration, and Manitoba Hydro – less volumes and less costs beginning in May 2025 .[50]

E.6. PPAs Overall

Based on our review and the explanations Xcel provided, the Department concludes the Company's forecasted 2026 long-term purchased energy costs appear reasonable for the purpose of setting 2026 forecasted FCA rates. As a result, the Department recommends the Commission accept Xcel's forecasted 2026 purchased energy costs for the purpose of setting initial FCA rates in this proceeding, subject to the subsequent true-up.

F. MISO MARKET PURCHASES AND SALES

F.1. MISO Day 2 (ENERGY MARKET) & Day 3 (Ancilliary Services Market)

The Department reviewed Xcel's MISO Day 2 and MISO Day 3 costs and revenues, as discussed on pages 21 and 22 of the Petition and shown in Part B, Attachment 9, and Part F, Workpaper 5. As shown therein, Xcel used an annualized average of actual costs from April 2021 through February 2025 (50 months) to forecast its 2026 congestion costs, financial transmission rights, incremental

[48] Petition, page 24, and Part H, Attachment 6
[49] Petition, page 10.
[50] Petition, page 15.

transmission losses, Revenue Sufficiency Guarantee (RSG)/ Revenue Neutrality Uplift (RNU), and Ancillary Services Market (ASM). For MISO market purchases and asset-based sales revenues, Xcel continued to model these items in PLEXOS. A summary of Xcel's forecasted 2026 and 2025 MISO Day 2 and Day 3 charges is provided in Department Table 7 below:

Department Table 7
Forecasted MISO Day 2 and Day 3 Charges

Line	Category	Forecast in $000s	
		2026	2025
1	Congestion	**[TRADE SECRET DATA HAS BEEN EXCISED]**	
2	Financial Transmission Rights		
3	Incremental Transmission Losses		
4	Rev. Suff. Guaranty & Rev. Neutrality Uplift Charges		
5	Ancillary Services Market a/k/a Day 3		
6 =Σ(1:5)	**MISO Market Charges Total**		
7	Short-Term Market Purchases		
8	Asset-Based Sales Revenues		
9 =Σ(6:8)	**Net MISO Day 2 & 3 Costs & Revenues**		

Source:
2026 Forecast: Petition, Part B, Attachment 9 (MISO Charges: Part F, WP 5; Purchases & Revenues, Part A, Att. 1, p. 1)
2025 Forecast: Xcel's 7/31/24 Reply Comments in Docket No. E002/AA-24-63 (MISO Charges: Att. F, Purchases & Revenues: Att. A)

F.2. Congestion Costs

As shown in the table above, Xcel forecasts congestion costs to **[TRADE SECRET DATA HAS BEEN EXCISED]** in 2026 relative to 2025's forecast. However, as shown in Part H, Attachment 4, Xcel's congestion forecast for 2026 is **[TRADE SECRET DATA HAS BEEN EXCISED]**. In other words, Xcel forecasts congestion costs for 2026 **[TRADE SECRET DATA HAS BEEN EXCISED]**.

In Department IR No. 1, the Department raised concerns that the Company may over-forecast congestion costs for 2026, as it did for 2023 and 2024. This concern arises from the Company's continued reliance on input data that includes unusually high congestion costs from 2021 and 2022, despite a clear downward trend in actual congestion costs in more recent years. To mitigate this distortion, the Department proposed that the Company consider either a 36-month average (2022–2024) or the most recent 2024 actuals as the forecasting basis, in order to reduce the impact of earlier high-cost months. In response, Xcel opposed both alternatives, stating that a one-year average would be too short to adequately capture cost variability, while a 36-month average still could lead to under-recovery of costs in 2026. The Company also noted that its forecasted 2026 congestion costs have decreased markedly from those projected for 2023 and 2024.[51]

[51] Xcel's response to the Department IR No. 1.

While the Department acknowledges the reduction in the 2026 forecast, it remains concerned that the projected congestion costs are still materially higher than actual costs realized in most recent years 2023 and 2024. In addition, the Department observes that the Company previously relied on a one-year period (April 2021–March 2022) in its 2023 congestion costs forecast,[52] which undermines the current argument that a single-year period is too narrow to capture variation. This inconsistency raises reasonable concerns about the flexibility in the Company's forecasting logic and whether it is applied consistently based on objective forecasting principles. The Department finds that the Company's position appears primarily focused on avoiding under-recovery, without adequately addressing the risk of over-forecasting and its implications for ratepayers. Therefore, the Department requests Xcel explain, in reply comments, how its forecasted congestion costs methodology is reasonable and in the public interest.

F.3. Asset-Based Margins

Xcel summarized its forecasted 2026 asset-based margins as follows:

> … the PLEXOS model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices representing LMP 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 2026 are **[TRADE SECRET DATA HAS BEEN EXCISED]** 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.

Xcel's forecasted 2026 asset-based margins of **[TRADE SECRET DATA HAS BEEN EXCISED]**, which are **[TRADE SECRET DATA HAS BEEN EXCISED]** than Xcel's actual 2024 asset-based margins of **[TRADE SECRET DATA HAS BEEN EXCISED]**.[53] However, Xcel's 2026 forecast is **[TRADE SECRET DATA HAS BEEN EXCISED]** than Xcel's forecasted 2025 asset-based margins.

[52] Docket No. E002/AA-22-179, Part F, Workpaper 5, (eDocket) 20225-185476-07.
[53] Petition, page 22.

Department Table 8
Asset-Based Margins ($ in millions)

2026 **2025**	**[TRADE SECRET DATA HAS BEEN EXCISED]**	
2024	$ 86.8	Actual
2023	$ 80.7	Actual
2022	$ 188.3	Actual

Sources:
Xcel's Petition on page 22
2025 Forecast: Xcel's 7/31/24 Reply Comments in Docket No. E002/AA-24-63, Attachment G

G. OUTAGES

G.1. Planned Outage Rates

Part B, Attachment 5 provides planned outages for each unit. The Department reviewed the table in the attachment and concludes Xcel has reasonably explained its forecasted planned outages.

G.2. Unplanned (Forced) Outage Rates

Xcel's forecasted 2026 unplanned outage rates and costs are provided in Part B, Attachments 6-7, and Part H, Workpaper 3. As shown therein, Xcel used a five-year average (2020 -2024) and then adjusted the forecast up and down using its judgment to arrive at a final assumption to forecast its unplanned outage rates for base load plants in 2026. For its peaking plants, Xcel used MISO's calculation of Equivalent Forced Outage Rate Demand (eFORd) to forecast its unplanned outage rates.

G.3. Outage Costs.

Department Table 9 below provides a summary of Xcel's forecasted 2026 planned and unplanned outages in MWh, and their related power replacement costs.

Department Table 9
Forecasted vs. Actual Outages – Costs and Lost Energy

	Planned Outages			Unplanned Outages			Total Outages		
	Costs (000s)	GWh	$/MWh	Costs (000s)	GWh	$/MWh	Costs (000s)	GWh	$/MWh
2026 Forecast	[TRADE SECRET DATA HAS BEEN EXCISED]								
2025 Forecast									
2022-24 Avg Actuals	$ 53,807	3,725	$14.44	$ 39,752	2,453	$16.21	$ 93,559	6,178	$15.14
2024 Actuals	$ 75,668	5,497	$13.77	$ 22,546	2,212	$10.19	$ 98,213	7,709	$12.74
2023 Actuals	$ 52,028	4,075	$12.77	$ 47,834	3,267	$14.64	$ 99,862	7,342	$13.60
2022 Actuals	$ 33,726	1,604	$21.03	$ 48,877	1,880	$26.00	$ 82,603	3,484	$23.71

Sources:
2026 Forecast and 2022-24 Actuals: Part H, Att. 3
2025 Forecast: Xcel's 7/31/24 Reply Comments in Docket No. E002/AA-24-63, Att. G

Xcel's forecasted total 2026 outage costs are **[TRADE SECRET DATA HAS BEEN EXCISED]**. As a result, the Department requests Xcel to explain the change in forecasted total outage costs for 2026 compared to 2025 in reply comments. The Department will make its final recommendation regarding Xcel's forecasted 2026 outages after reviewing Xcel's reply comments.

H. WIND PRODUCTION

H.1. Wind Production OveralL

When Company-owned wind projects are approved, in general, Xcel assumes certain average production levels over the life of the facilities, relative to the overall production capacity. The result is an assumed capacity factor. This assumption translates into assumed ratepayers benefits in terms of energy sold into the MISO market, which passes through the FCA. Xcel provides actual 2022-2024 and forecasted 2025 and 2026 wind capacity factors in Part H, Attachment 5. The Department summarizes Xcel's forecasted capacity factors information in Department Table 10 below.

Department Table 10
Xcel's Forecasted Capacity Factors at Xcel-Owned Facilities

Wind Farm Name	Assumed at Acquisition	Actual Generation								Forecast			
		2022		2023		2024		2022-2024 Avg.		2025		2026	
	CF	CF	% of Assu.	CF	% of Assu.	CF	% of Assu.	CF	% of Assu.	CF	% of Assu.	CF	% of Assu.
Blazing Star 1	[TRADE SECRET DATA HAS BEEN EXCISED]	52.2		46.1		46.5		48.2		[TRADE SECRET DATA HAS BEEN EXCISED]			
Blazing Star 2		51.1		46.6		47.3		48.3					
Borders		50.6		44.4		47.3		47.4					
Community Wind North		52.4		47.3		49.5		49.7					
Courtenay		46.6		39.6		42.0		42.7					
Crowned Ridge 2		50.4		44.3		45.7		46.8					
Dakota Range 1 & 2		43.5		36.0		39.6		39.7					
Foxtail		42.4		44.0		44.5		43.6					
Freeborn		45.1		43.1		42.8		43.7					
Grand Meadow		29.1						29.1					
Grand Meadow Repower				37.2		43.3		40.3					
Jeffers		54.3		49.8		50.4		51.5					
Lake Benton 2		51.8		49.1		49.7		50.2					
Mower		40.8		36.5		39.5		38.9					
Nobles		23.9						23.9					
Nobles Repower				42.6		42.9		42.8					
Northern Wind				39.9		46.0		42.9					
Pleasant Valley		49.5		42.6		44.1		45.4					
Rock Aetna				45.3		58.5		51.9					
Average													

The Department notes that the forecasted capacity factors for the Rock Aetna wind farm for the years 2025 and 2026 are not included in part H, Attachment 5. Therefore, the Department requests Xcel, in reply comments, explain why these forecasts have been omitted.

H.2. WIND CURTAILMENT

H.2.1. PPA Curtailment

The Petition states the following on page 9 regarding wind curtailment for PPAs:

> 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.

Part G, Workpaper 6 of the Petition, provides Xcel's detailed calculations of its forecasted 2026 wind curtailment costs for PPAs. Xcel's forecasted 2026 wind curtailment for PPAs totals **[TRADE SECRET DATA HAS BEEN EXCISED]** MWh, which Xcel estimates per the PPAs costs ratepayers **[TRADE SECRET DATA HAS BEEN EXCISED]**. Xcel's forecasted total wind curtailment costs for 2026 are **[TRADE SECRET DATA HAS BEEN EXCISED]**.

Department Table 11 summarizes Xcel's forecasted 2026 and prior year wind curtailment for PPAs.

Department Table 11
Xcel's Wind Curtailment Costs for PPAs

	Actual Wind Curtailment				Forecast	
	2022	2023	2024	2022-2024 Avg.	2025	2026
Curtailment Cost	[TRADE SECRET DATA HAS BEEN EXCISED]					
Lost MWh						

H.2.2. Owned-Wind Curtailment

The Petition (page 6) states the following related to curtailments for Company-owned wind:

> NSP-owned wind 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 turbine technology, plant design, and localized weather data. New projects are further adjusted to reflect warranty, preventative maintenance, daily faults, and other issues common with new wind farms in their first years of operation. Company-owned projects are modeled as curtailable projects since they can be curtailed by MISO. Curtailment of owned wind projects is forecast by the PLEXOS simulation. A white paper describing the wind profile forecast process in detail is provided with this filing as Part B, Attachment 10. There is no fuel price input for wind generation in the model because wind generation does not require any fuel purchases.

While the Department agrees there are no fuel costs or direct payments (like PPAs) associated with curtailment of Company-owned wind, the Department notes there can be a significant amount of curtailment and opportunity costs associated with these facilities, and with PPAs, curtailment from

company-owned wind farms causes ratepayers to pay more for electricity, as, without these curtailments, the company could have sold these MWh in the MISO market.

H.3. Wind Conclusion

The Department reviewed Xcel's forecasts and concluded they are reasonable for the purposes of setting 2026 rates, subject to true-up. The Department will provide a more detailed review of Xcel's 2026 wind production when Xcel files its 2026 true-up petition.

I. MINNESOTA-ONLY FCA COSTS

As shown in Department Table 3 above, the 2025 FCA forecasts contains two categories which are only charged to Minnesota ratepayers: Above Market Costs for Community Solar Gardens, and Biomass Buyout Costs. The Department reviews these two items below.

I.1. Community Solar Gardens - AMC

In its September 17, 2014 Order in Docket No. E002/M-13-867[54], the Commission approved Xcel's proposal to recover CSG program costs, including customer bill credits, additional Renewable Energy Credits (RECs), and unsubscribed energy, through the FCA mechanism.

On page 9 of the Petition, Xcel provided a detailed discussion on how CSG costs are modeled in PLEXOS and how CSG-AMC are reflected in its forecasted 2024 FCA, stating:

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

[54] In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of Its Proposed Community Solar Garden Program, Order, Minnesota Public Utilities Commission, Docket No. E-002/M-13-867, eDocket 20149-103114-01

The 2026 forecast provided more information on CSGs on pages 15-16. As noted on page 15 of the Petition and reviewed in more detail in Department Table 6 above, Xcel is forecasting a decrease in overall CSG costs and, correspondingly, a decrease in CSG-AMC costs. Xcel estimates that CSGs result in an annual FCA rate that is $5.96/MWh or 19% higher than it would be otherwise.

Pursuant to Minn. Stat. § 216B.1641, subd. 11, Xcel will exclude the $5.96/MWh cost for customers eligible for bill payment assistance and not subscribing to a CSG. As stated on page 16 of the Petition, Xcel has calculated the net cost of generation for CSGs as 0.583 cents per kWh for 2026. This rate is used to exclude the net costs of CSG generation for customers who are eligible for exemption. The Company includes the rate update as part of its proposed tariffs in Part A, Attachment 5.

Based on our review, the Department recommends the Commission accept Xcel's 2026 forecasted CSG-AMC costs for the purpose of setting initial FCA rates in this proceeding, subject to subsequent true-up.

I.2. Biomass Buyout Costs

Xcel's Minnesota FCA costs historically have included biomass buyout costs related to the early termination of biomass PPAs in accordance with the Commission's Orders in Docket Nos. E002/M-17-530, E002/M-17-551, and E002/M-17-531.[55] For the 2026 forecast, the only buyout costs included are for the Benson PPA, for which Xcel is forecasting costs will be **[TRADE SECRET DATA HAS BEEN EXCISED]**. Part G, Workpaper 4 provides Xcel's forecasted Benson buyout costs per month.

Based on our review, the Department concludes Xcel's forecasted 2026 biomass buyout costs appear reasonable. As a result, the Department recommends the Commission accept Xcel's forecasted 2026 biomass buyout costs for the purpose of setting initial FCA rates in this proceeding, subject to subsequent true-up.

J. JURISDICTIONAL & CLASS COST ALLOCATION

As Xcel notes in Part B, Attachment 13:

> 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.

[55] In the Matter of Xcel Energy's Petition for Approval to Terminate the Power Purchase Agreement (PPA) with Benson Power, LLC, Acquire the Benson/Fibrominn Plant, and Close the Facility, Docket No. E002/M-17-530; In the Matter of Xcel Energy's Petition for Approval to Terminate the PPA with Laurentian Energy Authority I, LLC, Docket No. E002/M-17-551, Order, Minnesota Public Utilities Commission, January 23, 2018, (eDocket) 20181-139242-01
In the Matter of Petition of Approval to Terminate the Pine Bend Power Purchase Agreement (PPA), Docket No. E002/M-17-531, Order, Minnesota Public Utilities Commission, November 8, 2017, (eDocket) 201711-137229-01

As noted on pages 16-17, Xcel continued to assign costs to NSPM through the Interchange Agreement energy allocator and then allocated costs to the Minnesota jurisdiction based on sales.[56] To calculate class rates, Xcel is likewise not proposing any changes in its previously approved methodology.

Given that Xcel proposes to continue to use approved cost allocation methods, the Department recommends approval of Xcel's proposed jurisdictional and class cost allocations for 2026 forecast purposes, subject to true-up.

IV. DEPARTMENT RECOMMENDATIONS

The Department will make a recommendation regarding whether to accept Xcel's 2026 fuel forecast after receiving the information requested from Xcel in reply comments, as noted below.

Compliance Items:
The Department recommends the Commission accept Xcel's compliance with reporting requirements for the current Petition relating to its 2026 FCA forecast.

Sales Forecast:
The Department recommends the Commission accept Xcel's 2026 forecasted sales in this proceeding, subject to subsequent true-up.

Company-Owned Generation:
The Department recommends the Commission accept Xcel's forecasted 2026 fuel costs for Company-owned generation for the purpose of setting initial 2026 FCA rates in this proceeding, subject to subsequent true-up. However, since the Company has indicated its expectation to sell all the nuclear PTCs, the Department requests Xcel provide in **reply comments** an analysis of the costs and benefits of transferring versus not transferring these credits.

Long-Term PPAs:
The Department recommends the Commission accept Xcel's forecasted 2026 long-term purchased energy costs for the purpose of setting initial 2026 FCA rates in this proceeding, subject to subsequent true-up.

MISO Costs & Revenues
The Department requests Xcel explain in **reply comments** how its forecasted congestion costs methodology is reasonable and in the public interest. The Department will make its final recommendation regarding Xcel's forecasted 2026 MISO costs and revenues after reviewing Xcel's reply comments.

[56] See also Xcel's response to DOC IR 4.

Outage Costs:
The Department requests Xcel explain in **reply comments** the change in forecasted total outage costs for 2026 compared to 2025. The Department will make its final recommendation regarding Xcel's forecasted 2026 outages after reviewing Xcel's reply comments.

Wind Production:
The Department notes that the forecasted capacity factors for the Rock Aetna wind farm for the years 2025 and 2026 are not included in part H, Attachment 5. Therefore, the Department requests Xcel, in **reply comments**, explain why these forecasts have been omitted.

Except for the issue above, the Department concludes Xcel has reasonably explained its forecasted 2026 wind production costs. Assuming Xcel provides a reasonable explanation of this issue, the Department recommends the Commission accept Xcel's forecasted 2026 wind production for the purposes of setting 2026 rates, subject to true-up. The Department will provide a more detailed review of Xcel's 2026 wind production when Xcel files its 2026 true-up Petition.

Minnesota-Only FCA Costs (Community Solar Gardens – AMC and Biomass Buyout Costs):
Based on our review, the Department recommends the Commission accept Xcel's forecasted 2025 CSG-AMC costs for the purpose of setting initial 2026 FCA rates in this proceeding, subject to subsequent true-up.

The Department also recommends the Commission accept Xcel's forecasted 2026 biomass buyout costs for the purpose of setting initial 2026 FCA rates in this proceeding, subject to subsequent true-up.

Jurisdictional & Class Cost Allocation:
The Department recommends approval of Xcel's proposed jurisdictional and class cost allocations for 2026 forecast purposes, subject to true-up.

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☐ **Public Document**

Xcel Energy		Information Request No. Informal 1
Docket No.:	E002/AA-25-63	
Response To:	Minnesota Department of Commerce	
Requestor:	Staff Analysts	
Date Received:	April 15, 2025	

Question:
Provide copies of all live spreadsheets relating to our 2026 Fuel Forecast Petition filed on May 1, 2025.

Response:
Live spreadsheets supporting our Petition can be accessed at the following site:

[redacted]

Please note that many of these live files are marked as "Not-Public" as they contain information the Company considers 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). The information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Please see a full Not-Public justification included with our Petition filed in this docket on May 1, 2025.

Preparer:	Rebecca Eilers
Title:	Manager, Regulatory Affairs
Department:	NSPM Regulatory
Telephone:	612-330-5570
Date:	May 1, 2025

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☐ **Public Document**

Xcel Energy		Information Request No.	1
Docket No.:	E002/AA-25-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo & Mark Johnson		
Date Received:	May 21, 2025		

Question:
Topic: Congestion Costs
Reference(s): Petition, Part F, WP – 5; Docket E002/AA-22-179 True-up Filing; Docket E002/AA-23-153 True-up Filing.

As part of the current review of Xcel's 2026 forecasted congestion costs, the Department understands that the Company continues to rely on 50-month historical average costs to estimate these projected costs. The Department does not oppose the use of this method in principle. However, based on the recent true-up filings data for the years 2023 and 2024, it appears that the forecasted congestion costs for these years significantly exceeded the actual costs calculated using the same methodology (see table below). The reason for this overestimation is that the input data includes very high costs from 2021 and 2022, while congestion costs have been decreasing substantially in recent years (2023 and 2024). The Department is concerned that if the inputs in the forecasting model are not revised, it could lead to an overcollection of congestion costs for 2025 and 2026.

Please explain whether Xcel agrees with the Department's concern, or, if not, provide the reasons why. For forecasted congestion costs, would the Company oppose the use of a three-year average from 2022 to 2024, or most recent 2024 actuals instead? Please explain why.

Congestion costs net of Financial Transmission Rights 2023, 2024 - Forecast to Actuals ($ million)

Category	2023 F	2023 Actual	Delta $	Delta %	2024 F	2024 Actual	Delta $	Delta %
Congestion Costs	338.03	157.80	(180.23)	-53%	259.40	173.90	(85.50)	-33%
FRT Revenues	(109.39)	(34.20)	75.19	-69%	(91.92)	(45.21)	46.71	-51%
Net	**228.64**	**123.60**	**(105.04)**	**-46%**	**167.48**	**128.69**	**(38.79)**	**-23%**

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Response:
Because congestion costs and FTR revenues are volatile and difficult to predict, the Company continues to support its current forecast model. The volatility and unpredictability stems from the impact of numerous different factors, including transmission outages both planned and unplanned (e.g. storm related, etc.), new renewable additions, generator retirements, and fuel prices, in particular natural gas. Although the Company has insight on some factors for the 2026 test period for its own resources, it does not have this insight for other market participants in MISO, which compounds the difficulty to predict these costs for 2026.

The Company selected the historical period for this case to capture a long enough period to reflect the volatility that has existed in congestion costs and FTR revenues due to the contributing factors mentioned above. The Company would oppose the use of a single year, such as 2024 actual, for this case because it does not provide enough length to appropriately capture the variation in these costs due to the contributing factors discussed. For example, 2024 was marked by very low natural gas prices throughout the year which impacted congestion costs. Current future natural gas prices for 2026 are much higher than 2024 which could lead to higher congestion costs in 2026 if those prices are realized.

The three-year average from 2022 to 2024 spans additional time and is accordingly more reflective of the drivers that have caused significant volatility in congestion costs and is therefore more appropriate than using a 2024 actual alone. The three-year period 2022 to 2024 also reflects costs that are closer to the Company's original filing. However, even using the three-year average, the Company is still concerned that it could under-recover these costs in 2026 due to changes in transmission availability, new renewable additions, generator retirements, and volatility of fuel prices both for our system and elsewhere in the MISO footprint.

It is important to note that the forecast of congestion costs for 2026 has decreased markedly from the table shown by the Department above. For our 2026 filing, congestion costs are forecast at [redacted] lower than the 2023 and 2024 forecast shown in the Department's table listed in this IR. Therefore, the Company's forecasting process has already captured much of the reduction noted by the Department, and we believe it is still a reasonable approach to projecting congestion costs for 2026.

Please note that this response is marked as "Not Public" as it contains information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information

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pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Preparer:	David G. Horneck
Title:	Director, Generation Modeling Services
Department:	Generation Modelings Services
Telephone:	(303)571-2816
Date:	June 2, 2025

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☐ **Public Document**

Xcel Energy		Information Request No.	2
Docket No.:	E002/AA-25-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo & Mark Johnson		
Date Received:	May 21, 2025		

Question:
Topic: Nuclear Production Tax Credit (PTC)
Reference(s): Petition, Part B, Att 15; Docket E002/AA-23-153 True-up Filing.

a. Please provide a more detailed explanation (than provided in Part B, Att 15) regarding how the Company forecasts the nuclear PTCs for 2026.
b. Please update the forecasted nuclear PTCs for 2025, including actuals through April 30, 2025 and updated forecast for the rest of 2025. Provide a narrative that explains the Company's updated forecast.
c. Please explain the reason for the significant reduction in forecasted 2026 nuclear PTCs [redacted] compared to the actual amount for 2024 ($176 million). Please compare and address the differences in nuclear PTCs between actual 2024, forecasted 2025, and forecasted 2026.

Response:
a. 2026 nuclear PTCs are forecasted as an annual calculation based on both generation data and annual gross receipts that have been forecasted for 2026. Additionally, there is a phaseout of the credit based on annual gross receipts (which are calculated as generation multiplied by Locational Marginal Pricing (LMP)). This phase out begins when LMPs exceed $25/MWh. 2026 LMPs are forecasted to be [redacted].

b. Please see Attachment A to this response for forecasted nuclear PTCs for 2025, including actual generation and LMP data for January 1, 2025-April 30, 2025 and forecasted generation and LMP data for May 1, 2025-December 31, 2025. We note that we had not yet provided the 2025 forecast, so this does not update a previous forecast on the record. See Part c below for an explanation of why there is a reduction in nuclear PTCs for both 2025 and 2026 as compared to the 2024 actuals.

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c. The significant reduction in forecasted 2026 nuclear PTCs compared to the actual amount for 2024 is primarily driven by higher annual gross receipts, which cause the credit to be reduced (as discussed in Part a, above). Additionally, annual gross receipts for 2025 are higher than the actual gross receipts for 2024, so the 2025 credit is also reduced. Please see Attachment B to this response for a summary of the nuclear PTCs and annual gross receipts for 2024, 2025, and 2026.

Please note that this response as well as Attachment A and Attachment B are marked as "Not Public" as they contain information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Preparer:	Laura Brennan
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Date:	June 2, 2025

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Date:	June 2, 2025

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Northern States Power Company
Nuclear PTCs

Docket No. E002/AA-25-63
DOC IR No. 2
Attachment A - Page 1 of 1

[PROTECTED DATA BEGINS

	2025 Fcst PTCs ($)
Monticello	[redacted]
Prairie Island I	
Prairie Island II	
Total 2026 Fcst PTCs ($)	
Less Transaction Costs	
Net Nuclear PTCs ($)	[redacted]

	Allocator (IA Demand)
Allocation to NSPW	15.9307%
Allocation to NSPM	**84.0693%**

Allocation of NSPM to State	Allocator (EEnergy)	Tax Gross-up 1/(1-T)*	Grossed up PTCs
Minnesota	**86.4668%**	**1.4033512**	[redacted]
North Dakota	6.5614%	1.3228371	
South Dakota	6.9718%	1.2658228	

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* T = Composite Tax Rate in each State

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Nuclear PTC

	2024 PTCs ($)	2025 Fcst PTCs ($)	2026 Fcst PTCs ($)
Monticello	[redacted]		
Prairie Island 1			
Prairie Island 2			

Gross Receipts (Generation x LMP)

	2024 PTCs ($)	2025 Fcst PTCs ($)	2026 Fcst PTCs ($)
Monticello	[redacted]		
Prairie Island 1			
Prairie Island 2			

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Xcel Energy		Information Request No.	3
Docket No.:	E002/AA-25-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo & Mark Johnson		
Date Received:	May 21, 2025		

Question:
Topic: Unit Costs
Reference(s): Petition, Part H, Att. 1, 'IR 7 (c)' worksheet

Please explain in more detail the reason for the deviation in generation (megawatt-hours) forecasted for 2026 relative to the average from 2022-2024, for:

a. Coal.
b. Gas PPAs.
c. ST market purchase.
d. Sales Revenue.

Response:

a. Coal generation in the 2022-2024 average included coal generation at Sherco 2 in 2022 and 2023 and none beginning in 2024 when the unit was retired. This is the main driver for the lower forecast coal generation in 2026 than the 2022-2024 average. Excluding Sherco 2 from the 2022-2024 average results in coal generation 13 percent lower than forecast. A secondary driver to lower forecast coal generation in 2026 is [redacted] in 2026.
b. Gas PPA generation was low in 2022 due to much higher natural gas prices. The unit cost of gas in 2022 was double the three-year average reflecting much higher natural gas prices. Removing 2022 from the average results in gas PPA generation than is 9 percent lower than forecast. In addition, the forecast for 2026 increases as a result of lower forecast generation from other PPAs (primarily Manitoba Hydro) and lower forecast coal generation as discussed in the response to Part a above.
c. Market purchases and sales volumes should be evaluated collectively due to accounting practice that account for day-ahead and real-time market activity separately. This practice results in higher actual purchase and sales volumes for

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the 2022-2024 average. Therefore, the forecast model, which does not model separate day-ahead and real time activity, is most appropriately compared to net purchase and sale activity. When compared on a net basis, market activity is forecast to be 17 percent lower than the three-year average. The reduction is primarily driven by lower forecast generation from other PPAs (primarily Manitoba Hydro) and lower forecast coal generation as discussed in Part a above.

d. See response to Part c above.

Please note that this response is marked as "Not Public" as it contains information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Preparer:	David G. Horneck
Title:	Director, Generation Modeling
Department:	Generation Modeling Services
Telephone:	(303)571-2816
Date:	June 2, 2025

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☐ **Public Document**

Xcel Energy		Information Request No.	4
Docket No.:	E002/AA-25-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Cuong Ngo & Mark Johnson		
Date Received:	May 21, 2025		

Question:
Topic: Jurisdictional Allocators
Reference(s): N/A

Please provide all jurisdictional allocators (% and methodology) used to develop the Minnesota 2026 FCA forecast, and state which costs/revenues/sales each allocator was applied to.

a. Please explain why the allocators used are reasonable for allocating each cost, revenue, or sales.
b. Please compare these allocators to those used over the past 3 years and explain any differences.

Response:
The monthly jurisdictional allocators for the 2026 FCA forecast are included in Attachment A to this response.

a. Previously we had used a sales allocator to assign costs to the Minnesota jurisdiction for the fuel clause calculation, which can produce a different level of costs assigned to Minnesota than the Interchange Agreement assigns under the tariff.

   The Commission's November 9, 2023 Order in Docket No. E002/AA-23-153 approved the allocation of fuel costs to Minnesota using the FERC-approved Interchange Agreement tariff which governs cost allocation between our NSP-Minnesota and NSP-Wisconsin operating companies.

   In our May 1, 2025 Petition in this docket, we 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

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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 pay for their allocation of the fuel costs assigned to the NSPM operating company.

b. A comparison of the monthly FCA fuel cost forecast allocators from 2023 through 2026 is provided in Attachment A to this response.

   Based on Attachment A, the largest difference in allocators is approximately 1.7 percent. Minor variations in allocators across months and years are expected, as the usage ratios across the jurisdictions are not exactly the same in each month.

Please note that Attachment A is marked as "Not Public" as it contains information the Company considers to be "not-public data" pursuant to Minn. Stat. §13.02, Subd. 9. This is information the Company considers to be "Trade Secret" information pursuant to Minn. Stat. § 13.37, subd. 1(b), because it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Preparer:	Hui Chen
Title:	Principal Pricing Analyst
Department:	NSPM Regulatory
Telephone:	(612) 330-6749
Date:	June 2, 2025

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2023 - Dec 2023
As filed in Docket No. E002/AA-22-179
Costs in $1,000's

Protected Data is shaded.

Line #		1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	11/1/2023	12/1/2023	2023 Total
1														
4														
27	**Total System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	-$4,842	-$7,115	-$14,647	-$17,453	-$20,615	-$16,925	-$18,690	-$18,996	-$14,512	-$11,333	-$7,911	-$5,886	-$158,926
31	**Less Renewable Connect Pilot**													
32	**Less Renewable Connect MTM**													
33	**Less Renewable Connect LT**													
34														
35	**Net System Costs**													
36														
37	**Net System Sales**													
38	Calendar Month MWh Sales													
39														
40	**Less Renewable Connect Pilot MWh Sales**													
41	**Less Renewable Connect MTM MWh Sales**													
42	**Less Renewable Connect LT MWh Sales**													
43														
44	**Net Sys MWh Sales**													38,267,186
45														
46	**System Cost in cents/kWh**													
47														
48	**Minnesota Juris. MWh Sales**													
49														
50	**Less Renewable Connect Pilot MWh Sales**													
51	**Less Renewable Connect MTM MWh Sales**													
52	**Less Renewable Connect LT MWh Sales**													
53														
54	**Net MN MWh Sales**													26,971,930
55														
56	**MN Fuel Cost**													
57	**Solar Gardens - Above Market Cost**	$4,842	$7,115	$14,647	$17,453	$20,615	$16,925	$18,690	$18,996	$14,512	$11,333	$7,911	$5,886	$158,926
58	**Laurentian Buyout costs**													
59	**Pine Bend Buyout Cost**													
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													$985,330

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	Net NSP System Sales Allocator	69.612%	69.316%	69.459%	69.301%	70.513%	71.151%	71.574%	71.793%	71.392%	70.877%	70.387%	69.767%	70.483%

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2024 - Dec 2024

Protected Data is shaded.

Line #	As filed in Docket No. E002/AA-23-153	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	2024 Total
1	*Costs in $1,000's*													
2														
3	**Own Generation**													
4	Fossil Fuel	[PROTECTED DATA BEGINS												
27	**Total NSP System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**													
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**													31,199,824
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 MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													26,842,355
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$9,071	$13,744	$24,016	$27,215	$32,232	$26,744	$28,587	$27,890	$20,805	$16,566	$11,293	$8,881	$247,045
63	**Laurentian Buyout costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													$1,030,253

PROTECTED DATA ENDS]

Interchange Agreement Energy Req Allocator	81.989%	81.870%	81.976%	82.013%	82.179%	83.144%	83.423%	83.238%	82.347%	81.539%	81.931%	81.809%	82.355%
Net NSPM Sales Allocator	85.306%	85.338%	85.396%	85.971%	86.280%	86.626%	86.807%	86.722%	86.649%	86.098%	85.604%	85.273%	86.034%
Net Allocator	69.942%	69.867%	70.004%	70.507%	70.904%	72.025%	72.417%	72.186%	71.354%	70.204%	70.136%	69.761%	70.853%

Northern States Power Company
Electric Utility - State of Minnesota
Jan 2025 - Dec 2025
As filed in Docket No. E002/AA-24-63
Costs in $1,000's

Protected Data is shaded.

Line #		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
1														
2														
4		[PROTECTED DATA BEGINS												
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 Mark													
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]	
	Interchange Agreement Energy Req Allocator	81.877%	81.893%	81.860%	81.882%	82.063%	83.027%	83.329%	83.151%	82.267%	81.455%	81.874%	81.775%	82.256%
	Net NSPM Sales Allocator	85.279%	85.414%	85.610%	85.618%	85.906%	86.346%	86.848%	86.637%	86.357%	85.652%	85.333%	85.319%	85.897%
	Net Allocator	69.824%	69.949%	70.081%	70.105%	70.496%	71.691%	72.369%	72.040%	71.044%	69.767%	69.865%	69.769%	70.656%

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

Protected Data is shaded.

Line #	As filed in Docket No. E002/AA-25-63	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
1	*Costs in $1,000's*													
4		[PROTECTED DATA BEGINS												
27	Total NSP System Costs													
28														
29	Less Sales Revenue													
30	Less Solar Gardens - Above Market Cost	-$4,349	-$7,865	-$15,779	-$18,468	-$22,311	-$21,668	-$18,188	-$16,508	-$15,814	-$11,532	-$6,920	-$4,004	-$163,405
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													31,883,904
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													27,434,341
60														
61	MN Fuel Cost													
62	Solar Gardens - Above Market Cost	$4,349	$7,865	$15,779	$18,468	$22,311	$21,668	$18,188	$16,508	$15,814	$11,532	$6,920	$4,004	$163,405
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													
72	Forecast MN Nuclear PTCs													
73	Total MN FCA Costs including MN Nuclear PTCs													$832,139
74	Forecast MN FCA Cost incl. NPTCs in cents/kWh													3.033
75	Forecast MN FCA Cost incl. NPTCs in $/MWh													30.33
													PROTECTED DATA ENDS]	
	Interchange Agreement Energy Req Allocator	82.303%	82.485%	82.287%	81.870%	82.818%	83.671%	84.126%	83.845%	83.145%	82.563%	82.150%	82.772%	82.921%
	Net NSPM Sales Allocator	85.334%	85.731%	85.359%	85.482%	86.297%	86.590%	87.089%	86.632%	86.514%	85.888%	85.513%	85.638%	86.044%
	Net Allocator	70.232%	70.715%	70.239%	69.984%	71.469%	72.451%	73.264%	72.636%	71.932%	70.911%	70.249%	70.884%	71.349%

Comparison of FCA Fuel Cost Forecast Allocators

	January	February	March	April	May	June	July	August	September	October	November	December	Annual
2023	69.61%	69.32%	69.46%	69.30%	70.51%	71.15%	71.57%	71.79%	71.39%	70.88%	70.39%	69.77%	70.48%
2024	69.94%	69.87%	70.00%	70.51%	70.90%	72.02%	72.42%	72.19%	71.35%	70.20%	70.14%	69.76%	70.85%
2025	69.82%	69.95%	70.08%	70.11%	70.50%	71.69%	72.37%	72.04%	71.04%	69.77%	69.87%	69.77%	70.66%
2026	70.23%	70.72%	70.24%	69.98%	71.47%	72.45%	73.26%	72.64%	71.93%	70.91%	70.25%	70.88%	71.35%
Min	69.61%	69.32%	69.46%	69.30%	70.50%	71.15%	71.57%	71.79%	71.04%	69.77%	69.87%	69.76%	70.48%
Max	70.23%	70.72%	70.24%	70.51%	71.47%	72.45%	73.26%	72.64%	71.93%	70.91%	70.39%	70.88%	71.35%
Range of Variation	0.62%	1.40%	0.78%	1.21%	0.97%	1.30%	1.69%	0.84%	0.89%	1.14%	0.52%	1.12%	0.87%

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Xcel Energy		Information Request No.	7
Docket No.:	E002/AA-24-63		
Response To:	Minnesota Department of Commerce		
Requestor:	Stephen Collins		
Date Received:	May 30, 2024		

Question:

Topic: Annual Data Comparison (DOC IR No. 2, Docket No. E002/AA-23-153)
Reference(s): Petition, page 21 and Part H, Att. 1, 'IR 2(a), (b), and (c)' worksheets

The recurring IR referenced in the petition is to, in the same format as Part A, Attachment 1, page 1 of 3, under the "2025 Total" column, please provide 2025 forecast, 2021 actuals, 2022 actuals, 2023 actuals, and three-year average for 2021 to 2023 for each line item (1-71) on a live spreadsheet with all links and formulas intact. In addition, please add the additional rows/columns necessary to show the annual MWh's associated with each line item (when applicable) and the resulting annual $/MWh. In addition, the Department requested (DOC informal IR 1.b. in Docket No. E002/AA-23-153) that Xcel update the response to provide systemwide sales (lines 37-44 as provided in the 2023 forecast Petition in Docket No. E002/AA-22-179).

(a) Please provide a corrected version of this recurring IR response item (with all the information requested in last year's FCA forecast) and use this corrected version in future FCA petitions.
(b) Please explain the difference between lines 43-49 of Part A, Attachment 1 in the instant petition and lines 37-44 of Part A, Attachment 1 of the 5/2/22 petition in 22-179. Please also explain why Xcel changed how it reports forecasted sales in this attachment.

Response:

(a) Please see the updated version of Part H, Attachment 1, page 1 of 1 provided with this response.

(b) The Company proposed a new rate class allocation methodology in our May 1, 2023 Petition in Docket No. E002/AA-23-153 – the 2024 Fuel Forecast proceeding. The Commission approved this methodology in its November 9, 2023 Order in that docket, Order Point No. 3. Therefore, the referenced lines have been calculated differently in our 2025 forecast compared to our 2023

forecast filed in our Petition in Docket No. E002/AA-22-179 and the Net System Sales are not needed for the jurisdictional calculation.

7/1/24 DOC Comments, E002/ AA-24-63 Attachment DOC-1 TRADE SECRET

The attached updated Part H, Attachment 1 contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Thus, Xcel Energy considers this non-public data.

Preparer:	Hui Chen
Title:	Principal Pricing Analyst
Department:	NSPM Regulatory
Telephone:	612-330-6749
Date:	June 10, 2024

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Northern States Power Company
Electric Utility - State of Minnesota
2026 Forecast, 2022-2024 Actual Fuel, Purchased Power and Other Costs

Line #		2026			2022			2023			2024			2022 - 2024 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				$242,848	9,523.9	$25.50	$174,754	6,451.3	$27.09	$139,293	5,513.1	$25.27	$185,632	7,162.8	$25.92
6	Wood/RDF				$9,781	513.5	$19.05	$9,693	505.5	$19.18	$8,731	473.0	$18.46	$9,402	497.3	$18.91
7	Natural Gas CC				$217,122	3,852.6	$56.36	$169,158	6,357.5	$26.61	$169,165	7,696.2	$21.98	$185,148	5,968.8	$31.02
8	Natural Gas & Oil CT				$46,559	528.5	$88.10	$36,196	827.8	$43.73	$34,970	1,124.6	$31.10	$39,242	826.9	$47.45
9	Subtotal				$516,310	14,418.5	$35.81	$389,801	14,142.1	$27.56	$352,160	14,806.9	$23.78	$419,424	14,455.8	$29.01
10																
11	Hydro				$0	848.0	$0.00	$0	834.3	$0.00	$0	877.5	$0.00	$0	853.3	$0.00
12	Solar											72.7	$0.00			
13	Wind				$0	9,361.3	$0.00	$0	9,238.5	$0.00	$0	9,648.3	$0.00	$0	9,416.0	$0.00
14																
15	Nuclear Fuel				$117,174	14,696.2	$7.97	$95,337	11,927.7	$7.99	$104,608	11,955.8	$8.75	$105,706	12,859.9	$8.22
16																
17	**Purchased Energy**															
18	LT Purchased Energy (Gas)				$155,586	2,494.9	$62.36	$135,913	4,345.2	$31.28	$118,274	4,779.5	$24.75	$136,591	3,873.2	$35.27
19	LT Purchased Energy (Solar)				$48,633	787.9	$61.73	$48,841	731.4	$66.78	$55,139	847.7	$65.04	$50,871	789.0	$64.48
20	Community Solar*Gardens (CSG)	$258,674	2,081.3	$124.29	$184,030	1,403.5	$131.12	$206,275	1,531.1	$134.72	$222,637	1,586.4	$140.34	$204,314	1,507.0	$135.57
21	LT Purchased Energy (Wind)				$244,613	6,470.0	$37.81	$208,370	5,609.5	$37.15	$224,133	5,771.9	$38.83	$225,705	5,950.5	$37.93
22	LT Purchased Energy (Other)				$190,665	2,219.6	$85.90	$186,040	2,259.5	$82.34	$191,029	2,288.0	$83.49	$189,245	2,255.7	$83.90
23	ST Market Purchases				$146,773	2,770.6	$52.98	$94,895	2,365.4	$40.12	$73,226	2,636.7	$27.77	$104,964	2,590.9	$40.51
24	MISO Market Charges				$239,474			$148,146			$169,317			$185,646		
25	Subtotal				$1,209,774	16,146.5	$74.92	$1,028,480	16,842.1	$61.07	$1,053,756	17,910.2	$58.84	$1,097,336	16,966.2	$64.68
26																
27	**Total NSP System Costs**				$1,843,257	55,470.5	$33.23	$1,513,618	52,984.6	$28.57	$1,510,524	55,271.3	$27.33	$1,622,466	54,575.5	$29.73
28																
29	**Less Sales Revenue**				($564,368)	(13,721.3)	$41.13	($282,329)	(11,711.8)	$24.11	($309,911)	(14,872.0)	$20.84	($385,536)	(13,435.0)	$28.70
30	**Less Solar Gardens - Above Market Cost**	(163,405)		$78.51	($99,903)			($155,166)			($180,137)			($145,069)		
31	**Less Renewable*Connect Pilot**				($6,291)	(183.2)	$34.33	($6,739)	(189.9)	$35.49	($6,791)	(822.7)	$8.25	($6,607)	(398.6)	$16.57
32	**Less Renewable*Connect MTM**				($18,190)	(493.3)	$36.87	($16,858)	(539.6)	$31.24	($27,003)	(125.4)	$215.32	($20,683)	(386.1)	$53.57
33	**Less Renewable*Connect LT**															
34																
35	**NSP Net System Costs Excluded CSG Above Market**				$1,154,506	41,072.7	$28.11	$1,052,526	40,543.2	$25.96	$986,682	39,451.2	$25.01	$1,064,571	40,355.7	$26.38
36	**& Renewable*Connect Costs**															

Data Source:

2026 Part A, Attachment 1 Page 1 of 3, May 1, 2025 Petition, Docket No. E002/AA-25-63
Part A, Attachment 2 Page 1 of 1, May 1, 2025 Petition, Docket No. E002/AA-25-63
Part A, Attachment 3 Page 1 of 1, May 1, 2025 Petition, Docket No. E002/AA-25-63

2022 Part A, Attachment 2 Page 1 of 1, March 1, 2023 True-Up Report, Docket No. E002/AA-21-295
Part A, Attachment 5 Page 1 of 1, March 1, 2023 True-Up Report, Docket No. E002/AA-21-295
Part A, Attachment 6 Page 1 of 1, March 1, 2023 True-Up Report, Docket No. E002/AA-21-295

2023 Part A, Attachment 2 Page 1 of 1, March 1, 2024 True-Up Report, Docket No. E002/AA-22-179
Part A, Attachment 5 Page 1 of 1, March 1, 2024 True-Up Report, Docket No. E002/AA-22-179
Part A, Attachment 6 Page 1 of 1, March 1, 2024 True-Up Report, Docket No. E002/AA-22-179

2204 Part A, Attachment 2 Page 1 of 1, March 1, 2025 True-Up Report, Docket No. E002/AA-23-153
Part A, Attachment 5 Page 1 of 1, March 1, 2025 True-Up Report, Docket No. E002/AA-23-153
Part A, Attachment 6 Page 1 of 1, March 1, 2025 True-Up Report, Docket No. E002/AA-23-153

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

Northern States Power Company
Electric Utility - State of Minnesota
2026 Forecast Fuel, Purchased Power and Other Costs

Line #		2026			2024			
1	*Costs in $1,000's*	Costs	GWh	$/MWh	Costs	GWh	$/MWh	
2								
3	**Own Generation**	[redacted]						2024 Delta and key drivers
4	Fossil Fuel							[redacted]
5	Coal				$139,293	5,513.1	$25.27	
6	Wood/RDF				$8,731	473.0	$18.46	
7	Natural Gas CC				$169,165	7,696.2	$21.98	
8	Natural Gas & Oil CT				$34,970	1,124.6	$31.10	
9	Subtotal				$352,160	14,806.9	$23.78	
10								
11	Hydro				$0	877.5	$0.00	
12	Solar				$0	72.7	$0.00	
13	Wind				$0	9,648.3	$0.00	
14								
15	Nuclear Fuel				$104,608	11,955.8	$8.75	
16								
17	**Purchased Energy**							
18	LT Purchased Energy (Gas)				$118,274	4,779.5	$24.75	
19	LT Purchased Energy (Solar)				$55,139	847.7	$65.04	
20	Community Solar*Gardens (CSG)	$258,674	2,081.3	$124.29	$222,637	1,586.4	$140.34	-11.4% Lower solar rate due to ARR garden reprice to VOS per Commission order
21	LT Purchased Energy (Wind)	[redacted]			$224,133	5,771.9	$38.83	[redacted]
22	LT Purchased Energy (Other)				$191,029	2,288.0	$83.49	
23	ST Market Purchases				$73,226	2,636.7	$27.77	
24	MISO Market Charges				$169,317			
25	Subtotal				$1,053,756	17,910.2	$58.84	
26								
27	**Total NSP System Costs**				$1,510,524	55,271.3	$27.33	
28								
29	**Less Sales Revenue**				($309,911)	(14,872.0)	$20.84	
30	**Less Solar Gardens - Above Market Cost**	(163,405)		$78.51	($180,137)			
31	**Less Renewable*Connect Pilot**				($6,791)	(822.7)	$8.25	
32	**Less Renewable*Connect MTM**				($27,003)	(125.4)	$215.32	
33	**Less Renewable*Connect LT**							
34								
35	**NSP Net System Costs Excluded CSG Above Market**				$986,682	39,451.2	$25.01	
36	**& Renewable*Connect Costs**	PROTECTED DATA ENDS]						
37								

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

Northern States Power Company
Electric Utility - State of Minnesota
2026 Forecast Fuel, Purchased Power and Other Costs

Line #		2026			2022 - 2024 Average			
1	*Costs in $1,000's*	Costs	GWh	$/MWh	Costs	GWh	$/MWh	
2								
3	**Own Generation**	[redacted]						3 Yr Avg Delta and key drivers
4	Fossil Fuel							[redacted]
5	Coal				$185,632	7,162.8	$25.92	
6	Wood/RDF				$9,402	497.3	$18.91	
7	Natural Gas CC				$185,148	5,968.8	$31.02	
8	Natural Gas & Oil CT				$39,242	826.9	$47.45	
9	Subtotal				$419,424	14,455.8	$29.01	
10								
11	Hydro				$0	853.3	$0.00	
12	Solar				$0			
13	Wind				$0	9,416.0	$0.00	
14								
15	Nuclear Fuel				$105,706	12,859.9	$8.22	
16								
17	**Purchased Energy**							
18	LT Purchased Energy (Gas)				$136,591	3,873.2	$35.27	
19	LT Purchased Energy (Solar)				$50,871	789.0	$64.48	
20	Community Solar*Gardens (CSG)	$258,674	2,081.3	$124.29	$204,314	1,507.0	$135.57	-8.3% Lower solar rate due to ARR garden reprice to VOS per Commission order
21	LT Purchased Energy (Wind)				$225,705	5,950.5	$37.93	
22	LT Purchased Energy (Other)				$189,245	2,255.7	$83.90	
23	ST Market Purchases				$104,964	2,590.9	$40.51	
24	MISO Market Charges				$185,646			
25	Subtotal				$1,097,336	16,966.2	$64.68	
26								
27	**Total NSP System Costs**				$1,622,466	54,575.5	$29.73	
28								
29	**Less Sales Revenue**				($385,536)	(13,435.0)	$28.70	
30	**Less Solar Gardens - Above Market Cost**	(163,405)			($145,069)			
31	**Less Renewable*Connect Pilot**				($6,607)	(398.6)	$16.57	
32	**Less Renewable*Connect MTM**				($20,683)	(386.1)	$53.57	
33	**Less Renewable*Connect LT**							
34								
35	**NSP Net System Costs Excluded CSG Above Market**				$1,064,571	40,355.7	$26.38	
36	**& Renewable*Connect Costs**	PROTECTED DATA ENDS]						
37								

NOT-PUBLIC DOCUMENT
NOT FOR PUBLIC DISCLOSURE

Actual Price

	Ventura
1/1/2022	$4.38
2/1/2022	$4.55
3/1/2022	$4.48
4/1/2022	$6.29
5/1/2022	$7.59
6/1/2022	$7.24
7/1/2022	$6.72
8/1/2022	$8.17
9/1/2022	$6.88
10/1/2022	$5.00
11/1/2022	$5.01
12/1/2022	$6.81
	$6.09

	Ventura
1/1/2023	$3.62
2/1/2023	$2.31
3/1/2023	$2.36
4/1/2023	$1.93
5/1/2023	$1.85
6/1/2023	$2.00
7/1/2023	$2.25
8/1/2023	$2.28
9/1/2023	$2.21
10/1/2023	$2.26
11/1/2023	$2.37
12/1/2023	$2.06
	$2.29
	$4.19

	Ventura
1/1/2024	$7.19
2/1/2024	$1.55
3/1/2024	$1.35
4/1/2024	$1.26
5/1/2024	$1.57
6/1/2024	$1.80
7/1/2024	$1.66
8/1/2024	$1.65
9/1/2024	$1.87
10/1/2024	$1.90
11/1/2024	$1.89
12/1/2024	$2.71
	$2.20
	$2.20

4/2/2025	Ventura
1/1/2025	$5.94
2/1/2025	$5.84
3/1/2025	$3.27
4/1/2025	$2.84
5/1/2025	$2.82
6/1/2025	$2.94
7/1/2025	$3.11
8/1/2025	$3.12
9/1/2025	$2.92
10/1/2025	$2.94
11/1/2025	$3.80
12/1/2025	$4.93
	$3.71
	$3.71

	Initial Filing
	$1.51
	$1.51

MINN.HUB

	On	Off	Avg
1/1/2022	$43.27	$33.58	$37.95
2/1/2022	$43.03	$34.06	$38.34
3/1/2022	$35.54	$31.06	$33.28
4/1/2022	$50.75	$37.32	$43.59
5/1/2022	$60.16	$38.09	$48.53
6/1/2022	$66.04	$38.26	$51.84
7/1/2022	$71.84	$44.35	$56.77
8/1/2022	$83.37	$49.33	$66.16
9/1/2022	$69.59	$40.93	$54.94
10/1/2022	$50.36	$31.66	$40.10
11/1/2022	$36.71	$23.59	$30.00
12/1/2022	$47.13	$34.96	$40.72
	$54.82	$36.43	$45.19

	On	Off	Avg
1/1/2023	$33.60	$26.82	$30.03
2/1/2023	$23.34	$18.02	$20.55
3/1/2023	$28.62	$22.72	$25.64
4/1/2023	$27.57	$19.19	$22.91
5/1/2023	$30.98	$16.29	$23.56
6/1/2023	$43.90	$21.09	$32.24
7/1/2023	$45.03	$26.54	$34.89
8/1/2023	$46.39	$25.27	$35.72
9/1/2023	$34.08	$24.71	$29.08
10/1/2023	$35.95	$23.80	$29.55
11/1/2023	$35.14	$25.66	$30.30
12/1/2023	$30.73	$23.28	$26.65
	$34.61	$22.78	$28.43

	On	Off	Avg
1/1/2024	$54.33	$38.15	$46.15
2/1/2024	$26.13	$21.18	$23.57
3/1/2024	$22.66	$16.13	$19.08
4/1/2024	$23.16	$16.75	$19.88
5/1/2024	$26.44	$20.25	$23.31
6/1/2024	$27.16	$17.50	$21.79
7/1/2024	$41.05	$24.37	$32.62
8/1/2024	$35.13	$21.21	$27.80
9/1/2024	$34.59	$21.87	$27.80
10/1/2024	$30.91	$18.86	$24.82
11/1/2024	$30.30	$21.35	$25.53
12/1/2024	$41.12	$28.24	$34.33
	$32.75	$22.16	$27.22
			$27.22

[redacted]

4/2/2025	Initial Filing
1/1/2025	[redacted]
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	

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

Protected Data is shaded.

Line #	*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
1														
2	**Own Generation**													
3	Fossil Fuel													
4	Coal													
5	Wood/RDF													
6	Natural Gas CC													
7	Natural Gas & Oil CT													
8	Subtotal													
9														
10	Hydro													
11	Solar													
12	Wind													
13														
14	Nuclear Fuel													
15														
16	**Purchased Energy**													
17	LT Purchased Energy (Gas)													
18	LT Purchased Energy (Solar)													
19	Community Solar*Gardens (CSG)	$8,418	$14,577	$22,402	$25,786	$31,519	$33,719	$34,076	$29,998	$24,376	$17,646	$10,033	$6,325	$258,674
20	LT Purchased Energy (Wind)													
21	LT Purchased Energy (Other)													
22	ST Market Purchases													
23	MISO Market Charges													
24	Subtotal													
25														
26	**Total NSP System Costs**													
27														
28	**Less Sales Revenue**													
29	**Less Solar Gardens - Above Market Cost**	($4,349)	($7,865)	($15,779)	($18,468)	($22,311)	($21,668)	($18,188)	($16,508)	($15,814)	($11,532)	($6,920)	($4,004)	($163,405)
30	**Less Renewable*Connect Pilot**													
31	**Less Renewable*Connect Flex (MTM)**													
32	**Less Renewable*Connect LT**													
33														
34	**NSP Net System Costs Excluded CSG Above Market & Renewable*Connect Costs**													
35														
36	**Interchange Agreement Energy Req Allocator**													
37														
38	**NSPM System Costs Excluded CSG Above Market & Renewable*Connect Costs**													
39														
40	**NSPM System Calendar Month MWh Sales**													
41														
42	**Less Renewable*Connect Pilot MWh Sales**													
43	**Less Renewable*Connect Flex (MTM) MWh Sales**													
44	**Less Renewable*Connect LT MWh Sales**													
45														
46	**Net NSPM System Calendar Month MWh Sales**													31,885,904
47														
48	**NSPM System Cost in cents/kWh**													
49														
50	**Minnesota Jurisdiction MWh Sales**													
51														
52	**Less Renewable*Connect Pilot MWh Sales**													
53	**Less Renewable*Connect Flex (MTM) MWh Sales**													
54	**Less Renewable*Connect LT MWh Sales**													
55														
56	**Net MN MWh Sales**	2,390,300	2,137,256	2,184,027	1,884,787	2,138,870	2,419,983	2,841,154	2,659,892	2,222,550	2,105,321	2,058,840	2,391,361	27,434,341
57														
58	**MN Fuel Cost**													
59	**Solar Gardens - Above Market Cost**	$4,349	$7,865	$15,779	$18,468	$22,311	$21,668	$18,188	$16,508	$15,814	$11,532	$6,920	$4,004	$163,405
60	**Benson Buyout Cost**													
61														
62	**Forecast MN FCA Costs**													
63														
64	**Forecast MN FCA Cost in cents/kWh**													
65														
66	**Forecast MN FCA Cost in $/MWh**													
67														
68														
69														
70														
71														

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

Protected Data is shaded.

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
1														
2	**Own Generation**													
3	Fossil Fuel	[PROTECTED DATA BEGINS												
4	Coal	[redacted]												
5	Wood/RDF													
6	Natural Gas CC													
7	Natural Gas & Oil CT													
8	Subtotal													
9														
10	Hydro													
11	Solar													
12	Wind													
13														
14	Nuclear Fuel													
15														
16	**Purchased Energy**													
17	LT Purchased Energy (Gas)													
18	LT Purchased Energy (Solar)													
19	Community Solar*Gardens	70.1	119.7	186.6	205.9	251.7	269.3	272.1	239.6	194.7	140.9	80.1	50.5	2,081.3
20	LT Purchased Energy (Wind)	[redacted]												
21	LT Purchased Energy (Other)													
22	ST Market Purchases													
23	Subtotal													
24														
25	**Total System GWh**													
26														
27	**Less Sales GWh**													
28	**Less Renewable*Connect Pilot GWh**													
29	**Less Renewable* Connect Flex (MTM) GWh**													
30	**Less Renewable* Connect LT GWh**													
31														
32	**Net System GWh**													42,958.6
33													PROTECTED DATA ENDS]	

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. E002/AA-25-63

Dated this **30th** day of **June 2025**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	AA-25-63
2	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
3	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
4	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	AA-25-63
5	James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
6	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
7	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	AA-25-63
8	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	AA-25-63
9	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	AA-25-63
10	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	AA-25-63
11	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	AA-25-63
12	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
13	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	AA-25-63
15	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	AA-25-63
16	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	AA-25-63
17	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
18	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	AA-25-63
19	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	AA-25-63
20	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	AA-25-63
21	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	AA-25-63
22	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	AA-25-63
23	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
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32	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
33	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
34	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
35	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	AA-25-63
36	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	AA-25-63
37	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		No	AA-25-63
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43	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	AA-25-63
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46	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63
47	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	AA-25-63
48	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	AA-25-63
49	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	AA-25-63
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54	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		Yes	AA-25-63
55	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	AA-25-63
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65	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	AA-25-63
66	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-63