MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**November 2, 2023**		**Agenda Item 1***
Company	Northern States Power Company d/b/a Xcel Energy		
Docket No.	E-002/AA-23-153		
	In the Matter of Xcel Energy's Petition for Approval of its 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges		
Issues	At what level should Xcel Energy's 2024 Annual Forecasted Rates for its Energy Adjustment Rider be set?		
Staff	Ashley Marcus	ashley.marcus@state.mn.us	651-201-2192

✓ **Relevant Documents**	**Date**
Xcel Energy – Initial 2023 Forecast Filing (Public and Trade Secret)	May 1, 2023
Department of Commerce – Comments	June 29, 2023
Xcel Energy – Reply Comments	July 31, 2023
Department of Commerce – Response Comments	August 24, 2023
Xcel Energy – Letter	October 23, 2023

Table of Contents

BACKGROUND

On May 1, 2023, Northern States Power Company d/b/a Xcel Energy (Xcel, NSP, the Company) made its 2024 Annual Fuel Forecast and Monthly Fuel Cost Charges filing.

On June 29, 2023, the Minnesota Department of Commerce – Division of Energy Resources (Department) filed comments recommending approval of Xcel's 2024 sales forecast, its company-owned generation, long-term purchased power agreements (PPAs), MISO Day 2 and Day 3 charges, forecasted Community Solar Gardens (CSG) – Above Market Costs and Biomass Buyout Costs. Additionally, the Department requested that, in reply comments, Xcel provide additional information regarding, asset-based margins, outage costs, wind curtailment costs, and jurisdictional allocations.

On July 31, 2022, Xcel filed reply comments that provided the information the Department requested and updated some of the inputs that were used in the initial forecast.

On August 24, 2023, the Department provided response comments addressing Xcel's reply to the Department's requested information and recommended additional approvals and reporting.

On October 23, 2023, Xcel filed a letter updating adjustment factors that reflect decisions made in Xcel most recent rate.[1]

DISCUSSION

I. Xcel Energy – Initial Filing

A. PLEXOS Software

As they have done in previous years, Xcel used the PLEXOS software that models its system load and generating unit characteristics, along with fuel commodity prices and electric market prices. PLEXOS uses mathematical programming and optimization techniques for power generation modeling and simulation.

B. 2024 Forecast

Xcel's 2024 MN-jurisdiction forecasted sales were 26,842,355 MWh and forecasted costs were $1,030,253,000 resulting in a $38.38/MWh average.[2] Tables 1 and 2 summarize Xcel's proposed 2024 monthly fuel cost rates, by class. These charges will be recovered through the Fuel Clause Adjustment (FCA).

---

[1] Docket No. E-002/GR-21-630.

[2] Xcel Energy Initial Filing, Part A, Attachment 1, Page 1.

Table 1 - Xcel Proposed 2024 Monthly Fuel Clause Rates by Customer Class ($/kWh)[3]

Month	Residential	Commercial & Industrial					Outdoor Lighting
		Non-Demand	Demand				
			Non-TOD	On-Peak	Off-Peak		
January	$0.03388	$0.03430	$0.03324	$0.04154	$0.02721		$0.02658
February	$0.03637	$0.03683	$0.03568	$0.04460	$0.02920		$0.02852
March	$0.03937	$0.03987	$0.03863	$0.04829	$0.03161		$0.03088
April	$0.04222	$0.04275	$0.04142	$0.05178	$0.03390		$0.03311
May	$0.04512	$0.04569	$0.04427	$0.05533	$0.03623		$0.03539
June	$0.04233	$0.04287	$0.04153	$0.05192	$0.03399		$0.03320
July	$0.04253	$0.04307	$0.04172	$0.05218	$0.03412		$0.03333
August	$0.04218	$0.04271	$0.04138	$0.05175	$0.03385		$0.03307
September	$0.03899	$0.03948	$0.03825	$0.04782	$0.03129		$0.03057
October	$0.03806	$0.03854	$0.03734	$0.04668	$0.03055		$0.02984
November	$0.03505	$0.03549	$0.03438	$0.04299	$0.02813		$0.02748
December	$0.03249	$0.03290	$0.03188	$0.03985	$0.02609		$0.02548

Table 2 – Xcel Proposed 2024 Monthly Fuel Clause Rates for C&I General Time of Use Service Pilot ($/kWh)

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04197	$0.03564	$0.01863
February	$0.04507	$0.03826	$0.01998
March	$0.04879	$0.04142	$0.02162
April	$0.05232	$0.04442	$0.02319
May	$0.05591	$0.04747	$0.02480
June	$0.05246	$0.04454	$0.02325
July	$0.05273	$0.04475	$0.02331
August	$0.05229	$0.04438	$0.02314
September	$0.04832	$0.04102	$0.02140
October	$0.04717	$0.04004	$0.02090
November	$0.04344	$0.03687	$0.01924
December	$0.04027	$0.03419	$0.01785

Xcel will update the fuel clause rider tariff sheet to reflect the actual monthly fuel cost charges to be implemented and will provide an updated final tariff sheet in a compliance filing within 10 days after the Order is received.

[3] Xcel Initial Filing at 4.

C. 2024 Forecast Key Inputs

1. NSP System Load

The objective of the PLEXOS simulation is to commit and dispatch resources to meet the hourly load requirement at the lowest cost. The simulation determines the hourly load requirement based on Xcel's most recent forecast of monthly energy and monthly peak demands. Based on a typical hourly shape for the NSP system load, the monthly load forecast is then converted into an hourly forecast.

2. Company-Owned Hydro Generation

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

3. Company-Owned Wind Generation

Inputs for Company-owned wind generation reflect the individual hourly profiles of each Company-owned project. Profiles for Midcontinent Independent System Operator (MISO) Commercial Pricing Nodes (CP Nodes) are developed based on historic weather data and excluding 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 forecasted by the PLEXOS simulation. There is no fuel price input for wind generation in the model because wind generation does not require fuel purchases.

4. Company-Owned Coal Generation

Each Company-owned coal unit is modeled in the PLEXOS simulation. Key modeling parameters such as operating capacity and heat rate are provided by the Company's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is inputted based on NSP's current overhaul schedule. Forced outage rates are inputted for each unit and determined based on historical Generation Availability Data System (GADS) data and expected conditions of the units going forward, including managed decline as plants near retirement.

Coal prices are forecasted based on coal purchases under contract and rail contracts in effect at the time of filing. Coal requirements that are not under contract are forecasted based on market prices.

All coal units, except for Sherco 2 which is planned to retire in 2023, are assumed available to operate year-round for 2024. Additionally, the 2024 forecast assumes that the Environmental Protection Agency (EPA) will publish its proposed "good neighbor" rule to limit NOx emissions for NSP plants during the ozone season in 2023 which runs from May 1, 2023 through September 30, 2023.[4] The proposal, if enacted for 2024, may require NSP to either purchase NOx allowances to allow generation and emissions beyond proposed limits or to limit operation at NSP coal plants to remain within emission limits in the proposal. Xcel plans to monitor both developments and update modeling assumptions with the best available information in the July Reply Comments.

5. Company-Owned Wood/RDF Generation

Key modeling parameters, such as operating capacity and heat rate, for Company-owned wood/refuse derived fuel (RDF) unit are provided by Xcel's Energy Supply business unit based on each individual plant's capabilities. Planned maintenance is inputted based on the current overhaul schedule. Forced outage rates are inputted for each plant and determined based on the plant's historical performance. Wood and RDF prices are forecasted based on existing contracts.

6. Company-Owned Natural Gas Generation

Modeling parameters such as operating capacity and heat rate are provided by Xcel's Energy Supply business unit based on capabilities of the individual plants. Planned maintenance is inputted based on the current overhaul schedule. Forced outage input rates for each unit are determined based on historical GADS data and expected conditions of the units going forward. For peaking plants, the model is based on a three-year history of MISO's calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd).

Forecasted natural gas prices are based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Natural gas transport costs are based on Xcel's transport and delivery contracts in place at the time of filing.

7. Company-Owned Nuclear Generation

Modeling parameters include monthly operating capacity based on each individual unit's capability. Planned maintenance is inputted based on the current overhaul schedule. Forced outage rates for each unit are determined based on historical GADS data and expected conditions of the units going forward. Nuclear fuel price is based on the Company's existing nuclear fuel contracts.

---

[4] The U.S. Environmental Protection Agency (EPA) issued its final Good Neighbor Plan on March 15, 2023, published in the Federal Register on June 5, 2023, and will be effective August 4, 2023. https://www.epa.gov/csapr/important-dates-good-neighbor-plan-nox-ozone-season-group-3-trading-program

8. Purchased Natural Gas Generation

Modeling parameters such as operating capacity and heat rate are based on each individual plant's capability or according to terms specified in the power purchase agreement (PPA). Planned maintenance is inputted based on the PPA counterparty's overhaul schedule. Each unit's forced outage rates are based on the MISO calculation of each unit's eFORd three-year of history. Forecasted natural gas prices are based on NYMEX futures prices for natural gas at the Ventura hub. Natural gas transport costs are based on the Company's transport and delivery contracts in place at the time of filing.

9. Purchased Solar Generation

Solar profiles are based on historical results from projects with operational data. PPA prices are based on contract terms.

The Solar*Rewards Community program is modeled in the PLEXOS simulation and includes expectations of future growth based on current applications for gardens seeking to participate in the program. To forecast 2024 capacity for community solar projects, Xcel estimated in-service dates and project completions (in capacity) by month and year. Forecasted additional applications were based on historical averages. Capacity assumptions are then modeled to determine MWh and average dollars per kWh. In consideration of simulation run times, the program is modeled as one entity within PLEXOS rather than individually by garden. The assumed price is a weighted rate based on an escalation of the historical Applicable Retail Rate (ARR) and the rates 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). This program's costs are shared by all jurisdictions in the NSP system. The cost of the program above market is directly assigned to Minnesota customers.

10. Purchased Wind Generation

Wind PPAs modeling reflects each individual project's hourly profiles. Profiles for individual MISO CP Nodes are developed based on historic weather data and excluding 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. Projects subject to MISO output curtailment are modeled as curtailable projects. Those for which curtailment is not allowed are modeled as non-curtailable projects. The price for each wind PPA is based on the terms of each contract.

11. Purchased Generation – Other

PPAs that do not fit within one of the prior three categories (primarily small hydro PPAs, the remaining biomass PPA, and the PPA with Manitoba Hydro) are modeled based on historical generation (for small hydro PPAs) or according to contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

12. Market Purchases and Sales

If a supply source results in lower cost than utilization of one of the NSP system dispatchable resources, the PLEXOS simulation can purchase energy from a simulated MISO market. The simulation can make this decision hourly, within the constraints of the modeled system. Additionally, the PLEXOS model forecasts monthly intersystem sales opportunities of excess generation. This is done through an hourly dispatch simulation based on projected hourly market prices that represent LMP for the NSP system. The forecasted sales revenue from these asset-based sales results in reduced system fuel costs.

13. Other FCA costs

There are other costs that flow through the FCA that are not part of the PLEXOS simulation. Since those cost categories do not impact the PLEXOS commit and dispatch algorithm, they can be included outside the simulation. A list of these costs with a brief description includes:

- Biomass PPA termination costs are included in the filing according to the terms of the termination agreements:
    - Benson Power LLC – Early termination of agreement covering the purchase of generation from poultry litter and wood fueled biomass facility. Per the Commission's November 14, 2019 Order in Docket No. E-002/AA-19-293, Xcel applied a 9.06 percent ROE to the Benson termination cost calculation.
- Certain MISO costs/revenues associated with transmission congestion, financial transmission rights (FTRs), incremental transmission losses, revenue sufficiency guarantee (RSG), revenue neutrality uplift (RNU) and ancillary services. Forecasted costs in this filing are based on historical actual costs and revenues observed for these MISO charge types.
- Gas demand and storage costs are costs associated with reserving gas delivery capacity and gas storage which are based on contract terms for the capacity and storage contracts.
- Rail car lease and maintenance costs include estimated lease, maintenance and tax costs associated with coal delivery to the King plant and are based on historical amounts per "ton mile" (round trip from A.S. King to the source) multiplied by the forecasted coal offtake (in tons).

14. FCA Exclusions

PPAs that serve the Renewable*Connect program are included in the PLEXOS model. Renewable*Connect uses a pool of resources that, in addition to several new projects, includes projects that formerly served Windsource. These program costs are covered by specific fees paid by subscribers, so an adjustment was made to remove the PPA costs related to those programs. Relatedly, sales to these program participants are removed from Minnesota retail sales used in determining the FCA rate for Minnesota customers.

15. Future Model Updates

Xcel indicated that, in the July reply comments, the Company anticipated updating the following inputs:[5]

- Natural Gas Prices
- Logical Marginal Price (LMP)
- Fuel Oil
- Gas transport costs
- Coal prices (including diesel, rail, spot, and contracts)
- MISO costs
- Company-owned resource inputs
- Other PPA changes and approvals
- Other inputs that may materially impact costs

D. Forecast Drivers

Total 2024 MN-jurisdiction FCA costs are forecasted to decrease by $39 million when compared to authorized 2023 costs. Key drivers impacting the forecast include decreased congestion costs, decreased costs for natural gas and coal generation, and decreased biomass buyout costs. This is offset by increased forecast costs for purchases from the Solar*Rewards Community program, decreased revenues from asset-based sales into the MISO market, and increased purchased wind costs.

The decrease in congestion costs is primarily driven by large additions of renewable energy in the MISO footprint without sufficient addition of transmission to deliver energy from generators to load centers within the MISO footprint.

The decrease in natural gas generation costs is driven by decreased natural gas prices. The volume of natural gas-fired generation is forecasted to increase for 2024, but the gas price decrease offsets the increase in volume of generation resulting in a net decrease in costs. Forward LMP prices in MISO forecast continued high gas generation for 2024 for system needs as well as for asset-based sales into the MISO market due to the efficient combined-cycle generation in the NSP portfolio.

The decrease in coal generation costs is driven by decreased forecast volume of coal generation, primarily due to the retirement of Sherco Unit 2 which is assumed to occur in 2023. Unit costs for coal and rail delivery are forecasted to decline by 1 percent for 2024. Coal

[5] A summary of the updated forecast inputs included in Xcel's reply comments start on page 18 of these briefing papers.

generation volumes are also impacted by the EPA "good neighbor" rule assumed to be in effect by the ozone season for 2024.[6]

The decrease in biomass buyout costs is driven by the final payment for the Laurentian purchase power agreement which occurred in 2023. The remaining biomass buyout costs relate to the Benson purchase power agreement.

CSG above market costs increase for the 2024 forecast because LMP prices are projected to be 30 percent lower than those authorized in 2023. This results in less of the program costs being assigned to the NSP jurisdictions as market-cost based energy and more being direct assigned to Minnesota as above market costs.

The increase in purchased wind costs is driven by the extension of the PPA with MinnDakota which occurred in 2023, in addition to updated wind patterns for wind PPAs which show increased production primarily for the newest wind PPAs on the NSP system.

E. Customer Class Rate Calculation

Xcel proposed to allocate FCA costs to Minnesota using the FERC-approved Interchange Agreement tariff, which governs cost allocation between the NSP-Minnesota (NSPM) and NSP-Wisconsin (NSPW) operating companies. The Interchange Agreement is a formula rate which assigns charges between these two operating companies for costs related to the integrated electric system including fuel and purchased power costs that are recovered through the fuel clause. Previously, Xcel 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. Xcel assigned costs to the NSP-Minnesota operating company through the application of the Interchange Agreement energy allocator, then allocated the NSP-Minnesota fuel costs to the Minnesota jurisdiction using the sales allocator. This allows customers and Xcel to remain whole on prudently incurred fuel cost recovery, as Minnesota customers would pay for their allocation of the fuel costs assigned to the NSPM operating company.

To determine the proposed monthly fuel cost by customer class, Minnesota jurisdictional costs are divided by Minnesota jurisdictional MWh sales subject to the FCA (excluding Renewable*Connect program MWh) which results in the Minnesota jurisdictional per-unit cost. This per-unit cost multiplied by the Fuel Adjustment Factor (FAF), including the Class Ratio Adjustment, determines the proposed monthly class fuel cost charge (FCC) factors. Finally, a Class Ratio Adjustment is applied to match forecasted recovery with forecasted expense.

---

[6] The U.S. Environmental Protection Agency (EPA) issued its final Good Neighbor Plan on March 15, 2023, published in the Federal Register on June 5, 2023, and will be effective August 4, 2023. https://www.epa.gov/csapr/important-dates-good-neighbor-plan-nox-ozone-season-group-3-trading-program

F. Assumptions Regarding Pending Commission Proceedings

Xcel noted that Commission action on the following proceedings could impact Xcel's 2024 actual fuel costs:

- Renewable Connect (Docket No. E-002/M-21-222) – limited program modifications and updated pricing.

Xcel stated that, if known, Commission action would be incorporated into the Company's reply comments updates.

G. Managing Price Risk Volatility

Xcel noted that its real-time market strategy meets the intent of the Commission's Order in Docket No. E-002/M-04-1970 which requires the Company to limit its level of activity in the real-time market to 5 percent of total purchases for retail customers or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810.

II. Department of Commerce – Comments

A. Annual Compliance and Reporting Requirements

The Department noted that, in Part C, Attachment 1 of the 2024 forecast report, Xcel provided a compliance and reporting requirements matrix. A corrected matrix was provided in response to Department information request (IR) No. 10.

Based on its review, the Department recommended that Xcel's compliance filings and reporting requirements be accepted.

B. Sales Forecast

Based on its review, the Department concluded that Xcel's 2024 sales forecast appeared reasonable. Therefore, the Department recommended that Xcel's 2024 forecasted sales to set FCA rates for 2024 be accepted. The Department stated that Xcel's FCA revenues and costs are subject to true-up in the 2024 True-up Report, which is scheduled to be filed on March 1, 2025. Finally, the Department noted that its 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. A summary of Xcel's net system sales and production levels are provided in Table 3.

Table 3 - Xcel's 2024 and 2023 Forecasted Sales and Generation vs. 2020-2022 Actuals (MWh)[7]

	2024 Forecast	2023 Forecast	2022 Actuals	2021 Actuals	2020 Actuals	2020 - 22 Avg. Actuals
Net System Sales	38,197,851	38,738,602	39,686,566	39,305,604	38,456,375	39,149,515
Net MN Sales	26,842,355	27,443,347	28,318,349	28,195,869	27,564,206	28,026,141
Net System Gen.	42,176,000	42,329,000	41,072,700	40,986,200	40,108,800	40,722,567

The Department requested that Xcel explain, in reply comments, the key drivers of forecasted 2024 sales being lower than historical averages and forecasted 2024 system generation being higher.

C. Forecasted FCA Costs

The Department reviewed Xcel's actual and average 2020-2022 FCA costs and noted that there are significant cost variances over the years between the various cost categories. However, 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.

1. Company-Owned Generation

The Department provided a trade secret summary of Xcel's forecasted 2023 and 2024 FCA costs and actual 2020-2022 FCA costs for Company-owned generation by fuel type in dollars and dollars per MWh.[8]

Based on its review, the Department concluded that Xcel's 2024 forecasted fuel costs for Company-owned generating units appears to be reasonable. As a result, the Department recommended that, subject to true-up, Xcel's forecasted costs in this category be approved to set 2024 FCA rates.

2. Long Term PPAs

The Department provided a trade secret breakout of Xcel's long-term purchased energy by type using 2020-2022 actuals, 2020-2022 three-year average, and Xcel's 2023 and 2024 forecasts.[9]

Based on its review and explanations provided by Xcel, the Department concluded that 2024 forecasted long-term purchased energy costs appears to be reasonable. As a result, the Department recommended that, subject to true-up, Xcel's forecasted costs in this category be approved to set 2024 FCA rates. The Department did not have any objections to Xcel's forecasted "Other" PPAs, but requested that Xcel explain, in reply comments, the key drivers behind forecast changes relative to historical levels.

---

[7] Department Comments at 10, Table 2.

[8] Department Trade Secret Comments at 14, Table 4.

[9] Department Trade Secret Comments at 16, Table 5.

3. MISO Energy Market (MISO Day 2) and Ancillary Services Market (ASM or MISO Day 3)

The Department provided a trade secret summary of Xcel's forecasted 2023 and 2024 MISO Day 2 and Day 3 charges which are based on an annualized average for actual costs from April 2021 through December 2022.[10] This is a departure from FCA filings prior to the 2023 forecast where Xcel used a historical five-year average to forecast costs. Given the significant increases in costs experienced in 2021 and 2022, the Department agreed with this approach and noted it would result in a more accurate forecast.

In Department IR No. 3, the Department asked Xcel to explain in detail where its total MISO Day 2 and Day 3 charges were included in its forecasted 2023 FCA cost summary. Additionally, the Department asked Xcel to provide its forecasted 2023 and actual 2020-2022 net MISO Day 2 and Day 3 charges.

Xcel replied that the MISO Day 2 and Day 3 costs and revenues can be found in Part A, Attachment 1, page 1 of 3 and is the sum of lines 23, 24 and 29. Xcel also provided actual net MISO Day 2 and MISO Day 3 costs and revenues for 2020- 2021, as reflected in Table 4.

Table 4 – Xcel's Day 2 and Day 3/ASM charges, 2020-2022, Actual[11]

Year	Day 2	Day 3/ASM	Total
2020	($104,623,614.70)	$18,474,150.97	($86,149,463.73)
2021	($153,735,316.84)	$35,849,420.45	($117,885,896.39)
2022	($225,986,444.67)	$42,468,105.37	($183,518,339.30)

The Department explained that, historically, Xcel provided schedules showing the allocation of MISO Day 2 and Day 3 charges between retail and asset-based wholesale categories for purposes of determining asset-based margins. However, Xcel did not include an itemization of asset-based margins because, as required by a settlement agreement for NSP-Minnesota, 100 percent of asset-based margins are now returned to ratepayers. Therefore, no itemization is necessary. As a result and similar to the 2021-2023 Forecast Reports, the Department understands that Xcel did not allocate its forecasted 2024 MISO Day 2 and Day 3 charges between retail and asset-based wholesale categories. Instead, all MISO Day 2 and Day 3 costs and revenues, except those recovered in base rates, are included in Xcel's forecasted 2024 FCA rates.

Based on its review and explanations provided by Xcel, the Department concluded that 2024 forecasted MISO Day 2 and Day 3 charges appear reasonable. As a result, the Department recommended that, subject to true-up, Xcel's forecasted charges in these categories be approved to set 2024 FCA rates.

---

10 Department Trade Secret Comments at 18, Table 5.

11 Department Comments at 20.

4. Asset Based Margins

In IR No. 4, the Department asked Xcel to confirm it is returning 100 percent of asset-based margins to ratepayers and to provide its actual asset-based margins for 2020-2022. Xcel replied that it planned to return 100 percent of asset-based margins. The calculations found in Part A, Attachment 1, Page 1 of the Petition return 100 percent of asset-based margins to customers through inclusion of 100 percent of the asset-based sales revenues at line 29 and 100 percent of the asset-based sales cost at line 27. As requested, Xcel also provided 2020-2022 actuals as shown in Table 5.

Table 5 - Actual Asset-Based Margins

Year	Amount ($M)
2020	$51.5
2021	$125.3
2022	$188.3

The Department recommended that Xcel, in reply comments, explain the variance between forecasted 2024 and actual 2022 asset-based margins.

The Department indicated that it would make its final recommendation regarding Xcel's forecasted 2024 asset-based margins charges after it has reviewed Xcel's reply comments.

5. Outages

a. Outage Rates

The Department reviewed Xcel's forecasted planned (unforced) outages rates and found that the Company reasonably explained its forecast. The Department noted that Xcel uses MISO's calculation of eFORD based on three years of history to forecast peaking units unplanned outage rates. Xcel's forecast for base load units unplanned (forced) outages is based on a five-year average. Xcel stated that unplanned outages for coal plants are forecasted based on "expected conditions of the units going forward, including managed decline as plants near retirement."[12] The Department requested that Xcel explain and justify its forecast method in reply comments. The Department will provide a recommendation on Xcel's proposed outage rates after reviewing its response.

b. Outage Costs

The Department, in IR No. 6, asked Xcel to provide its actual 2020-2022 planned and unplanned MWh's and related power replacement costs and, in its trade secret Table 7, the Department summarized Xcel's planned and unplanned MWh's and related replacement power costs for the 2024 forecast, the 2023 forecast, and the 2020-2022 actuals.

---

[12] Xcel Initial Filing at 6.

Except for the unplanned outage rates for certain power plants, the Department concluded Xcel reasonably explained its forecasted 2024 outage costs. Assuming Xcel, in reply comments, provides a reasonable explanation of this issue, the Department recommended, subject to true-up, the Commission accept Xcel's forecasted 2024 outage costs for purposes of establishing 2024 FCA rates.

6. Wind Production

The Department asked Xcel to provide, in IR No. 11, for each wind facility included on Xcel's system (PPAs and Company-owned wind), the assumed capacity factor at the time the project or PPA was approved by the Commission, and then compare this assumption to the actual capacity factor for each wind facility for the years 2020, 2021, and 2022, and forecasted capacity factors for 2023 and 2024. The Department provided a trade secret table to summarize this data.[13]

The Department requested Xcel, in reply comments, provide a discussion and explanation of actual wind capacity factors relative to the Company's assumptions when it proposed the projects be acquired.

The Department intends to continue monitoring actual production levels and, to the extent lower than assumed production continues to be an ongoing problem, will further investigate and make warranted recommendations, given that the Commission has stated in numerous wind acquisition approvals that it will hold Xcel accountable for assumed benefits that do not materialize.

a. PPA Curtailments

The Department asked Xcel to provide additional detail on wind curtailment costs and MWh for PPAs forecasted for 2024 and actuals for 2020-2022. The Department reviewed Xcel's forecasted 2024 wind curtailment costs for PPAs with the additional detail and concluded it appeared to be reasonable. The Department recommended that, subject to true-up, Xcel's forecasted 2024 wind curtailment costs for PPAs to set FCA rates for 2024 to be accepted.

b. Company-Owned Curtailments

The Department asked Xcel to provide its forecasted 2024 wind curtailment in MWh for Company-owned wind farms its forecasted 2024 and actual 2020-2022.

The Department noted that Xcel's wind curtailment MWh for Company-owned wind farms has been, on average, increasing over the years, presumably due to the addition of new wind farms coupled with ongoing congestion. The Department emphasized that congestion on Company-owned wind farms has a real cost due to the lost opportunity to sell the energy into MISO. The

[13] Department Trade Secret Comments at 24, Table 8.

Department also noted the significant changes in forecasted 2024 curtailment MWh for some Company-owned wind farms (Blazing Star 1, Blazing Star 2, Borders, Courtenay, and Pleasant Valley) compared to 2020-2022 actuals and recommended Xcel, in reply comments, explain large variations in forecasted 2024 curtailments over 2021 and 2022 actuals. The Department will make its final recommendation regarding Xcel's forecasted 2024 wind curtailments for Company-owned facilities after reviewing Xcel's reply comments.

7. Minnesota Only FCA Costs

a. Community Solar Garden – Above Market Costs

The Department reviewed Xcel's CSG calculations and concluded that Xcel's forecasted 2024 CSG above market costs appear to be reasonable. As a result, the Department recommended, subject to true-up, Xcel's forecasted costs in this category be accepted to set 2024 FCA rates.

b. Biomass Buyout Costs

The Department reviewed Xcel's forecasted 2024 biomass buyout costs and noted that costs decreased due to the Laurentian PPA buyout ending in 2023. Based on its review, the Department concluded that Xcel's forecasted 2024 biomass buyout costs appear to be reasonable. As a result, the Department recommended, subject to true-up, Xcel's forecasted costs in this category be accepted to set 2024 FCA rates.

c. MISO Planning Resource Auction Revenues

In response to Department IR No. 9, Xcel confirmed it continues to incorporate MISO Planning Resource Auction revenues into base rates, not the FCA.

d. Jurisdictional Allocation

Xcel proposed to update it jurisdictional allocator. To make a full assessment of the reasonableness of Xcel's proposal, the Department requested Xcel provide the following in reply comments:

- A comparison, for the 2024 forecast, 2023 forecast, and 2020-2022 actuals, of the percent of costs allocated to the Minnesota jurisdiction, using the proposed method versus the old method, with supporting calculations.
- A comparison of Xcel's proposed Minnesota FCA jurisdictional allocation method to jurisdictional allocators approved for base rates and in other riders in Minnesota.
- A comparison of Xcel's proposed Minnesota FCA jurisdictional allocation method to FCA jurisdictional allocators approved for base rates and in other riders in other states, including a discussion of how Xcel's methodologies avoid double recovery across jurisdictions.

The Department also requested Xcel discuss why it believes its proposed allocator is reasonable given its response to the above. The Department will provide final comments on Xcel's proposed jurisdictional allocator after reviewing Xcel's reply comments.

III. Xcel Energy – Reply Comments

A. Sales Forecast

Xcel noted that, as a result of updated inputs, 2024 forecasted fuel costs decreased by $7.5 million and the forecasted average rate decreased to $38.10/MWh. Xcel's 2024 MN-jurisdiction forecasted sales remain the same at 26,842,355 MWh and forecasted costs decreased to $1,022,748,000.[14]

Table 6 – 2024 Forecast Comparison MN Jurisdictional

	Forecast - Xcel Initial Filing	Forecast - Xcel Reply Comments	Difference
Sales (MWh)	26,842,355	26,842,355	0
FCA Costs	$1,030,253,000	$1,022,748,000	(7,505,000)
FCA Costs/MWh	$38.38	$38.10	($0.28)

The Department requested that Xcel explain the key drivers of forecasted 2024 sales being lower than historical averages and forecasted 2024 system generation being higher.

The decrease in 2024 net system sales forecast, when comparing historical averages, is primarily due to the implementation of the long-term Renewable*Connect program scheduled to launch in late 2023. Another factor is the new Demand Side Management (DSM) measures and increased penetration of distributed solar generation.

B. Long-Term PPAs

In response to the Department's request for comments explaining the key drivers for the forecasted increase in energy purchased from "Other" PPAs relative to historical levels, Xcel explained that Manitoba Hydro is the key driver with steadily increasing energy. A new contract with Manitoba Hydro began in 2021, so 2020 included no energy purchases, 2021 included a partial year of energy purchases, and 2022 included a full year of energy purchases from the new contract.

C. Asset Based Margins

The Department requested that Xcel fully explain the difference in forecasted 2024 asset-based margins compared to actual 2022 asset-based margins. Xcel explained that LMP is the primary driver. LMP has fallen in response to factors that are driving natural gas prices lower in 2024 than were observed for 2022. Lower LMP results in lower asset-based revenues and that translates to lower margins. Another factor is the reduction in baseload generation that is primarily driven by the retirement of Sherco 2 at the end of 2023. Xcel explained that less baseload generation results in less surplus generation to sell into the MISO market which results in less asset-based sales revenues. Additionally, Xcel stated that coal resources are some

[14] Xcel Energy Reply Comments, Attachment A, Page 1.

of the lowest cost resources on the system and less asset-based sales from them has a compounding effect on asset-based sales margins.

D. Outage Costs

The Department requested that Xcel explain and justify the methodology used to calculate unplanned outages for King and Sherco 1 and 3. Xcel explained that capital and O&M spending is reduced when plants are near retirement which results in longer periods of maintenance to keep the plant in an operable condition so that it is available for operation in the highest load winter and summer months. With work reduced to just maintenance, there is an increased risk of equipment failures causing forced outages. Xcel states its goal is to balance reliability and prudent spending on a retiring asset.

E. Wind Production

The Department requested that Xcel provide a discussion and explanation of actual wind capacity factors relative to forecast assumptions when the projects are proposed to be acquired. Xcel explained that the capacity factor assumption used at the time of acquisition is typically derived from a P50 energy production estimate, which means that over the life of the wind farm there is a 50 percent chance that the assumption will be exceeded. Xcel stated that wind curtailment has been increasing across the MISO footprint but expects the impact of curtailment to be reduced as additional upgrades to the transmission system are completed. Xcel stated that lower capacity factor sensitivities are typically evaluated to assess the risk that actual capacity factors may be lower than assumed.

F. Wind Curtailment Costs

The Department recommended that Xcel provide an explanation for the significant change in forecasted 2024 wind curtailment costs over 2021 and 2022 actuals for Blazing Star 1, Blazing Star 2, Borders, Courtenay, and Pleasant Valley wind farms. Specifically, Xcel stated:

> As noted by the Department on page 29, curtailment at owned wind projects has been increasing since 2020. Department Table 10 lists ten projects that went in-service in 2020 or later, which is the main driver to increasing curtailment for owned wind projects over this period. In addition, two projects have been repowered, further contributing to greater wind generation and, as a result, greater curtailment. The increase in curtailment for specific projects noted by the Department is a result of the curtailment modeling technique used in the PLEXOS simulation. All owned wind projects are treated nearly equally in the simulation from a cost offer standpoint and the simulation curtails only enough wind to balance supply and demand without regard to which projects are being curtailed. Therefore, some projects are curtailed at a higher level, while some show zero curtailments, as shown in Department Table 10. Our expectation is that some curtailment will occur at all Company-owned projects throughout the course of a year; however, this is not something that can be achieved using the curtailment model that is in the PLEXOS simulation. From 2020 to 2022 there is considerable variation from year to year in the curtailment for each owned wind

project listed in Department Table 10. This is something that would be nearly impossible to replicate with any degree of accuracy in a forecast model. Furthermore, from a production cost standpoint, project by project variation will not impact total production costs since the owned wind projects are all modeled at zero cost.

Wind curtailment MWh for Company-owned wind facilities has been on average increasing over the years, largely due to the addition of new wind facilities coupled with ongoing congestion. Congestion costs, which have been high since 2021, are primarily driven by large additions of renewable energy in the MISO footprint without sufficient addition of transmission to deliver energy from generators to load centers within the MISO footprint. The Company monitors congestion costs regularly, and if future actual costs show another step change or significant trend, we plan to update accordingly in our next update.[15]

G. Jurisdictional Allocation

The Department requested that Xcel provide a comparison of the percent of costs allocated to the Minnesota jurisdiction, using the proposed method versus the old method, with supporting calculations. Table 7 compares the jurisdictional allocation methodologies.[16]

Table 7 - Xcel Comparison of Jurisdictional Allocation Methodologies

	Actual 2020	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
NSPM Interchange Energy Allocator	83.36%	83.37%	82.99%	82.40%	82.35%
NSP System Fuel & Purchased Power (MN Definition) (before direct assignments)	$824,656,729	$1,055,539,341	$1,154,505,952		
Current NSPM:					
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to NSP System costs					
MN Jur Allocation (Calendar Sales)	$591,408,165	$758,155,890	$824,281,061		
ND Jur Allocation (Billed Sales)	$45,468,548	$56,643,924	$63,092,970		
SD Jur Allocation (Billed Sales)	$46,244,552	$59,087,583	$64,640,906		
Total NSPM Jur Allocation	$683,121,265	$873,887,397	$952,014,937		
Total NSPM Jur Allocation - Current Method	**82.84%**	**82.79%**	**82.46%**	**82.13%**	**81.70%**
NSPM Under/(Over)	$4,278,364	$6,065,310	$6,097,667	$3,271,975	$7,021,546
Proposed NSPM:					
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to costs after I/A					
MN Jur Allocation (Calendar Sales)	$595,082,071	$763,512,307	$829,609,136		
ND Jur Allocation (Billed Sales)	$45,748,690	$57,019,650	$63,501,266		
SD Jur Allocation (Billed Sales)	$46,533,297	$59,486,355	$65,067,044		
Total NSPM Jur Allocation	$687,364,058	$880,018,312	$958,177,446		
Total NSPM Jur Allocation - Proposed Method	**83.35%**	**83.37%**	**82.99%**	**82.40%**	**82.35%**
NSPM Under/(Over)	$35,571	($65,605)	($64,842)	$0	$0

[15] Xcel Energy Reply Comments at 7 – 8.

[16] Xcel's 2023 and 2024 Forecast is Trade Secret

Xcel proposed a two-step allocation process that would first assign costs between the NSPM and NSPW operating companies using the FERC-governed Interchange Agreement energy allocator, then assign costs using the sales allocator. Previously, Xcel solely used the sales allocator to assign costs. Xcel stated this change would result in minor over- or under-recoveries for each year, which are due to the allocation of costs to North Dakota and South Dakota using billing month sales.

The Department requested a comparison of Xcel's proposed Minnesota FCA jurisdictional allocation method to jurisdictional allocators approved for base rates and in other riders in Minnesota as well as in other states. The Department also requested Xcel to discuss how it avoids double recovery across jurisdictions. Specifically, Xcel stated:

> Based on the Company's Cost Assignment and Allocation Manual (CAAM), the cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction. We consider energy-related expenses to be production variable, therefore an energy allocator is used for all appliable variable electric production expenses. We follow this same method in both base rates and riders.

H. Forecast Input Updates

1. Coal Pricing

Market prices and escalation assumptions for coal and rail were updated. Forecast coal generation prices have increased and the overall impact on coal generation cost/MWh is an increase of 1.1 percent as compared Xcel's Initial Filing.

2. Natural Gas Prices

Natural gas prices have been updated to NYMEX closing prices as of July 12, 2023. The annual average price of natural gas for Ventura has decreased to $3.72/MMBtu, which is 4.8 percent lower than Xcel's Initial Filing.

3. Electric Market Prices

Xcel's price forecast for MISO LMP has been updated to correspond with the date of the updated natural gas prices from market close on July 12, 2023. The average annual price has decreased to $30.02/MWh, which is 3.5 percent lower than the Initial Filing.

4. MISO Costs

MISO costs were updated based on the most recent historical data available through June 2023.

5. Maintenance Updates

Xcel updated planned maintenance for 2024 to reflect the latest planned schedules for its generating plants. Xcel provided an explanation of the change in the trade secret version of this filing.

I. Revised Monthly Rate Summary

Tables 8 and 9 summarize the rates by month and by customer class revised to reflect the updated 2024 forecast inputs.

Table 8 - Xcel Revised Proposed 2024 Monthly Fuel Clause Rates by Customer Class ($/kWh)[17]

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.03306	$0.03348	$0.03244	$0.04054	$0.02655	$0.02594
February	$0.03623	$0.03668	$0.03554	$0.04443	$0.02909	$0.02841
March	$0.03891	$0.03939	$0.03817	$0.04772	$0.03123	$0.03051
April	$0.04221	$0.04274	$0.04141	$0.05177	$0.03389	$0.03310
May	$0.04485	$0.04541	$0.04400	$0.05499	$0.03601	$0.03518
June	$0.04184	$0.04236	$0.04104	$0.05131	$0.03359	$0.03281
July	$0.04244	$0.04297	$0.04163	$0.05207	$0.03405	$0.03326
August	$0.04143	$0.04195	$0.04064	$0.05082	$0.03325	$0.03248
September	$0.03947	$0.03996	$0.03872	$0.04841	$0.03168	$0.03094
October	$0.03812	$0.03860	$0.03740	$0.04676	$0.03060	$0.02989
November	$0.03454	$0.03497	$0.03389	$0.04236	$0.02773	$0.02708
December	$0.03223	$0.03263	$0.03162	$0.03953	$0.02587	$0.02527

[17] Xcel Energy Reply Comments, Part A, Attachment 1, Page 2.

Table 9 - Xcel Revised Proposed 2024 Monthly Fuel Clause Rates for C&I General Time of Use Service Pilot ($/kWh)[18]

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Non-TOD	On-Peak	Off-Peak
January	$0.04096	$0.03478	$0.01818
February	$0.04489	$0.03811	$0.01990
March	$0.04822	$0.04093	$0.02136
April	$0.05231	$0.04441	$0.02319
May	$0.05557	$0.04718	$0.02465
June	$0.05184	$0.04401	$0.02298
July	$0.05262	$0.04465	$0.02326
August	$0.05136	$0.04359	$0.02273
September	$0.04892	$0.04152	$0.02166
October	$0.04725	$0.04011	$0.02093
November	$0.04281	$0.03634	$0.01896
December	$0.03994	$0.03391	$0.01770

Xcel will submit a compliance filing within 10 days of Commission Order to reflect the final approved rates.

IV. Department of Commerce – Response to Reply Comments

A. Asset Based Margins

The Department was satisfied with Xcel's explanation for the forecasted decrease in asset-based margins and recommended that, subject to true-up, Xcel's asset-based margin forecast be accepted.

B. 2024 Sales Forecast

The Department appreciated Xcel's clarification on the key drivers of forecasted 2024 sales being lower than historical averages and forecasted 2024 system generation being higher. The Department was satisfied with Xcel's explanation.

C. Unplanned Outage Rates

The Department noted that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful

[18] *Id.*

planning, prudent timing, and efficient completion of scheduled work."[19] The Department stated that the forecasted unplanned outage rates appear to be reasonable but expects Xcel to manage overall costs. Specifically, the Department stated:

> Xcel may have a reduced incentive to minimize unplanned outages. This is because (1) generation maintenance expense is recovered at a fixed level through base rates, which gives utilities an incentive to minimize generation maintenance expense between rate cases; (2) the amount of generation maintenance expense is linked to a utility's unplanned outages; and (3) utilities do not have a strong incentive to minimize the replacement power costs for which they receive flow through recovery through the FCA. As a result, the Department monitors the difference between investor-owned utilities' actual and approved generation maintenance expenses in FCA true-up filings.[20]

The Department recommended that Xcel be required to specifically report on the prudency of its management of unplanned outages at Sherco 1, King and Sherco 3 in Xcel's next FCA true-up report.

D. Other PPAs

The Department appreciated Xcel's explanation that the new contract with Manitoba Hydro was the primary driver of increased purchased energy for "Other" PPAs.

E. Owned Wind Production

The Department stated it will continue monitoring actual wind production levels. If lower than assumed production continues to be an ongoing problem, the Department will further investigate and make warranted recommendations, to hold Xcel accountable for assumed benefits that do not materialize.

The Department recommended that Xcel be required to report the following starting with its next FCA true-up report (to be filed in 2024):

- Xcel shall provide two tables, in the format of Table 8 in the Department's June 29, 2023, comments in the instant docket, showing, for each Xcel-owned wind facility, the assumed versus actual wind capacity factors for the true-up year and the three prior years.
- The first table must show capacity factors after curtailment and the second table must show capacity factors if no curtailment had occurred.

---

[19] Department of Commerce Response to Reply Comments at 7, February 6, 2008 Order in Docket No. E999/AA-06-1208, page 5.

[20] Department Response Comments at 7.

F. Curtailments

The Department appreciated Xcel's explanation that increased curtailment costs were driven by increased wind generation and congestion costs. Satisfied with Xcel's response, the Department recommended that, subject to true-up, Xcel's forecasted 2024 wind curtailments for company-owned facilities be accepted.

G. Jurisdictional Allocation

The Department concluded Xcel's new two-step jurisdictional allocation method is reasonable. The Department noted that the proposal accurately reflected cost allocation between NSPM and NSPW as reflected in the FERC Interchange Agreement and therefore better supports accurate cost recovery versus the prior pure-sales method, and it does not unfairly burden Minnesota relative to other NSPM jurisdictions. The Department recommended the approval of Xcel's proposed jurisdictional allocator update.

H. Forecast Updates

1. Coal, Natural Gas and MISO Prices

The Department concluded these updates were reasonable given they reflect updated commodity price information.

2. MISO Charges

The Department concluded Xcel's update to reduce forecasted MISO charges is reasonable considering the developments year-to-date cited by Xcel's trade secret reply comments.

3. Outages

The Department concluded that Xcel provided sufficient information about its updated outage forecast and recommended approval.

I. Recommendations Summary

After a thorough review, the Department recommended the following:

- Acceptance of Xcel's compliance with reporting requirements for the instant petition relating to its 2024 FCA forecast.
- Acceptance of Xcel's 2024 forecasted sales, subject to subsequent true-up.
- Acceptance of Xcel's forecasted 2024 fuel costs for company-owned generation for the purpose of setting initial 2024 FCA rates, subject to subsequent true-up.
- Acceptance of Xcel's forecasted 2024 long-term purchased energy costs for the purpose of setting initial 2024 FCA rates, subject to subsequent true-up.
- Acceptance of Xcel's forecasted 2024 MISO Day 2 and Day 3 charges for the purpose of setting initial 2024 FCA rates, subject to subsequent true-up.
- Acceptance of Xcel's asset-based margin forecast, subject to true-up.

- Acceptance of Xcel's forecasted 2024 outage costs for purposes of establishing FCA rates, subject to true-up.
- Require Xcel to report on the prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition.
- Require Xcel to report the following starting with its next FCA true-up report (to be filed in 2024): Xcel shall provide two tables, in the format of Table 8 in the Department's June 29, 2023, comments in the instant docket, showing, for Xcel-owned wind facility, the assumed versus actual wind capacity factors for the true-up year and the three prior years. The first table must show capacity factors after curtailment and the second table must show capacity factors if no curtailment had occurred.
- Acceptance of Xcel's forecasted 2024 wind curtailment costs for PPAs and Company-owned wind to set FCA rates for 2024, subject to true-up.
- Acceptance of Xcel's forecasted 2024 Community Solar Garden – Above Market Costs them for the purpose of setting initial 2024 FCA rates, subject to subsequent true-up.
- Acceptance of Xcel's forecasted 2024 biomass buyout costs for the purpose of setting initial 2024 FCA rates, subject to subsequent true-up.
- Approval of Xcel's updated jurisdictional allocation method.
- Approval of Xcel's forecast updates.

V. Xcel Energy - Letter

On October 23, 2023, Xcel filed a letter updating adjustment factors that reflect decisions made in Xcel most recent rate.

Staff notes that, prior to the filing, Xcel informed staff that the updates reflected in this filing had been discussed with the Department and that the Department agreed with Xcel's calculations. However, since the Department has not confirmed that it is in agreement, at the hearing, the Commission may want to ask the Department for confirmation.

VI. Staff Comments

After reviewing Xcel's and the Department's filings, Staff concurs with the Department's recommendation that Xcel's 2024 FCA forecast, based on revised forecasted sales of 26,842,355 MWh and revised forecasted costs of $1,022,748,000, be approved. Staff also agrees that the updated customer class rate calculation using the FERC Interchange Agreement should be approved.

DECISION OPTIONS

Forecasted Sales and Fuel Costs

1. Approve Xcel Energy's 2024 FCA Forecast Petition. (Xcel, Department)

2. Authorize Xcel Energy to implement its 2024 FCA forecast, based on revised forecasted sales of 26,842,355 MWh and revised forecasted costs of 1,022,748,000, MN Jurisdictional. (Xcel, Department)

Jurisdictional Allocation Method

3. Approve Xcel Energy's proposed customer class rate calculation update. (Xcel, Department)

Compliance and Reporting

4. Require Xcel Energy to report on the prudency of its management of unplanned outages at Sherco 1, King, and Sherco 3 in Xcel's next FCA true-up petition. (Department)

5. Require Xcel Energy to provide the following in its next FCA true-up petition:

   A. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors after curtailment.
   B. For each Xcel-owned wind facility, provide the assumed versus actual wind capacity factors for the true-up year and the three prior years showing capacity factors if no curtailment had occurred. (Department)

6. Require Xcel to submit a compliance filing with revised tariff sheets and supporting calculations within 10 days of the Commission's Order in this docket for implementation effective January 1, 2024. (Staff, Xcel)

Adjustment Factors

7. Approve revised adjustment factors reflected in Xcel's October 23, 2023 filing. (Xcel)