MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**October 31, 2024**	**Agenda Item 5***
Company	Northern States Power Co., d/b/a Xcel Energy	
Docket No.	E-002/AA-24-63	
	In the Matter of Xcel Energy's Petition for Approval of its 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges for the months of January – December 2025.	
Issues	At what level should Xcel's 2025 Annual Forecasted Rates for its Energy Adjustment Rider be set?	

Staff James S. Worlobah james.worlobah@state.mn.us (612) 201-2238

✓ Relevant Documents	Date
Xcel Energy - Initial 2025 Filing (Public and Trade Secret)	May 1, 2024
Department of Commerce – Comments (Public and Trade Secret)	July 1, 2024
Xcel Energy – Reply Comments (Public and Trade Secret)	July 31, 2024
Xcel Energy - Motion	August 2, 2024
Department of Commerce – Reply Letter to Motion	August 16, 2024
Department of Commerce – Response to Reply Comments (Public and Trade Secret)	August 20, 2024

Table of Contents

I. Statement of the Issue

At what level should Xcel's 2025 annual forecasted rates for its Energy Adjustment Rider be set?

BACKGROUND

On May 1, 2024, Northern States Power Co., d/b/a Xcel Energy (Xcel, NSP, the Company) made its 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges filing.

On July 1, 2024, the Department of Commerce – Division of Energy Resources (Department) filed Comments recommending approval of Xcel's initial sales forecast, its Company-owned generation, long-term purchased energy costs, MISO costs and revenues, forecasted Community Solar Gardens – Above Market Costs (CSG-AMC) and Biomass Buyout Costs, forecasted wind production, and proposed jurisdictional and class cost allocations. Additionally, the Department requested that, in reply comments, Xcel provide additional information on the Company's proposal to implement a CSG-AMC exclusion for certain customers, its methodology for forecasting unplanned outages at each baseload unit and how its forecasted unplanned outage rates for coal plants are reasonable and prudent.

On July 31, 2024, Xcel filed reply comments that provided additional information requested by the Department, updated several inputs to its 2025 forecast and requested approval of the updated forecast and resulting 2025 monthly FCA rates.

On August 2, 2024, Xcel filed a Motion to incorporate the proposed rate for the exclusion of the net cost of CSG generation from the FCA docket and a process for the approval of future updates to the rate.

On August 16, 2024, the Department filed a Reply letter to support Xcel's Motion and recommendations for approval of the Company's petition with requirements.

On August 20, 2024, the Department filed a response to Xcel's Reply Comments, recommended approval of Xcel's petition with updates to incorporate information provided by Xcel in reply comments and Xcel's August 2, 2024 motion.

DISCUSSION

II. Xcel Energy – Initial Filing

A. PLEXOS Software

As 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. The simulation is hourly, such that several key inputs, such as NSP System load and wind patterns, are inputted with hourly profiles.

B. 2025 Forecast Summary

Xcel's 2025 MN-jurisdiction forecasted sales were 26,922,097 MWh and forecasted costs were $888,562,000, resulting in a $33.00/MWh average,[1] a decrease of approximately $134 million or 13.4 percent when compared to 2024 authorized forecasted Fuel Clause costs. Tables 1 and 2 summarize Xcel's proposed 2025 monthly fuel cost rates, by class.

Table 1 - Proposed 2025 Monthly Fuel Clause Rates by Customer Class ($/kWh)[2]

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

[1] Xcel's Petition, Part A, Attachment 1, page 1.

[2] Xcel's Petition, at 4.

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

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

Xcel will update the Company website with the full year of monthly fuel cost charges by December 1, 2024,[3] or upon approval by the Commission if approval is not received prior to December 1. The rates will be presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

C. Revised Tariff Sheet

The Company provided as Part A, Attachment 5, redline and clean revisions to the Fuel Clause Rider tariff, Sheet No. 5-91.1,[4] reflecting the monthly fuel cost charges it proposed to implement. Xcel will update the tariff sheet to reflect the actual monthly fuel cost charges to be implemented based on the Commission's decisions in this proceeding and will provide an updated final tariff sheet within 10 days after the Order is received.

D. 2025 Forecast Key Inputs

1. NSP System Load

The objective of the PLEXOS simulation is to commit and dispatch resources to meet the hourly load requirement at the lowest cost. The 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.

[3] Xcel's Petition, at 4.

[4] *Id.*

2. Company-Owned Hydro Generation

Inputs for NSP-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 any fuel purchases.

3. Company-Owned Wind and Solar Generation

Inputs for Company-owned wind and solar 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 exclude any prior historical curtailments. For new projects that do not yet have an annual generation profile, the profiles are based on plant design and localized weather data. Since MISO can curtail them, Company-owned projects are modeled as curtailable and are forecasted by the PLEXOS simulation.[5] There is no fuel price input for wind or solar generation in the model because the generation does not require any fuel purchases.

4. Company-Owned Coal Generation

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

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

In this initial filing, seasonal operations are assumed based on the Commission's November 8, 2023 Order in Docket No. E999/CI-19-704[6] that approved seasonal operations at the Allen S. King plant. The remaining units at the Sherburne County station, Unit 1 and Unit 3, are assumed available to operate year-round in 2025. Additionally, the 2025 filing assumes that the EPA "good neighbor" rule will go in effect in 2025. The rule limits NOx emissions for NSP plants during the ozone season which runs from May 1, 2025 through September 30, 2025.[7] The proposal, if enacted for 2025, may require NSP to either purchase NOx allowances to allow generation and emissions beyond proposed limits or to limit operation at NSP coal plants to remain within emission limits in the proposal. Xcel stated it would monitor the rule's status and,

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[5] The Petition's Part B, Attachment 10 describes the renewable profile forecast process in detail.

[6] *Id*, at 7.

[7] *Id*.

in reply comments, update its modeling assumptions with the best available information.

5. Company-Owned Wood/RDF Generation

Key modeling parameters, such as operating capacity and heat rate, for NSP-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. Forecasted Wood and RDF prices are based on existing contracts.

6. Company-Owned Natural Gas Generation

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 to the model based on the current overhaul schedule. Forced outage rates are inputted for each unit and determined based on historical GADS data and expected conditions of the units going forward. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three years of history.

Forecasted natural gas fuel prices are based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time of filing.

7. Company-Owned Nuclear Generation

Modeling parameters include monthly operating capacity based on each individual unit's capacity. Planned maintenance is inputted to the model based on the current overhaul schedule. Forced outage rates are inputted for each unit and 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.

8. Purchased Natural Gas Generation

Key modeling parameters such as operating capacity and heat rate are determined based on capabilities of the individual plants or according to terms specified in the PPA. Planned maintenance is inputted to the model based on the overhaul schedule provided by the PPA counterparty. Forced outage rates are inputted for each unit and based on the MISO calculation of each unit's eFORd based on three years of history.

Forecasted natural gas fuel 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.[8] 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 with an assumed price for the program based on a weighted rate of different vintages of Value of Solar (VOS). The 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 Location Marginal Price (LMP). This program cost is shared with all jurisdictions in the NSP system. The above market program cost is directly assigned to Minnesota customers.

10. Purchased Wind Generation

Wind PPAs modeling reflects each individual project's hourly profiles. 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. 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 and the Manitoba Hydro PPA) are modeled based on historical generation (for the small hydro PPAs) or according to their contract terms (for the Manitoba Hydro PPA). Price is determined based on contract terms or based on historical prices with assumed escalation.

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.

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[8] Recovery was approved by Commission Order on September 17, 2014 in Docket No. E-002/M-13-867.

13. Other FCA Costs

There are other costs that flow through the FCA that are not part of the PLEXOS simulation. Since these 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 agreement.[9]
- Certain MISO market charges and revenues are not modeled in PLEXOS. This includes costs/revenues associated with transmission congestion, financial transmission rights (FTRs), incremental transmission losses, revenue sufficiency guarantee (RSG), revenue neutrality uplift (RNU) and ancillary services. 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 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 King to the source) multiplied by the forecasted coal offtake (in tons).

14. FCA Exclusions

PPAs that serve the Renewable*Connect programs are included in the PLEXOS model.[10] The Renewable*Connect program uses a pool of resources that, in addition to several new projects, includes projects that formerly served Windsource. Given that these program costs are covered by specific fees paid by subscribers, an adjustment was made to remove the PPA costs related to those programs. Additionally, 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 anticipates updating the following inputs:[11]

- Natural Gas Prices,

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[9] Recovery was approved by Commission Order on January 23, 2018 in Docket No. E-002/M-17-530.

[10] Recovery of the Renewable*Connect Pilot Program was approved by Commission Order on February 27, 2017 in Docket No. E-002/M-15-985. Recovery of the Renewable*Connect expansion was approved by Commission Order on August 12, 2019 in Docket No. E-002/M-19-33 and rates for the program were approved by Commission Order on May 18, 2023 in Docket No. E-002/M-21-222.

[11] A summary of the updated forecast inputs included in Xcel's reply comments start on page 21 of these briefing papers.

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

E. Forecast Drivers

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

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

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

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

(1) Forecast included in Reply Comments filed July 31, 2023 in Docket No. E-002/AA-23-153. Approved in the November 9, 2023 Commission Order.

The 2025 forecast cost decrease is driven by lower PPA purchase costs from PPAs scheduled to terminate prior to and during 2025, lower Solar*Rewards Community program costs, lower net congestion/FTR costs, and lower coal generation costs and is offset by higher forecast natural gas generation costs and lower revenues from asset-based sales into the MISO market.

1. PPA Terminations

Two purchased energy contracts are scheduled to terminate in 2024: one with the St. Paul Cogeneration facility and the second with the Hennepin Energy Resource Company. Additionally, two contracts with Manitoba Hydro are scheduled to terminate in 2025. Together, these four fixed energy contracts reduce 2025 costs by almost $142 million.[12] The energy provided by these contracts is partially being replaced by greater natural gas generation and lower surplus energy available to MISO.

At current market prices, offsetting costs for natural gas generation and offsetting revenues for surplus generation sales are lower than the average price for the fixed energy provided by these contracts, resulting in a net decrease in 2025 costs.

*2. Solar*Rewards Community Program Costs*

2025 Solar*Rewards costs are forecasted to decline by $65 million at the NSP system level and by $67 million lower costs direct assigned to the Minnesota jurisdiction. Lower costs are anticipated due both to lower volume of generation forecast for the program and lower overall average rate for energy purchases.

Based on actual installations through 2023, 2025 CSG energy purchases are forecasted to decrease by 7.8 percent and average energy rates are forecasted to decline by 12.9 percent ($39 million) from 2024 approved levels.[13] The decrease, which represents a partial year impact, is driven by the Commission's February 15, 2024 verbal decision in Docket No. E-002/M-13-867, which lowers the bill credits for gardens currently paid at the Annual Retail Rate (ARR) to the 2017 VOS vintage rates beginning on April 1, 2025.

The market costs correspondingly decrease due to lower forecast volume of purchases in addition to less spread between the market rate, which is based on forecasted LMP, and the anticipated lower average garden rate due to the ARR to VOS conversion.

Pursuant to Minn. Statute 216B.1641 subd.11, utilities must exclude the net cost of community solar garden generation from the fuel clause adjustment for customers who are eligible for this exemption. The Commission's December 28, 2023 Order in Docket Nos. E-002/CI-23-335 and E-002/M-13-867[14] approved Xcel's proposal to calculate this credit by dividing forecasted CSG above market costs by the forecasted net FCA kWh. Based on the proposed fuel forecast, Xcel

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[12] Xcel's Petition, at 13.

[13] Xcel's Petition, at 14.

[14] *Id*.

has calculated the 2025 net cost for CSGs generation as $6.79/MWh. Thus, the Solar*Rewards Community program results in an annual FCA rate for Minnesota customers that is 21 percent higher than the rate would be without this program.

Xcel noted that it expects to have systems in place on January 1, 2025 to apply this exclusion. Additionally, it expects to file the tariff language for this exclusion in compliance with the pending Order authorizing this exemption tariff. In the coming months, Xcel anticipates filing a motion in two dockets (this 2025 fuel clause docket and the above-mentioned CSG docket) seeking authorization:

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

3. Net Congestion/FTR Costs

Congestion costs, which have been high since 2021, are primarily driven by large additions of renewable energy in the MISO footprint without sufficient addition of transmission.[15] Xcel stated that, based on the most recent actual costs, it would update its forecast in its July Reply Comments.

4. Coal Generation Costs

Driven by lower forecasted coal generation volume due to Allen S. King plant's seasonal operations and the EPA "good neighbor" rule that is assumed to be in effect by the 2025 ozone season, when compared to 2024 authorized costs, 2025 coal generation costs are forecasted to decrease.[16] Additionally, 2025 unit costs for coal and rail delivery are forecasted to decline by 2.6 percent.

5. Natural Gas Generation Costs

When compared to 2024 authorized costs, 2025 natural gas-fired generation costs are forecasted to increase. Most of the increase in costs is driven by a 7.8% increase in forecasted natural gas generation. The forecasted increase is due to lower forecasted coal and nuclear generation and less fixed energy from PPAs. 2025 Natural gas prices as reflected by NYMEX futures, on average, approximately equal to 2024 authorized prices. Forward LMP prices in MISO forecast continued high gas generation for 2025 for system needs as well as for asset-based sales into the MISO market due to the efficient combined-cycle generation in the NSP

[15] Xcel's Petition, at 15.
[16] *Id*.

portfolio.

6. Asset-Based Sales Revenues

When compared to 2024 authorized revenues, 2025 revenues are projected to decrease. The decline is driven by the forecasted reduction in coal, nuclear, and fixed energy from PPA terminations previously discussed. Lower generation from these resources results in less surplus generation available to sell into MISO, as more energy is required for NSP system needs. Forward LMP for the 2025 test year are projected to be 7.3 percent higher than prices authorized for 2024, offsetting the impact of less generation slightly. Despite lower forecast revenue, off-system sales are still providing a significant offset to 2025 forecasted costs.

F. Customer Class Rate Calculation

To determine the proposed monthly fuel cost by customer class, Xcel takes the 2025 NSP system forecasted costs, add in the forecasted recovery of the Minnesota jurisdiction biomass PPA termination costs and the market Community Solar Gardens costs, which are direct-assigned to the Minnesota jurisdiction. The sum of the Minnesota jurisdiction costs divided by the forecasted Minnesota jurisdiction MWh sales subject to the FCA (excluding Renewable*Connect program MWh) yields the Minnesota jurisdiction per unit cost.[17] 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. A Class Ratio Adjustment is applied to match forecasted recovery with forecasted expense.

G. Managing Price Risk Volatility

The Company addresses fuel and purchased power price risk through an integrated analysis of its future costs. It manages risk associated with planned outages by scheduling maintenance for its generating facilities typically during the Fall and Spring, when weather conditions are moderate, and prices are expected to be relatively low. Outage information is submitted to MISO for approval.

Additionally, Xcel analyzes its FTR position in the MISO market to ensure that the Company is hedged to the extent possible against congestion cost risk. The Company operates in the MISO wholesale energy and ancillary services market, which uses security constrained regional dispatch with LMP and FTRs to provide a partial hedge against congestion risk.

Xcel periodically reviews its FTR portfolio to ensure that it is properly hedged, given the limitations of the FTR auction process against congestion cost risk in the MISO Day-ahead market (there is no FTR protection in the real-time market). The Company analyzes key congestion risks between its generation and purchase power nodes and its load nodes to determine the optimal FTR portfolio. Moreover, Xcel reviews its exposure to fuel price risk,

[17] Xcel's Petition, at 17.

which has been a long-term issue for the NSP System due to the predominance of coal and nuclear energy in its generation fleet. The increase in natural gas-fired generation and purchased power in the resource portfolio helps mitigate this risk.

Xcel contracts for natural gas storage with Northern Natural Gas (NNG) and ANR Pipeline to provide operational flexibility and to ensure availability of fuel for power plant operations. Storage gas also provides price stability and certainty throughout the year as previously stored gas can be withdrawn to displace daily spot purchases if market prices spike. Gas stored with ANR Pipeline is reportedly purchased during the summer and used as a source of supply during the winter months. The Company's storage service with NNG is provided under a service requested by NSP specifically for electric generation customers effective June 1, 2018.

NSP has more flexibility through these contracts to inject and withdraw throughout the year to manage daily swings in demand for gas fired generation. Electric Generation service on NNG allows withdrawals, which provides protection against price volatility year-round, including the summer months when electric demand peaks.[18] Given the potential variability in generating units being dispatched, a significant portion of system requirements may be covered with the use of storage. Therefore, Xcel does not use financial instruments to hedge natural gas purchases for generation.

III. Department of Commerce – Comments

A. Annual Compliance and Reporting Requirements

The Department noted that, in Part C, Attachment 1 of the 2025 forecast report, Xcel provided a compliance and reporting requirements matrix. Based on its review, the Department recommended that Xcel's compliance filings and reporting requirements be accepted.

B. Sales Forecast

As summarized in Table 4, Xcel's 2025 Minnesota sales forecast, is lightly above its 2024 sales forecast and somewhat below its 2020-2022 three-year average of actual sales.[19]

[18] Xcel's Petition, at 18.
[19] Department's Comments, at 11.

Table 4 – Xcel's Energy Sales Forecasts (GWh)[20]

Item	2025	2024	2023	2022	2021	Avg
	Forecast		Actuals			
Net System Generation	42,465	42,176	40,543	41,073	40,986	40,867
Net System Sales	38,242	38,198	39,260	39,687	39,306	39,418
Net NSPM System Sales	31,342	31,200	32,372	32,722	32,517	32,537
Net MN Sales	26,922	26,842	27,972	28,318	28,196	28,162

Source: Xcel's response to DOC IR 3

Given it is using the same methods as in prior proceedings and the forecast is within the range of prior years, the Department concluded that Xcel's 2025 sales forecast appears reasonable. Consequently, the Department recommended the Commission accept Xcel's 2025 forecasted sales and noted Xcel's FCA revenues and costs are subject to true-up in a petition to be filed in 2026. Furthermore, the Department noted that its recommendations in this docket should not be used in Xcel's future rate cases or other rate proceedings.

C. 2025 FCA Cost Summary

The Department reviewed Xcel's actual and average 2021-2023 FCA costs and noted that, over the years, there are significant cost variances 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. The Department provided its analysis of Xcel's FCA costs by category in the following sections.

1. Company-Owned Generation

The Department provided a trade secret summary of Xcel's forecasted 2024 and 2025 FCA costs and actual 2021-2023 FCA costs for Company-owned generation by fuel type in dollars and dollars per MWh.[21]

Based on its review, the Department concluded that Xcel's 2025 forecasted fuel costs for Company-owned generating units appears to be reasonable. The Department therefore recommended that, subject to true-up, Xcel's forecasted costs in this category be approved to set 2025 FCA rates.

2. Long-term Power Purchase Agreements

The Department provided a trade secret breakout of Xcel's long-term purchased energy by type using 2021-2023 actuals, 2021-2023 three-year average, and Xcel's 2024 and 2025 forecasts.[22]

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[20] Excludes Windsource and Renewable*Connect.

[21] Department's Comments (Table 4), at 15.

[22] Department's Comment (Table 5), at 18.

Based on its review and explanations provided by Xcel, the Department concluded that the Company's forecasted 2025 long-term purchased energy costs appears to be reasonable. Consequently, the Department recommended that, subject to true-up, Xcel's forecasted costs in this category be approved to set 2025 FCA rates.

3. MISO Day 2 (Energy Market) & Day 3 (Ancillary Services Market)

The Department provided a trade secret summary[23] of Xcel's forecasted 2024 and 2025 MISO Day 2 and Day 3 charges which are based on an annualized average for actual costs from April 2021 through February 2024. This is a departure from pre-2023-forecast FCA filings, 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 is likely to result in a more accurate 2025 forecast.

Based on its review, the Department concluded the Company's forecasted 2025 MISO Day 2 and Day 3 charges appear reasonable for purposes of setting forecasted 2025 FCA rates. As a result, the Department recommended that, subject to true-up, Xcel's forecasted 2025 MISO Day 2 and Day 3 charges for the purpose of setting initial FCA rates be approved.

4. Outages

The Department reviewed Xcel's Part B, Attachment 5 that provides planned outages for each unit and concluded Xcel reasonably explained its forecasted planned outages.[24]

As shown in Table 5, for unplanned outage rates for base-load units, Xcel uses the average of the prior five years of actual data and then adjusts the forecast up and down using its judgment to arrive at a final assumption.

[23] Department's Comment (Table 7), at 21.

[24] *Id*, at 24.

Table 5 – Xcel's Forecasted Baseload Unplanned Outages[25]

Plant	Fuel	Expected Retirement	2019	2020	2021	2022	2023	2019-23 Average	2025 Forecast	Delta
			[TRADE SECRET DATA SHADED							
Monticello	Nuclear	TBD								
PI 1	Nuclear	TBD								
PI 2	Nuclear	TBD								
Black Dog	Gas	TBD								
Highbridge 1&2	Gas	TBD								
Riverside 1&2	Gas	TBD								
Sherco 1	Coal	2026								
Sherco 3	Coal	2030								
King	Coal	2028								
										TRADE SECRET DATA SHADED]

Source: Part B, Att. 6, page 1 of 2 and Part G, WP 7

Except for the unplanned outage rates for baseload power plants, the Department concluded Xcel has reasonably explained its forecasted 2025 outage costs. Assuming Xcel provides a reasonable explanation of this issue, the Department recommended the Commission accept Xcel's forecasted 2025 outage costs, subject to true-up, for purposes of establishing FCA rates in this proceeding.

5. Wind Production

The Department reviewed Xcel's actual 2020-2023 and forecasted 2024 and 2025 wind capacity factors[26] and concluded they are reasonable for purposes of setting 2025 rates, subject to true-up. The Department will provide a more detailed review of Xcel's 2025 wind production when Xcel files its 2025 true-up petition.

6. Minnesota-Only FCA Costs

The Department reviewed the two 2025 FCA forecast categories that are charged to Minnesota ratepayers only:[27] Above Market Costs for Community Solar Gardens, and Biomass Buyout Costs.

a. Community Solar Gardens – Above market Costs

The Commission's September 17, 2014 Order in Docket No. E-002/M-13-867 approved Xcel's proposal to recover CSG program costs, including customer bill credits, additional Renewable Energy Credits (RECs), and unsubscribed energy through the FCA.

Xcel forecasted a decrease in overall and above-market CSG costs. As stated above, Xcel calculated that CSGs result in an annual FCA rate that is $6.79/MWh higher than otherwise.[28] Pursuant to Minn. Stat. § 216B.1641, subd. 11, Xcel will exclude the $6.79/MWh cost for

[25] Department's Comments, at 24.

[26] Petition, Part H, Attachment 5.

[27] *Id*.

[28] Xcel Petition, at 14.

customers eligible for bill payment assistance and not subscribing to a CSG. Xcel will file the tariff language for this exclusion in compliance with the pending Order authorizing this exemption tariff. The Department requested Xcel provide an update on its proposal in reply comments.

Based on its review, the Department recommended, subject to subsequent true-up, the Commission accept Xcel's 2025 forecasted CSG-AMC costs for the purpose of setting initial FCA rates in this processing. The Department further requested Xcel provide additional information on its CSG-AMC exclusion for certain customers as specified above.

b. Biomass Buyout Costs

Xcel's Minnesota FCA costs have historically included biomass buyout costs related to the early termination of biomass PPAs.[29] Based on its review, the Department concluded Xcel's forecasted 2025 biomass buyout costs appear reasonable. As a result, the Department recommended, subject to subsequent true-up, the Commission accept Xcel's forecasted 2025 biomass buyout costs for the purpose of setting initial FCA rates in this proceeding.

7. Jurisdictional & Class Cost Allocation

The Department noted that Xcel continues to assign costs to NSPM through the Interchange Agreement energy allocator and then allocates costs to the Minnesota jurisdiction based on sales.[30] To calculate class rates, Xcel is likewise not proposing any changes in its previously approved methodology. Given that Xcel proposed to continue using approved cost allocation methods, the Department recommended, subject to true-up, approval of Xcel's proposed jurisdictional and class cost allocations for 2025 forecast purposes.

8. Recommendations

- **<u>Compliance Items:</u>**
  The Department recommended the Commission accept Xcel's compliance with reporting requirements for the instant petition relating to its 2025 FCA forecast.

- **<u>Sales Forecast:</u>**
  The Department recommended the Commission accept Xcel's 2025 forecasted sales in this proceeding, subject to subsequent true-up.

- **<u>Company Owned Generation:</u>**
  The Department recommended the Commission accept Xcel's forecasted 2025 fuel costs for company-owned generation for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

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[29] Department's Comment, at 26.

[30] Also see Xcel's response to DOC IR 8.

- **Long-Term PPAs:**
  The Department recommended the Commission accept Xcel's forecasted 2025 long-term purchased energy costs for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **MISO Costs & Revenues:**
  The Department recommended the Commission accept Xcel's forecasted 2025 MISO costs and revenues for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **Outage Costs:**
  The Department requested Xcel explain, in reply comments, (a) its methodology for forecasting unplanned outages at each baseload unit and (b) how its forecasted unplanned outage rates for coal plants are reasonable and prudent. The Department will provide a recommendation on Xcel's proposed outage rates after reviewing Xcel's response.

  Except for its baseload unplanned outage rates, the Department concluded Xcel has reasonably explained its forecasted 2025 outage costs. Assuming Xcel provides a reasonable explanation of this issue, the Department recommended the Commission accept Xcel's forecasted 2025 outage costs for purposes of establishing FCA rates in this proceeding, subject to true-up.

- **Wind Production:**
  The Department recommended the Commission accept Xcel's forecasted 2025 wind production for the purpose of setting 2025 rates, subject to true-up. The Department will provide a more detailed review of Xcel's 2025 wind production when Xcel files its 2025 true-up petition.

- **Minnesota-Only FCA Costs (Community Solar Gardens – Above Market Costs and Biomass Buyout Costs):**
  Based on its review the Department recommended the Commission accept Xcel's forecasted 2025 CSG-AMC costs for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up. However, the Department requested Xcel's reply comments provide additional information on the Company's proposal to implement a CSG-AMC exclusion for certain customers.

  The Department also recommended the Commission accept Xcel's forecasted 2025 biomass buyout costs for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **Jurisdictional & Class Cost Allocation:**
  The Department recommended approval of Xcel's proposed jurisdictional and class cost allocations for 2025 forecast purposes, subject to true-up.

IV. Xcel Energy – Reply Comments

Xcel's reply comments updated several inputs to the initial forecast and provided additional information requested by the Department. Updates to model inputs result in a $2.6 million increase to forecasted 2025 fuel costs, or $0.27/MWh, for a revised average rate of $33.27/MWh.[31]

A. Outage Rates

As requested by the Department, Xcel explained its methodology for forecasting unplanned outages at each baseload unit and how its forecasted unplanned outage rates for coal plants are reasonable and prudent.

The Company's forecasted rates represent a combined planned and unplanned rate designed to provide a reasonable forecast of unit availability for the year. Xcel's methodology starts with a five-year average of historical unplanned outage rates, adjusted for historical planned outages, and then adjusts only the coal units for higher levels of outages (which could be planned or unplanned) expected for these plants as they near retirement.[32]

The forecast's goal is to combine historical actual outage data with reasonable future maintenance planning to predict future outage rates. Xcel contended that the methodology is reasonable and prudent because it relies on actual historical outage data, accounting for both planned and unplanned outages, and accounts for the impact of the age of the units on outages. The Company further noted that coal plant outages are forecasted not only based on historical data but also based on expected conditions of the units going forward, including managed decline as plants near retirement.[33]

B. Community Solar Garden Net Cost Exclusion

The Department requested Xcel to provide additional information on the Company's proposal to implement a CSG net cost exclusion for certain customers[34] In Docket Nos. E-002/M-13-867 and E-002/M-23-335, Xcel filed a proposal for calculation of a rate to be considered the net cost of community solar garden generation as follow:

> In our Annual Fuel Forecast and Monthly Fuel Cost Charge proceedings, we show the above Location Marginal Price (LMP) market CSG costs that are in the fuel forecast and used in the fuel clause adjustment (FCA) rates. Using above LMP market CSG costs from the current FCA filing, we propose to determine the net cost of CSG generation as follows:

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[31] Xcel's Reply Comments, at 1.

[32] *Id*, at 2.

[33] Sherco Unit 2 retired in December 2023, with the remainder of the Company's coal units retiring in 2026 (Sherco 1), 2028 (King) and 2030 (Sherco 3).

[34] Xcel's Reply Comments, at 4.

> Residential Above LMP Market Cost of CSG generation per kWh = Above LMP Market Cost Allocation to Residential ÷ Residential Sales (kWh)
>
> Using our 2024 FCA forecast filed July 31, 2023 as an example, the Residential Above LMP Market Cost of CSG would be 0.9204 cents per kWh. In our August 15, 2023 Lessons-Learned Report in the ongoing fuel clause reform docket, we proposed to allocate above LMP Market CSG costs to class based on CSG subscription capacity. If that proposal is approved, then the 2024 Residential Above Market Cost of CSG would be 0.4252 cents per kWh.
>
> The Company proposes to include the cost of these credits for recovery in the Fuel Clause True-up filing due March 1 annually.
>
> In practice, to verify that the customer is not a current CSG subscriber, we will need to provide this adjustment to customers as a credit on their bill with a one-month lag. This adjustment will be effective prospectively after the Company has systems in place to provide the bill credit.

The Commission approved Xcel's proposed calculation methodology in Order Point 5C of their December 28, 2023 Order.[35] As such, the Company calculated the CSG exclusion credit rate using the Commission approved methodology and consistent with the 2025 fuel forecast filed in this Reply. Xcel plans to file a Motion to establish this rate as the net cost of generation rate of exclusion of CSG costs effective January 2025.

C. Forecast Input Updates

Xcel updated its forecast inputs, which include those that are significant cost drivers to any year's fuel forecast and those that should be updated to remain true to an objective of reform. As noted above, updated model inputs result in increases, with the following details:

1. Coal Pricing

Forecasted coal general prices have increased, with an overall impact on coal generation cost/MWh an increase of 1.1 percent, compared to the initial filing.

2. Natural Gas Prices

Natural gas prices have been updated to NYMEX closing prices as of July 10, 2024.The annual average price of natural gas for Ventura has decreased to $3.54/MMBtu, which is 4.5 percent lower than the initial filing.

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[35] Xcel's Reply Comments, at 4.

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 10, 2024. The average annual price for MISO LMP decreased to $31.97/MWh, which is 0.7 percent lower than the initial filing.

4. MISO Costs

Xcel updated MISO costs based on the most recent historical data available through June, 2024.

5. Maintenance Updates

2025 planned maintenance was updated to reflect the Company's latest planned schedules. The updated replacement power cost estimate was provided in Attachment G.

6. PPA Updates

Updated 2025 PPA updates reflect changes that occurred since the initial filing.

7. Benson Power, LLC

The Commission's January 23, 2018 Order in Docket No. E-002/M-17-530 approved the early termination of the Power Purchase Agreement (PPA) between the Company and Benson Power, LLC; with recovery of costs associated with the termination through the FCA. The Commission's November 14, 2019 Order in Docket No. E-002/AA-19-293 required Xcel to apply a 9.06 percent ROE to the Benson termination. However, the Commission's July 17, 2023 Order in the Xcel's electric rate case in Docket No. E-002/GR-21-630 approved an ROE of 9.25 percent. As a result, the Company updated the ROE applied to the Benson termination cost calculation to 9.25 percent for the 2025 fuel forecast in this filing.

8. Jurisdictional Allocation Update

Xcel updated the monthly interchange allocators, which is shown on Attachment A, page 1.

D. Revised Rate Summary

1. Community Solar Garden Net Cost Exclusion Rate

The updated fuel forecast impacts the CSG exclusion credit calculation. Therefore, Xcel updated its calculation by dividing forecasted Residential CSG above market costs by the forecasted Residential FCA kWh. Based on the updated fuel forecast, Xcel calculated the net cost of generation for CSGs as 0.681 cents per kWh for 2025.[36] The Company requested approval of

[36] Xcel's Reply Comments, at 7.

this updated credit for purposes of excluding the net cost of CSG generation costs for customers eligible for exemption.

2. *Land Sales Adjustment*

The Commission's April 12, 2023 Order in Docket No. E-002/PA-23-110 approved Xcel's proposal to credit, through the FCA, the jurisdictional gains related to sales of land in Becker, Minnesota. Additionally, the Commission's May 2, 2023 Order in Docket No. E-002/PA-23-118 approved the Company's proposal to credit, through the FCA, the jurisdictional gains related to sales of land in Red Wing, Minnesota. Compliance filings were made on June 5, 2024 and June 7, 2024, respectively; providing the final journal entries associated with these sales.[37] The gain to be credited to Minnesota customers for the Becker land sale is $148,069, and the gain to be credited to Minnesota customers for the Red Wing land sale is $59,025. Xcel has adjusted its January 2025 fuel rates to include the credits related to these land sales.

3. *Revised Monthly Fuel Clause Rates by Customer Class*

In Tables 6 and 7, Xcel summarize updated 2025 monthly fuel clause rates by month and by customer class.

Table 6 –Revised 2025 Monthly Fuel Clause Rates by Customer Class ($/kWh)[38]

Month	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.03269	$0.03267	$0.03218	$0.04087	$0.02568	$0.02459
February	$0.03573	$0.03570	$0.03517	$0.04468	$0.02806	$0.02686
March	$0.03611	$0.03608	$0.03554	$0.04516	$0.02835	$0.02713
April	$0.03871	$0.03867	$0.03809	$0.04841	$0.03039	$0.02909
May	$0.03614	$0.03611	$0.03557	$0.04519	$0.02838	$0.02717
June	$0.03707	$0.03704	$0.03648	$0.04637	$0.02909	$0.02785
July	$0.03524	$0.03520	$0.03467	$0.04408	$0.02764	$0.02646
August	$0.03393	$0.03390	$0.03339	$0.04245	$0.02662	$0.02548
September	$0.03244	$0.03241	$0.03193	$0.04058	$0.02546	$0.02437
October	$0.03080	$0.03077	$0.03031	$0.03852	$0.02418	$0.02315
November	$0.02847	$0.02844	$0.02801	$0.03560	$0.02234	$0.02139
December	$0.02950	$0.02947	$0.02903	$0.03689	$0.02315	$0.02216

[37] *Id*, at 8.
[38] Xcel's Reply Comments, at 9.

Table 7 –Revised 2025 Monthly Fuel Clause Rates for C&I General Time of Use Service Pilot ($/kWh)[39]

Month	Commercial & Industrial General TOU Service Pilot		
	Demand		
	Peak	Base	Off-Peak
January	$0.04242	$0.03421	$0.01684
February	$0.04638	$0.03739	$0.01838
March	$0.04688	$0.03779	$0.01856
April	$0.05024	$0.04051	$0.01990
May	$0.04690	$0.03782	$0.01859
June	$0.04813	$0.03879	$0.01904
July	$0.04576	$0.03687	$0.01807
August	$0.04406	$0.03551	$0.01741
September	$0.04212	$0.03395	$0.01666
October	$0.03998	$0.03223	$0.01583
November	$0.03695	$0.02979	$0.01463
December	$0.03829	$0.03087	$0.01516

V. Department of Commerce – Response to Reply Comments

A. Forecasted Input Updates

Based on its review of Xcel's updates on Coal Prices, Natural Gas Prices, MISO Prices, Net MISO Revenues, Power Purchase Agreements, Benson Early Termination, Jurisdictional Allocators and Renewable Connect Sales, the Department agreed with and/or concluded that the updates are reasonable.

B. Outages

In response to the Department's request in its Comments, that Xcel explained in Reply Comments: (a) its methodology for forecasting unplanned outages at each baseload unit and (b) how its forecasted unplanned outage rates for coal plants are reasonable and prudent. Xcel clarified that the baseload outage rates are combined planned and unplanned outage rates. Additionally, the Department noted Xcel clarified that these combined outage rates are used as single input in PLEXOS to represent Xcel's estimated total random outages by unit. The Company further agreed to correctly label the combined outage rate schedules in future FCA filing, while clarifying its outage forecast process.

The Department concluded Xcel has reasonably clarified its procedures for forecasting its 2025 outages. Therefore, subject to true-up, it recommended the Commission accept Xcel's 2025 outage forecast for the purpose of setting 2025 rates.

[39] Xcel's Reply Comments, at 9.

C. Community Solar Garden Exclusion Rate

As noted in its Reply Comments, Xcel filed a motion on August 2, 2024 to establish the net CSG rate tariff in Docket Nos. E-002/CI-23-335, E-002/M-13-867, and E-002/AA-24-63. As discussed below, in its response letter to the motion, the Department supported Xcel's forecasted CSG exclusion rate.[40]

D. Land Sales Credits

Based on its review, the Department concluded Xcel has appropriately reflected credits for the Becker and Red Wing land sales to Minnesota Jurisdiction, consistent with the Commission Orders requiring they be included in the FCA. Moreover, the Department concluded Xcel has appropriately reflected these credits in its calculation of forecasted FCA rates.

E. FCA Cost Summary

As shown in Table 10, the Department summarized Xcel's updated 2025 FCA forecasted costs and compared them to the approved 2024 forecast and 2021-2023 actuals and averages.

[40] Department's Reply Letter to Motion, at 4.

Table 10 – Updated Xcel Minnesota Net FCA Costs: 2021-2025 in (in 1000's)

				2025	2024	2023	2022	2021	2021-23 Avg.
				Forecast*	Forecast**	Actuals			
				[TRADE SECRET DATA EXCISED					
1		Own Generation	$			$ 485,138	$ 633,483	$ 563,490	$ 560,704
2	+	Long-Term Purchased Energy	$			$ 579,164	$ 639,497	$ 559,674	$ 592,778
3	+	Community Solar Gardens	$	$ 264,458	$ 329,263	$ 206,275	$ 184,030	$ 183,652	$ 191,319
4	+	MISO Market Charges				$ 148,146	$ 239,474	$ 229,886	
5	+	Short-Term Market Purchases	$			$ 94,895	$ 146,773	$ 85,141	$ 108,936
6	=	Total NSP System Costs	$			$ 1,513,618	$ 1,843,257	$ 1,621,843	$ 1,659,573
7	-	Asset-Based Sales Revenues	$			$ (282,329)	$ (564,368)	$ (437,200)	$ (427,966)
8	-	CSG-AMC	$	$ (184,921)	$ (249,377)	$ (155,166)	$ (99,903)	$ (110,745)	$ (121,938)
9	-	RC Pilot	$			$ (6,739)	$ (6,291)	$ (6,190)	$ (6,407)
10	-	RC MTM	$			$ (16,858)	$ (18,190)	$ (12,169)	$ (15,739)
11	-	RC LT	$			$ -	$ -	$ -	$ -
12	=	Net System FCA Costs	$			$ 1,052,526	$ 1,154,506	$ 1,055,539	$ 1,087,524
13		Net System Sales***	MWh	38,242,162	38,197,851	39,260,332	39,686,566	39,305,604	39,417,501
14		**Net System FCA Unit Costs**	**$/MWh**			**$26.81**	**$29.09**	**$26.85**	**$27.59**
15		Net MN Sales	MWh	26,788,077	26,842,355	27,971,766	28,318,349	28,195,869	28,161,995
16		MN FCA Costs	$			$ 753,515	$ 824,270	$ 758,124	$ 778,636
17	+	CSG-AMC	$	$ 184,921	$ 249,377	$ 155,061	$ 99,883	$ 110,646	$ 121,863
18	+	Laurentian Buyout	$			$ -	$ 13,062	$ 13,192	$ 8,751
19	+	Benson Buyout	$			$ 22,412	$ 9,844	$ 10,249	$ 14,168
20	+	Other adjustments	$			$ 4,349	$ 3,162	$ 1,834	$ 3,115
21		Net MN FCA Costs	$	$ 891,200	$ 1,022,748	$ 935,337	$ 950,221	$ 894,044	$ 926,534
22		**Net MN FCA Unit Costs**	**$/MWh**	**$33.27**	**$38.10**	**$33.44**	**$33.55**	**$31.71**	**$32.90**
23		**MN FCA Premium Unit Costs********	**$/MWh**			**$6.63**	**$4.46**	**$4.85**	**$5.31**
				TRADE SECRET DATA EXCISED]					

* 7/31/24 Reply Comments, Attachment A
** 7/31/23 Reply Comments in Docket No. E002/AA-23-153, Attachment A.
*** Net system sales are assumed to be the same as DOC initial comments due to NSPM system sales also not changing.
**** The costs of CSGs and biomass buyout costs are both solely assigned to the Minnesota jurisdiction.

F. Recommendations

Based on its review and analyses, the Department provided the following final recommendations:

- **<u>Compliance Items:</u>**
  The Department recommended the Commission accept Xcel's compliance with reporting requirements for the instant petition related to its 2025 FCA forecast.

- **<u>Sales Forecast:</u>**
  The Department recommended the Commission accept Xcel's 2025 forecasted sales in this proceeding, subject to subsequent true-up.

- **<u>Company Owned Generation:</u>**
  The Department recommended the Commission accept Xcel's updated forecast of 2025 fuel costs for company-owned generation for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **<u>Long-Term PPAs:</u>**
  The Department recommended the Commission accept Xcel's updated forecast of 2025 long-term purchased energy costs for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **<u>MISO Costs & Revenues:</u>**
  The Department recommended the Commission accept Xcel's updated forecast of 2025 MISO costs and revenues for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **<u>Outage Costs:</u>**
  The Department concluded Xcel has reasonably explained its updated forecast of 2025 outage costs and recommended the Commission accept Xcel's updated forecast of 2025 outage costs for the purpose of establishing FCA rates in this proceeding, subject to true-up.

- **<u>Wind Production:</u>**
  The Department recommended the Commission accept Xcel's forecasted 2025 wind production for the purpose of setting 2025 rates, subject to true-up. The Department will provide a more detailed review of Xcel's 2025 wind production when Xcel files its 2025 true-up petition.

- **<u>Minnesota-Only FCA Costs (Community Solar Gardens – Above Market Costs and Biomass Buyout Costs):</u>**
  The Department recommended the Commission accept Xcel's updated forecast of 2025 CSG-AMC costs and related rates for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

  The Department also recommended the Commission accept Xcel's updated forecast of 2025 biomass buyout costs for the purpose of setting initial 2025 FCA rates in this proceeding, subject to subsequent true-up.

- **<u>Land Sales Adjustments:</u>**
  The Department recommended the Commission accept Xcel's proposed incorporation of 2024 land sales gains to Becker of $148,069 credit and Red Wing of $59,025 credit into 2025 FCA rates.

- **<u>Jurisdictional & Class Cost Allocation:</u>**
  The Department recommended approval of Xcel's proposed jurisdictional (including updated interchange allocators) and class cost allocations for 2025 forecast purposes, subject to true-up.

VI. Xcel Energy – Motion

Xcel submitted a Motion to establish a 2025 net cost of generation rate of exclusion for Community Solar Gardens (CSG) costs and a process for approval of future updates. In the Company's compliance filing in Docket Nos. E-002/CI-23-335 and E-002/M-13-867, Xcel filed Tariff Sheet No. 5-91.4, with a provision that stated:

> EXCLUSION OF COMMUNITY SOLAR GARDEN COSTS
> To comply with Minn. Stat. § 216B.1641, Subd. 11, the fuel adjustment charge to residential customers who have received bill payment assistance or income-qualified energy assistance programs within the proceeding twelve-month timeframe and who also do not subscribe to a community solar garden shall exclude the "net cost of community solar garden generation". To achieve this exclusion, these customers shall receive a bill credit of $[To Be Determined] per kWh of billed usage that removes "net cost of community solar garden generation". This credit will start to apply and appear on customer bills only after the Company has systems in place to provide this credit and application of this credit will be done only on a prospective basis after the Company has systems in place.

Xcel's initial 2025 CSG exclusion rate of 0.679 cent per kWh was updated to 0.681 cent per kWh in Reply Comments.[41] The Company expects that the Commission will determine approved rates for the Fuel Forecast docket later this year, with an effective date of January 1, 2025. As such, it expects to have a system in place on January 1, 2025 to apply this exclusion. Consequently, Xcel seeks authorization:

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

A. Proposed Rate

Pursuant to Minn. Statute 216B.1641 subd.11, utilities must exclude the net cost of community solar garden generation from the fuel clause adjustment for customers who are eligible for this

[41] Xcel's Reply Comments, at 7.

exemption. Order Point 5C of the Commission's December 28, 2023 Order, in Docket Nos. E-002/CI-23-335 and E-002/M-13-867 approved the Company's proposal to calculate this credit by dividing forecasted CSG above market costs by the forecasted net FCA kWh.[42] Based on the Company's recalculated net cost of 0.681 cent per kWh of generation for CSGs, Xcel expects to have a system in place on January 1, 2025 to apply this exclusion. As a result, the Company recommended that the following language currently on Tariff Sheet 5-91.4 be removed:

> This credit will start to apply and appear on customer bills only after the Company has systems in place to provide this credit and application of this credit will be done only on a prospective basis after the Company has systems in place.

B. Proposed Process for Annual Updates

Given that the CSG exemption rate is a component of fuel cost, Xcel proposed that annual updates to this rate be made in the initial annual fuel forecast dockets due by May 1 of each year and not in the CSG dockets (E-002/CI-23-335 and E-002/M-13-867).[43] Forecasted rates would include the proposed exemption and the filing would include the proposed tariff sheet reflecting the proposed rate. Final reports showing the actual excluded amount for the prior calendar year would be shown in the True-Up Reports filed on March 1 each year following the conclusion of that forecast year.

C. Conclusion

Xcel requested its Motion be granted to set the CSG exclusion rate and annual update process as set forth above, and specifically requests the following relief:

- That the Commission approve the proposed net cost of generation rate for inclusion on Tariff Sheet No. 5-91.4, with an effective date of January 1, 2025;
- That the following language be removed from Tariff Sheet No. 5-91.4: "This credit will start to apply and appear on customer bills only after the Company has systems in place to provide this credit and application of this credit will be done only on a prospective basis after the Company has systems in place."
- That future changes to this rate be changed on a calendar year cadence, with future proposed changes to be made only in future Fuel Forecast dockets and not in the CSG dockets (E-002/CI-23-335 and E-002/M-13- 867), unless if the Commission orders otherwise.

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[42] Xcel's Motion, at 2-3.

[43] Xcel's Motion, at 3.

VII. Department of Commerce – Response Letter to Motion

The Department expressed support for proposals outlined in Xcel's August 2, 2024 Motion, regarding the tariff rate for net cost of Community Solar Garden generation.[44] It pointed out that Xcel's calculation methodology for the net cost of CSG generation appears consistent with the methodology approved by the December 28, 2023 Order.

The Department supports utilizing the net cost of CSG generation rate approved by the Commission later this year in the FCA docket for inclusion in tariff sheet 5-91.4, with an effective date of January 1, 2025. The Department recommended the Commission require Xcel to update the tariff sheet to reflect the rate approved by the Commission in the FCA docket and provide the updated final tariff sheet in its compliance filing due within 10 days after the Order approving 2025 FCA rates is issued.

A. Tariff Language Removal

Predicated on the coinciding implementation on January 1, 2025 of the exclusion rate, the 2025 FCA, and the necessary systems to apply the exclusion rate, the Department concluded that Xcel's proposed and approved tariff language in tariff sheet 5-91.4 is no longer necessary. Accordingly, the Department supports Xcel's request for removal of the tariff language.

B. Future Rate Updates

The Department supports Xcel's proposal to incorporate updates to the net cost of CSG generation in the FCA docket. It noted that the calculation methodology for the net cost of CSG generation approved by the Commission is also directly connected to the market CSG costs established in the FCA docket.[45] Additionally, the Department asserted that incorporating the net cost of CSG generation updates in the existing process of the FCA docket also provides efficiencies for the regulatory process.

For greater transparency regarding the calculation of the net cost of CSG generation in the FCA docket and to ensure the calculation complies with the Commission's approved methodology, the Department requested Xcel provide its calculations of the net cost of CSG generation as an attachment to its FCA filings moving forward.

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[44] Motion – Regarding Tariff Rate for Net Cost of CSG Generation, Northern States Power Company dba Xcel Energy, In the Matter of Implementation of 2023 Legislative Changes to Xcel Energy's Community Solar Garden Program; In the Matter of Northern States Power Company, dba Xcel Energy, for Approval of its Proposed Community Solar Garden Program; and In the Matter of the Petition of Northern States Power Company for Approval of the 2025 Annual Fuel Forecast and Monthly Fuel Cost Charges, Docket Nos. E-002/CI-23-335, E-002/M-13-867, E-002/AA-24-63 (August 2, 2024). (eDocket No. 20248- 209228-01). Hereinafter "Motion."

[45] Department Response to Motion, at 5.

C. Conclusion and Recommendations

Based on its review and analysis of Xcel's Motion, the Department supported the proposals and provided the following recommendations:

- The Department recommended the Commission approve the proposed net cost of generation rate for inclusion on Tariff Sheet No. 5-91.4, with an effective date of January 1, 2025;
- The Department recommended the Commission require Xcel to update Tariff Sheet No. 5- 91.4 to reflect the rate approved by the Commission in Docket No. E-002/AA-24-63 and provide the updated final tariff sheet in its compliance filing within 10 days of the Order approving 2025 rates being issued;
- The Department recommended the Commission approve that the following language be removed from Tariff Sheet No. 5-91.4:

  > This credit will start to apply and appear on customer bills only after the Company has systems in place to provide this credit and application of this credit will be done only a prospective basis after the Company has systems in place.
- The Department recommended the Commission approve that future changes to this rate be changed on a calendar year cadence, with future proposed changes to be made only in future Fuel Forecast dockets and not in the CSG dockets (E-002/CI-23-335 and E-002/M-13-867), unless if the Commission orders otherwise.
- The Department recommended the Commission require Xcel to provide the calculations of the proposed net cost of generation rate as an attachment in the Fuel Forecast dockets.

VIII. Staff Comments

Upon reviewing Xcel's and the Department's filings, staff agrees with the Department's recommendations that:

- Xcel's 2025 FCA forecast, based on the revised forecasted sales of 26,788,077 MWh and revised costs of $891,200, be approved.
- Xcel's calculated net cost for CSGs generation of 0.681 cent per kWh for 2025, be approved and that future changes to this rate be made on a calendar year basis, and only in future Fuel Forecast dockets.

IX. Decision Options

Forecasted Sales and Fuel Costs

1. Approve Xcel's revised 2025 FCA Forecast Petition. (Xcel, Department)

2. Authorize Xcel Energy to implement its 2025 FCA forecast, based on the revised forecasted sales of 26,788,077 MWh and revised forecasted costs of $891,200,000, Minnesota Jurisdictional. (Xcel, Department)

Jurisdictional & Class Cost Allocation Method

3. Approve Xcel's proposed jurisdictional and class cost allocations for 2025 forecast purposes. (Xcel, Department)

Land Sales

4. Approve Xcel's proposed incorporation of 2024 land sale gains of $148,069 and $59,025 credits to Becker and Red Wing respectively. (Xcel, Department)

Minnesota-Only FCA Costs (Community Solar Gardens – Above Market Costs and Biomass Buyout Costs)

5. Approve Xcel's updated forecast of 2025 CSG-AMC costs and related rates. (Xcel, Department)

6. Approve Xcel's proposed net cost of generation rate for inclusion on Tariff Sheet No. 5-91.4, with an effective date of January 1, 2025. (Xcel, Department)

7. Grant Xcel's motion to remove the following language from Tariff Sheet No. 5-91.4:

   This credit will start to apply and appear on customer bills only after the Company has systems in place to provide this credit and application of this credit will be done only on a prospective basis after the Company has systems in place. (Xcel, Department)

8. Approve that future changes to the net cost of CSG-AMC generation rate be effected on a calendar year basis and be made only in future FCA dockets. (Xcel, Department)

9. Require Xcel to update Tariff Sheet No. 5-91.4 to reflect the rate approved by the Commission and provide the updated final tariff sheet in its compliance filing within 10 days of the Order approving 2025 rates. (Department)

10. Require Xcel to provide the calculations of the proposed net cost of generation rate as an attachment in the fuel forecast dockets. (Department)

11. Approve Xcel's updated forecast of 2025 biomass buyout costs.