MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	November 23, 2021	Agenda Item 1*
Company	Northern States Power Company d/b/a Xcel Energy	
Docket No.	**E-002/AA-21-295**	
	In the Matter of Xcel Energy's Petition for Approval of its 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges	
Issue	At what level should Xcel Energy's 2022 Annual Forecasted Rates for its Energy Adjustment Rider be set?	

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✓ Relevant Documents	Date
Xcel Energy – Initial 2022 Forecast Filing (Public and Trade Secret)	April 30, 2021
Department of Commerce – Comments (Public and Trade Secret)	June 30, 2021
Xcel Energy – Reply Comments (Public and Trade Secret)	July 30, 2021
Department of Commerce – Response to Reply Comments (Public and Trade Secret)	August 30, 2021

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I. Statement of the Issue

At what level should Xcel Energy's 2022 Annual Forecasted Rates for its Energy Adjustment Rider be set?

II. Background

On April 30, 2021, Northern States Power Company d/b/a Xcel Energy (Xcel, NSP, the Company) made its 2022 Annual Fuel Forecast and Monthly Fuel Cost Charges filing.

On June 30, 2021, the Minnesota Department of Commerce – Division of Energy Resources (Department, DOC) filed comments recommending approval of Xcel's 2022 sales forecast, its forecasted Company-owned Generation by type and location, its purchased energy (long-term PPAs) forecast and its forecasted Community Solar Gardens – Above Market Costs and Biomass Buyout Costs, and MISO costs. Additionally, the Department requested that, in reply comments, Xcel provide additional information regarding MISO Day 2 and Day 3 charges, asset-based margins, outage costs and wind curtailment costs.

On July 30, 2021, 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 30, 2021, the Department filed reply comments accepting Xcel additional information and recommended approval of Xcel's revised 2022 forecast.

III. Parties' Comments

A. Xcel Energy – Initial Filing

1. 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.

2. 2022 Forecast Summary

Xcel's 2022 MN-jurisdiction forecasted sales were 26,631,660 MWh and forecasted costs were $805,608,000 resulting in a $30.25/MWh average.[1]

3. Proposed 2022 Monthly Fuel Clause Rates by Customer Class

Table 1 summarizes Xcel's proposed 2022 monthly fuel cost rates, by class. These charges will be recovered through the Fuel Clause Adjustment (FCA).

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[1] Attachment 1, Part A, Page 1.

Table 1 – Proposed 2022 Monthly Fuel Clause Rates by Customer Class ($/kWh)

Month	Residential	Commercial & Industrial Outdoor				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.02480	$0.02512	$0.02434	$0.03041	$0.01992	$0.01946
February	$0.03012	$0.03050	$0.02955	$0.03695	$0.02417	$0.02361
March	$0.03029	$0.03067	$0.02972	$0.03716	$0.02431	$0.02375
April	$0.03059	$0.03097	$0.03001	$0.03751	$0.02456	$0.02399
May	$0.03312	$0.03353	$0.03249	$0.04062	$0.02659	$0.02597
June	$0.03880	$0.03929	$0.03807	$0.04760	$0.03114	$0.03042
July	$0.03258	$0.03299	$0.03196	$0.03998	$0.02614	$0.02553
August	$0.03281	$0.03322	$0.03218	$0.04026	$0.02632	$0.02570
September	$0.03238	$0.03279	$0.03177	$0.03972	$0.02600	$0.02539
October	$0.03026	$0.03064	$0.02969	$0.03712	$0.02429	$0.02372
November	$0.02764	$0.02799	$0.02712	$0.03391	$0.02218	$0.02167
December	$0.02564	$0.02596	$0.02515	$0.03144	$0.02058	$0.02010

4. 2022 Forecast Key Inputs

a. 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.

b. 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.

c. Company-Owned Wind Generation

Inputs for NSP-owned wind generation reflect the individual hourly profiles of each NSP-owned project. These profiles are based on specific historical results for projects with an annual generation profile based on at least twelve months of operational data. 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. There is no fuel price input for wind generation in the model because wind generation does not require any fuel purchases.

d. 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 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.

In the past, coal plants have been offered into the MISO market as "must-run" generation plants because it was the most cost-effective way to operate the plants and because of their operational limitations. However, Xcel now offers most of these units on an "economic" basis, which allows MISO to de-commit the units if other sources of energy are more cost effective. Additionally, King and Sherco 2 only operate seasonally in the months of January, February, June, July, August and December.

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

e. Company-Owned Wood/RDF Generation

Key modeling parameters, such as operating capacity and heat rate, for NSP-owned wood/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.

f. 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.

g. 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.

h. 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 PPA. Planned maintenance is inputted based on the PPA counterparty's overhaul schedule. Each unit's forced outage rates are based on historical GADS data and expected conditions of the units going forward.

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.

i. 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 2022 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.

j. Purchased Wind Generation

Wind PPAs modeling reflects each individual project's hourly profiles. For existing PPAs, the profiles are based on historical results from the projects' specific operational data. For new PPAs, the profiles are based on turbine technology, plant design, and localized weather data.

In consideration of simulation run times and the limited value provided by individual modeling for these non-dispatchable resources, some small wind PPAs are aggregated into single groups. 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.

k. 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 their contract terms (for the biomass and Manitoba Hydro PPAs). Price is determined based on contract terms or based on historical prices with assumed escalation.

l. 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.

m. 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.
  - Laurentian Energy Authority I LLC – Early termination of agreement covering the purchase of generation from wood fueled biomass facilities.
- 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).
- Wind Curtailment costs are based on observed curtailment for prior years where large additions of wind generation preceded transmission expansion or transmission outages

were higher than normal due to transmission expansion activity. Specifically, Xcel based the 2022 wind curtailment estimate on the 2003-2020 average curtailment percentage, adjusted to remove the highest curtailment year (greater than 10 percent) and the lowest curtailment years (less than 3 percent). 2022 MWh production for each PPA wind farm eligible for curtailment payments in 2022 was based on the 2015-2020 average historical MWh. For projects that are not yet in-service or only recently placed in-service, Xcel used capacity factors based on the wind patterns. Total projected curtailment costs were determined by multiplying the curtailment percentage by the projects' MWh production for each project and by the PPA cost per MWh.

n. FCA Exclusions

PPAs that serve the Renewable*Connect programs are included in the PLEXOS model. Renewable*Connect currently uses a portion of one wind PPA and one solar PPA to serve participant customer sales. Renewable*Connect Month-to-Month (MTM) uses a pool of resources that, in addition to several new projects, includes projects that formerly served Windsource.

Because these program costs are covered by specific fees paid by subscribers, 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.

o. Future Model Updates

Xcel indicated that, for the July 31, 2021 reply comments, the Company anticipated updating the following inputs:

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

5. Forecast Drivers

Total 2022 MN-jurisdiction FCA costs are forecast to increase by over $55 million when compared to authorized 2021 costs. Key drivers impacting the forecast include:

- Wind expansion and lower coal generation due to increased economic offers in the marketplace place downward pressure.

- Increases in the Solar*Rewards Community program, increased Manitoba Hydro purchases and higher projected MISO costs add upward pressure.

The 2022 forecast reflects completion of the latest round of wind generation expansion. The Dakota Range owned wind project is expected to go into service by the end of 2021. Additionally, the next phase of wind upgrades begins with the repower of the owned Nobles wind project in late 2022. Finally, the Deuel Harvest and Heartland Divide PPA wind farms and the one Elk Creek solar bridge PPA project are also expected to be in service by the end of 2021.

Reflecting the change in operational strategy of utilizing economic offers in the MISO market for King, Sherco 2 and Sherco 3, coal generation in 2022 is forecasted to decline significantly. The decline in coal generation is offset by increases in generation from low-cost renewable generation and natural gas generation.

The 2022 forecast includes projected increases in the Solar*Rewards Community program which is expected to increase 7% and contribute over $11 million of additional cost for Minnesota customers. Partially offsetting the increase in program size and cost is a 1.6% decrease in the average program cost to $127.29/MWh driven by an increase in program participants on the lower Value of Solar (VOS) rate.

Additionally, the new contract with Manitoba Hydro that began in May 2021 will be in effect for all of 2022 which increases forecasted purchase costs.

6. Customer Class Rate Calculation

To determine the proposed monthly fuel cost by customer class, Minnesota jurisdictional costs are divided by Minnesota jurisdictional MWh sales subject to the Fuel Clause Adjustment (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 in order to match forecasted recovery with forecasted expense.

7. Assumptions Regarding Pending Commission Proceedings

Xcel noted that Commission action on the following proceedings could impact Xcel's 2022 actual fuel costs:

- The proposed amendment to the Mower Elk Creek Solar PPA (Docket No. E-002/M-19-568).
- The limited program modifications and updated pricing to Renewable Connect (Docket No. E-002/M-21-222).

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

8. Managing Price Risk Volatility

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

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

Xcel reviewed its exposure to fuel price risk which, historically, has been a long-term issue due to the predominance of coal and nuclear energy in the generation fleet. However, the increase in natural gas-fired generation and purchased power in the resource portfolio helps mitigate this risk.

The Company contracts for natural gas storage with Northern Natural Gas (NNG) and ANR Pipeline to provide operational flexibility and to ensure availability of fuel for power plant operations. Storage gas also provides price stability and certainty throughout the year as previously stored gas can be withdrawn to displace daily spot purchases if and when market prices spike. Gas stored with ANR Pipeline is purchased during the summer and used as a source of supply during the winter months.

Effective June 1, 2018, the Company's storage service with NNG was converted to a new service requested by Xcel specifically for electric generation customers. Through this conversion, Xcel now has more flexibility to inject and withdraw throughout the year to manage daily swings in demand for gas fired generation. Unlike traditional storage services, which must be filled during the summer months for use during the winter, the new Electric Generation service on NNG allows for withdrawals, and hence protection against price volatility year-round, including the summer months when electric demand peaks. With such a significant portion of system requirements covered through the use of storage, the Company does not use financial instruments to hedge natural gas.

Finally, Xcel's coal acquisition and implementation strategies were also discussed; however, they are trade secret.

9. 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% 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.

B. Department of Commerce - Comments

1. Annual Compliance and Reporting Requirements

The Department noted that, in Part C, Attachment 1 of the 2022 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.

2. 2022 Sales Forecast

The Department noted that Xcel's 2022 forecasted production is slightly higher than its 2021 forecast and similar to the three-year average shown in Table 2.

Table 2 – Xcel's 2018-2020 Actual Sales and Production Levels (MWh's)[2]

	2020 Actuals	2019 Actuals	2018 Actuals	2018-2020 Average
Total Net System Sales of Electricity for FCA	38,456,375	39,826,993	41,588,127	39,957,165
Total Net System Production Level	40,109,000	40,909,000	44,647,000	41,888,000

Based on its review, the Department concluded that Xcel's 2022 sales forecast appears reasonable. Therefore, the Department recommends that Xcel's 2022 forecasted sales in this proceeding to set FCA rates for 2022 be accepted. The DOC stated that Xcel's FCA revenues and costs are subject to true-up in the 2023 True-up Report. 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.

3. Forecasted 2022 System Costs

The Department reviewed Xcel's actual and average 2018-2020 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.

[2] The Department's trade-secret version of this table also includes 2021 and 2022 forecasts.

a. Forecasted Fuel Costs for Company-Owned Generation

The Department provided a (trade secret) summary[3] of Xcel's forecasted 2021 and 2022 FCA costs and actual 2018-2020 FCA costs for Company-owned generation by fuel type in dollars and dollars per MWh.

The Department noted that, compared to prior years, there are significant changes in per MWh forecasted 2022 for the following: coal costs, wood/RDF costs, natural gas costs for combined-cycle generating units and natural gas and oil costs for combustion-turbine (CT) generating units. These changes are expected due to the increase of renewables on Xcel's system.

Based on its review, the Department concluded that Xcel's 2022 forecasted fuel costs for Company-owned generating units appears reasonable. As a result, the Department recommended that, subject to true-up, Xcel's forecasted costs in this category be approved to set 2022 FCA rates.

b. Purchased Energy – Long-Term PPAs

The Department provided a (trade secret) breakout[4] of Xcel's long-term purchased energy by type using 2018-2020 actuals, 2018-2020 three-year average, and Xcel's 2020 and 2021 forecasts.

The Department noted changes between Xcel 2022 forecasted costs and 2020 actual costs for the following categories:

- Long-term gas PPA costs per MWh.
- Long-term solar PPA costs per MWh.
- Long-term wind PPA costs per MWh.
- Long-term other PPA costs per MWh.
- Long-term PPA costs are associated with CSGs.

Based on its review and explanations provided by Xcel, the Department concluded that 2022 forecasted long-term purchased energy costs appear 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 2022 FCA rates.

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

The Department provided a (trade secret) summary[5] of Xcel's forecasted 2021 and 2022 MISO Day 2 and Day 3 charges which are based on a historical five-year average.

[3] Department Table 3.

[4] Department Table 4.

[5] Department Table 5.

During its review of the individual MISO Day 2 and Day 3 charges, the Department noted that Xcel's 2022 forecast excluded certain MISO charge types that were included in previous AAA filings. Additionally, the Department noted that Xcel included other non-MISO items in its 2022 forecast such as incremental transmission line losses.

Based on the above, the Department concluded that Xcel's forecasted 2022 MISO Day 2 and Day 3 shown in the DOC's (trade secret) Table 5 do not reflect Xcel's 2022 MISO Day 2 and Day 3 charges reflected in its forecasted 2022 FCA. As a result, the Department's IR #3 asked Xcel to explain in detail where its total MISO Day 2 and Day 3 charges were included in its forecasted 2022 FCA cost summary and to provide 2018-2020 actuals for 2017-2019. Xcel replied that:

> MISO Day 2 and Day 3 costs and revenues is the sum of lines 23, 24 and 29 from Part A, Attachment 1, page 1 of 3.
>
> Xcel also provided actual net MISO Day 2 and MISO Day 3 costs and revenues for 2018-2020, as reflected in Table 3.

Table 3 – Xcel's Day 2 and Day 3/ASM charges, 2018-2020, Actual

Year	Day 2	Day 3/ASM	Total
2018	($96,601,239.15)	$30,912,909.52	($65,688,329.63)
2019	($126,376,906.38)	$8,961,055.19	($117,415,851.19)
2020	($104,623,614.70)	$18,474,150.97	($86,149,463.73)

The Department explained that, in prior years' AAA filings, 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% of asset-based margins are now returned to ratepayers. Therefore, no itemization is necessary. As a result, and similar to last year's 2021 Forecast Report, the Department understands that Xcel did not allocate its forecasted 2022 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 2022 FCA rates.

Based on its review and explanations provided by Xcel, the Department concluded that 2022 forecasted MISO Day 2 and Day 3 charges appear reasonable at this time. As a result, the Department recommended that, subject to true-up, Xcel's forecasted charges in these categories be approved to set 2022 FCA rates.

d. Asset-Based Margins

During its review, the Department was unable to locate or identify Xcel's forecasted asset-based margins. Therefore, in IR #4, the Department asked Xcel to explain in detail where its asset-based margins are reflected. Additionally, the Department asked Xcel if the Company was proposing to keep a portion of its asset-based margins and to provide its forecasted asset-based margins for 2022 and actuals for 2018-2020.

Xcel replied that 2021 asset-based margins are reflected in the Net System Costs shown at line 35 of Part A, Attachment 1, page 1 of 3. Asset-based margins are the difference between asset-based Sales Revenues shown at line 29 less the underlying generation fuel costs incurred to make the asset-based sales which are part of the total fuel costs shown at line 27. Xcel Energy's (trade secret) 2021 estimate of asset-based margins is included at line 35. The Company confirmed that it plans to return 100% of asset-based margins. As requested, Xcel also provided 2017-2019 actuals:

Table 4 – Actual Asset-Based Margins, 2018-2020 (in millions)

Year	Amount
2018	$46.4
2019	$40.0
2020	$51.5

Based on the above, the Department concluded that Xcel's forecasted 2022 sales revenue associated with asset-based margins is reflected in line 6 of the Department's (trade secret) Table 2 while the costs or fuel associated with these asset-based margins is included as part of line 1 in the same table.

The Department recommended that Xcel, in reply comments, explain the variance between forecasted 2022 and 2020 asset-based margins.

The Department indicated that it would make its final recommendation regarding Xcel's forecasted 2022 asset-based margins charges after it has reviewed Xcel's reply comments.

e. Outage Costs

The Department, in IR #7, asked Xcel to provide its actual 2018-2020 planned and unplanned MWh's and related power replacement costs and, in its (trade secret) Table 6, the DOC summarized Xcel's planned and unplanned MWh's and related replacement power costs for the 2022 forecast, the 2021 forecast, and the 2018-2020 actuals.

The Department noted that Xcel's forecasted 2022 outage costs and total outage MWh diverge from past years' outage costs. As a result, the Department requested that Xcel, in reply comments, explain the reason for the divergence.

The Department indicated that it would make its final recommendation regarding Xcel's forecasted 2022 outages after it has reviewed Xcel's reply comments.

f. Wind Curtailment Cost Report and Summary

The Department reviewed Xcel's forecasted 2022 wind curtailment costs and because they significantly differ from forecasted 2021 costs, the Department asked Xcel to explain the reasons for the difference.

The Department indicated that it would make its final recommendation regarding Xcel's forecasted 2022 wind curtailment costs after it has reviewed Xcel's reply comments.

g. Other FCA Costs – Community Solar Gardens Above Market Costs

The Department reviewed Xcel's CSG calculations concluded that Xcel's forecasted 2022 CSG above market costs appear to be reasonable and recommended that they be accepted for the purpose of setting 2022 FCA rates.

h. Other FCA Costs – Biomass Buyout Costs

The Department reviewed Xcel's forecasted 2022 biomass buyout costs and noted that forecasted 2022 biomass buyout costs for the remaining two projects are similar to previous years' biomass buyout cots.

Based on its review, the Department concluded that Xcel's forecasted 2022 biomass buyout costs appear to be reasonable and recommended that they be accepted for the purpose of setting 2022 FCA rates.

C. Xcel Energy – Reply Comments

1. Revised Forecast

Xcel noted that, as result of updated inputs, 2022 forecasted fuel costs increased by $43.8 million and the forecasted average rate increased by $1.22/MWh to $31.47/MWh. Xcel's revised 2022 MN-jurisdiction forecasted sales showed a minimal increase to 26,988,335 MWh and revised forecasted costs increased to $849,447,000.

2. Asset-Based Margins

Xcel explained that the reduced margins are a result of higher forecasted load and higher forecasted natural gas prices. Higher load results in less surplus generation available for asset-based sales, and correspondingly less in margins. Additionally, the 2022 natural gas price forecast is 45% higher than average actual gas prices for 2020. Higher gas prices means that the underlying cost of gas-fired generation used to make asset-based sales is higher and; therefore, resulting margins from those units will be lower.

3. Outage Costs

Xcel pointed out that some values in the Department's Table 6 were incorrect. Once corrected, the forecasted 2022 outage costs are in-line with the forecasted outage MWhs and that the 2022 outage forecast is significantly less than the 2021 outage forecast. Xcel provided a (trade secret) corrected Department Table 6 that showed the updated values in red.

4. Wind Curtailment Costs

Xcel agreed with the Department that forecasted 2022 wind curtailment cost are significantly higher those forecasted for 2021. While this is correct, the 2022 forecast is lower than the actual wind curtailment that Xcel currently expects will occur in 2021. This is largely due to higher than expected regional congestion and the resulting negative LMP in the MISO energy market. In its 2021 fuel forecast, Xcel updated the wind curtailment forecast methodology in order to capture the impacts of a significant amount of new generation going into service prior to completion of all required transmission upgrades along with planned transmission outages. However, at the time the 2021 forecast was completed, the impact of the new generation on congestion was not clear, and the scope of the transmission outages occurring in 2021 was unknown. Xcel used a similar methodology for the 2022 forecast and noted that the Company expects higher curtailment to continue for the foreseeable future although lower than the 2021 level.

As shown in Table 5, for 2022, Xcel identified years where a significant amount of new generation went into service prior to completion of all transmission upgrades, excluded the highest curtailment cost year as an outlier and then averaged the curtailment percentage for the remaining highest years where curtailment was greater than 3%. Using that methodology, anticipates a 5.91% curtailment rate for 2022.

Table 5 – Historical Wind Curtailment Costs

Year	% Curtailment
2003	4.24%
2005	5.31%
2007	6.44%
2013	6.30%
2014	5.74%
2015	3.81%
2020	9.52%
Average	5.91%

5. Forecast Input Updates

a. Coal Prices

Xcel updated market prices and escalation assumptions for coal and rail costs. Forecast coal prices have remained relatively flat, while rail and diesel fuel surcharge prices have increased resulting in an overall price increase for 2022. Xcel's Attachment D shows the updated coal prices compared to those assumed in the initial filing. The overall impact on coal generation cost/MWh is an increased 2.0% from the original filing.

b. Natural Gas Prices

Natural gas prices have been updated to NYMEX closing prices as of July 15, 2021. The annual average price of natural gas for Ventura has increased to $3.27/MMBtu, which is 22.4% higher than the original filing. Xcel's Attachment E shows the updated natural gas prices compared to those assumed in the initial filing.

c. Electric Market Prices

The price forecast for MISO LMP has been updated to correspond with the date of the updated natural gas prices. The average annual price has increased to $19.85/MWh, which is 11.9% higher than the original filing. Xcel's Attachment E shows a comparison between original and the updated monthly LMPs.

d. MISO Costs

Xcel updated MISO costs to reflect the most recent historical data available through June 2021. Details on the updated costs by MISO charge type are shown in Xcel's Attachment F.

e. Sales Forecast

Xcel updated its load forecast in PLEXOS to reflect the most current 2022 sales forecast. Xcel's Attachment G shows a comparison between original and the updated sales forecasts.

f. Revised Monthly Rate Summary

Table 4 summarizes the rates by month and by customer class revised to reflect the updated 2022 forecast inputs.

Table 6 – Updated Proposed 2022 Monthly Fuel Clause Rates by Customer Class ($/kWh)

Month	Residential	Commercial & Industrial Outdoor				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.02597	$0.02630	$0.02548	$0.03184	$0.02086	$0.02038
February	$0.03066	$0.03104	$0.03008	$0.03761	$0.02460	$0.02403
March	$0.03268	$0.03309	$0.03206	$0.04009	$0.02623	$0.02562
April	$0.03256	$0.03297	$0.03194	$0.03992	$0.02614	$0.02554
May	$0.03453	$0.03496	$0.03387	$0.04234	$0.02772	$0.02708
June	$0.03979	$0.04029	$0.03903	$0.04880	$0.03194	$0.03119
July	$0.03392	$0.03435	$0.03328	$0.04161	$0.02722	$0.02658
August	$0.03386	$0.03428	$0.03321	$0.04154	$0.02716	$0.02653
September	$0.03328	$0.03369	$0.03265	$0.04081	$0.02671	$0.02609
October	$0.03116	$0.03155	$0.03057	$0.03822	$0.02501	$0.02443
November	$0.02891	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
December	$0.02662	$0.02696	$0.02612	$0.03265	$0.02138	$0.02088

D. Department of Commerce – Response to Reply Comments

1. Sales Forecast

The Department reviewed Xcel's updated 2022 sales forecast and concluded that it appears reasonable. As a result, the Department recommended that, subject to true-up, Xcel's updated 2022 forecasted sales be approved.

2. Asset Based-Margins

Based on the information Xcel provided, the Department concluded that Xcel reasonably explained the changes in its forecasted 2022 asset-based margins. As a result, the Department recommended that, subject to true-up, Xcel's updated 2022 asset-based margins forecast be approved.

3. Outage Costs

The Department agreed with Xcel's correction to its initial Table 6. As a result, the Department agreed with Xcel that the 2022 forecasted outage costs are in-line with the forecasted outage MWhs and that the 2022 outage forecast is significantly less than the 2021 outage forecast.

The Department also reviewed Xcel's updated 2022 outage costs and agreed that the updated 2022 outage forecast remains significantly less than the 2021 outage forecast and is in line with recent historical outage costs. Addition, the Department concluded that Xcel reasonably explained the increase in updated 2022 outage costs compared to its initial forecast (due to higher LMP prices).

Based on the above, the Department concluded that Xcel's updated outage costs forecast appears reasonable. As a result, the Department recommended that, subject to true-up, Xcel's updated 2022 outage costs forecast be approved.

4. Wind Curtailment Costs

Based on the information Xcel provided, the Department concluded that Xcel reasonably explained the changes in its forecasted 2022 wind curtailment costs. As a result, the Department recommended that, subject to true-up, Xcel's updated 2022 forecast of wind curtailment costs be approved.

5. Xcel's Updated 2021 Forecasted FCA Cost Summary

The Department reviewed Xcel's proposed updates to its forecasted 2022 FCA costs and resulting monthly FCA rates and noted that Xcel's proposed cost updates result in a $43.8 million increase to the initial 2022 forecasted FCA costs. Also, as shown in its (trade secret) Table 5, The Department also highlighted the update's impact on Minnesota's FCA Premium.

Based on its review of Xcel's updates, the Department concluded that the proposed updates to the 2022 FCA costs appear reasonable and recommended that, subject to true-up, the Commission approve them for purposes of setting initial monthly FCA rates shown in Table 6 of these briefing papers.

IV.Staff Comments

After reviewing Xcel's and the Department's filings, Staff concurs with the Department's recommendation that Xcel's 2022 FCA forecast, based on revised forecasted sales of 26,988,335 MWh and revised forecasted costs of $849,447,000, be approved.

Staff notes that, despite a minimal change in sales, Xcel's revised 2022 forecasted costs increased almost $44 million, or 5.4%. Part of the increase is attributable to the increase in natural gas prices. However, since Xcel updated its forecast, natural gas prices have continued to increase – Staff's review of NYMEX daily prices revealed that, since August 25, 2021, natural gas prices have been above $4.00 every day and, since September 24, 2021, there have been only 4 days where the price was below $5.00.[6]

Staff does not suggest that a new forecast is necessary; however, Staff is concerned about the possible impact of the higher gas prices which could ultimately result in either an upward adjustment sometime in 2022 (if the 5% threshold for increases is met) or a high under-recovery when the 2022 true-up is filed in 2023. For this reason, the Commission may want to ask Xcel's opinion regarding the likelihood that either of these two scenarios may come to fruition.

[6] Through November 9, 2021. Source: https://www.eia.gov/dnav/ng/hist/rngwhhdd.htm.

V. Decision Alternatives

Forecasted Sales and Fuel Costs

1. Authorize Xcel Energy to implement its 2022 FCA forecast, based on initially forecasted sales of 26,631,660 MWh and forecasted fuel costs of $805,608,000. (Xcel initial forecast)

2. Authorize Xcel Energy to implement its 2022 FCA forecast, based on revised forecasted sales of 26,988,335 MWh and revised forecasted costs of $849,447,000. (Xcel revised forecast, DOC agreed)

Additional Compliance Items

3. Require Xcel, in its 2023 true-up filing, to identify the number and MWhs of planned outages that were originally classified as unplanned. (DOC)

4. 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, 2022. (Staff)