MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	June 24, 2021		Agenda Item 3*
Company	Northern States Power Company d/b/a Xcel Energy		
Docket No.	**E-002/AA-19-293**		
	In the Matter of Xcel Energy's Petition for Approval of its 2020 Annual Fuel Forecast and Monthly Fuel Cost Charges		
Issue	Should the Commission approve Xcel's 2020 Fuel Adjustment Clause true-up?		
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✓ **Relevant Documents**	**Date**
Xcel Energy – True-Up Report (Public and Trade Secret)	March 1, 2021
Department of Commerce – Comments	April 15,2021

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I. Statement of the Issue

Should the Commission approve Xcel's 2020 Fuel Adjustment Clause true-up?

II. Background

On March 1, 2021, Xcel Energy (Xcel, NSP, the Company) made its Annual True-up Compliance Report for its 2020 Annual Fuel Forecast and Monthly Fuel Cost Charges filing seeking recovery of $3.8 million.

On April 15, 2021, the Minnesota Department of Commerce – Division of Energy Resources (Department, DOC) filed comments recommending approval of Xcel's 2021 true-up petition (Petition).

III. Parties' Comments

A. Xcel Energy – True-Up Filing

As summarized in Table 1, Xcel stated that its actual fuel expense of $746.3 million was $49.8 million lower than the approved forecast of $796.1 million. Actual average fuel cost of $27.07/MWh was also lower than the authorized rate of $27.81MWh. A comparison of the actual $746.3 million expense to the actual $741.3 million recovery results in a $5.0 million under-collection, after the $25 million in pandemic relief refund provided in the summer of 2020. Additionally, the authorized November and December 2019 true-up refund was under-refunded by $1.2 million in March and April 2020. Combined, all these factors resulted in a $3.8 million under-recovery for 2020.

Xcel indicated that significant drivers for differences between our 2020 forecast and actuals were:

- reduction in coal production due to a shift from must-commit status to economic dispatch and seasonal operations of coal units;
- a corresponding increase in gas production;
- lower gas and LMP prices than forecast
- less wind production than forecast due to the reduction in size of the Crowned Ridge project, lower production during wind repowering construction, delayed in-service dates of several new wind facilities, and lower wind output than forecast;
- less community solar garden production than forecast;
- lower cost recovery due to lower sales, largely driven by the pandemic;
- higher costs from the MISO market than forecast.

Table 1 - 2020 Fuel Cost and Revenue Comparison Summary, MN Jurisdiction

	Actual ($ in 000's)	Forecast ($ in 000's)	Variance ($ in 000's)	Variance (%)
Total FCA Costs	$746,292	$796,051	($49,759)	-6.3%
MWh Sales	27,564,206	28,627,389	(1,063,184)	-3.7%
FCA Cost in $/MWh	$27.07	$27.81	($0.74)	-2.7%
Fuel Collections – net of $25M relief	$741,262	$796,051	($54,789)	-6.9%
2019 True-up	($1,188)			
(Over) Under Recovery	$3,842			

Despite a worldwide pandemic and other unpredictable occurrences, and after reducing rates mid-year to provide immediate pandemic relief, Xcel only under-collected of 0.5% of total fuel costs.[1] Although the Company's year-end results resulted in a $3.8 million under-collection, in April 2020, the Company estimated a year-end fuel cost over-collection of $25 million, and implemented an authorized rate reduction in June, July, and August to provide immediate relief from economic impacts of the pandemic. At the time, Xcel believed that, even with the early refund, it still would end the year on target; however, several factors impacted the results throughout the year. First, in April, system congestion had been trending in-line with the forecast and there were no indicators that it would increase dramatically, as it did in June through December. Second, Revenue Neutrality Uplift (RNU) charges related to Hurricane Laura in August could not have been anticipated in April. Third, Xcel had not anticipated the full extent the pandemic would have on supply chain and construction timelines for wind projects - Blazing Star I, Blazing Star II, and Freeborn came on-line later than their anticipated April dates. Finally, in early April, Xcel assumed that, by the fourth quarter of 2020, the pandemic would slow and sales levels would return to normal. In reality, COVID-19 infection rates actually worsened after summer, and sales levels did not rebound as expected.

1. Proposed True-Up Rate Factors

Given the relatively small size of the under-recovery, Xcel proposed to collect the $3.8 million in one month, September 2021, as outlined in the Commission's June 12, 2019 Order in docket E-999/CI-03-802. Beginning in October 2021, the previously-approved monthly fuel cost charges would resume for the remaining months of the year. Table 2 shows the specific proposed rates, by customer class.

[1] $3.8M/$746.3M = 0.5%

Table 2 - Proposed September True-Up Factors by Customer Class ($/kWh)[2]

	Residential	C&I, Non-Demand	C&I Demand, Non-TOD	C&I Demand, On-Peak	C&I Demand, Off-Peak	Outdoor Lighting
Proposed True-Up	$0.00177	$0.00179	$0.00174	$0.00217	$0.00142	$0.00139
Approved Rate	$0.02890	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
Total September Rates	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405

Xcel proposed to update the Company web site with the true-up factors by August 1, 2021, or upon issuance of the Commission's Order and to provide customers 30 days' notice of the rate change. Monthly fuel rates are presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

2. Detailed Variance Explanations

a. Company-Owned Hydro Generation

The Company-owned hydro generation forecast was based on a 30-year annual historical average of hydro generation for NSP System plants. There is no fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases. Company-owned hydro facilities experienced higher than normal water flows in 2020, which resulted in more hydro generation than forecast. More hydro generation than forecast reduced generation from other fuel types. Table 3 compares Xcel's hydro forecast to actuals.

Table 3 - Comparison, Hydro Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Hydro	$0	$0	$0	1,245	905	340	$0.00	$0.00	$0.00

b. Company-Owned Wind Generation

Xcel's wind generation forecast model incorporates individual hourly profiles of each Company-owned project based on historical data for projects with at least twelve months of operational data. For new projects that did not yet have annual data, the profiles were based on turbine technology, plant design, and localized weather data.

Actual 2020 Company-owned wind production was less than forecast primarily due to the reduction in size of the Crowned Ridge project and due to pandemic-related supply chain and construction delays for wind projects forecasted to have been placed in-service in 2020: Blazing Star I, Blazing Star II, and Freeborn. Construction delay caused 75% of the variance between the forecasted and actual wind production in 2020. The remainder of the variance was caused by below average wind output over the course of the year. There is no fuel price input for wind generation in the forecast model because wind generation does not require any fuel purchases.

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[2] The true-up factor details are shown in Part A, Attachment 3 and Part A, Attachment 5

Less actual wind generation than forecast increased generation from other fuel types. Table 4 compares Xcel's Company-owned wind forecast to actuals.

Table 4 - Comparison, Company-Owned Wind Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Company-Owned Wind	$0	$0	$0	5,001	5,683	(681)	$0.00	$0.00	$0.00

c. Company-Owned Coal Generation

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. The coal forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted coal rates.

The 2020 forecast modeled all coal units as must-commit year-round. However, early in the year, Xcel offered both the King and Sherco 1 plants into the market on an economic basis. Additionally, in the fall of 2020, the Company implemented its seasonal dispatch plan at the King and Sherco 2 units. As a result, the coal units ran significantly less than forecasted, and actual Company-owned coal generation cost was less than forecast. Table 5 compares Xcel's Company-owned coal forecast to actuals.

Table 5 - Comparison, Company-Owned Coal Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Company-Owned Coal	$182,474	$262,686	($80,212)	8,527	12,160	(3,633)	$21.40	$21.60	($0.20)

d. Company-Owned Wood/RDF Generation

The wood/refuse-derived fuel (RDF) forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted wood/RDF rates. Actual 2020 Company-owned wood/RDF cost was less than forecast due to lower realized wood prices at Bayfront. Table 6 compares Xcel's Company-owned Wood/RDF forecast to actuals.

Table 6 - Comparison, Company-Owned Wood/RDF Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Company-Owned Wood/RDF	$9,013	$11,912	($2,899)	554	453	100	$16.28	$26.27	($9.99)

e. Company-Owned Natural Gas Generation

The Company-owned natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants. Planned maintenance for each unit, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted natural gas rates. 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. Natural gas fuel prices are forecast 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 transport and delivery contracts in place at the time the forecast filing was made.

Actual 2020 Company-owned natural gas generation was higher than forecast due to a combination of the seasonal and economic dispatch of the Company's owned coal units and lower actual gas prices than forecasted. Mild weather and high storage inventory levels contributed to gas prices remaining low in 2020. The injection season ending October ended 5% higher than 2019 and the five-year average. Also, 2020 consumption was down as a result of the COVID-19 pandemic. Given the low natural gas prices, gas generation was used as a replacement for the reduced coal generation. The higher use of gas than forecasted, was off-set by lower gas commodity prices. The fixed gas demand costs were spread over greater volumes, which lowered the average $/MWh, as seen in Table 7.

Table 7 - Comparison, Company-Owned Natural Gas Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Owned Gas (CC)	$120,536	$86,497	$34,040	6,121	2,687	3,434	$19.69	$32.19	($12.50)
Owned Gas (CT)	$18,924	$16,546	$2,378	715	321	394	$26.45	$51.53	($25.07)

f. Company-Owned Nuclear Generation

The Company-owned nuclear forecast includes key modeling parameters, such as monthly operating capacity, based on each individual unit's capability. Planned maintenance for each unit and forced outage rates are based on historical data and expected conditions going forward. Forecasted nuclear fuel price is based on existing nuclear fuel contracts at the time the forecast was filed.

Due to a lower-than-forecast outage rate, actual nuclear generation experienced better-than-forecast performance in 2020. As of March 1, 2021 Monticello operated at 657 continuous days, Prairie Island Unit 1 at 139 days[3] and Unit 2 at 490 days. Over the past several years, plants have experienced improved performance during plant refueling outages, which were completed on time and on budget.[4] Table 8 compares Xcel's nuclear forecast to actuals.

Table 8 - Comparison, Company-Owned Nuclear Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Nuclear	$119,986	$116,954	$3,032	14,677	14,071	606	$8.17	$8.31	($0.14)

g. Purchased Natural Gas Generation

The purchased natural gas forecast includes key modeling parameters, such as operating capacity and heat rate, based on capabilities of the individual plants or according to terms specified in the individual Power Purchase Agreements (PPAs). Planned maintenance for each unit based on the overhaul schedule provided by the PPA counterparty, as well as forced outage rates based on historical data and expected plant conditions going forward, are included in the forecasted purchased natural gas rates.

Actual 2020 purchased natural gas generation was higher than forecast due to a combination of the seasonal and economic dispatch of the Company's owned coal units and lower actual gas prices than forecasted. Mild weather and high storage inventory levels contributed to gas prices remaining low in 2020. The injection season ending October ended 5% higher than 2019 and the five-year average. Also, consumption was down in 2020 as a result of the COVID-19 pandemic. Given the low natural gas prices, gas generation was used as a replacement for the reduced coal generation. The higher use of gas than forecasted, however, was off-set by the lower gas commodity prices. The fixed gas costs were spread over greater volumes, which lowered the average $/MWh, as seen in Table 9.

Table 9 - Comparison, Purchased Natural Gas Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Gas PPAs	$79,565	$54,866	$24,699	3,716	1,995	1,721	$21.41	$27.50	($6.09)

h. Purchased Solar Generation (PPAs)

Each solar PPA is modeled in the forecast with hourly profiles for each project. These profiles are based on historical results from projects with operational data, and prices are based on the terms of each contract.

[3] Following a fall 2020 refueling outage.

[4] Part C, Attachments 4 and 5 provide details on 2020 actual outages, including a comparison of forecast to actual outage costs by unit.

Actual 2020 purchased solar production volumes were lower than forecast for the Aurora, North Star and Marshall facilities.[5] Table 10 compares Xcel's solar PPAs forecast to actuals.

Table 10 - Comparison, Solar PPAs Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Solar PPAs	$41,490	$46,819	($5,329)	589	671	(82)	$70.41	$69.77	$0.64

i. Purchased Solar Generation (Community Solar Gardens)

The community solar gardens (CSG) program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. Xcel identifies current projects to anticipate in-service dates and estimate project completion (in capacity) by month and year. Xcel also forecasts additional applications based on a three-year historical average (removing outliers) to help account for future projects. The program is modeled as one entity rather than individually by garden. The assumed price for the program is based on historical price data for 2018 escalated to 2020, incorporating the Value of Solar (VOS) Rate for projects with 2017 and 2018 VOS vintages forecasted to be in-service in 2020. The market cost of energy from the solar gardens generation is based on the assumed Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers.

The 2020 actual CSG production and cost were lower than forecasted. The CSG forecast is based on assumptions of when community solar projects are completed (or receive permission to operate) and assumptions of how many under which rate vintages will operational during the forecast year. Completion dates can be impacted by weather, construction, and scheduling. In 2020, operation dates were impacted by the pandemic as well. All of these factors had an impact on the actual production and bill credits.[6] Table 11 compares Xcel's CSG forecast to actuals.

Table 11 - Comparison, Community Solar Gardens Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
CSG Market	$151,466	$175,824	($24,358)	1,200	1,351	(151)	$126.27	$130.13	($3.86)
CSG Above Market	$130,420	$143,527	($13,107)						
Total CSG	$281,886	$319,351	($37,465)						

[5] See Part C, Attachment 7 for actual solar PPA production and cost by month and by contract.

[6] See Part C, Attachments 8-10 for more details about actual CGS above-market costs and total number of gardens and subscriptions.

j. Purchased Wind Generation

The wind PPA forecast reflects the hourly profiles for each individual project. For existing PPAs, profiles are based on historical data. For new PPAs, the profiles are based on turbine technology, plant design, and localized weather data. The price for each wind PPA is based on the terms of each contract. Projects for which the Company can allow MISO to curtail output are modeled as curtailable projects, using a 5-year historical average for curtailment costs. Those for which curtailment is not allowed are modeled as non-curtailable projects.

Actual purchased wind generation was less than forecast due to several factors. First, the reduction of the size of the Crowned Ridge PPA project from 300 to 200 MW accounts for 41% of the variance. Second, the Community Wind North, Jeffers, and Mower facilities had reduced production during construction for repowering of the facilities as compared to the forecast. Reduced generation at these facilities accounts for 40% of the variance. The remainder of the variance was primarily caused by below average wind output over the course of the year. Curtailment costs in 2020 were significantly higher than forecast.[7] Table 12 compares Xcel's wind PPAs forecast to actuals.

Table 12 - Comparison, Wind PPAs Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Wind PPAs	$201,803	$222,159	($20,356)	5,539	6,816	(1,277)	$36.43	$32.59	$3.84

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 the 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.

Actual 2020 other purchased generation costs were lower than forecast due to lower volumes and prices for the HERC facility,[8] lower volumes for the Manitoba Hydro facility, and lower prices at the St. Paul Cogeneration facility. Table 13 compares Xcel's other PPAs forecast to actuals.

Table 13 - Comparison, Other PPAs Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance	2020 $/MWh, Actual	2020 $/MWh, Forecast	2020 $/MWh, Variance
Other PPAs	$136,985	$142,057	($5,073)	1,780	1,879	(99)	$76.95	$75.62	$1.33

[7] See Part C, Attachments 1 and 2 for greater detail on wind curtailment results.

[8] The HERC facility was offline for more than a month.

I. Market Purchases and Sales

For forecasting purposes, the PLEXOS simulation can purchase energy from a simulated MISO market if that source of supply results in lower cost than utilization of one of Xcel's dispatchable resources. The simulation can make this decision hourly within the constraints of the modeled system. Additionally, the model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices designed to represent LMP for the NSP system. The sum of these quantities represents the equivalent MISO Day 2 and Day 3 forecasted costs.

Actual 2020 net market purchases and sales were higher than forecast due to high revenue neutrality uplift (RNU) charges resulting from Hurricane Laura and high congestion costs from June through December. The likely contributors to the increase in congestion were: 1) new wind additions on Xcel's system and elsewhere in MISO west; 2) transmission work on Xcel's system to improve wind deliverability; 3) transmission work on other utility systems that impact Xcel's wind generators. Wind additions and transmission work for other utility systems is hard to account for because Xcel has no advance knowledge of this work and very little knowledge of it after the fact. Table 14 compares Xcel's net MISO forecast to actuals.

Table 14 - Comparison, Net MISO Forecast to Actuals

	2020 ($000), Actual	2020 ($000), Forecast	2020 ($000), Variance	2020 GWh, Actual	2020 GWh, Forecast	2020 GWh, Variance
Net MISO	($91,379)	($101,316)	$9,937	(8,979)	(5,283)	(3,696)

Also, Locational Marginal Prices (LMPs) were lower in 2020 than in 2019. MINN.HUB is a weighted average of price nodes in the northwest region of the MISO market, inclusive of Xcel's entire service territory. On average, LMPs at MINN.HUB for the day-ahead market were 22.6% lower in 2020 than in 2019. LMPs have a direct impact on the cost to purchase power to serve NSP load in the MISO market and lower LMPs result in lower market expenses to serve NSP load. However, lower LMPs also reduce the revenue NSP receives from short-term market sales, which also impacts final costs to its customers. Table 15 compares 2020 forecast to actuals by primary MISO charge type.[9]

Table 15 - Comparison, MISO Charge Type Forecast to Actuals ($000s)

Category	Actual	Forecast	Variance
Congestion	$63,309	$34,171	$29,138
FTR	($36,690)	($31,988)	($4,702)
incremental Transmission Losses	($10,111)	($6,087)	($4,024)
RSG/RNU	$11,829	$4,071	$7,758
ASM	($1,359)	($1,568)	$209
Total MISO Charges	$26,978	($1,400)	$28,378

[9] Xcel provided additional MISO charge details in Part B, Attachments 1-14. Additionally, Xcel discussed system congestion in Part B, Attachment 1 and within the wind curtailment report provided as Part C, Attachment 1

m. Retail Sales

Actual Minnesota retail sales in 2020, net of Windsource and Renewable*Connect sales, were 28,141,222 MWh, compared with the 2020 sales forecast of 29,109,898 MWh developed in February 2019 and used in the creation of the 2020 fuel forecast. Thus, actual-to-forecast variance was -968,676 MWh. Contributing factors to the forecast variance include achievement of more DSM savings than forecasted, unforeseen loss of electricity sales due to large commercial and industrial customer relocations/shutdowns of operations, and COVID-19 pandemic impacts from reduced economic and business activity. These factors were in part offset by the positive effects of weather on actual 2020 sales, less Combined Heat and Power (CHP) plant generation than forecasted, and other additional factors. COVID-related estimated sales reduction of 981,588 was the largest contributor to the forecast variance in 2020.

3. Other Items Impacting Total Fuel Cost

a. Costs Excluded from Fuel Costs

Part A, Attachment 3 provides monthly details of the direct assigned WindSource and Renewable*Connect amounts for 2020, which are excluded from total fuel costs.

b. Solar Energy Standard Exclusion

The Commission's January 16, 2018 Order in Docket No. E-002/M-17-425 approved the Company's plan for crediting Solar Energy Standard (SES)-related costs back to SES-exempt customers and to annually recover this amount from the Company's customers through the riders through which solar costs are charged.[10] The 2019 annual FCA recovery of $525,932 is shown in Part A, Attachment 2, line 112, the month the excluded customers were issued their bill credit.[11] The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. This charge was not included in the original forecast given the small amount and in order to include only the exact amount after it is known.

c. Saver's Switch Discount Recover

The Saver's Switch discount is applied during the months of June through September, and therefore the 2020 true-up shows these amounts for those months in our detailed monthly actuals report shown in Part A, Attachment 2, line 113. The amount is also included in the "Other Adjustments" line on Part A, Attachment 1. This charge was not included in the original forecast given the small amount and in order to include only the exact amounts after they are known.

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[10] The Fuel Clause Adjustment (FCA), Renewable Development Fund (RDF) and the Conservation Improvement Program (CIP) Riders.

[11] The Company provided this amount in the June 1, 2020 SES Annual Report filed in Docket No. E-999/M-20-464

d. Asset Based Margins

Table 16 shows that actual 2020 asset-based margins were $4.5 million higher than forecasted.

Table 16 - Actual 2020 Asset-Based Margins ($ millions)

	Revenue	Cost	Margin
Forecast	$119.3	$72.2	$47.1
Actuals	$200.2	$148.6	$51.6
Variance	($80.9)	($76.4)	($4.5)

4. Reporting in Compliance with Minnesota Rules and Other Compliance Items

Xcel provided information attesting to their compliance to the following:

- 7825.2800 Policies and Actions
- 7825.2810 Annual Report of Automatic Adjustment Charges
- 7825.2820 Annual Auditor's Report
- 7825.2830 Annual Five-Year Projection
- 7825.2840 Annual Notice of Reports Availability
- Other items in compliance with various Commission Orders in various dockets.

B. Department of Commerce – Comments

The Department reviewed Xcel's Petition to determine (1) whether the Company's actual 2020 Fuel Clause Adjustment (FCA) costs were reasonable and prudent, (2) whether the Company correctly calculated the 2020 true-up amount and recovery factors for its FCA, and (3) whether the Petition complies with the reporting requirements set forth in the applicable Minnesota rules and Commission orders.

1. Prudency and Reasonableness of Xcel's Actual 2020 Fuel/Purchased Power Costs

The Department noted that Xcel's actual 2020 fuel/purchased power costs were slightly less than the forecasted costs that were approved by the Commission in its July 15, 2020 Order; however, Xcel's actual MWh sales were also lower than forecasted. The combination of these two factors resulted in an under-recovery amount of $3.8 million for the Minnesota jurisdiction.

As shown in Table 1 above, Xcel's 2020 MWh sales were approximately 3.7% less than forecasted and that the Company's total system actual fuel/purchased power costs recoverable through the FCA for 2020 were about 6.3% less than the forecasted 2020 costs. Overall, this results in a 2.7%[12] decrease in the average fuel/purchased power cost on a per MWh basis.

[12] In page 5 of their comments, the Department initially stated that the difference to be a 2.6% decrease; however, Department Table 2 shows and subsequent comments in page 7, the Department states that the difference is 2.7%. Staff believes that the 2.6% was an inadvertent typo.

As summarized in the following Table 17, the cost and offsetting credit/revenue components of the Company's actual and forecasted 2020 fuel/purchased power costs recoverable through the FCA can be broken into several major categories.

Table 17 - Xcel's Forecasted and Actual 2020 FCA Cost Summary ($ in 1000's)

	2020 Actuals	2020 Forecast	Percentage Difference
Xcel's Generating Stations	$450,934	$494,595	-8.8%
Plus: LT Purchased Energy	$459,843	$465,901	-1.3%
Plus: LT CSG	$151,466	$175,824	-13.9%
Plus: ST Market Purchases	$108,791	$18,017	503.8%
Total System Costs	**$1,171,034**	**$1,154,337**	**1.4%**
Less: Sales Revenues	($200,170)	($119,333)	67.7%
Less: CSG-AMC	($130,594)	($143,527)	-9.0%[13]
Less: Windsource	($9,474)	($7,605)	24.6%
Less: Renewable Connect	($6,139)	($6,395)	-4.0%
Net System FCA Costs	**$824,657**	**$877,477**	**-6.0%**
Total System Sales (MWh)	39,033,390	40,469,326	
Less: Windsource (MWh)	(394,474)	(291,602)	
Less: Renewable Connect (MWh)	(182,541)	(190,907)	
Net System Sales (MWh)	**38,456,375**	**39,986,817**	**-3.8%**
MN Jurisdictional Sales (MWh)	28,141,221	29,109,898	
Less: Windsource (MWh)	(394,474)	(291,602)	
Less: Renewable Connect (MWh)	(182,541)	(190,907)	
Net MN Sales (MWh)	**27,564,206**	**28,627,389**	**-3.7%**
MN FCA Costs	$591,397	$628,440	-5.9%
Add: CSG-AMC	$130,420	$143,527	-9.1%
Add: Laurentian Buyout	$13,134	$13,180	-0.3%
Add: Pine Bend Buyout	$113	$120	-5.8%
Add: Benson Buyout	$10,452	$10,783	-3.1%
Other	$777	$0	0.0%
Net MN FCA Costs	**$746,292**	**$796,051**	**-6.3%**
Net MN FCA Costs $/MWh	**$27.07**	**$27.81**	**-2.6%**

[13] Department Table 2 shows this difference to be (1.7%); however, this discrepancy does not affect any underlying totals.

The Department reviewed Xcel's explanations for the variances between its actual and forecasted 2020 fuel/purchased power costs and, based on its review, the Department concluded that Xcel has reasonably explained the differences between its actual and forecasted 2020 fuel/purchased power costs. Therefore, the Department recommends that the Commission find that Xcel's actual 2020 fuel/purchased power costs recoverable through the FCA were reasonable and prudent.

The Department reviewed Xcel's explanations for the variances between its actual and forecasted 2020 retail sales and, based on its review, the Department concluded that Xcel has reasonably explained the differences between its actual and forecasted 2020 retail sales.

2. Xcel's 2020 Fuel Clause Adjustment True-Up

The Department reviewed Xcel's 2020 true-up calculations and resulting rate factors and, based on its review, the Department concluded that Xcel 2020 true-up calculations and resulting rate factors appear reasonable and recommended that they be approved.

3. Compliance with Reporting Requirements

The Department verified that Xcel's Petition included the information required per the following:

- Minnesota Rules 7825.2800 - 7825.2840, as revised on pages 3 - 4 and approved in Point 1 of the Commission's June 12, 2019 Order in Docket No. E-999/CI-03-802.
- Annual FCA true-up general reporting guidelines, as outlined on page 7 and approved in Point 5 of the Commission's June 12, 2019 Order in Docket No. E-999/CI-03-802.
- Annual FCA true-up reporting compliance matrix specific to Xcel, as shown in Attachment 3 of the March 1, 2019 joint comments and approved in Point 7 of the Commission's June 12, 2019 Order in Docket No. E-999/CI-03-802.

The Department did perform a more detailed review of Xcel's Generation Maintenance Expenses and correlation to incremental forced outage costs compliance filing, as discussed below.

In its February 6, 2008 Order in Docket No. E-999/AA-06-1208 (06-1208 Order), the Commission required all electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, to include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case. This requirement stems from the drastic increase in Investor-Owned Utilities' (IOUs) outage costs during FYE06 and FYE07. When a plant experiences a forced outage, the utility must replace, usually through wholesale market purchases, the megawatt hours that plant would have produced had it been operating. The cost of those market purchases flows through the FCA directly to ratepayers. The high level of outage costs in FYE06 and FYE07 raised the issues of whether plants were being maintained appropriately to prevent forced outages, and whether IOUs were spending as much on plant maintenance as they were charging to their customers in base rates. The Commission agreed with the Department and the Large Power Interveners that "utilities have a duty to minimize unplanned facility outages through adequate maintenance and to minimize the costs of scheduled outages through careful planning, prudent timing, and efficient completion of scheduled work." (06-1208 Order at 5)

In Table 18, the Department summarized Xcel's maintenance spending.

Table 18 - Comparison of Generation Maintenance Expense for Xcel ($ Millions)

Test Year	Approved Amount	Actual 2016-2020 Avg	Difference
2016	$184.7	$158.6[14]	$26.1

Due to the link between the level of maintenance expense and forced outages, and due to the different ratemaking incentives that have existed for maintenance expenses versus replacement fuel costs (incentive to minimize operations and maintenance expense between rate cases with little to no incentive to minimize replacement power costs because of flow through recovery), in future FCA true-up filings, the Department intends to continue to monitor the IOUs' actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance amount approved in Xcel's most recent rate cases.

The Department noted that Xcel's average maintenance spending for 2016-2020 was $158.6 million or 14.1% lower than the $184.7 million provided in Xcel's rates. As a result, the Department considered Xcel's incremental forced outage costs for 2020 as reported in Part C, Attachment 5 of the Petition. As shown therein, Xcel's incremental forced outage costs were significantly less than forecasted. As a result of the low incremental forced outage costs for 2020, the Department will accept Xcel's forced outage costs for the 2020 true-up. However, the Department will carefully review Xcel's generation maintenance expense level in the upcoming rate case and correlation to incremental force outage costs in future FCA forecasts and true-up filings.

The Department concluded that Xcel's Petition complies with the applicable reporting requirements and recommends that the Commission approve the compliance reporting portions of the Company's Petition.

4. Conclusion and Recommendations

Based on its review, the Department concluded that (1) Xcel's actual fuel/purchased power costs for 2020 were reasonable and prudent, (2) Xcel correctly calculated its 2020 true-up amount for under-recovered costs of $3.8 million and the resulting rate factors and recommends that the Commission approve them, and (3) Xcel's Petition complies with the applicable reporting requirements. Therefore, the Department recommended that the Commission take the following actions:

- Find that Xcel's actual 2020 fuel/purchased power costs recoverable through the FCA rider were reasonable and prudent for 2020.

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[14] Xcel's actual generation maintenance expense was $187.8 million for 2016, $160.5 million for 2017, $173.4 million for 2018, $140.0 for million 2019, and $131.1 million for 2020.

- Find that Xcel correctly calculated its 2020 true-up amount for under-recovered costs of $3.8 million and the resulting rate factors.
- Approve the compliance reporting portions of Xcel's Petition.

IV.Staff Comments

Staff has reviewed and verified Xcel's calculations and concurs with the Company and the Department's recommendation that Xcel's Petition be approved as filed.

V. Decision Alternatives

Fuel Adjustment Clause True-Up Compliance Filing

1. Accept and approve Xcel's 2020 Fuel Adjustment Clause true-up compliance filing. (Xcel, DOC)

2. Do not accept and approve Xcel's 2020 Fuel Adjustment Clause true-up compliance filing.

True-Up Amount

3. Authorize Xcel to recover the 2020 under-collection of $3.842 million. (Xcel, DOC)

4. Authorize Xcel to recover a different amount.

Timing of True-Up

5. Authorize Xcel to recover the 2020 true-up amount as a one-time surcharge in September 2021. (Xcel, DOC)

6. Authorize Xcel to recover the 2020 true-up amount over a different timetable.