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Minneapolis, MN 55401

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July 31, 2023

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: REPLY COMMENTS
2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-23-153

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the June 29, 2023 Comments of the Minnesota Department of Commerce, Division of Energy Resources in the above-referenced docket. The Company provides additional information as requested by the Department and updates several inputs to our 2024 forecast.

Please note that portions of our Reply and attachments are marked as "Not Public." Certain data is considered to be "not public data" pursuant to Minn. Stat. §13.02, Subd.9, and is "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as this data derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Becky Billings at (612) 702-1730 or becky.j.billings@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosures
cc: Service List

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2024 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-23-153

REPLY COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the Minnesota Department of Commerce - Division of Energy Resources' June 29, 2023 Comments regarding our Petition requesting approval of the 2024 monthly Fuel Clause Adjustment (FCA) rates and associated forecast in the above-referenced docket.

We appreciate the Department's thorough review of the Company's 2024 fuel forecast and proposed rates and its recommendation that the Commission accept the Company's compliance items and many of the inputs used in our forecast. In this Reply, we provide additional information as requested by the Department and update several inputs to our forecast. The updates to model inputs result in a decrease of $7.5 million in forecast 2024 fuel costs, and a decrease of $0.28/MWh to the forecast annual average rate to $38.10/MWh compared to our initial Petition.

REPLY COMMENTS

A. Sales Forecast

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

The 2024 Net System Sales forecast is about 952,000 MWh lower than the 2020-2022 actual average and the Company's 2023 forecast. This is primarily due to the implementation of the long-term Renewable*Connect program scheduled to launch in late 2023, which is projected to net about 636,000 MWh from the gross calendar sales forecast for 2024. The remainder of the difference between the 2024 Net System Sales forecast recent actuals and the 2023 forecast is due to new Demand Side Management (DSM) measures and increased penetration of distributed solar generation.

Table 1 below summarizes the sales information provided in the Company's response to DOC IR 2(a), as revised in our response to DOC Informal IR 1. Table 1 shows the "Calendar Month MWh Sales" forecast for 2024 is comparable to the recent historical average and the 2023 forecast, and only slightly lower (0.68 percent) due to the accumulation of new DSM savings and new solar installations.

Table 1:
Sales Forecast Comparison

	2024	**2020**	**2021**	**2022**	**2020 - 2022 Average**	**Difference Between 2024 and 2020-2022 Average**
Costs in $1,000's	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**	
Net System Sales						
	[PROTECTED DATA BEGINS					**[PROTECTED DATA BEGINS**
Calendar Month MWh Sales		39,033,390	39,923,939	40,363,073	39,773,467	
Less Renewable*Connect Pilot MWh Sales		(182,541)	(177,779)	(183,231)	(181,184)	
Less Renewable*Connect MTM MWh Sales		(394,474)	(440,556)	(493,276)	(442,769)	
Less Renewable*Connect LT MWh Sales						
	PROTECTED DATA ENDS]					**PROTECTED DATA ENDS]**
Net NSP System Calendar Month MWh Sales	38,197,851	38,456,375	39,305,604	39,686,566	39,149,515	(951,664)

Department Table 2 on page 11 of their Comments lists actual "Net System Gen." for years 2020 through 2022 as taken from the Company's response to DOC IR 1(b). The values listed in DOC IR 1(b) were taken from the table provided in response to DOC IR 2(a) at line 35. The table provided for DOC IR 2(a) was developed with the primary focus being to pair costs with generation to determine $/MWh by resource type in order to respond to DOC IR 2(b) and 2(c), which asked the Company to explain $/MWh variances of 5 percent or more by resource type. It was not the focus of the table provided for DOC IR 2(a) to provide a rigorous calculation of total net system generation, but rather, the total listed at line 35 is a simple sum of the generation for the resource types listed above at rows 5 through 33. It is possible that the total net system generation at row 35 for 2020 to 2022 as provided in the response to DOC IR 2(a) is understated due to missing generation for resource types that are not easily identified, such as "behind the meter" generation, in addition to others.

B. Long-Term PPAs

The Department requested the Company to explain the key drivers behind the forecasted increase in energy purchased from "Other" PPAs relative to historical levels. As noted in our initial Petition, the Company's long-term PPA "Other" category consists of PPAs that do not fit within the gas, wind, or solar category (primarily small hydro PPAs, the remaining biomass PPA, and the PPA with Manitoba Hydro). The PPAs with Manitoba Hydro are the key drivers to the forecasted increase in energy purchased from "Other" PPAs as compared to 2020-2022 levels, as noted by the Department. As noted in our initial Petition in Docket No. E002/AA-20-417 at page 14, a new contract with Manitoba Hydro began in 2021. The Commission approved the PPA with Manitoba Hydro in its May 26, 2011 Order in Docket No. E002/M-10-633. As such, 2020 included no energy purchases from the new contract, 2021 included a partial year of energy purchases from the new contract, and 2022 included a full year of energy purchases from the new contract. The step changes from 2020 to 2022 are reflected in the steadily increasing energy for this category, as shown in Department Table 5. Table 2 below shows the change in energy committed to under the contracts with Manitoba Hydro from 2020 to 2024.

Table 2:
Manitoba Hydro Contract Purchases (GWh)

	[PROTECTED DATA BEGINS
2020	
2021	
2022	
2023	
2024	
	PROTECTED DATA ENDS]

D. Asset Based Margins

The Department requested the Company fully explain the difference in forecasted 2024 asset-based margins compared to actual 2022 asset-based margins.

The primary reason that forecasted 2024 asset-based margins are lower than actual asset-based margins for 2022 is forward LMP for the 2024 test year are projected to be substantially lower than actual LMP for 2022. Forward LMP for the 2024 test year are projected to be 31 percent lower than actual LMP for 2022. The average of the 2024 hourly LMP assumed in the forecast is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** versus $45.24/MWh for 2022 actual LMP. LMP has fallen in response to factors that are driving natural gas prices lower in 2024 than were observed for 2022. Prices in 2022 were the high point for natural gas over the last several years, averaging $6.10/MMBtu as compared to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as assumed in our initial Petition. Lower LMPs for 2024 are resulting in forecast asset-based sales revenues that are **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** than actual asset-based sales revenues for 2022. Less revenues translates into less margin.

Another reason asset-based sales margins are forecasted lower for 2024 than actual asset-based margins for 2022 is highlighted in Department Table 4. This table compares generation from Company-owned resources for the 2024 filing and for actual generation in 2022. Department Table 4 shows that for baseload resources coal, wood/RDF, and nuclear; generation is forecast to be **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** lower for 2024 than actual generation for 2022 for the reasons discussed in our initial Petition. The primary driver to the reduction in baseload generation is the retirement of Sherco 2 at the end of 2023. Less baseload generation results in less surplus generation to sell into the MISO market which results in less asset-based sales revenues. In addition, these are some of the lowest cost resources on the Company's system and less asset-based sales from them has a compounding effect on asset-based sales margins.

Table 3 below shows the updated margin forecast based on the updated annual fuel forecast the Company is presenting in these Reply Comments. The change in the margin forecast is driven by the modeling inputs that have changed as part of our forecast update and as discussed more fully in section F below. We note that current market data using forward-looking prices is a better representation of 2024 asset-based margins than historical actual margins.

Table 3:
Asset-Based Margin Updated Reply Forecast ($ millions)

	Revenue	Cost	Margin
[PROTECTED DATA BEGINS			
2023			
			PROTECTED DATA ENDS]

E. Outage Costs

The Department requested that the Company explain and justify the methodology used to calculate unplanned outages for King and Sherco 1 and 3. As discussed in our initial Petition and as noted by the Department in Comments, unplanned outages for coal plants are forecasted based on "expected conditions of the units going forward, including managed decline as plants near retirement." It would be imprudent for the Company to expend large sums of money on capital investment in plants that are nearing retirement. This will naturally result in longer periods of maintenance to keep the plant in an operable condition so that it is available for operation in the highest load winter and summer months.

As assets near a retirement date, usually within a two-year window, we reduce capital and O&M spend. For example, Sherco Unit 2 had an overhaul in 2022 and has a retirement date of December 31, 2023. During this overhaul, the outage scope was reduced to required inspections and minimal preventative maintenance.

As work scopes are reduced for retiring units, there are inherent reliability risks that must be weighed. In the example of Sherco Unit 2, with minimum work performed during the 2022 overhaul, there are risks of increased boiler tube leaks or equipment failures causing derates or a forced outage, reducing energy availability factor (EAF). Xcel Energy's goal is to balance reliability and prudent spend on a retiring asset.

F. Wind Production

The Department noted that the actual and forecasted capacity factors have been consistently lower than assumed and that this trend is expected to continue in 2023 and 2024. The Department requested that the Company provide a discussion and explanation in our Reply Comments.

The capacity factor assumption used in the analysis at the time of acquisition is typically derived from a P50 energy production estimate, which means that over the life of the wind farm there is a 50 percent chance that the assumption will be exceeded. Actual values will vary from year to year and be both lower and higher than the assumed capacity factor. We note that, while the actual capacity factors have generally been lower than the assumed capacity factors, in some cases the actual capacity factors are higher.

In addition, wind curtailment has been increasing across the MISO footprint, as discussed further below. The analysis conducted in our acquisition filings generally included curtailment in the modeling. For example, the analysis on the impact of the 1550 MW wind portfolio noted that:

> *In the Strategist model, dump energy represents the amount of excess energy that could not be utilized by the dispatch simulation. From 2019 through 2030, this accounts for 3.8% percent of the total energy produced by the proposed projects when MISO market interactions were modeled.*[1]

Therefore, at the time of the acquisition, an estimate of potential curtailment was part of the modeling analysis. The dump energy analyzed in the model is not included in the capacity factor estimates, which are inputs into the model. For repowered wind projects, the amount of incremental curtailment included in the modeling was minimal. We also note that Grand Meadow and Nobles received significant curtailment after the 10 year PTC window expired, resulting in them being bid into the MISO market at higher cost than other wind farms. While curtailment has been increasing across the system and has been higher then modeled at the time of acquisition, we expect the impact of curtailment to be reduced as additional upgrades to the transmission system are completed.

In addition, we believe the P50 estimate is the best estimate to use as a base assumption. Lower capacity factor sensitivities are typically evaluated as part of the analysis at the time of acquisition to assess the risk that actual capacity factors may be lower than assumed.

G. Wind Curtailment Costs

With respect to forecasted 2024 wind curtailment costs for Company-owned wind, the Department recommends that the Company provide an explanation for the significant change in forecasted 2024 curtailments over 2021 and 2022 actuals for Blazing Star 1, Blazing Star 2, Borders, Courtenay, and Pleasant Valley wind farms.

As noted by the Department on page 29, curtailment at owned wind projects has been increasing since 2020. Department Table 10 lists ten projects that went in-service in

[1] Docket No. E002/M-16-777, Xcel Energy Supplement (March 16, 2017).

2020 or later, which is the main driver to increasing curtailment for owned wind projects over this period. In addition, two projects have been repowered, further contributing to greater wind generation and, as a result, greater curtailment. The increase in curtailment for specific projects noted by the Department is a result of the curtailment modeling technique used in the PLEXOS simulation. All owned wind projects are treated nearly equally in the simulation from a cost offer standpoint and the simulation curtails only enough wind to balance supply and demand without regard to which projects are being curtailed. Therefore some projects are curtailed at a higher level, while some show zero curtailments, as shown in Department Table 10. Our expectation is that some curtailment will occur at all Company-owned projects throughout the course of a year; however, this is not something that can be achieved using the curtailment model that is in the PLEXOS simulation. From 2020 to 2022 there is considerable variation from year to year in the curtailment for each owned wind project listed in Department Table 10. This is something that would be nearly impossible to replicate with any degree of accuracy in a forecast model. Furthermore, from a production cost standpoint, project by project variation will not impact total production costs since the owned wind projects are all modeled at zero cost.

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

H. Jurisdictional Allocation

The Department requests the Company provide additional information regarding our jurisdictional allocation proposal in Reply Comments. Please see Table 4 below and Attachment H for comparisons of jurisdictional allocation of fuel costs under the proposed methodology compared to the methodology used in the past in the FCA forecast proceedings.

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Table 4: Comparison of Jurisdictional Allocation Methodologies

	Actual 2020	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
NSPM Interchange Energy Allocator	**83.36%**	**83.37%**	**82.99%**	**82.40%**	**82.35%**
				[PROTECTED DATA BEGINS	
NSP System Fuel & Purchased Power (MN Definition) (before direct assignments)	$824,656,729	$1,055,539,341	$1,154,505,952		
Current NSPM:					
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to NSP System costs					
MN Jur Allocation (Calendar Sales)	$591,408,165	$758,155,890	$824,281,061		
ND Jur Allocation (Billed Sales)	$45,468,548	$56,643,924	$63,092,970		
SD Jur Allocation (Billed Sales)	$46,244,552	$59,087,583	$64,640,906		
Total NSPM Jur Allocation	$683,121,265	$873,887,397	$952,014,937		
					PROTECTED DATA ENDS]
Total NSPM Jur Allocation - Current Method	**82.84%**	**82.79%**	**82.46%**	**82.13%**	**81.70%**
NSPM Under/(Over)	$4,278,364	$6,065,310	$6,097,668	$3,271,975	$7,021,545
Proposed NSPM:				**[PROTECTED DATA BEGINS**	
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to costs after I/A					
MN Jur Allocation (Calendar Sales)	$595,082,071	$763,512,307	$829,609,136		
ND Jur Allocation (Billed Sales)	$45,748,690	$57,019,650	$63,501,266		
SD Jur Allocation (Billed Sales)	$46,533,297	$59,486,355	$65,067,044		
Total NSPM Jur Allocation	$687,364,058	$880,018,312	$958,177,446		
					PROTECTED DATA ENDS]
Total NSPM Jur Allocation - Proposed Method	**83.35%**	**83.37%**	**82.99%**	**82.40%**	**82.35%**
NSPM Under/(Over)	$35,571	($65,605)	($64,841)	$0	$0

The Company's jurisdictional allocation proposal is reasonable, as it appropriately assigns Minnesota customers costs based on the FERC-governed Interchange Agreement. The proposed method of allocation results in minor over- or under-recoveries for each year, which are due to the allocation of costs to North Dakota and South Dakota using billing month sales.

The Department also requested information regarding jurisdictional allocators used in the Company's electric rate case and rider proceedings. We provide the following information in response to this request. Based on the Company's Cost Assignment and Allocation Manual (CAAM), the cost causation allocators used for electric production expense or plant investment is a twelve-month coincident peak demand or energy, depending on the type of expense or plant investment. If the expense is variable in nature, energy is used to make the assignment to jurisdiction. If it is determined that the expense or plant investment exists to support NSPM's infrastructure and is fixed in nature, the demand allocator is used to make the assignment to jurisdiction.

We consider energy-related expenses to be production variable, therefore an energy allocator is used for all appliable variable electric production expenses. We follow this same method in both base rates and riders as noted by mechanism below:

- Base rates – Jurisdiction allocation of variable electric production expenses are allocated using the MN 12-month CP Energy (Electric Energy) allocator. Variable electric production expenses and plant investments are also subject to the Interchange Agreement between NSPM and NSPW and are allocated using the monthly energy requirements (Interchange Electric Energy allocator) or 36-month CP demands (Interchange Electric Demand allocator), respectively.
    - The 2022 to 2024 MYRP allocators were as follows:
        - Electric Energy – 86.7239% for all years
        - Interchange Electric Demand – 83.7474%, 83.6077% and 83.4708% in 2022, 2023 and 2024 respectively.
        - Interchange Electric Energy - 82.3059%, 82.1443% and 82.1445% in 2022, 2023 and 2024 respectively.
- Renewable Energy Standard (RES) Rider – There are no energy-related expenses included in the RES Rider. Plant investments are allocated consistent with base rates above. Attachment H shows RES Rider allocators used by year starting on line 14. The rider filing uses a forecasted allocation that is updated or trued-up to the final actual allocation for each applicable year.
- Transmission Cost Recovery (TCR) Rider – There are no energy-related expenses or plant investments included in the TCR Rider. The TCR Rider uses demand allocators for the fixed expenses and plant investments (MN 12-month CP Demand and Interchange Electric Demand). Distribution-Grid Modernization costs recovered through the TCR Rider are allocated to NSPM's State Jurisdictions (Minnesota, North Dakota and South Dakota) using direct assignment, or use a general, intangible, customer count, or meter count allocation.
- Conservation Improvement Program (CIP) and Renewable Development Fund (RDF) Riders – Most costs are direct assigned to jurisdiction based on the specific project/program. No CIP costs exist in ND. No RDF costs exist for ND or SD. In some instances, RDF costs are subject to the Interchange Agreement and are shared with NSPW.

Table 5 below reflects the context provided above for the multi-year rate plan (MYRP):

Table 5: 2022 to 2024 MYRP Allocation

1		2022	2023	2024
2	Allocations			
3	MN 12-month CP Energy	86.7239%	86.7239%	86.7239%
4	Interchange Electric Demand	83.7474%	83.6077%	83.4708%
5	Interchange Electric Energy	82.3059%	82.1443%	82.1445%
6				
7	Energy related costs			
8	Plant Investments (Line 3 * Line 4)	72.6290%	72.5079%	72.3891%
9	Expenses (Line 3 * Line 5)	71.3789%	71.2387%	71.2389%

I. Forecast Input Updates

As outlined in the procedural schedule for fuel clause reform, utilities are able to update their forecast inputs with their July Reply Comments. We have updated the following inputs, which we consider to be significant cost drivers to any year's fuel forecast, and those that should be updated to remain true to an objective of reform to provide the most accurate forecast of test year costs that we are able at the time of Commission review.

The updates to model inputs result in a decrease of $7.5 million in forecast 2024 fuel costs, and a decrease of $0.28/MWh to the forecast annual average rate to $38.10/MWh. We provide Attachments A, B, and C to summarize the updated forecast, which correspond to Part A, Attachments 1, 2, and 3 of the May 1 forecast filing.

1. *Coal Pricing*

Market prices and escalation assumptions for coal and rail were updated for our Reply filing. Forecast coal generation prices have increased for this Reply update and are compared to our original filing in Attachment D. The overall impact on coal generation cost/MWh is an increase of 1.1 percent as compared to our original filing.

2. *Natural Gas Prices*

Natural gas prices have been updated to NYMEX closing prices as of July 12, 2023. The annual average price of natural gas for Ventura has decreased to $3.72/MMBtu, which is 4.8 percent lower than our original filing. A comparison of the updated monthly natural gas prices to the prices assumed in our original May 1 filing is shown in Attachment E.

3. Electric Market Prices

Our price forecast for MISO LMP has been updated to correspond with the date of the updated natural gas prices from market close on July 12, 2023. The average annual price has decreased to $30.02/MWh, which is 3.5 percent lower than our original filing. A comparison of the updated monthly LMPs to the LMPs assumed in our original May 1 filing is shown in Attachment E.

4. MISO Costs

We updated MISO costs based on the most recent historical data available through June 2023. Details on the updated costs by MISO charge type are shown in Attachment F. The net of MISO Day 2 and Day 3 costs and revenues in the reply forecast is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** resulting in a **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** from the initial filing forecast of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. The primary driver of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** as shown in Attachment F.

5. Maintenance Updates

We have updated planned maintenance for 2024 for our Reply filing to reflect the latest planned schedules for our generating plants. The primary change is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Our 2024 updated replacement power cost estimate for this reply filing is provided as Attachment G.

J. Revised Monthly Rate Summary

Tables 6 and 7 below summarizes the rates by month and by customer class revised to reflect the updated 2024 forecast inputs using the Class Ratio Adjustment. See Attachment A, pages 1, 2, 3a and 3b for details.

Table 6:
Revised 2024 Monthly Fuel Clause Rates by Customer Class ($/kWh)

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

Table 7:
Revised 2024 Monthly Fuel Clause Rates for
C&I General Time of Use Service Pilot ($/kWh)

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

We will make a tariff compliance filing within 10 days of the Commission Order in this docket to reflect the final approved rates.

Conclusion

The Company appreciates this opportunity to submit its Reply to the Department's review of our 2024 fuel forecast. Through this Reply, we have provided additional information in response to the questions raised by the Department and have updated several inputs to the 2024 forecast. We respectfully request that the Commission accept and approve Xcel Energy's 2024 Annual Fuel Forecast and resulting proposed monthly fuel cost charges for the months January-December 2024 as updated and supplemented by this Reply.

Dated: July 31, 2023

Northern States Power Company

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

Protected Data is shaded.

Line #	*Costs in $1,000's*	1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	2024 Total
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens (CSG)	$14,599	$21,710	$29,260	$33,691	$39,318	$34,634	$40,978	$39,184	$27,579	$21,727	$14,741	$11,842	$329,263
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	MISO Market Charges													
25	Subtotal													
26														
27	**Total NSP System Costs**													
28														
29	**Less Sales Revenue**													
30	**Less Solar Gardens - Above Market Cost**	($9,373)	($14,161)	($24,060)	($27,191)	($32,281)	($26,925)	($28,912)	($28,158)	($20,958)	($16,641)	($11,564)	($9,156)	($249,377)
31	**Less Renewable*Connect Pilot**													
32	**Less Renewable*Connect MTM**													
33	**Less Renewable*Connect LT**													
34														
35	**NSP Net System Costs Excluded CSG Above Market**													
36	**& Renewable*Connect Costs**													
37														
38	**Interchange Agreement Energy Req Allocator**													
39														
40	**NSPM System Costs Excluded CSG Above Market**													
41	**& Renewable*Connect Costs**													
42														
43	**NSPM System Calendar Month MWh Sales**													
44														
45	**Less Renewable*Connect Pilot MWh Sales**													
46	**Less Renewable*Connect MTM MWh Sales**													
47	**Less Renewable*Connect LT MWh Sales**													
48														
49	**Net NSPM System Calendar Month MWh Sales**													31,199,824
50														
51	**NSPM System Cost in cents/kWh**													
52														
53	**Minnesota Jurisdiction MWh Sales**													
54														
55	**Less Renewable*Connect Pilot MWh Sales**													
56	**Less Renewable*Connect MTM MWh Sales**													
57	**Less Renewable*Connect LT MWh Sales**													
58														
59	**Net MN MWh Sales**													26,842,355
60														
61	**MN Fuel Cost**													
62	**Solar Gardens - Above Market Cost**	$9,373	$14,161	$24,060	$27,191	$32,281	$26,925	$28,912	$28,158	$20,958	$16,641	$11,564	$9,156	$249,377
63	**Laurentian Buyout costs**													
64	**Pine Bend Buyout Cost**													
65	**Benson Buyout Cost**													
66														
67	**Forecast MN FCA Costs**													$1,022,748
68														
69														
70	**Forecast MN FCA Cost in cents/kWh**													**3.810**
71														
72														
73	**Forecast MN FCA Cost in $/MWh**													38.10

PROTECTED DATA ENDS]

Proposed 2024 Monthly Fuel Clause Charges ($/KWh)

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

Proposed 2024 Monthly Fuel Clause Charges ($/KWh)

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

Northern States Power Company
Electric Utility - State of Minnesota
Monthly Fuel Clause Charge January 2024 - December 2024

Docket No. E002/AA-23-153
Reply Comments
Corresponds to May 1 Part A, Attachment 1
Attachment A - Page 3 of 3

Protected Data is shaded.

Month Fuel Cost Charges Applied to Customer Billing	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Months
FORECASTED COST OF FUEL													
	[PROTECTED DATA BEGINS												
[1] Forecasted MN Cost in $1,000's													**$1,022,748**
[2] Forecasted Minn. Retail Sales Subject to FCC *													26,842,355
[3] Forecasted MN Cost in cents/kWh [1]/[2]*100													**3.810¢**
												PROTECTED DATA ENDS]	
Class FAF Ratio													
[4] Residential FAF Ratio	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177
[5] C&I Non-Demand FAF Ratio	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305
[6] C & I Demand Non-TOD FAF Ratio	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984
[7] C & I Demand TOD On-Peak FAF Ratio	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486
[8] C & I Demand TOD Off-Peak FAF Ratio	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166
[9] Outdoor Lighting FAF Ratio	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976
2023 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[10] Residential [3]*[4]													
[11] C & I Non-Demand [3]*[5]													
[12] C & I Demand Non-TOD [3]*[6]													
[13] C & I Demand TOD On-Peak [3]*[7]													
[14] C & I Demand TOD Off-Peak [3]*[8]													
[15] Outdoor Lighting [3]*[9]													
MN Retail MWh Subject to FCA *													
[16] Residential													
[17] C & I Non-Demand													
[18] C & I Demand Non-TOD													
[19] C & I Demand TOD On-Peak													
[20] C & I Demand TOD Off-Peak													
[21] Outdoor Lighting													
[22] Total													26,842,355
2024 Class Fuel Cost Revenues in $1,000's													
[23] Residential [10]*[16]/100													
[24] C & I Non-Demand [11]*[17]/100													
[25] C & I Demand Non-TOD [12]*[18]/100													
[26] C & I Demand TOD On-Peak [13]*[19]/100													
[27] C & I Demand TOD Off-Peak [14]*[20]/100													
[28] Outdoor Lighting [15]*[21]/100													
[29] Total [23]+[24]+[25}+[26]+[27]+[28]													$1,020,905
[30] **2024 Cost vs Revenue Diff in $1,000's** [1]-[29]													
[31] **2024 Cost vs Revenue Diff in $1,000's** [30]													
[32] **MN Retail MWh Subject to FCA *** [22]													
[33] **Monthly Class Ratio Adjustment** [31]/[32]*100													
													PROTECTED DATA ENDS]
2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[34] **Residential** [10]/100+[33]/100	**$0.03306**	**$0.03623**	**$0.03891**	**$0.04221**	**$0.04485**	**$0.04184**	**$0.04244**	**$0.04143**	**$0.03947**	**$0.03812**	**$0.03454**	**$0.03223**	
[35] **C & I Non-Demand** [11]/100+[33]/100	**$0.03348**	**$0.03668**	**$0.03939**	**$0.04274**	**$0.04541**	**$0.04236**	**$0.04297**	**$0.04195**	**$0.03996**	**$0.03860**	**$0.03497**	**$0.03263**	
[36] **C & I Demand Non-TOD** [12]/100+[33]/100	**$0.03244**	**$0.03554**	**$0.03817**	**$0.04141**	**$0.04400**	**$0.04104**	**$0.04163**	**$0.04064**	**$0.03872**	**$0.03740**	**$0.03389**	**$0.03162**	
[37] **C & I Demand TOD On-Peak** [13]/100+[33]/100	**$0.04054**	**$0.04443**	**$0.04772**	**$0.05177**	**$0.05499**	**$0.05131**	**$0.05207**	**$0.05082**	**$0.04841**	**$0.04676**	**$0.04236**	**$0.03953**	
[38] **C & I Demand TOD Off-Peak** [14]/100+[33]/100	**$0.02655**	**$0.02909**	**$0.03123**	**$0.03389**	**$0.03601**	**$0.03359**	**$0.03405**	**$0.03325**	**$0.03168**	**$0.03060**	**$0.02773**	**$0.02587**	
[39] **Outdoor Lighting** [15]/100+[33]/100	**$0.02594**	**$0.02841**	**$0.03051**	**$0.03310**	**$0.03518**	**$0.03281**	**$0.03326**	**$0.03248**	**$0.03094**	**$0.02989**	**$0.02708**	**$0.02527**	

* Excluded Renewable*Connect MWh

2024 Proposed Costs verses Revenues		
2023 Class Fuel Cost Revenues in $1,000's	**[PROTECTED DATA BEGINS**	
[40] Residential [34]*[16]		
[41] C & I Non-Demand [35]*[17]		
[42] C & I Demand Non-TOD [36]*[18]		
[43] C & I Demand TOD On-Peak [37]*[19]		
[44] C & I Demand TOD Off-Peak [38]*[20]		
[45] Outdoor Lighting [39]*[21]		
[46] Total [40]+[41]+[42}+[43]+[44]+[45]		$1,022,760
[47] Total Forecasted MN Costs [1]		$1,022,748
[48] **2023 Cost vs Revenue Diff in $1,000's** [47]-[46]		($12)
		PROTECTED DATA ENDS]

Northern States Power Company Docket No. E002/AA-23-153
Electric Utility - State of Minnesota Reply Comments
Monthly Fuel Clause Charge January 2024 - December 2024 Corresponds to May 1 Part A, Attachment 1
C&I General Time of Use Service Pilot Program *Protected Data is shaded.* Attachment A - Page 4 of 4

	Monthly Fuel Cost Charges Applied to Customer Billing	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Months
	Forecasted Cost of Fuel													
		[PROTECTED DATA BEGINS												
[1]	Forecasted MN Cost in $1,000's													**$1,022,748**
[2]	Forecasted Minn. Retail Sales Subject to FCC *													26,842,355
[3]	**Forecasted MN Cost in cents/kWh** [1]/[2]*100													**3.810¢**
													PROTECTED DATA ENDS]	
	Class FAF Ratio													
[4]	C&I Demand General TOU Peak Ratio	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617	1.2617
[5]	C&I Demand General TOU Base Ratio	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708	1.0708
[6]	C&I Demand General TOU Off-Peak Ratio	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579	0.5579
	2024 Monthly Fuel Cost Charges	**[PROTECTED DATA BEGINS**												
[7]	**C&I Demand General TOU Peak** [3]*[4]													
[8]	**C&I Demand General TOU Base** [3]*[5]													
[9]	**C&I Demand General TOU Off-Peak** [3]*[6]													
[10]	**Monthly Class Ratio Adjustment**													
														PROTECTED DATA ENDS]
	2024 Proposed Monthly Fuel Cost Charges in $/kWh													
[11]	**C&I Demand Generl TOU Peak** [7]+[10]	**$0.04096**	**$0.04489**	**$0.04822**	**$0.05231**	**$0.05557**	**$0.05184**	**$0.05262**	**$0.05136**	**$0.04892**	**$0.04725**	**$0.04281**	**$0.03994**	
[12]	**C&I Demand General TOU Base** [8]+[12]	**$0.03478**	**$0.03811**	**$0.04093**	**$0.04441**	**$0.04718**	**$0.04401**	**$0.04465**	**$0.04359**	**$0.04152**	**$0.04011**	**$0.03634**	**$0.03391**	
[13]	**C&I Demand General TOU Off-Peak** [9]+[13]	**$0.01818**	**$0.01990**	**$0.02136**	**$0.02319**	**$0.02465**	**$0.02298**	**$0.02326**	**$0.02273**	**$0.02166**	**$0.02093**	**$0.01896**	**$0.01770**	

* Excluded Renewable*Connect MWh

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

Protected Data is shaded.

Line #		1/1/2024	2/1/2024	3/1/2024	4/1/2024	5/1/2024	6/1/2024	7/1/2024	8/1/2024	9/1/2024	10/1/2024	11/1/2024	12/1/2024	2024 Total
1	*Energy in GWhs*													
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	102.5	152.4	205.5	236.6	276.1	243.2	287.7	275.1	193.6	152.6	103.5	83.1	2,311.9
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System GWh**													
27														
28	**Less Sales GWh**													
29	**Less Renewable*Connect Pilot GWh**													
30	**Less Renewable* Connect MTM GWh**													
31	**Less Renewable* Connect LT GWh**													
32														
33	**Net System GWh**													42,176.3

PROTECTED DATA ENDS]

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

Protected Data is shaded.

Line #														
1	*$/MWh*	**1/1/2024**	**2/1/2024**	**3/1/2024**	**4/1/2024**	**5/1/2024**	**6/1/2024**	**7/1/2024**	**8/1/2024**	**9/1/2024**	**10/1/2024**	**11/1/2024**	**12/1/2024**	**2024 Total**
2														
3	**Own Generation**													
4	Fossil Fuel	**[PROTECTED DATA BEGINS**												
5	Coal													
6	Wood/RDF													
7	Natural Gas CC													
8	Natural Gas & Oil CT													
9	Subtotal													
10														
11	Hydro													
12	Solar													
13	Wind													
14														
15	Nuclear Fuel													
16														
17	**Purchased Energy**													
18	LT Purchased Energy (Gas)													
19	LT Purchased Energy (Solar)													
20	Community Solar*Gardens	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42	$142.42
21	LT Purchased Energy (Wind)													
22	LT Purchased Energy (Other)													
23	ST Market Purchases													
24	Subtotal													
25														
26	**Total System $/MWh**													
27														
28	**Less Sales**													
29	**Less Solar Gardens - Above Market Cost**	$91.43	$92.89	$117.11	$114.94	$116.93	$110.72	$100.48	$102.34	$108.23	$109.08	$111.72	$110.12	$107.87
30	**Less Renewable*Connect Pilot**													
31	**Less Renewable* Connect MTM**													
32	**Less Renewable*Connect LT**													
33														
34	**Net System $/MWh**													$25.58

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
Coal Pricing - Updated July 2023

Docket No. E002/AA-23-153
Reply Comments
Attachment D - Page 1 of 1

Protected Data is shaded.

2024 Forecast Year

[PROTECTED DATA BEGINS

		Total Price							**Coal Price**							**Rail Price**							**Diesel Price**					
July 31 Reply Filing																												
May 1 Filing																												
Change																												

PROTECTED DATA ENDS]

Northern States Power Company Docket No. E002/AA-23-153
Electric Utility - State of Minnesota Reply Comments
Gas and LMP Pricing - Updated July 2023 Attachment E - Page 1 of 1

Protected Data is shaded.

2024 Forecast Year

	Ventura $/MMBtu		
	May 1 Filing	**July 31 Reply Filing**	**Change**
1/1/2024	6.68	6.26	
2/1/2024	6.61	6.22	
3/1/2024	3.37	3.33	
4/1/2024	2.92	2.93	
5/1/2024	2.83	2.80	
6/1/2024	2.95	2.86	
7/1/2024	3.15	3.05	
8/1/2024	3.18	3.09	
9/1/2024	3.03	2.95	
10/1/2024	3.14	3.08	
11/1/2024	3.86	3.48	
12/1/2024	5.18	4.59	
Average	3.91	3.72	-0.19
			-4.8%

[PROTECTED DATA BEGINS

LMP $/MWh		
May 1 Filing	**July 31 Reply Filing**	**Change**
31.11	30.02	-1.09
		-3.5%

PROTECTED DATA ENDS]

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Northern States Power Company
Electric Utility - State of Minnesota
MISO Costs - Updated July 2023
2024 Forecast Year

MISO Charge Category	May 1 Filing	July 31 Reply Filing	Change
(in $1000s)	**[PROTECTED DATA BEGINS**		
Congestion			
FTR			
Incremental Transmission losses			
RSG/RNU			
ASM			
TOTAL			

PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Replacement Power Costs Estimate

		Planned							Unplanned						
Unit	Type	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
		[PROTECTED DATA BEGINS													
Black Dog 25	NSP CC														
High Bridge 1x1	NSP CC														
High Bridge 2x1	NSP CC														
Riverside 1x1	NSP CC														
Riverside 2x1	NSP CC														
Allen S King	NSP Coal														
Sherburne 1	NSP Coal														
Sherburne 2	NSP Coal														
Sherburne 3	NSP Coal														
Monticello	NSP Nuclear														
Prairie Island 1	NSP Nuclear														
Prairie Island 2	NSP Nuclear														
Total															
Combined															

PROTECTED DATA ENDS]

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Northern States Power Company Docket No. E002/AA-23-153
Electric Utility - State of Minnesota Reply Comments
Jurisdictional Allocation - Comparison of Past Methodology to Proposed Metholology Attachment H - Page 1 of 1

Protected Data is shaded.

[PROTECTED DATA BEGINS

	Actual 2020	Actual 2021	Actual 2022	Forecast 2023	Forecast 2024
NSPW Billed Mwh	6,622,253	6,756,319	6,954,598		
NSPW Calendar Mwh	6,610,509	6,788,154	6,966,792		
MN Jurisdiction Billed Mwh	28,163,178	28,757,104	28,962,043		
ND Jurisdiction Billed Mwh	2,134,822	2,126,168	2,177,305		
SD Jurisdiction Billed Mwh	2,153,808	2,189,309	2,215,704		
	32,451,809	33,072,581	33,355,052		
MN Jurisdiction Calendar Mwh	28,141,220	28,814,202	28,994,856		
ND Jurisdiction Calendar Mwh	2,127,670	2,132,533	2,180,366		
SD Jurisdiction Calendar Mwh	2,153,991	2,189,071	2,221,059		
	32,422,880	33,135,806	33,396,281		
Total MN Adj (Windsource/Renewable Connect)	(577,015)	(618,336)	(676,507)		
System Billed Mwh	38,497,047	39,210,564	39,633,143		
System Calendar Mwh	38,456,374	39,305,624	39,686,566		
NSPM Interchange Energy Allocator	**83.36%**	**83.37%**	**82.99%**	**82.40%**	**82.35%**
NSP System Fuel & Purchased Power (MN Definition) (before direct assignments)	$824,656,729	$1,055,539,341	$1,154,505,952		
Current NSPM Allocators:					
MN Jur Allocation (Calendar Sales-System)	71.68%	71.73%	71.35%	70.84%	70.27%
ND Jur Allocation (Billed Sales-System)	5.55%	5.42%	5.49%	5.59%	5.66%
SD Jur Allocation (Billed Sales-System)	5.59%	5.58%	5.59%	5.67%	5.75%
	82.82%	82.73%	82.43%	82.10%	81.68%
Proposed NSPM Allocators:					
MN Jur Allocation (NSPM Calendar Sales (NSPM Base))	86.56%	86.71%	86.55%	86.29%	86.03%
ND Jur Allocation (NSPM Billed Sales (NSPM Base))	6.70%	6.55%	6.66%	6.81%	6.93%
SD Jur Allocation (NSPM Billed Sales (NSPM Base))	6.76%	6.75%	6.78%	6.90%	7.04%
	100.01%	100.01%	99.99%	100.00%	100.00%
Current NSPM:					
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to NSP System costs					
MN Jur Allocation (Calendar Sales)	$591,408,165	$758,155,890	$824,281,061		
ND Jur Allocation (Billed Sales)	$45,468,548	$56,643,924	$63,092,970		
SD Jur Allocation (Billed Sales)	$46,244,552	$59,087,583	$64,640,906		
Total NSPM Jur Allocation	$683,121,265	$873,887,397	$952,014,937		
Total NSPM Jur Allocation - Current Method	**82.84%**	**82.79%**	**82.46%**	**82.13%**	**81.70%**
NSPM Under/(Over)	$4,278,364	$6,065,310	$6,097,668	$3,271,975	$7,021,545
Proposed NSPM:					
Fuel (NSPM After Interchange)	$687,399,629	$879,952,707	$958,112,604		
Recovery Methods: Apply allocators to costs after I/A					
MN Jur Allocation (Calendar Sales)	$595,082,071	$763,512,307	$829,609,136		
ND Jur Allocation (Billed Sales)	$45,748,690	$57,019,650	$63,501,266		
SD Jur Allocation (Billed Sales)	$46,533,297	$59,486,355	$65,067,044		
Total NSPM Jur Allocation	$687,364,058	$880,018,312	$958,177,446		
Total NSPM Jur Allocation - Proposed Method	**83.35%**	**83.37%**	**82.99%**	**82.40%**	**82.35%**
NSPM Under/(Over)	$35,571	-$65,605	-$64,841	$0	$0

PROTECTED DATA ENDS]

CERTIFICATE OF SERVICE

I, Ella Giefer, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. **E002/AA-23-153**

Dated this 31st day of July 2023

/s/

____

Ella Giefer
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties	450 Syndicate St N Ste 35 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_23-153_AA-23-153
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_23-153_AA-23-153
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Allen	Barr	allen.barr@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Ste 1400 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_23-153_AA-23-153
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
George	Crocker	gwillc@nawo.org	North American Water Office	5093 Keats Avenue Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_23-153_AA-23-153
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-153_AA-23-153
Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Christopher	Droske	christopher.droske@minneapolismn.gov	City of Minneapolis	661 5th Ave N Minneapolis, MN 55405	Electronic Service	No	OFF_SL_23-153_AA-23-153
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_23-153_AA-23-153
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_23-153_AA-23-153
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Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_23-153_AA-23-153
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Shubha	Harris	Shubha.M.Harris@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401 - FL 8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_23-153_AA-23-153
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_23-153_AA-23-153
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC	PO Box 270636 Superior, CO 80027-9998	Electronic Service	No	OFF_SL_23-153_AA-23-153
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Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_23-153_AA-23-153
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_23-153_AA-23-153
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_23-153_AA-23-153
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 E 7th St St Paul, MN 55106	Electronic Service	No	OFF_SL_23-153_AA-23-153
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_23-153_AA-23-153
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_23-153_AA-23-153
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_23-153_AA-23-153
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Christa	Moseng	christa.moseng@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 Saint Paul, MN 55164-0620	Electronic Service	No	OFF_SL_23-153_AA-23-153
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_23-153_AA-23-153
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_23-153_AA-23-153
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	Yes	OFF_SL_23-153_AA-23-153
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Scott	Strand	SStrand@elpc.org	Environmental Law & Policy Center	60 S 6th Street Suite 2800 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_23-153_AA-23-153
Carla	Vita	carla.vita@state.mn.us	MN DEED	Great Northern Building 12th Floor 180 East Fifth Street St. Paul, MN 55101	Electronic Service	No	OFF_SL_23-153_AA-23-153
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_23-153_AA-23-153
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153
Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_23-153_AA-23-153
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_23-153_AA-23-153