414 Nicollet Mall
Minneapolis, Minnesota 55401

October 31, 2023

— Via Electronic Filing —

Steve Kahl, Executive Secretary
North Dakota Public Service Commission
State Capitol, 600 East Boulevard
Bismarck, ND 58505-0480

Re: November 2023 Fuel Cost Rider Rates
Case No. PU-23-011

Dear Mr. Kahl:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric Fuel Cost Rider (FCR) rates for November 2023.

The table below shows the FCR rates by customer class:

November 2023	FCR rate/kWh
Residential	\$0.02258
C & I Non-Demand	\$0.02266
C & I Demand	\$0.02253
C & I Demand Time of Day (On-Peak)	\$0.02725
C & I Demand Time of Day (Off-Peak)	\$0.01877
Outdoor Lighting	\$0.01748

See Attachment A for the supporting calculations of these rates.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2020 rate proceeding (Case No. PU-20-441), new base rates were implemented on October 1, 2021. The new Service Category Ratios listed below became effective when actual October

2021 fuel and purchased energy costs were first passed through in December 2021 FCR rates:

Service Category Ratios	Effective Oct 1, 2021
Residential	1.0094
C & I Non-Demand	1.0129
C & I Demand	1.0069
C & I Demand Time of Day (On-Peak)	1.2181
C & I Demand Time of Day (Off-Peak)	0.8392
Outdoor Lighting	0.7813

MID-CONTINENT INDEPENDENT SYSTEM OPERATOR (MISO) CHARGES

Day 2 Market

Pursuant to the Commission's Orders in Case Nos. PU-05-147 and PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs in the FCR. The current FCR rates reflect MISO Day 2 charge types including three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.[1] Consistent with these Orders and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the November 2023 FCR the net MISO Day 2 costs for September 2023 as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is $14,135,578 which is the net of many items.[2] Pursuant to the above-mentioned Orders, the Company also provides more detailed information in Attachment C of this filing to support the calculation of the MISO Day 2 costs.

Ancillary Services Market (ASM)

With the implementation of the MISO ASM on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the FCR, pursuant to Commission guidance in Case No. PU-09-016. Consistent with the MISO Order and the required "net" accounting of ASM costs and revenues, we reflect in the November 2023 FCR rates the net MISO ASM costs for September 2023 as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is $5,568,297, which is the net of many items. The detailed records are contained in Attachment C.

[1] Previously embedded in other FTR charge types.

[2] This excludes Schedule 24 charge and includes Schedule 49 charge.

CUSTOMER REFUNDS AND CREDITS

Asset Based Margins

Under the terms of the Revised Second Amended Settlement adopted by the Commission on February 26, 2014 (retroactive to January 1, 2014), the Company began passing through to North Dakota customers 100 percent of wholesale asset-based margins.[3] Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), credits derived from any disallowed resources (Company-owned or power purchase agreements) after January 1, 2021 are excluded from this sharing. Because of the nature of the calculation, the adjustment to remove the margins will only be done once the MISO S105 settlements are complete. Margins of $1,807,533 have been included as an offsetting credit in this month's FCR. See Attachments B and F.

Non-Asset Based Margins

Beginning in February 2011, 50% of the prior year retail share of Non-Asset Based Margins is credited to North Dakota customers via the November FCR. The North Dakota retail share of the 2022 Non-Asset Based Margin credit amount is $134,902. With the prior month true up the total applicable amount to the November 2023 FCR is $69,323. See Attachments B and F.

Sales of Renewable Energy Credits (RECs)

Pursuant to the Commission Order in Case No. PU-10-19, the Company was authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the North Dakota jurisdictional share of net proceeds generated by the sale back to customers through the FCR. Under the Commission's February 26, 2014 Order Adopting Settlement, the share of the net proceeds to customers was increased to 100 percent. Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), credits derived from any disallowed resources or power purchase agreements after January 1, 2021 are excluded from this sharing. There were no sales of disputed resources or power purchase agreements RECs sale during the current reporting period. With the prior month true up, the REC sales credit for the current reporting period is $363,085. See Attachments B and F.

PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement, the following procedural changes reflected in the Revised Second Amended Settlement were made to provide additional transparency regarding cost recovery of renewable energy projects or purchases:

- The Company will notify the Commission in its monthly FCR filings of any new renewable projects, qualifying in part or whole for FCR cost recovery, whose costs are included in the calculation of FCR rates;

[3] Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

- The Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year;
- If, within 6 months of the filing of the annual summary, the Commission does not initiate a review of the new PPA(s) listed, the Company will be allowed to recover the related costs for the duration of the contract(s); and
- Renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will not be included in the FCR unless and until the Commission has granted an Advance Determination of Prudence (ADP) for the resource.

The following PPAs have been excluded from the FCR as a result of Commission review and disapproval:

1. School Sisters of Notre Dame (0.8 MW)[4]
2. Marshall Solar LLC (62.25 MW)[5]
3. North Star Solar PV (100 MW)[6]
4. Aurora Distributed Solar (100 MW)[7]

It should be noted that MISO market energy purchases are not subject to the above requirements.

NEGOTIATED AGREEMENT PURCHASED POWER AGREEMENT EXCLUSIONS

Pursuant to the Commission's March 9, 2016 Order Accepting the Negotiated Agreement (Case Nos. PU-12-813, *et. al.*), the costs and volumes of 15 Community-Based Energy Development (C-BED) and two solar PPAs are to be excluded from the calculation of the Company's monthly FCR rates. Dragonfly Solar PPA was added to the exclusion list in September 2018 (see table below). The Company completed the closing process for the acquisition of the Jeffers and Community Wind North projects from Longroad Energy effective December 31, 2020. The PPAs with Jeffers Wind 20 LLC, North Community Turbines LLC and North Wind Turbines LLC were terminated effective December 31, 2020.

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[4] Case No. PU-16-458, ORDER REGARDING 2015 POWER PURCHASE AGREEMENT COSTS, October 5, 2016.

[5] The 62.25 MW Marshall Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No. PU-14-810).

[6] The 100 MW North Star Solar project is one of the three projects in the Company's proposed 187 MW solar energy portfolio that was not approved by the Commission (Case No. PU-14-810).

[7] The Company's application for an advance determination of prudence for the proposed 100 MW Aurora Distributed Solar project was denied (Case No. PU-15-95).

1. Jeffers Wind 20, LLC (50 MW)	10. North Wind Turbines (15 MW)
2. Big Blue (36 MW)	11. Valley View Transmission (10 MW)
3. Community Wind South (Zephyr) (30 MW)	12. Uilk Wind Farm (4.5 MW)
4. Ridgewind Power Partners LLC (25 MW)	13. Hilltop Power (2 MW)
5. Adams Wind Generations (20 MW)	14. Winona County Wind (1.5 MW)
6. Danielson Wind Farms (20 MW)	15. Woodstock Municipal Wind, LLC (0.8 MW)
7. Ewington Energy Systems LLC (20 MW)	16. Outland Solar (2 MW)
8. Grant County Wind, LLC (20 MW)	17. Best Power (St. Johns Solar) (0.4 MW)
9. North Community Turbines (15 MW)	18. Dragonfly Solar, LLC (0.8 MW)

See Attachment D for more details concerning the calculation of the replacement energy costs (i.e., the system average) used to effectuate the impact of disallowing these resources.

NSP-OWNED WIND RESOURCE PRICING ADJUSTMENT

Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the Company owned Community Wind North, Jeffers wind and Rock Aetna wind facilities are repriced at average system cost and recovered in the monthly FCR charge. The effect of the repricing is included in Attachment D.

MISO Revenue Exclusion for Disputed Resources

Pursuant to the Commission's August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the MISO wholesale revenues of disputed resources are excluded from the calculation of the Company's monthly FCR after January 1, 2021. The September 2023 system amount is $1,745,073 as shown on line 12 of Attachment B.

COMMUNITY SOLAR GARDENS COST TREATMENT

In our response to NDPSC Staff Data Request No. 1 submitted in Case No. PU-17-12 on August 23, 2017, the Company committed to including additional information in our FCR filings regarding the costs related to the Minnesota Community Solar Gardens (CSG) program production and cost assignment to North Dakota. As shown on Attachment H, North Dakota customers do not pay the actual costs of CSG production but are instead allocated a portion of the "market" costs for the same energy produced by the CSG program. As a result, North Dakota customers are insulated from all CSG costs.

BIOMASS PPA TERMINATION COST RECOVERY

Pursuant to the Commission's June 27, 2018 Orders in Case No. PU-17-270 (ADP – Benson, Pine Bend, and Hennepin Energy Recovery Center (HERC) PPA terminations), Case No. PU-17-271 (Deferred Accounting for Benson, Pine Bend, and HERC PPA termination), and Case No. PU-17-322 (Deferred Accounting for Laurentian PPA terminations), this month's FCR includes $50,613 in termination cost recovery. The itemized cost recovery information is found in Attachment F.

MONTHLY FCR RATE CALCULATION AND SUPPORTING DOCUMENTS

This filing includes the following supporting documents:

- Attachment A – Summary of Monthly FCR Rate Calculation
- Attachment B – Four Month Fuel Cost Rider Costs
- Attachment C – MISO Day 2 and ASM Settlement Charges
- Attachment D – Replacement Costs for Disallowed Resources and Residential Bill Impact
- Attachment E – Derivation of FCR True-Up Adjustment
- Attachment F – Summary of Credits and Other Adjustment Included in the FCR
- Attachment G – Historical Trend of FCR Charges (Residential)
- Attachment H – Community Solar Garden Costs Allocated to North Dakota FCA

If you have any questions regarding the information contained in this filing, please contact Alex Nisbet at 701-241-8632 or Alex.J.Nisbet@xcelenergy.com.

Sincerely,

/ s /

LISA PETERSON
DIRECTOR, REGULATORY PRICING & ANALYSIS

cc: Alex Nisbet

Enclosures

Northern States Power Company
Electric Utility - State of North Dakota

Summary of Fuel Cost Rider Rates - November 2023

	System Fuel and Purchased Energy Costs	4 Month Total	
1	NSP System Fuel/Energy Costs (Retail)	$336,712,223	Att B, p. 1, line 6
2	MISO Charges	$80,212,623	Att B, p. 1, line 10
3	Disallowed Resource Costs	($6,340,859)	Att B, p. 1, line 14
4	Net NSP System Costs	$410,583,987	

	ND Fuel and Purchased Energy Costs	4 Month Total	
5	NSP System MWh Sales (Retail)	14,337,245	Att B, p. 1, line 16
6	Average NSP System Cost per kWh	2.864¢	line 4 / line 5/10
7	ND MWh Sales (Retail)	716,614	Att B, p. 1, line 18
8	ND Fuel & Purchased Energy Costs	$20,522,091	line 6 x line 7*10

	Credits and Other Adjustments Applicable to ND	September 2023	
9	Wholesale Margins Credit	($1,876,856)	Att B, p. 1, line 20,21
10	REC Sales Proceeds Credit	($363,085)	Att B, p. 1, line 22
11	Biomass PPA Termination Costs	$50,613	Att B, p. 1, line 23
12	Net Credits and Other	($2,189,328)	

	Over/Under Recovered Costs	Amount	
13	True-Up Amount for September 2023	($2,301,169)	Att E, p.1, line 19

	ND Net FCR Costs	4 Month Total.	
14	Net FCR Costs	$16,031,594	line 8+line 12+line 13
15	Net FCR Cost per kWh	2.237¢	line 14 / line 7/10

Fuel Cost Rider Rate By Class

	Customer Class	**ND Cost of Fuel/kWh**	**Cust. Class Ratio[1]**	**FCR Rate**
16	Residential	2.237¢	1.0094	**2.258¢**
17	C & I Non-Demand	2.237¢	1.0129	**2.266¢**
18	C & I Demand Non-TOD	2.237¢	1.0069	**2.253¢**
19	C & I Demand TOD On-Peak	2.237¢	1.2181	**2.725¢**
20	C & I Demand TOD Off-Peak	2.237¢	0.8392	**1.877¢**
21	Outdoor Lighting	2.237¢	0.7813	**1.748¢**

[1] See Fuel Cost Rider Tariff.

Northern States Power Company
Electric Utility - State of North Dakota

4 Month Fuel Cost Rider Costs - November 2023

		(A)	(B)	(C)	(D)	(E)
	Fuel & Purchased Energy Costs	Jun-23	Jul-23	Aug-23	Sep-23	4 Month Total
1	Account 151 - Fossil Fuel	$36,795,609	$46,074,657	$44,983,367	$29,930,245	$157,783,878
2	Account 518 - Nuclear Fuel	$8,358,040	$10,183,003	$10,504,441	$9,632,783	$38,678,267
3	Account 555 - Purchased Power[1]	$57,919,806	$75,239,651	$69,467,948	$55,818,423	$258,445,828
4	Sub-Total NSP Sys Energy Costs	$103,073,455	$131,497,311	$124,955,756	$95,381,451	$454,907,973
5	Exclude Costs of InterSystem Sales	($21,970,159)	($39,541,971)	($33,992,005)	($22,691,615)	($118,195,750)
6	Total Sys Fuel & Purch Energy	$81,103,296	$91,955,340	$90,963,751	$72,689,836	$336,712,223
	MISO Charges					
7a	Day 2 Market	$14,493,447	$6,707,396	$18,085,107	$14,226,083	$53,512,033
7b	MISO Excess Congestion Credit	$0	$0	$0	$0	$0
8	Exclude Schedule 24	($101,741)	($93,678)	($110,291)	($90,505)	($396,215)
9	Ancillary Services Market	$4,292,970	$4,915,221	$12,320,316	$5,568,297	$27,096,805
10	Total MISO Charges	$18,684,676	$11,528,939	$30,295,132	$19,703,876	$80,212,623
	Disallowed Resources Costs[2]					
11	Exclude Costs of Disallowed PPAs	($6,715,957)	($6,688,328)	($6,372,210)	($5,352,396)	($25,128,892)
12	Exclude MISO Revenues	$2,467,471	$2,834,543	$2,357,175	$1,745,073	$9,404,261
13a	Replacement Energy Costs	$3,283,662	$3,109,073	$3,683,736	$2,997,929	$13,074,399
13b	Proxy Price Adjustment (St. Paul Cogen)	($291,369)	($1,157,114)	($1,010,793)	($1,231,350)	($3,690,626)
14	Net Disallowance	($1,256,194)	($1,901,827)	($1,342,092)	($1,840,745)	($6,340,859)
15	Net NSP System Costs	$98,531,778	$101,582,452	$119,916,791	$90,552,967	$410,583,987
	ND Fuel and Purchased Energy Costs	Jun-23	Jul-23	Aug-23	Sep-23	4 Month Total
16	NSP System Sales (Retail)	3,429,602	3,538,774	3,892,160	3,476,709	14,337,245
17	Avg. NSP System Cost per kWh	2.873¢	2.871¢	3.081¢	2.605¢	2.864¢
18	ND Sales (Retail)	188,693	169,267	190,167	168,487	716,614
19	ND Fuel & Purchased Energy Costs	$5,421,150	$4,859,656	$5,859,045	$4,389,086	$20,522,091
	Other Adjustments and True-Up					
20	Asset-Based Margins	($2,314,822)	($1,870,581)	($2,346,342)	($1,807,533)	($8,339,278)
21	Non-Asset-Based Margins	($52,273)	($92,665)	($39,612)	($69,323)	($253,874)
22	REC Sales Proceeds (100%)	($1,401,151)	($443,779)	($1,032,167)	($363,085)	($3,240,182)
23	Biomass PPA Termination Costs[3]	$1,045,986	$50,911	$50,762	$50,613	$1,198,273
24	Net Credits and Other	($2,722,260)	($2,356,114)	($3,367,358)	($2,189,328)	($10,635,061)

[1] Excludes demand-related expenses, MN Windsource energy costs, and MN Solar Gardens energy costs. October amounts included an one-time credit compensated by a third-party for its building of a new wind project that falls within the restricted boundary of Company's Lake Benton project.
[2] Excludes costs exceeding average system costs for 21 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813) & other dockets (Dragonfly Solar). Includes Company owned Jeffers Wind, Community Wind North and Rock Aethna wind costs where replacement costs are repriced based on based average system cost. St. Paul Cogen PPA proxy price adjustment based on LMP.
[3] Benson and Laurentian PPAs.

Northern States Power Company
Electric Utility - State of North Dakota

MISO Day 2 Settlement Charges - November 2023

		FERC Account	Retail Expense (Rev)
	Energy and Losses		
1	Day Ahead Asset Energy - Energy	555	$10,114,382
2	Day Ahead Asset Energy - Losses	555	$3,752,459
3	Day Ahead Financial Bilateral Transaction Loss	555	$2,058
4	Day Ahead Non-Asset Energy - Energy	555	($8,282,605)
5	Day Ahead Non-Asset Energy - Losses	555	$252,933
6	Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	($2,058)
7	Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	$0
8	Real Time Asset Energy - Energy	555	($493,280)
9	Real Time Asset Energy - Losses	555	$46,334
10	Real Time Distribution of Losses	555	($571,798)
11	Real Time Financial Bilateral Transaction - Losses	555	$0
12	Real Time Losses Rebate on Carve-out Grandfathered Agreements	555	$0
13	Real Time Net Inadvertent Distribution	555	$31,951
14	Real Time Non-Asset Energy - Energy	555	$53,757
15	Real Time Non-Asset Energy - Losses	555	($0)
16	**Total Energy and Losses**		$4,904,132
	Congestion		
17	Day Ahead Asset Energy - Congestion	555	$11,908,620
18	Day Ahead Financial Bilateral Transaction - Congestion	555	$38,918
19	Day Ahead Non-Asset Energy - Congestion	555	($2,947,323)
20	Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	($38,918)
21	Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	$0
22	Real Time Asset Energy - Congestion	555	$12,419
23	Real Time Financial Bilateral Transaction - Congestion	555	$0
24	Real Time Congestion Rebate - Carve-out Grandfather Agreements	555	$0
25	Real Time Non-Asset Energy - Congestion	555	($0)
26	**Total Congestion-Related**		$8,973,716
	Financial Transmission Rights (FTR)		
27	FTR Hourly Allocation	555	($447,307)
28	FTR Monthly Allocation	555	($225,925)
29	FTR Transaction	555	$0
30	FTR Yearly Allocation	555	$0
31	FTR Full Funding Guarantee	555	($162,522)
32	FTR Guarantee Uplift	555	$162,188
33	FTR Monthly Transaction	555	$0
34	**Total Financial Transmission Rights Charges**		($673,566)

MISO Day 2 Settlement Charges - November 2023

		FERC Account	Retail Expense (Rev)
	Uplift		
35	Real-Time Revenue Neutrality Uplift	555	$1,639,185
36	**Total Uplift**		$1,639,185
	Revenue Sufficiency Guarantee (RSG)		
37	Day Ahead RSG Distribution	555	$77,675
38	Day Ahead RSG Make Whole Payment	555	($5,518)
39	Real time RSG First Pass Distribution	555	($4,930)
40	Real Time RSG Make Whole Payment	555	($5,225)
41	Real Time Price Volatility Make Whole Payment	555	($49,922)
42	**Total Revenue Sufficiency Guarantee**	555	$12,080
	Market Administration[1]		
43	Day Ahead Market Administration	575.7	$479,254
44	Real Time Market Administration	575.7	$52,766
45	FTR Market Administration	575.7	$20,567
46	**Total Market Administration**		$552,586
	Virtual Energy		
47	Day Ahead Virtual Energy	555	$0
48	Real Time Virtual Energy	555	$0
49	**Total Virtual Energy**	555	$0
	Auction Revenue Rights (ARR)		
50	ARR FTR Auction Transactions	555	$11,797,849
51	ARR Monthly Revenue	555	($11,807,204)
52	ARR Stage 2 Distribution	555	($848,713)
53	ARR Monthly Infeasible Revenue	555	$38,789
54	**Total Auction Revenue Rights**		($819,280)
	Other Miscellaneous		
55	Real Time Miscellaneous	555	($453,275)
56	Real Time Uninstructed Deviation	555	$0
57	**Total Other Miscellaneous**		($453,275)
58	**Total MISO Day 2 Charges**		**$14,135,578**

[1] Excludes Schedule 24 costs, which are recovered in base rates.

MISO Ancillary Services Markets (ASM) Charges - November 2023

		FERC Account	Retail Expense (Rev)
	Procurement		
1	Day Ahead Regulation	555	($191,615)
2	Day Ahead Spinning Reserve	555	($121,306)
3	Day Ahead Supplemental Reserve	555	($50,449)
4	Real Time Regulation	555	($1,044)
5	Real Time Spinning Reserve	555	$63,764
6	Real Time Supplemental Reserve	555	$53,001
7	**Total Procurement**		($247,649)
	Resource Energy		
8	Real Time Excessive Energy	555	$8,062
9	Real Time Excessive Energy - Congestion	555	$0
10	Real Time Excessive Energy - Losses	555	$0
11	Real Time Non-Excessive Energy	555	$6,100,430
12	Real Time Non-Excessive Energy - Congestion	555	($431,374)
13	Real Time Non-Excessive Energy - Losses	555	($90,379)
14	Real Time Net Regulation Adjustment	555	($11,446)
15	**Total Resource Energy**		$5,575,293
	Cost Distribution		
16	Real Time Regulation Reserve Cost Distribution	555	$135,041
17	Real Time Spinning Reserve Cost Distribution	555	$87,504
18	Real Time Supplemental Reserve Cost Distribution	555	($7,692)
19	**Total Cost Distribution**		$214,854
	Penalties		
20	Real Time Excessive/Deficient Energy Deployment	555	$25,799
21	Real Time Contingency Reserve Deployment Failure	555	$0
22	**Total Penalties**		$25,799
23	**Grand Total ASM Charges[2]**		**$5,568,297**

[2] Included new MISO ASM charges:
DA Short Term Reserve Amount
RT Short Term Reserve Amount
RT Short Term Reserve Distribution Amount
Short Term Reserve Deployment Failure Charge
Short Term Reserve Procurement
RT ST Reserve Gen Alloc Reclass

Northern States Power Company
Electric Utility - State of North Dakota

Derivation of September 2023 Replacement Costs for Disallowed Resources & Residential Bill Impact

		NSP System	ND Allocation[1]	ND Jurisdiction	
	Fuel & Purchased Energy Costs				
1	Fuel & Purch Energy Costs (Retail)[2]	$91,162,363	4.8462%	$4,417,877	
	Disallowed PPA Costs				
2	Disallowed C-BED Wind PPAs[3]	($1,612,692)	4.8462%	($78,154)	
3	Disallowed Solar PPAs	($3,243,379)	4.8462%	($157,179)	
4	Curtailment Payments	($496,325)	4.8462%	($24,053)	
5	Total Exclusion	($5,352,396)		($259,386)	Line 2 +Line 3+Line 4
6	Adjusted Fuel & Purchased Energy Costs	$85,809,967	4.8462%	$4,158,491	Line 1 - line 5
	Energy Sales (Billing Mo.)				
7	MWh Energy Sales	3,476,709	4.8462%	168,487	Att B Line 16,18 (D)
8	Disallowed Resources MWh Energy Sales	(115,084)	4.8462%	(5,577)	
9	Adjusted MWh Sales (Billing Mo.)	3,361,625		162,910	
	Replacement Costs				
10	Avg. Sys. Cost w/o Disallowed Resources ($/MWh)	$25.53		$25.53	Line 6 / line 9
11	Replacement Cost for Disallowed Resources[4]	$2,937,663		$142,360	Line 8 x line 10
12	Adjusted Fuel & Purch Energy Costs (Retail)	$85,809,967	4.8462%	$4,158,491	Line 6
13	Exclude MISO Revenues	$1,745,073	4.8462%	$84,569	Att B Line 12
	(Includes Jeffers, Community Wind North & Rock Aetna)				
14	Net System Cost Excludes MISO Revenues	$87,555,040		4,243,060	Line12 + Line 13
15	Adjusted MWH Sales (Billing Mo.)	3,361,625		162,910	Line 9
16	Adjusted Average System Cost ($/MWh)	$26.05		$26.05	Line 14/Line 9
17	Net Replacement Cost	($2,997,929)		($145,281)	Line 16 * Line 8
	ND Residential Bill Impact				
18	Cost Exclusion	($5,352,396)		($259,386)	Line 5
19	Exclude MISO Revenues	$1,745,073		$84,569	Line 13
20	Net Replacement Costs	($2,997,929)		($145,281)	Line 17
21	Net Impact of Disallowance and Repricing	($6,605,252)		($320,098)	Line 18+Line 19+line 20
22	FCR Impact of Disallowance & Repricing/kWh			-0.190¢	Line 21 / line 7/10
23	Residential Monthly Bill Impact (750 kWh)			($1.42)	Line 22 x 750

[1] Based on ratio of ND billed energy sales to NSP System billed sales as shown in line 7
[2] Cost before disallowed resources excluded and includes MISO charges, less St. Paul Cogen proxy price adjustment.
[3] Originally 15 C-BED PPAs. Two of the C-BED PPAs, Jeffers Wind and Community Wind North, became Company owned facilities in January 2021.
[4] Reflects the average system fuel and purchased energy cost per kWh (excluding the disallowed PPAs, Jeffers Wind, Community Wind North and Rcok Aetna wind costs and volumes) applied to the energy volumes of the disallowed PPAs.

Northern States Power Company
Electric Utility - State of North Dakota

Derivation of FCR True-Up Adjustment - September 2023

Cost to Recover in September 2023

		[a] Sep Sys Fuel Cost/kWh[1]	[b] Sep ND MWh Sales[2]	Amount	
1	Fuel & Purchased Energy Costs	2.605¢	168,487	$4,389,086	
2	True Up Amount for July 2023			($2,051,687)	
3	Net Costs			$2,337,399	Line 1+Line 2

Cost Recovered in September 2023

	Fuel & Purchased Energy	Sales	Amount	
4	(i) Residential	53,921	$1,535,103	
5	(ii) C & I Non-Demand	6,829	$194,994	
6	(iii) C & I Demand Non-TOD	60,251	$1,709,914	
7	(iv) C & I Demand TOD On-Peak	17,616	$605,084	
8	(v) C & I Demand TOD Off-Peak	28,547	$675,668	
9	(vi) Outdoor Lighting	1,323	$29,086	
10	Total	168,487	$4,749,850	
	True-Up Obligation			
11	(i) Residential	53,921	($37,127)	
12	(ii) C & I Non-Demand	6,829	($4,196)	
13	(iii) C & I Demand Non-TOD	60,251	($36,008)	
14	(iv) C & I Demand TOD On-Peak	17,616	($15,417)	
15	(v) C & I Demand TOD Off-Peak	28,547	($18,554)	
16	(vi) Outdoor Lighting	1,323	$20	
17	Total	168,487	($111,282)	
18	Net Recovery		$4,638,568	Line 10 + Line 17

Over/Under Recovered Costs

19	True-Up Amount for September 2023	($2,301,169)	Line 3 - Line 18

[1] Reflects the average for the month of September 2023.

[2] Actual ND sales in month of September 2023.

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Summary of Credits and Other Adjustments Included in the FCR by Month

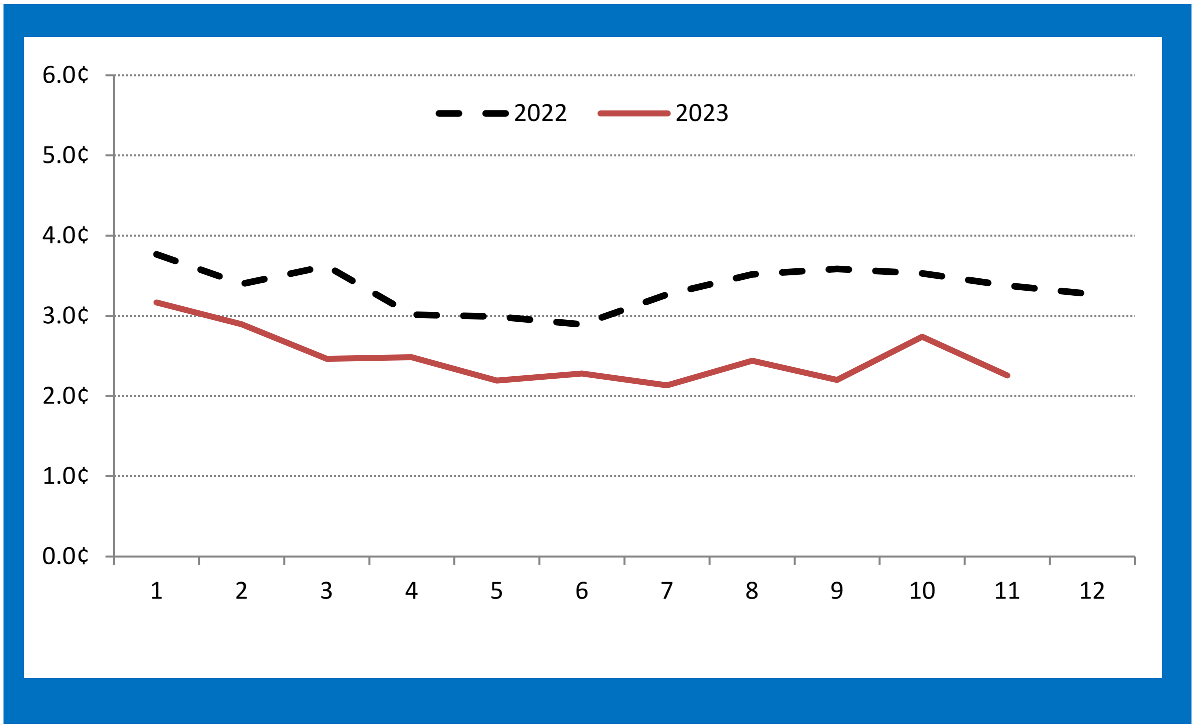
Margin Sharing and REC Sales Credits in Monthly FCR

	Month	Asset Based Margins	Non-Asset Based Margins		Renewable Energy Credits	Total
1	January	($2,212,492)	($218,593)		($419,663)	($2,850,748)
2	February	($3,212,835)	($83,891)		($78,616)	($3,375,342)
3	March	($1,843,835)	($158,626)		($298,607)	($2,301,068)
4	April	($2,579,084)	($68,772)		($69,186)	($2,717,042)
5	May	($1,577,507)	($124,409)		($603,264)	($2,305,180)
6	June	($2,314,822)	($52,273)		($1,401,151)	($3,768,246)
7	July	($1,870,581)	($92,665)		($443,779)	($2,407,025)
8	August	($2,346,342)	($39,612)		($1,032,167)	($3,418,121)
9	September	($1,807,533)	($69,323)		($363,085)	($2,239,941)
10	October					
11	November					
12	December					
13	**Total**	**($19,765,031)**	**($908,166)**		**($4,709,518)**	**($25,382,714)**

Biomass Contracts Termination Cost Recovery in Monthly FCR

	Month	Benson Amortization (Regulatory Asset)	Benson Amortization (Plant Impairment)	Benson ROE (Regulatory Asset)	Benson ROE (Plant Impairment)	Laurentian Payment	Total
		FERC 557	FERC 407	FERC 182.2	FERC 182.3		
14	January	$19,946	$22,386	$4,439	$5,036	$0	$51,806
15	February	$19,946	$22,386	$4,369	$4,957	$0	$51,657
16	March	$19,946	$22,386	$4,299	$4,877	$0	$51,507
17	April	$19,946	$22,386	$4,229	$4,798	$0	$51,358
18	May	$19,946	$22,386	$4,159	$4,719	$0	$51,209
19	June	$19,946	$22,386	$4,089	$4,640	$994,926	$1,045,986
20	July	$19,946	$22,386	$4,020	$4,560	$0	$50,911
21	August	$19,946	$22,386	$3,950	$4,481	$0	$50,762
22	September	$19,946	$22,386	$3,880	$4,402	$0	$50,613
23	October						
24	November						
25	December						
26	**Total**	**$179,512**	**$201,470**	**$37,434**	**$42,470**	**$994,926**	**$1,455,811**

Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges

		2022	Bill Impact[1]	2023	Bill Impact[1]
1	January	3.767¢	$28.25	3.167¢	$23.75
2	February	3.399¢	$25.49	2.894¢	$21.71
3	March	3.623¢	$27.17	2.466¢	$18.50
4	April	3.013¢	$22.60	2.484¢	$18.63
5	May	2.992¢	$22.44	2.195¢	$16.46
6	June	2.893¢	$21.70	2.283¢	$17.12
7	July	3.268¢	$24.51	2.134¢	$16.01
8	August	3.518¢	$26.39	2.440¢	$18.30
9	September	3.585¢	$26.89	2.201¢	$16.51
10	October	3.530¢	$26.48	2.739¢	$20.54
11	November	3.379¢	$25.34	2.258¢	$16.94
12	December	3.272¢	$24.54		
13	Average	3.353¢	$25.15	2.478¢	$18.59

[1] For non-electric heating residential customers using 750 kWh

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Community Solar Garden Costs Allocated To North Dakota FCA

		October 2022	November 2022	December 2022	January 2023	February 2023	March 2023	April 2023	May 2023	June 2023	July 2023	August 2023	September 2023	12-Month Total
1	Market Priced Cost	$6,013,752	$836,164	$1,155,848	$816,789	$2,449,101	$4,695,322	$5,526,749	$4,264,322	$8,582,800	$8,310,763	$8,695,068	$4,679,005	$56,025,684
2	Above Market Cost	$10,096,620	$7,059,312	$3,724,427	$5,873,105	$9,370,463	$13,539,743	$13,916,043	$19,797,267	$16,551,308	$16,742,634	$14,429,024	$15,750,409	$146,850,355
3	Total Solar Gardens (1)+(2)	$16,110,372	$7,895,476	$4,880,275	$6,689,894	$11,819,564	$18,235,065	$19,442,792	$24,061,589	$25,134,108	$25,053,397	$23,124,092	$20,429,414	$202,876,038
4	ND Billing Month Sales	150,007	163,041	186,332	225,866	180,910	217,616	153,860	165,101	188,693	169,267	190,167	168,487	2,159,347
5	Billing Month System Sales	3,009,352	2,814,720	3,219,118	3,636,832	3,114,850	3,440,601	2,819,882	3,017,125	3,429,602	3,538,774	3,892,160	3,476,709	39,409,725
6	ND Allocator (4)/(5)	4.98469%	5.79244%	5.78829%	6.21052%	5.80798%	6.32494%	5.45626%	5.47213%	5.50189%	4.78321%	4.88590%	4.84616%	5.47922%
7	Market Costs (1)	$6,013,752	$836,164	$1,155,848	$816,789	$2,449,101	$4,695,322	$5,526,749	$4,264,322	$8,582,800	$8,310,763	$8,695,068	$4,679,005	$56,025,684
8	**ND Solar Gardens Allocation** (7)x(6)	**$299,767**	**$48,434**	**$66,904**	**$50,727**	**$142,243**	**$296,976**	**$301,554**	**$233,349**	**$472,216**	**$397,521**	**$424,832**	**$226,752**	**$2,961,277**