



414 Nicollet Mall
Minneapolis, Minnesota 55401

October 29, 2021

— Via Electronic Filing —

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

**Re: November 2021 Fuel Cost Rider Rates
Case No. PU-21-012**

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 2021.

The table below shows the FCR rates by customer class:

November 2021	FCR rate/kWh
Residential	\$0.03246
C & I Non-Demand	\$0.03359
C & I Demand	\$0.03316
C & I Demand Time of Day (On-Peak)	\$0.04167
C & I Demand Time of Day (Off-Peak)	\$0.02590
Outdoor Lighting	\$0.02390

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), the new rates will be implemented on October 1, 2021. The new Service Category Ratios listed below will also become effective when actual October costs are first passed through in December FCR rates:

Service Category Ratios	Current	Effective Oct 1 2021
Residential	0.99691	1.0094
C & I Non-Demand	1.0318	1.0129
C & I Demand	1.0184	1.0069
C & I Demand Time of Day (On-Peak)	1.2798	1.2181
C & I Demand Time of Day (Off-Peak)	0.7954	0.8392
Outdoor Lighting	0.73410	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 FCR the net MISO Day 2 costs for September as recorded in Account 555. The MISO Day 2 cost recovery included in this month’s FCR is \$32,834,012 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 FCR rates the net MISO ASM costs for August as recorded in Account 555. The MISO ASM cost recovery included in this month’s FCR is \$500,634, 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.

INCLUDED REFUNDS

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 or power purchase agreements after January 1, 2021 are excluded from this sharing. This change will be implemented in a future monthly FCA filing as soon as practicable. September margins of \$1,055,282 have been included as an offsetting credit in this month's FCR. Additional information is found in Attachments B and F.

Non-Asset Based Margins

Beginning in February 2011, the prior year retail share of Non-Asset Based Margins is credited to North Dakota customers via the FCR over the following 12-month period. The North Dakota retail share of the 2020 Non-Asset Based Margin credit amount applicable to the November FCR is \$106,704. 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. This change will be implemented in a future monthly FCA filing as soon as practicable.. The REC sales credit for the current reporting period is \$829,966. 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;
- The Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year;

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

- 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.

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

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

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 on September 2018.

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, North Wind Turbines LLC have terminated effective December 31, 2020.

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. Ulk Wind Farm (4.5 MW)
4. Ridgewind Power Partners LLC (25 MW)	13. Hilltop Power (2 MW)

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).

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)

* PPA terminated

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 PPAs.

The August 2021 North Dakota Disallowed PPAs cost exclusion was overstated by \$10,607. The correction was reflected in the September true up calculation as shown in Line 19a, Attachment E, Page 1 of 1.

MISO REVENUE ADJUSTMENT

Pursuant to the Commission’s August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the MISO wholesale revenues of disputed resources are to be excluded from the calculation of the Company’s monthly FCR after January 1, 2021. This change will be implemented in a future monthly FCA filing as soon as practicable.

GENERATION RESOURCE ADJUSTMENT

Pursuant to the Commission’s August 18, 2021 Order Accepting Settlement (Case No. PU-20-441), the energy generated by the Company’s Community Wind North and Jeffers wind facilities are to be repriced at system average fuel or purchased energy costs and recovered in the monthly FCR charge. FCR recovery of these costs is retroactive to January 1, 2021 and will be implemented in a future monthly FCA filing as soon as practicable.

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 program production and cost allocation to North Dakota. This information is in Attachment H.

BIOMASS PPA TERMINATION COST RECOVERY

Pursuant to Commission’s June 27, 2018 Order in Case Nos. PU-17-270 (ADP – Benson, Pine Bend and HERC PPAs), PU-17-271 and PU-17-322 (Deferred Accounting of Benson, Pine Bend and Laurentian PPAs termination cost recovery) the November FCR includes \$54,199 in termination cost recovery. Pine Bend PPA termination cost recovery was

completed in May 2020 FCR. 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 Calculation of the Monthly 2021 FCR Rate
- Attachment B – Four Month Fuel Cost Rider Costs
- Attachment C – Detail of MISO Day 2 and ASM Settlement Charges
- Attachment D – Derivation of Replacement Costs for Disallowed PPAs
- Attachment E – Deviation of FCR True-Up Adjustment
- Attachment F – Summary of Credits and Special Charges 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 Dave Sederquist at 701-241-8632 or dave.sederquist@xcelenergy.com.

Sincerely,

/ s /

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

cc: David H. Sederquist

Enclosures

Summary of Fuel Cost Rider Rates - November 2021

System Fuel and Purchased Energy Costs

	<u>4 Month Total</u>	
1 NSP System Fuel/Energy Costs (Retail)	\$335,632,497	Att B, p. 1, line 6
2 MISO Charges	\$113,423,490	Att B, p. 1, line 10
3 Disallowed Purchased Power Costs	(\$15,811,110)	Att B, p. 1, line 14
4 Net NSP System Costs	<u>\$433,244,877</u>	

ND Fuel and Purchased Energy Costs

	<u>4 Month Total</u>	
5 NSP System MWh Sales (Retail)	14,762,855	Att B, p. 1, line 16
6 Average NSP System Cost per kWh	2.935¢	line 4 / line 5/10
7 ND MWh Sales (Retail)	740,582	Att B, p. 1, line 18
8 ND Fuel & Purchased Energy Costs	<u>\$21,736,082</u>	line 6 x line 7

Credits and Other Adjustments Applicable to ND

	<u>September 2021</u>	
9 Wholesale Margins Credit	(\$1,161,986)	Att B, p. 1, line 20,21
10 REC Sales Proceeds Credit	(\$829,966)	Att B, p. 1, line 22
11 Biomass PPA Termination Costs	\$54,199	Att B, p. 1, line 23
12 Net Credits and Other	<u>(\$1,937,753)</u>	

Over/Under Recovered Costs

	<u>Amount</u>	
13 True-Up Amount for September 2021	\$4,313,386	Att E, p.1, line 19

ND Net FCR Costs

	<u>4 Month Total</u>	
14 Net FCR Costs	\$24,111,715	line 8+line 12+line 13
15 Net FCR Cost per kWh	3.256¢	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	3.256¢	0.99690	3.246¢
17 C & I Non-Demand	3.256¢	1.03180	3.359¢
18 C & I Demand Non-TOD	3.256¢	1.01840	3.316¢
19 C & I Demand TOD On-Peak	3.256¢	1.27980	4.167¢
20 C & I Demand TOD Off-Peak	3.256¢	0.79540	2.590¢
21 Outdoor Lighting	3.256¢	0.73410	2.390¢

¹ See Fuel Cost Rider Tariff.

4 Month Fuel Cost Rider Costs - November 2021

	(A)	(B)	(C)	(D)	(E)
Fuel & Purchased Energy Costs	Jun-21	Jul-21	Aug-21	Sep-21	4 Month Total
1 Account 151 - Fossil Fuel	\$42,181,217	\$52,673,518	\$51,922,619	\$35,411,913	\$182,189,267
2 Account 518 - Nuclear Fuel	\$9,772,366	\$10,083,832	\$9,968,073	\$9,241,665	\$39,065,936
3 Account 555 - Purchased Power ¹	\$74,334,873	\$65,876,676	\$58,820,155	\$74,949,217	\$273,980,921
4 Sub-Total NSP Sys Energy Costs	\$126,288,456	\$128,634,026	\$120,710,847	\$119,602,795	\$495,236,124
5 Exclude Costs of InterSystem Sales	(\$31,388,999)	(\$36,621,865)	(\$42,772,615)	(\$48,820,149)	(\$159,603,628)
6 Total Sys Fuel & Purch Energy	\$94,899,457	\$92,012,161	\$77,938,233	\$70,782,646	\$335,632,497
MISO Charges					
7 Day 2 Market	\$31,427,447	\$12,738,162	\$20,955,484	\$32,941,405	\$98,062,499
8 Exclude Schedule 24	(\$118,880)	(\$109,672)	(\$86,086)	(\$107,393)	(\$422,031)
9 Ancillary Services Market	\$3,950,451	\$6,824,019	\$4,507,918	\$500,634	\$15,783,022
10 Total MISO Charges	\$35,259,018	\$19,452,509	\$25,377,317	\$33,334,646	\$113,423,490
Disallowed PPA Costs²					
11 Exclude Costs of Disallowed PPAs	(\$6,793,829)	(\$5,700,477)	(\$6,232,880)	(\$5,469,467)	(\$24,196,652)
12 Exclude Related Curtailment Costs	(\$243,835)	(\$155,415)	(\$204,379)	(\$441,485)	(\$1,045,115)
13 Replacement Energy Costs	\$3,279,828	\$1,967,306	\$2,048,093	\$2,135,430	\$9,430,657
14 Net Disallowance	(\$3,757,835)	(\$3,888,586)	(\$4,389,166)	(\$3,775,522)	(\$15,811,110)
15 Net NSP System Costs	\$126,400,640	\$107,576,084	\$98,926,383	\$100,341,770	\$433,244,877
ND Fuel and Purchased Energy Costs					
16 NSP System Sales (Retail)	3,537,121	3,830,394	3,917,329	3,478,011	14,762,855
17 Avg. NSP System Cost per kWh	3.574¢	2.808¢	2.525¢	2.885¢	2.935¢
18 ND Sales (Retail)	177,571	192,706	198,128	172,177	740,582
19 ND Fuel & Purchased Energy Costs	\$6,346,388	\$5,411,184	\$5,002,732	\$4,967,306	\$21,736,082
Other Adjustments and True-Up					
20 Asset-Based Margins	(\$2,512,747)	(\$904,747)	(\$2,255,956)	(\$1,055,282)	(\$6,728,733)
21 Non-Asset-Based Margins	(\$16,452)	(\$142,710)	(\$13,930)	(\$106,704)	(\$279,796)
22 REC Sales Proceeds (100%)	(\$483,961)	(\$1,098,295)	(\$355,482)	(\$829,966)	(\$2,767,704)
23 Biomass PPA Termination Costs ³	\$962,479	\$54,505	\$54,352	\$54,199	\$1,125,536
24 Net Credits and Other	(\$2,050,681)	(\$2,091,247)	(\$2,571,016)	(\$1,937,753)	(\$8,650,697)

¹ Excludes demand-related expenses, MN Windsource energy costs, and MN Solar Gardens energy costs.

² Excludes costs exceeding system average costs for 21 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813) & other ADP docket.

³ Benson, Laurentian and Pine Bend PPAs.

MISO Day 2 Settlement Charges - November 2021

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
Energy and Losses		
1 Day Ahead Asset Energy - Energy	555	\$11,308,797
2 Day Ahead Asset Energy - Losses	555	\$5,200,424
3 Day Ahead Financial Bilateral Transaction Loss	555	(\$3,033)
4 Day Ahead Non-Asset Energy - Energy	555	\$0
5 Day Ahead Non-Asset Energy - Losses	555	\$499,933
6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	\$3,033
7 Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	\$0
8 Real Time Asset Energy - Energy	555	\$2,237,352
9 Real Time Asset Energy - Losses	555	\$61,941
10 Real Time Distribution of Losses	555	(\$1,487,886)
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	(\$28,546)
14 Real Time Non-Asset Energy - Energy	555	\$160,255
15 Real Time Non-Asset Energy - Losses	555	\$0
16 Total Energy and Losses		<u><u>\$17,952,271</u></u>
Congestion		
17 Day Ahead Asset Energy - Congestion	555	\$35,440,478
18 Day Ahead Financial Bilateral Transaction - Congestion	555	\$41,854
19 Day Ahead Non-Asset Energy - Congestion	555	\$361,652
20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	(\$41,854)
21 Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	\$0
22 Real Time Asset Energy - Congestion	555	\$79,762
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		<u><u>\$35,881,892</u></u>
Financial Transmission Rights (FTR)		
27 FTR Hourly Allocation	555	(\$13,375,719)
28 FTR Monthly Allocation	555	(\$303,402)
29 FTR Transaction	555	\$0
30 FTR Yearly Allocation	555	\$0
31 FTR Full Funding Guarantee	555	(\$860,406)
32 FTR Guarantee Uplift	555	\$857,295
33 FTR Monthly Transaction	555	\$0
34 Total Financial Transmission Rights Charges		<u><u>(\$13,682,231)</u></u>

MISO Day 2 Settlement Charges - November 2021

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
Uplift		
35 Real-Time Revenue Neutrality Uplift	555	\$1,820,760
36 Total Uplift		<u>\$1,820,760</u>
Revenue Sufficiency Guarantee (RSG)		
37 Day Ahead RSG Distribution	555	\$118,572
38 Day Ahead RSG Make Whole Payment	555	(\$77,054)
39 Real time RSG First Pass Distribution	555	\$283,126
40 Real Time RSG Make Whole Payment	555	(\$384,182)
41 Real Time Price Volatility Make Whole Payment	555	(\$18,663)
42 Total Revenue Sufficiency Guarantee	555	<u>(\$78,200)</u>
Market Administration¹		
43 Day Ahead Market Administration	575.7	\$536,582
44 Real Time Market Administration	575.7	\$49,257
45 FTR Market Administration	575.7	\$17,803
46 Total Market Administration		<u>\$603,643</u>
Virtual Energy		
47 Day Ahead Virtual Energy	555	(\$8,792,422)
48 Real Time Virtual Energy	555	\$0
49 Total Virtual Energy	555	<u>(\$8,792,422)</u>
Auction Revenue Rights (ARR)		
50 ARR FTR Auction Transactions	555	\$3,988,864
51 ARR Monthly Revenue	555	(\$4,124,276)
52 ARR Stage 2 Distribution	555	(\$1,039,834)
53 ARR Monthly Infeasible Revenue	555	\$185,508
54 Total Auction Revenue Rights		<u>(\$989,737)</u>
Other Miscellaneous		
55 Real Time Miscellaneous	555	\$118,036
56 Real Time Uninstructed Deviation	555	\$0
57 Total Other Miscellaneous		<u>\$118,036</u>
58 Grand Total MISO Day 2 Charges		<u><u>\$32,834,012</u></u>

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

MISO Ancillary Services Markets (ASM) Charges - November 2021

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
Procurement		
1 Day Ahead Regulation	555	(\$237,884)
2 Day Ahead Spinning Reserve	555	(\$226,787)
3 Day Ahead Supplemental Reserve	555	(\$42,668)
4 Real Time Regulation	555	\$57,754
5 Real Time Spinning Reserve	555	\$113,202
6 Real Time Supplemental Reserve	555	\$30,194
7 Total Procurement		<u><u>(\$306,189)</u></u>
Resource Energy		
8 Real Time Excessive Energy	555	\$9,627
9 Real Time Excessive Energy - Congestion	555	\$0
10 Real Time Excessive Energy - Losses	555	\$0
11 Real Time Non-Excessive Energy	555	\$526,183
12 Real Time Non-Excessive Energy - Congestion	555	(\$190,522)
13 Real Time Non-Excessive Energy - Losses	555	\$106,109
14 Real Time Net Regulation Adjustment	555	(\$1,751)
15 Total Resource Energy		<u><u>\$449,645</u></u>
Cost Distribution		
16 Real Time Regulation Reserve Cost Distribution	555	\$174,002
17 Real Time Spinning Reserve Cost Distribution	555	\$135,418
18 Real Time Supplemental Reserve Cost Distribution	555	\$9,303
19 Total Cost Distribution		<u><u>\$318,722</u></u>
Penalties		
20 Real Time Excessive/Deficient Energy Deployment	555	\$38,456
21 Real Time Contingency Reserve Deployment Failure	555	\$0
22 Total Penalties		<u><u>\$38,456</u></u>
23 Grand Total ASM Charges		<u><u>\$500,634</u></u>

Derivation of September 2021 Replacement Costs for Disallowed PPAs

	<u>NSP System</u>	<u>ND Allocation¹</u>	<u>ND Jurisdiction</u>	
Fuel & Purchased Energy Costs				
1 Fuel & Purch Energy Costs (Retail) ²	\$104,117,292	4.9504%	\$5,154,269	Att B, Col D, line 6+10
Disallowed PPA Costs				
2 15 C-BED Wind PPAs	(\$1,675,354)	4.9504%	(\$82,937)	
3 7 Solar PPAs	(\$3,794,113)	4.9504%	(\$187,825)	
4 Wind Curtailment Payments	(\$441,485)	4.9504%	(\$21,855)	
5 Total Exclusion	(\$5,910,952)		(\$292,618)	
6 Adjusted Fuel & Purchased Energy Costs	\$98,206,340	4.9504%	\$4,861,650	Line 1 - line 5
Energy Sales (Billing Mo.)				
	[a]	[b]	[c]	
7 MWh Energy Sales	3,478,011	4.9504%	172,177	[b]=[c]/[a]
8 Disallowed PPA MWh Energy Sales	(74,019)	4.9504%	(3,664)	
9 Adjusted MWh Sales (Billing Mo.)	3,403,992		168,513	
Replacement Costs				
10 Avg. Cost (\$/MWh) w/o Disallowed PPAs	\$28.85		\$28.85	Line 6 / line 9
11 Replacement Cost for Disallowed PPAs ³	\$2,135,448		\$105,706	Line 8 x line 10
Impact of Disallowance				
12 Net Impact of Disallowance	(\$3,775,504)		(\$186,912)	Line 5 + line 11
13 FCR Rate Impact of Disallowance /kWh			-0.109¢	Line 12 / line 7
14 Residential Monthly Bill Impact (750 kWh)			(\$0.81)	Line 13 x 750

¹ Based on ratio of ND billed energy sales to NSP System billed sales as shown in line 7

² Including MISO charges

³ Reflects the average system fuel and purchased energy cost per kWh (excluding the disallowed PPA costs and volumes) applied to the energy volumes of the disallowed PPAs.

Derivation of FCR True-Up Adjustment - September 2021

Cost to Recover in September 2021

	[a] Sep Sys Fuel Cost/kWh ¹	[b] Sep ND MWh Sales ²	Amount	
1 Fuel & Purchased Energy Costs	2.885¢	172,177	\$4,967,306	
2 True Up Amount for July 2021			\$5,169,976	
3 Net Costs			<u>\$10,137,283</u>	Line 1 + Line 2

Cost Recovered in September 2021

	Sales	Amount	
4 (i) Residential	55,009	\$1,639,448	
5 (ii) C & I Non-Demand	7,201	\$221,066	
6 (iii) C & I Demand Non-TOD	58,533	\$1,771,455	
7 (iv) C & I Demand TOD On-Peak	19,271	\$734,514	
8 (v) C & I Demand TOD Off-Peak	30,978	\$733,960	
9 (vi) Outdoor Lighting	1,185	\$25,804	
10 Total	<u>172,177</u>	<u>\$5,126,247</u>	
True-Up Obligation			
11 (i) Residential	55,009	\$228,272	
12 (ii) C & I Non-Demand	7,201	\$29,580	
13 (iii) C & I Demand Non-TOD	58,533	\$239,517	
14 (iv) C & I Demand TOD On-Peak	19,271	\$103,165	
15 (v) C & I Demand TOD Off-Peak	30,978	\$104,847	
16 (vi) Outdoor Lighting	1,185	\$2,875	
17 Total	<u>172,177</u>	<u>\$708,256</u>	
18 Net Recovery		<u>\$5,834,503</u>	Line 10 + Line 17

Over/Under Recovered Costs

19a One Time Prior Month Adjustment ³	\$10,607	
19b True-Up Amount for September 2021	<u>\$4,313,386</u>	Line 3 - Line 18 + Line 19

¹ Reflects the average for the month of September 2021.

² Actual ND sales in month of September 2021.

³ August 2021 Disallowed PPA cost correction.

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

Margin Sharing and REC Sales Proceeds Credits

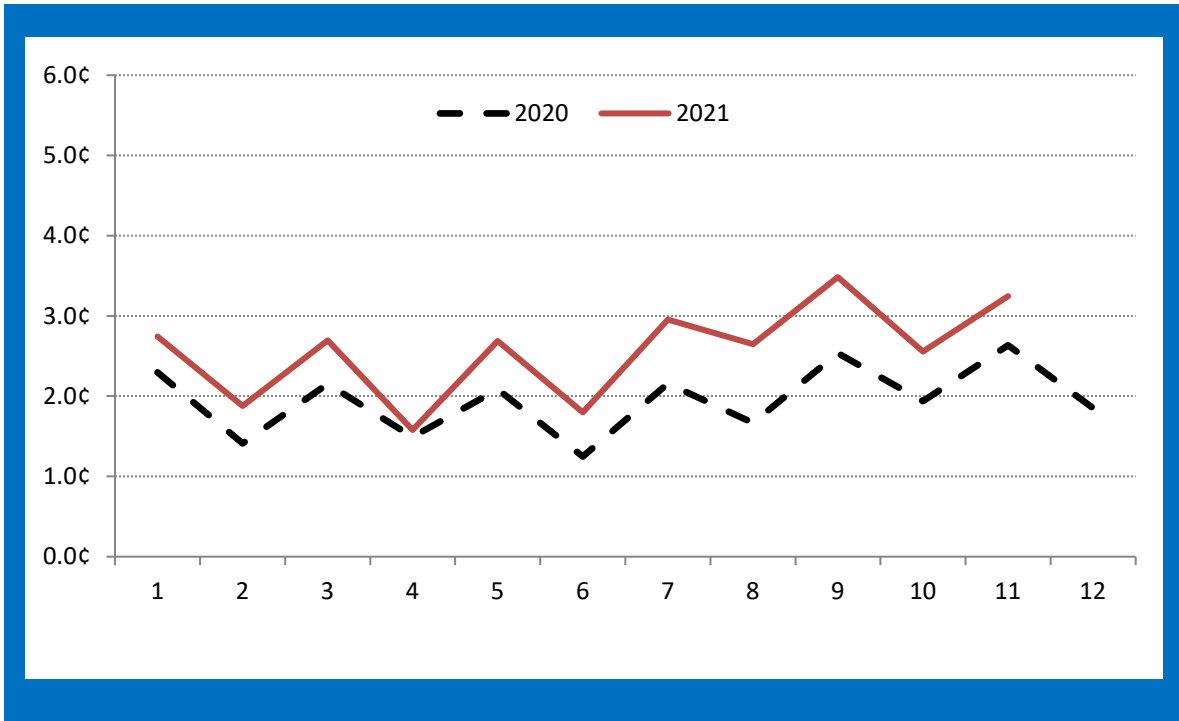
Month	Asset Based Margins	Non-Asset Based Margins	Renewable Energy Credits	Total
1 January	(\$909,675)	(\$353,975)	(\$117,989)	(\$1,381,639)
2 February	(\$3,171,095)	(\$14,652)	(\$39)	(\$3,185,786)
3 March	(\$518,508)	(\$258,147)	(\$83,954)	(\$860,609)
4 April	(\$2,628,486)	(\$18,186)	(\$2,404)	(\$2,649,076)
5 May	(\$672,711)	(\$202,692)	(\$1,540,277)	(\$2,415,680)
6 June	(\$2,512,747)	(\$16,452)	(\$483,961)	(\$3,013,160)
7 July	(\$904,747)	(\$142,710)	(\$1,098,295)	(\$2,145,753)
8 August				
9 September				
10 October				
11 November				
12 December				
13 Cumulative	(\$11,317,969)	(\$1,006,814)	(\$3,326,919)	(\$15,651,703)

Biomass Contracts Termination Cost Recovery

Month	Benson Amortization (Regulatory Asset)	Benson Amortization (Plant Impairment)	Benson ROE (Regulatory Asset)	Benson ROE (Plant Impairment)	Laurentian Payment	Pine Bend Payment	Total
	FERC 557	FERC 407	FERC 182.2	FERC 182.3			
14 January	\$19,946	\$22,387	\$6,117	\$6,790	\$0	\$0	\$55,239
15 February	\$19,946	\$22,387	\$6,047	\$6,712	\$0	\$0	\$55,091
16 March	\$19,946	\$22,387	\$5,977	\$6,635	\$0	\$0	\$54,944
17 April	\$19,946	\$22,387	\$5,907	\$6,723	\$0	\$0	\$54,962
18 May	\$19,946	\$22,387	\$6,364	\$6,640	\$0	\$0	\$55,336
19 June	\$19,946	\$22,387	\$5,768	\$6,557	\$907,822	\$0	\$962,479
20 July	\$19,946	\$22,387	\$5,698	\$6,475	\$0	\$0	\$54,505
21 August	\$19,946	\$22,387	\$5,628	\$6,392	\$0	\$0	\$54,352
22 September	\$19,946	\$22,387	\$5,558	\$6,309	\$0	\$0	\$54,199
23 October							
24 November							
25 December							
26 Cumulative	\$179,512	\$201,479	\$53,064	\$59,233	\$907,822	\$0	\$1,401,110

May 2021 Benson ROE included \$527 true-up return for change in deferred taxes.

Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges		<u>2020</u>	<u>Bill Impact¹</u>	<u>2021</u>	<u>Bill Impact¹</u>
1	January	2.298¢	\$17.24	2.742¢	\$20.57
2	February	1.413¢	\$10.60	1.878¢	\$14.09
3	March	2.152¢	\$16.14	2.694¢	\$20.21
4	April	1.492¢	\$11.19	1.579¢	\$11.84
5	May	2.087¢	\$15.65	2.688¢	\$20.16
6	June	1.248¢	\$9.36	1.797¢	\$13.48
7	July	2.157¢	\$16.18	2.955¢	\$22.16
8	August	1.667¢	\$12.50	2.648¢	\$19.86
9	September	2.538¢	\$19.04	3.484¢	\$26.13
10	October	1.937¢	\$14.53	2.555¢	\$19.16
11	November	2.635¢	\$19.76	3.246¢	\$24.35
12	December	<u>1.850¢</u>	<u>\$13.88</u>		
13	Average	1.956¢	\$14.67	2.570¢	\$19.27

¹ For non-electric heating residential customers using 750 kWh

