



414 Nicollet Mall
Minneapolis, Minnesota 55401

February 28, 2018

— Via Electronic Filing —

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

**Re: March 2018 Fuel Cost Rider Rates
Case No. PU-18-12**

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric Fuel Cost Rider (FCR) rates for March 2018.

The table below shows the March FCR rates by customer class:

March 2018	FCR rate/kWh
Residential	\$0.02392
C & I Non-Demand	\$0.02476
C & I Demand	\$0.02444
C & I Demand Time of Day (On-Peak)	\$0.03071
C & I Demand Time of Day (Off-Peak)	\$0.01909
Outdoor Lighting	\$0.01762

See Attachment A for the supporting calculations of these rates.

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 March 2018 FCR the net MISO Day 2 costs for December 2017 as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is \$8,583,734 which is the net of many items. 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 March 2018 FCR rates the net MISO ASM costs for January 2018 as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is \$5,385,647, which is the net of many items. The detailed records are contained in Attachment C.

INCLUDED REFUNDS

Asset Based Margins

Under the terms of the Revised Second Amended Settlement adopted by the Commission² 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. January margins of \$859,055 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 evenly over the following 12-month period. The North Dakota retail share of the 2016 Non-Asset Based Margin amount applicable to the March FCR is \$16. 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

¹ Previously embedded in other FTR charge types.

² 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

Adopting Settlement, the share of the net proceeds to customers was increased to 100 percent. The REC sales credit reported during the current reporting period is \$31,442. 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;
- 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)³
2. Marshall Solar LLC (62.25 MW)⁴
3. North Star Solar PV (100 MW)⁵
4. Aurora Distributed Solar (100 MW)⁶

³ Case No. PU-16-458, ORDER REGARDING 2015 POWER PURCHASE AGREEMENT COSTS, October 5, 2016.

⁴ 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).

⁵ 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).

⁶ 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).

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 (see table below) are to be excluded from the calculation of the Company's monthly FCR rates. 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.

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)
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)	

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 FCC filings regarding the costs related to the Minnesota Community Solar Gardens program production and cost allocation to North Dakota. This information is located in Attachment H.

MONTHLY FCR RATE CALCULATION AND SUPPORTING DOCUMENTS

This filing includes the following supporting documents:

- Attachment A – Summary of Calculation of the Monthly 2018 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 Included in the FCR by Month
- 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 /

AMY LIBERKOWSKI
DIRECTOR, REGULATORY PRICING AND ANALYSIS

CC: David H. Sederquist

Enclosures

Summary of Fuel Cost Rider Rates - March 2018

System Fuel and Purchased Energy Costs

	<u>4 Month Total</u>	
1 NSP System Fuel/Energy Costs (Retail)	\$327,310,179	Att B, p. 1, line 6
2 MISO Charges	\$39,800,895	Att B, p. 1, line 10
3 Disallowed Purchased Power Costs	(\$14,958,834)	Att B, p. 1, line 14
4 Net NSP System Costs	<u>\$352,152,241</u>	

ND Fuel and Purchased Energy Costs

	<u>4 Month Total</u>	
5 NSP System MWh Sales (Retail)	13,612,004	Att B, p. 1, line 16
6 Average NSP System Cost per kWh	2.587¢	line 4 / line 5/10
7 ND MWh Sales (Retail)	770,910	Att B, p. 1, line 18
8 ND Fuel & Purchased Energy Costs	<u>\$19,943,442</u>	line 6 x line 7

Credits and Other Adjustments Applicable to ND

	<u>January 2018</u>	
9 Wholesale Margins	(\$859,040)	Att B, p. 1, line 20,21
10 REC Sales Proceeds	(\$31,442)	Att B, p. 1, line 22
11 Net Credits and Other	<u>(\$890,482)</u>	

Over/Under Recovered Costs

	<u>Amount</u>	
12 True-Up Amount for January 2018	(\$554,468)	Att E, p.1, line 19

ND Net FCR Costs

	<u>4 Month Total</u>	
13 Net FCR Costs	\$18,498,492	line 8+line 11+line 12
14 Net FCR Cost per kWh	2.400¢	line 13 / line 7/10

Fuel Cost Rider Rate By Class

Customer Class	ND Cost of Fuel/kWh	Cust. Class Ratio ¹	FCR Rate
16 Residential	2.400¢	0.99690	2.392¢
17 C & I Non-Demand	2.400¢	1.03180	2.476¢
18 C & I Demand Non-TOD	2.400¢	1.01840	2.444¢
19 C & I Demand TOD On-Peak	2.400¢	1.27980	3.071¢
20 C & I Demand TOD Off-Peak	2.400¢	0.79540	1.909¢
21 Outdoor Lighting	2.400¢	0.73410	1.762¢

¹ See Fuel Cost Rider Tariff.

4 Month Fuel Cost Rider Costs - March 2018

	(A)	(B)	(C)	(D)	(E)
Fuel & Purchased Energy Costs	Oct-17	Nov-17	Dec-17	Jan-18	4 Month Total
1 Account 151 - Fossil Fuel	\$33,417,119	\$36,457,251	\$40,888,441	\$43,351,795	\$154,114,606
2 Account 518 - Nuclear Fuel	\$8,123,036	\$7,621,744	\$10,239,608	\$10,299,950	\$36,284,338
3 Account 555 - Purchased Power ¹	\$48,094,374	\$49,088,824	\$46,842,690	\$46,699,728	\$190,725,616
4 Sub-Total NSP Sys Energy Costs	\$89,634,529	\$93,167,819	\$97,970,739	\$100,351,473	\$381,124,560
5 Exclude Costs of InterSystem Sales	(\$9,950,534)	(\$10,476,616)	(\$15,202,377)	(\$18,184,853)	(\$53,814,381)
6 Total Sys Fuel & Purch Energy	\$79,683,995	\$82,691,203	\$82,768,362	\$82,166,620	\$327,310,179
MISO Charges					
7 Day 2 Market	\$8,161,139	\$6,995,871	\$7,648,438	\$8,681,027	\$31,486,476
8 Exclude Schedule 24 Plus Congest Refund	(\$78,134)	(\$102,498)	(\$100,192)	(\$97,293)	(\$378,117)
9 Ancillary Services Market	(\$355,798)	\$809,616	\$2,853,072	\$5,385,647	\$8,692,536
10 Total MISO Charges	\$7,727,207	\$7,702,990	\$10,401,318	\$13,969,381	\$39,800,895
Disallowed PPAs²					
11 Exclude Costs of Disallowed PPAs	(\$6,490,223)	(\$6,291,821)	(\$5,449,084)	(\$6,159,230)	(\$24,390,358)
12 Exclude Related Curtailment Costs	(\$51,721)	(\$2,923)	(\$12,340)	(\$3,285)	(\$70,269)
13 Replacement Energy Costs	\$2,309,648	\$2,753,862	\$2,301,182	\$2,137,101	\$9,501,793
14 Net Disallowance	(\$4,232,296)	(\$3,540,882)	(\$3,160,242)	(\$4,025,414)	(\$14,958,834)
15 Net NSP System Costs	\$83,178,905	\$86,853,311	\$90,009,438	\$92,110,586	\$352,152,241
ND Fuel and Purchased Energy Costs					
16 NSP System Sales (Retail)	3,384,935	3,016,975	3,256,121	3,953,973	13,612,004
17 Avg. NSP System Cost per kWh	2.457¢	2.879¢	2.764¢	2.32957¢	2.587¢
18 ND Sales (Retail)	169,768	162,945	189,170	249,027	770,910
19 ND Fuel & Purchased Energy Costs	\$4,171,200	\$4,691,187	\$5,228,659	\$5,801,258	\$19,943,442
Credits and True-Up					
20 Asset-Based Margins	(\$646,268)	(\$667,648)	(\$708,044)	(\$859,055)	(\$2,881,015)
21 Non-Asset-Based Margins	(\$20,406)	\$590	(\$13,488)	\$16	(\$33,289)
22 REC Sales Proceeds (100%)	(\$82,923)	(\$45,971)	(\$55,976)	(\$31,442)	(\$216,312)
23 Net Credits and Other	(\$749,597)	(\$713,029)	(\$777,508)	(\$890,482)	(\$3,130,616)

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

² Excludes 21 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement (PU-12-813) & other ADP dockets.

MISO Day 2 Settlement Charges - March 2018

Energy and Losses	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
1 Day Ahead Asset Energy - Energy	555	\$6,683,771
2 Day Ahead Asset Energy - Losses	555	\$4,935,913
3 Day Ahead Financial Bilateral Transaction Loss	555	\$3,719
4 Day Ahead Non-Asset Energy - Energy	555	(\$5,212,660)
5 Day Ahead Non-Asset Energy - Losses	555	\$162,168
6 Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	(\$3,719)
7 Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	\$0
8 Real Time Asset Energy - Energy	555	\$2,215,855
9 Real Time Asset Energy - Losses	555	\$3,837
10 Real Time Distribution of Losses	555	(\$1,774,973)
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	\$66,019
14 Real Time Non-Asset Energy - Energy	555	\$601
15 Real Time Non-Asset Energy - Losses	555	(\$8)
16 Total Energy and Losses		<u><u>\$7,080,523</u></u>
Congestion		
17 Day Ahead Asset Energy - Congestion	555	\$1,349,507
18 Day Ahead Financial Bilateral Transaction - Congestion	555	\$20,920
19 Day Ahead Non-Asset Energy - Congestion	555	\$73,152
20 Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	(\$20,920)
21 Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	\$0
22 Real Time Asset Energy - Congestion	555	\$46,610
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	(\$21)
26 Total Congestion-Related		<u><u>\$1,469,248</u></u>
Financial Transmission Rights (FTR)		
27 FTR Hourly Allocation	555	(\$511,778)
28 FTR Monthly Allocation	555	\$20,641
29 FTR Transaction	555	\$0
30 FTR Yearly Allocation	555	\$0
31 FTR Full Funding Guarantee	555	(\$61,441)
32 FTR Guarantee Uplift	555	\$66,631
33 FTR Monthly Transaction	555	\$0
34 Total Financial Transmission Rights Charges		<u><u>(\$485,947)</u></u>

MISO Day 2 Settlement Charges - March 2018

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
Uplift		
35 Real-Time Revenue Neutrality Uplift	555	\$114,567
36 Total Uplift		<u>\$114,567</u>
Revenue Sufficiency Guarantee (RSG)		
37 Day Ahead RSG Distribution	555	\$205,525
38 Day Ahead RSG Make Whole Payment	555	(\$343,298)
39 Real time RSG First Pass Distribution	555	\$483,401
40 Real Time RSG Make Whole Payment	555	(\$390,537)
41 Real Time Price Volatility Make Whole Payment	555	(\$327,715)
42 Total Revenue Sufficiency Guarantee	555	<u>(\$372,625)</u>
Market Administration¹		
43 Day Ahead Market Administration	575.7	\$540,143
44 Real Time Market Administration	575.7	\$34,072
45 FTR Market Administration	575.7	\$17,404
46 Total Market Administration		<u>\$591,619</u>
Virtual Energy		
47 Day Ahead Virtual Energy	555	\$0
48 Real Time Virtual Energy	555	\$0
49 Total Virtual Energy	555	<u>\$0</u>
Auction Revenue Rights (ARR)		
50 ARR FTR Auction Transactions	555	\$3,077,707
51 ARR Monthly Revenue	555	(\$3,050,584)
52 ARR Stage 2 Distribution	555	(\$157,244)
53 ARR Monthly Infeasible Revenue	555	\$39,325
54 Total Auction Revenue Rights		<u>(\$90,796)</u>
Other Miscellaneous		
55 Real Time Miscellaneous	555	\$277,144
56 Real Time Uninstructed Deviation	555	\$0
57 Total Other Miscellaneous		<u>\$277,144</u>
58 Grand Total MISO Day 2 Charges		<u><u>\$8,583,734</u></u>

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

MISO Ancillary Services Markets (ASM) Charges - March 2018

	<u>FERC Account</u>	<u>Retail Expense (Rev)</u>
Procurement		
1 Day Ahead Regulation	555	(\$189,944)
2 Day Ahead Spinning Reserve	555	(\$357,225)
3 Day Ahead Supplemental Reserve	555	(\$113,133)
4 Real Time Regulation	555	\$54,354
5 Real Time Spinning Reserve	555	\$224,823
6 Real Time Supplemental Reserve	555	\$44,558
7 Total Procurement		<u>(\$336,568)</u>
Resource Energy		
8 Real Time Excessive Energy	555	(\$4,832)
9 Real Time Excessive Energy - Congestion	555	\$0
10 Real Time Excessive Energy - Losses	555	\$0
11 Real Time Non-Excessive Energy	555	\$5,084,796
12 Real Time Non-Excessive Energy - Congestion	555	\$56,111
13 Real Time Non-Excessive Energy - Losses	555	(\$16,807)
14 Real Time Net Regulation Adjustment	555	(\$5,296)
15 Total Resource Energy		<u>\$5,113,972</u>
Cost Distribution		
16 Real Time Regulation Reserve Cost Distribution	555	\$189,978
17 Real Time Spinning Reserve Cost Distribution	555	\$214,561
18 Real Time Supplemental Reserve Cost Distribution	555	\$95,357
19 Total Cost Distribution		<u>\$499,896</u>
Penalties		
20 Real Time Excessive/Deficient Energy Deployment	555	\$108,351
21 Real Time Contingency Reserve Deployment Failure	555	(\$4)
22 Total Penalties		<u>\$108,347</u>
23 Grand Total ASM Charges		<u><u>\$5,385,647</u></u>

Derivation of January 2018 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	\$96,136,001	6.2981%	\$6,054,786	Att B, Col D, line 6+10
Disallowed PPA Costs				
2 15 C-BED Wind PPAs	(\$4,972,631)	6.2981%	(\$313,184)	
3 6 Solar PPAs	(\$1,186,600)	6.2981%	(\$74,734)	
4 Wind Curtailment Payments	(\$3,285)	6.2981%	(\$207)	
5 Total Exclusion	(\$6,162,515)		(\$388,124)	
6 Adjusted Fuel & Purchased Energy Costs	\$89,973,486	6.2981%	\$5,666,662	Line 1 - line 5
Energy Sales (Billing Mo.)				
	[a]	[b]	[c]	
7 MWh Energy Sales	3,953,973	6.2981%	249,027	[b]=[c]/[a]
8 Disallowed PPA MWh Energy Sales	(91,721)	6.2981%	(5,777)	
9 Adjusted MWh Sales (Billing Mo.)	3,862,252		243,250	
Replacement Costs				
10 Avg. Cost (\$/MWh) w/o Disallowed PPAs	\$23.30		\$23.30	Line 6 / line 9
11 Replacement Cost for Disallowed PPAs ³	\$2,137,099		\$134,604	Line 8 x line 10
Impact of Disallowance				
12 Net Impact of Disallowance	(\$4,025,416)		(\$253,520)	Line 5 + line 11
13 FCR Rate Impact of Disallowance /kWh			-0.102¢	Line 12 / line 7
14 Residential Monthly Bill Impact (750 kWh)			(\$0.76)	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 - January 2018

Cost to Recover in January 2018

	[a] Jan Sys Fuel Cost/kWh ¹	[b] Jan ND MWh Sales ²	Amount	
1 Fuel & Purchased Energy Costs	2.330¢	249,027	\$5,801,258	[a] x [b]
2 True Up Amount for November 2017			(\$168,640)	
3 Net Costs			<u>\$5,632,618</u>	Line 1 + Line 2

Cost Recovered in January 2018

	Sales	Amount	
<u>Fuel & Purchased Energy</u>			
4 (i) Residential	105,653	\$2,590,703	
5 (ii) C & I Non-Demand	13,540	\$343,561	
6 (iii) C & I Demand Non-TOD	77,873	\$1,949,807	
7 (iv) C & I Demand TOD On-Peak	18,041	\$567,710	
8 (v) C & I Demand TOD Off-Peak	31,892	\$623,750	
9 (vi) Outdoor Lighting	2,028	\$36,539	
10 Total	<u>249,027</u>	<u>\$6,112,070</u>	
<u>True-Up Obligation</u>			
11 (i) Residential	105,653	\$33,949	
12 (ii) C & I Non-Demand	13,540	\$4,359	
13 (iii) C & I Demand Non-TOD	77,873	\$21,844	
14 (iv) C & I Demand TOD On-Peak	18,041	\$6,735	
15 (v) C & I Demand TOD Off-Peak	31,892	\$7,400	
16 (vi) Outdoor Lighting	2,028	\$729	
17 Total	<u>249,027</u>	<u>\$75,016</u>	
18 Net Recovery		<u>\$6,187,086</u>	Line 10 + Line 17

Over/Under Recovered Costs

19 True-Up Amount for January 2018	<u>(\$554,468)</u>	Line 3 - Line 18
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¹ Reflects the average for the month of January 2018.

² Actual ND sales in month of January 2018.

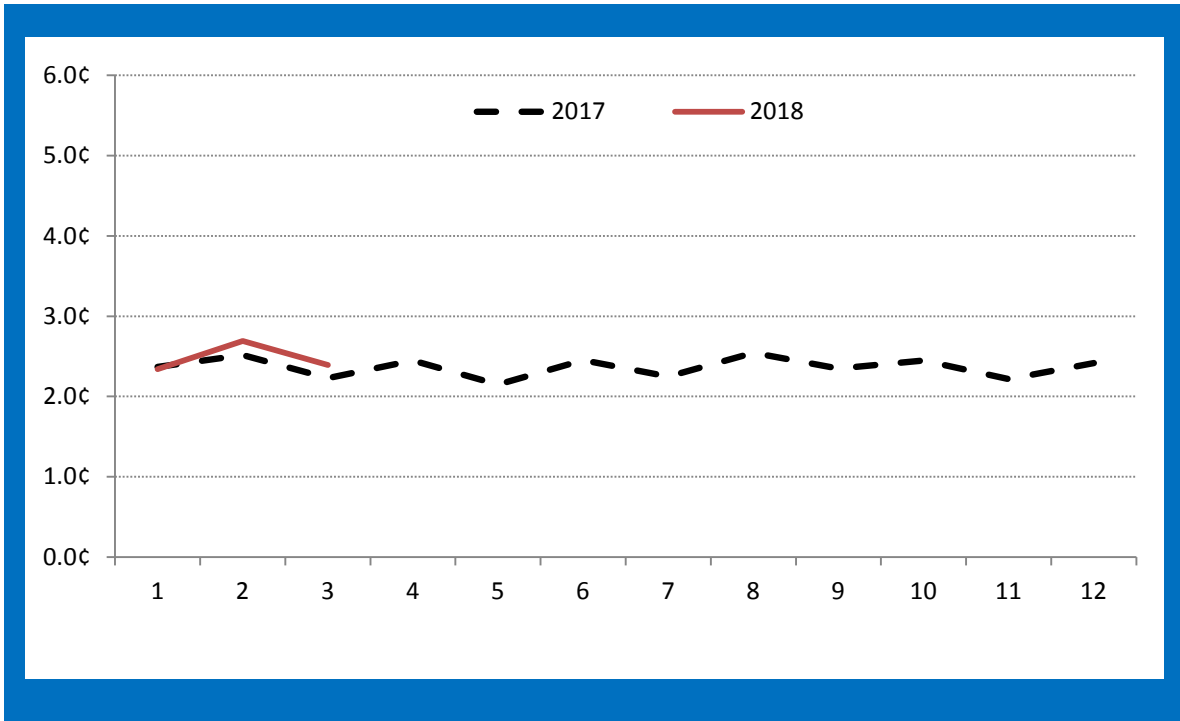
Summary of Credits Included in the FCR by Month

Month	Asset Based Margins	Non-Asset Based Margins	Renewable Energy Credits	Total
1 January	(\$859,055)	\$16	(\$31,442)	(\$890,482)
2 February	\$0	\$0	\$0	\$0
3 March	\$0	\$0	\$0	\$0
4 April	\$0	\$0	\$0	\$0
5 May	\$0	\$0	\$0	\$0
6 June	\$0	\$0	\$0	\$0
7 July	\$0	\$0	\$0	\$0
8 August	\$0	\$0	\$0	\$0
9 September	\$0	\$0	\$0	\$0
10 October	\$0	\$0	\$0	\$0
11 November	\$0	\$0	\$0	\$0
12 December	\$0	\$0	\$0	\$0
13 Cumulative	(\$859,055)	16	(\$31,442)	(\$890,482)

Summary of Credits Included in the FCR by Month

Month	Asset Based Margins	Non-Asset Based Margins	Renewable Energy Credits	Total
1 January	(\$509,237)	\$9,017	\$164,990	(\$335,230)
2 February	(\$676,186)	(\$64,765)	(\$39,558)	(\$780,509)
3 March	(\$596,839)	\$6,721	\$81,141	(\$508,977)
4 April	(\$590,888)	(\$48,403)	(\$26,888)	(\$666,179)
5 May	(\$696,674)	\$4,899	\$62,917	(\$628,858)
6 June	(\$532,869)	(\$37,304)	(\$149,448)	(\$719,621)
7 July	(\$655,165)	\$2,222	(\$78,098)	(\$731,041)
8 August	(\$540,919)	(\$27,324)	(\$108,254)	(\$676,497)
9 September	(\$632,175)	\$1,226	(\$60,169)	(\$691,118)
10 October	(\$646,268)	(\$20,406)	(\$82,923)	(\$749,597)
11 November	(\$667,648)	\$590	(\$45,971)	(\$713,029)
12 December	(\$708,044)	(\$13,488)	(\$55,976)	(\$777,508)
13 Cumulative	(7,452,912)	(187,016)	(338,237)	(7,978,164)

Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges				
	<u>2017</u>	<u>Bill Impact¹</u>	<u>2018</u>	<u>Bill Impact¹</u>
1 January	2.370¢	\$17.78	2.341¢	\$17.56
2 February	2.517¢	\$18.88	2.691¢	\$20.18
3 March	2.229¢	\$16.72	2.392¢	\$17.94
4 April	2.448¢	\$18.36		
5 May	2.148¢	\$16.11		
6 June	2.452¢	\$18.39		
7 July	2.248¢	\$16.86		
8 August	2.545¢	\$19.09		
9 September	2.349¢	\$17.62		
10 October	2.449¢	\$18.37		
11 November	2.218¢	\$16.64		
12 December	2.415¢	\$18.11		
13 Average	2.366¢	\$17.74	2.475¢	\$18.56

¹ For non-electric heating residential customers using 750 kWh

Community Solar Garden Costs Allocated To North Dakota FCA

	May 2017	June 2017	July 2017	August 2017	September 2017	October 2017	November 2017	December 2017	January 2018	9-Month Total
1 Market Priced Cost	\$377,734	\$431,817	\$609,372	\$487,903	\$538,579	\$400,192	\$360,301	\$280,158	\$774,649	\$4,260,705
2 Above Market Cost	\$1,302,631	\$1,314,177	\$1,545,018	\$1,083,508	\$1,403,783	\$1,491,177	\$1,626,438	\$1,067,338	\$2,023,834	\$12,857,904
3 Total Solar Gardens (1)+(2)	\$1,680,365	\$1,745,994	\$2,154,390	\$1,571,410	\$1,942,362	\$1,891,369	\$1,986,740	\$1,347,496	\$2,798,483	\$17,118,609
4 ND Billing Month Sales	168,757	169,300	181,331	193,840	167,968	169,768	162,945	189,170	249,027	1,652,106
5 Billing Month System Sales	3,111,065	3,463,397	3,639,082	3,878,032	3,365,649	3,384,935	3,016,975	3,256,121	3,953,973	31,069,229
6 ND Allocator (4)/(5)	5.42441%	4.88826%	4.98288%	4.99841%	4.99066%	5.01540%	5.40094%	5.80967%	6.29815%	5.31750%
7 Market Costs (1)	\$377,734	\$431,817	\$609,372	\$487,903	\$538,579	\$400,192	\$360,301	\$280,158	\$774,649	\$4,260,705
8 ND Solar Gardens Allocation	\$20,490	\$21,108	\$30,364	\$24,387	\$26,879	\$20,071	\$19,460	\$16,276	\$48,789	\$227,824

(7)x(6)