414 Nicollet Mall
Minneapolis, Minnesota 55401

December 29, 2017

— Via Electronic Filing —

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

Re: January 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 January 2018.

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

January 2018	FCR rate/kWh
Residential	$0.02341
C & I Non-Demand	$0.02423
C & I Demand	$0.02391
C & I Demand Time of Day (On-Peak)	$0.03005
C & I Demand Time of Day (Off-Peak)	$0.01868
Outdoor Lighting	$0.01724

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 January 2018 FCR the net MISO Day 2 costs for November 2017 as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is $6,893,374 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 January 2018 FCR rates the net MISO ASM costs for November 2017 as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is $809,616, 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 Commission[2] 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. November margins of $667648 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 January FCR is $590. 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 $45,971. 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. 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)	

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

Northern States Power Company
Electric Utility - State of North Dakota

Summary of Fuel Cost Rider Rates - January 2018

	System Fuel and Purchased Energy Costs	4 Month Total	
1	NSP System Fuel/Energy Costs (Retail)	$329,755,444	Att B, p. 1, line 6
2	MISO Charges	$24,079,600	Att B, p. 1, line 10
3	Disallowed Purchased Power Costs	($16,122,451)	Att B, p. 1, line 14
4	Net NSP System Costs	$337,712,593	

	ND Fuel and Purchased Energy Costs	4 Month Total	
5	NSP System MWh Sales (Retail)	13,645,591	Att B, p. 1, line 16
6	Average NSP System Cost per kWh	2.475¢	line 4 / line 5/10
7	ND MWh Sales (Retail)	694,522	Att B, p. 1, line 18
8	ND Fuel & Purchased Energy Costs	$17,189,420	line 6 x line 7

	Credits and Other Adjustments Applicable to ND	November 2017	
9	Wholesale Margins	($667,058)	Att B, p. 1, line 20,21
10	REC Sales Proceeds	($45,971)	Att B, p. 1, line 22
11	Net Credits and Other	($713,029)	

	Over/Under Recovered Costs	Amount	
12	True-Up Amount for November 2017	($168,640)	Att E, p.1, line 19

	ND Net FCR Costs	4 Month Total.	
13	Net FCR Costs	$16,307,751	line 8+line 11+line 12
14	Net FCR Cost per kWh	2.348¢	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	2.348¢	0.99690	**2.341¢**
17	C & I Non-Demand	2.348¢	1.03180	**2.423¢**
18	C & I Demand Non-TOD	2.348¢	1.01840	**2.391¢**
19	C & I Demand TOD On-Peak	2.348¢	1.27980	**3.005¢**
20	C & I Demand TOD Off-Peak	2.348¢	0.79540	**1.868¢**
21	Outdoor Lighting	2.348¢	0.73410	**1.724¢**

[1] See Fuel Cost Rider Tariff.

4 Month Fuel Cost Rider Costs - January 2018

		(A)	(B)	(C)	(D)	(E)
	Fuel & Purchased Energy Costs	Aug-17	Sep-17	Oct-17	Nov-17	4 Month Total
1	Account 151 - Fossil Fuel	$41,926,846	$35,370,005	$33,417,119	$36,457,251	$147,171,221
2	Account 518 - Nuclear Fuel	$10,199,102	$9,534,887	$8,123,036	$7,621,744	$35,478,769
3	Account 555 - Purchased Power[1]	$40,822,769	$44,847,564	$48,094,374	$49,088,824	$182,853,531
4	Sub-Total NSP Sys Energy Costs	$92,948,716	$89,752,456	$89,634,529	$93,167,819	$365,503,520
5	Exclude Costs of InterSystem Sales	($8,363,988)	($6,956,938)	($9,950,534)	($10,476,616)	($35,748,076)
6	Total Sys Fuel & Purch Energy	$84,584,729	$82,795,518	$79,683,995	$82,691,203	$329,755,444
	MISO Charges					
7	Day 2 Market	$3,853,904	$4,823,302	$8,161,139	$6,995,871	$23,834,217
8	Exclude Schedule 24 Plus Congest Refund	($90,918)	($90,769)	($78,134)	($102,498)	($362,319)
9	Ancillary Services Market	$836,146	($682,262)	($355,798)	$809,616	$607,702
10	Total MISO Charges	$4,599,132	$4,050,271	$7,727,207	$7,702,990	$24,079,600
	Disallowed PPAs[2]					
11	Exclude Costs of Disallowed PPAs	($5,701,437)	($6,529,285)	($6,490,223)	($6,291,821)	($25,012,766)
12	Exclude Related Curtailment Costs	($6,492)	($15,135)	($51,721)	($2,923)	($76,271)
13	Replacement Energy Costs	$1,687,861	$2,215,216	$2,309,648	$2,753,862	$8,966,587
14	Net Disallowance	($4,020,068)	($4,329,205)	($4,232,296)	($3,540,882)	($16,122,451)
15	Net NSP System Costs	$85,163,793	$82,516,584	$83,178,905	$86,853,311	$337,712,593
	ND Fuel and Purchased Energy Costs	Aug-17	Sep-17	Oct-17	Nov-17	4 Month Total
16	NSP System Sales (Retail)	3,878,032	3,365,649	3,384,935	3,016,975	13,645,591
17	Avg. NSP System Cost per kWh	2.196¢	2.452¢	2.457¢	2.879¢	2.475¢
18	ND Sales (Retail)	193,840	167,969	169,768	162,945	694,522
19	ND Fuel & Purchased Energy Costs	$4,256,726	$4,118,600	$4,171,200	$4,691,187	$17,189,420
	Credits and True-Up					
20	Asset-Based Margins	($540,919)	($632,175)	($646,268)	($667,648)	($2,487,010)
21	Non-Asset-Based Margins	($27,324)	$1,226	($20,406)	$590	($45,914)
22	REC Sales Proceeds (100%)	($108,254)	($60,169)	($82,923)	($45,971)	($297,317)
23	Net Credits and Other	($676,497)	($691,118)	($749,597)	($713,029)	($2,830,241)

[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.

Northern States Power Company
Electric Utility - State of North Dakota

MISO Day 2 Settlement Charges - January 2018

	Energy and Losses	FERC Account	Retail Expense (Rev)
1	Day Ahead Asset Energy - Energy	555	$5,685,963
2	Day Ahead Asset Energy - Losses	555	$3,013,940
3	Day Ahead Financial Bilateral Transaction Loss	555	($705)
4	Day Ahead Non-Asset Energy - Energy	555	($3,513,700)
5	Day Ahead Non-Asset Energy - Losses	555	$292,800
6	Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	$705
7	Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	$0
8	Real Time Asset Energy - Energy	555	$1,098,337
9	Real Time Asset Energy - Losses	555	$66,809
10	Real Time Distribution of Losses	555	($783,372)
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	$72,996
14	Real Time Non-Asset Energy - Energy	555	$28,235
15	Real Time Non-Asset Energy - Losses	555	($5)
16	**Total Energy and Losses**		$5,962,004

	Congestion		
17	Day Ahead Asset Energy - Congestion	555	$1,661,247
18	Day Ahead Financial Bilateral Transaction - Congestion	555	$7,279
19	Day Ahead Non-Asset Energy - Congestion	555	$131,541
20	Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	($7,279)
21	Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	$0
22	Real Time Asset Energy - Congestion	555	$70,778
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	$3,504
26	**Total Congestion-Related**		$1,867,070

	Financial Transmission Rights (FTR)		
27	FTR Hourly Allocation	555	($1,186,296)
28	FTR Monthly Allocation	555	($400,255)
29	FTR Transaction	555	$0
30	FTR Yearly Allocation	555	$0
31	FTR Full Funding Guarantee	555	$319,992
32	FTR Guarantee Uplift	555	($349,024)
33	FTR Monthly Transaction	555	$0
34	**Total Financial Transmission Rights Charges**		($1,615,583)

MISO Day 2 Settlement Charges - January 2018

		FERC Account	Retail Expense (Rev)
	Uplift		
35	Real-Time Revenue Neutrality Uplift	555	$179,786
36	**Total Uplift**		$179,786
	Revenue Sufficiency Guarantee (RSG)		
37	Day Ahead RSG Distribution	555	$128,386
38	Day Ahead RSG Make Whole Payment	555	($94,454)
39	Real time RSG First Pass Distribution	555	$126,340
40	Real Time RSG Make Whole Payment	555	($97,600)
41	Real Time Price Volatility Make Whole Payment	555	($33,374)
42	**Total Revenue Sufficiency Guarantee**	555	$29,299
	Market Administration[1]		
43	Day Ahead Market Administration	575.7	$513,588
44	Real Time Market Administration	575.7	$32,883
45	FTR Market Administration	575.7	$20,576
46	**Total Market Administration**		$567,047
	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	$3,419,040
51	ARR Monthly Revenue	555	($3,466,860)
52	ARR Stage 2 Distribution	555	($18,212)
53	ARR Monthly Infeasible Revenue	555	$28,488
54	**Total Auction Revenue Rights**		($37,545)
	Other Miscellaneous		
55	Real Time Miscellaneous	555	($58,704)
56	Real Time Uninstructed Deviation	555	$0
57	**Total Other Miscellaneous**		($58,704)
58	**Grand Total MISO Day 2 Charges**		**$6,893,374**

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

Northern States Power Company Attachment C
Electric Utility - State of North Dakota

MISO Ancillary Services Markets (ASM) Charges - January 2018

		FERC Account	Retail Expense (Rev)
	Procurement		
1	Day Ahead Regulation	555	($98,407)
2	Day Ahead Spinning Reserve	555	($354,966)
3	Day Ahead Supplemental Reserve	555	($22,302)
4	Real Time Regulation	555	($5,733)
5	Real Time Spinning Reserve	555	$277,025
6	Real Time Supplemental Reserve	555	$1,330
7	**Total Procurement**		($203,053)
	Resource Energy		
8	Real Time Excessive Energy	555	$602
9	Real Time Excessive Energy - Congestion	555	$0
10	Real Time Excessive Energy - Losses	555	$0
11	Real Time Non-Excessive Energy	555	$835,413
12	Real Time Non-Excessive Energy - Congestion	555	($68,469)
13	Real Time Non-Excessive Energy - Losses	555	($65,988)
14	Real Time Net Regulation Adjustment	555	$2,787
15	**Total Resource Energy**		$704,345
	Cost Distribution		
16	Real Time Regulation Reserve Cost Distribution	555	$125,645
17	Real Time Spinning Reserve Cost Distribution	555	$133,782
18	Real Time Supplemental Reserve Cost Distribution	555	$22,560
19	**Total Cost Distribution**		$281,988
	Penalties		
20	Real Time Excessive/Deficient Energy Deployment	555	$26,298
21	Real Time Contingency Reserve Deployment Failure	555	$38
22	**Total Penalties**		$26,337
23	**Grand Total ASM Charges**		**$809,616**

Northern States Power Company
Electric Utility - State of North Dakota

Derivation of November 2017 Replacement Costs for Disallowed PPAs

		NSP System	ND Allocation[1]	ND Jurisdiction	
	Fuel & Purchased Energy Costs				
1	Fuel & Purch Energy Costs (Retail)[2]	$90,394,192	5.4009%	$4,882,136	Att B, Col D, line 6+10
	Disallowed PPA Costs				
2	15 C-BED Wind PPAs	($5,334,685)	5.4009%	($288,123)	
3	6 Solar PPAs	($957,137)	5.4009%	($51,694)	
4	Wind Curtailment Payments	($2,923)	5.4009%	($158)	
5	Total Exclusion	($6,294,744)		($339,975)	
6	Adjusted Fuel & Purchased Energy Costs	$84,099,448	5.4009%	$4,542,160	Line 1 - line 5
	Energy Sales (Billing Mo.)				
		[a]	[b]	[c]	
7	MWh Energy Sales	3,016,975	5.4009%	162,945	[b]=[c]/[a]
8	Disallowed PPA MWh Energy Sales	(95,655)	5.4009%	(5,166)	
9	Adjusted MWh Sales (Billing Mo.)	2,921,320		157,779	
	Replacement Costs				
10	Avg. Cost ($/MWh) w/o Disallowed PPAs	$28.79		$28.79	Line 6 / line 9
11	Replacement Cost for Disallowed PPAs[3]	$2,753,907		$148,729	Line 8 x line 10
	Impact of Disallowance				
12	Net Impact of Disallowance	($3,540,837)		($191,246)	Line 5 + line 11
13	FCR Rate Impact of Disallowance /kWh			-0.117¢	Line 12 / line 7
14	Residential Monthly Bill Impact (750 kWh)			($0.88)	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.

Northern States Power Company Attachment E

Electric Utility - State of North Dakota Page 1 of 1

Derivation of FCR True-Up Adjustment - November 2017

Cost to Recover in November 2017

		[a] Nov Sys Fuel Cost/kWh[1]	[b] Nov ND MWh Sales[2]	Amount	
1	Fuel & Purchased Energy Costs	2.879¢	162,945	$4,691,187	[a] x [b]
2	True Up Amount for September 2017			($864,250)	
3	Net Costs			$3,826,936	Line 1 + Line 2

Cost Recovered in November 2017

	Fuel & Purchased Energy	Sales	Amount	
4	(i) Residential	54,690	$1,336,358	
5	(ii) C & I Non-Demand	8,053	$203,915	
6	(iii) C & I Demand Non-TOD	55,009	$1,375,860	
7	(iv) C & I Demand TOD On-Peak	16,961	$532,878	
8	(v) C & I Demand TOD Off-Peak	26,543	$518,283	
9	(vi) Outdoor Lighting	1,689	$30,435	
10	Total	162,945	$3,997,729	
	True-Up Obligation			
11	(i) Residential	54,690	($5,469)	
12	(ii) C & I Non-Demand	8,053	($23)	
13	(iii) C & I Demand Non-TOD	55,009	$298	
14	(iv) C & I Demand TOD On-Peak	16,961	$1,467	
15	(v) C & I Demand TOD Off-Peak	26,543	$1,148	
16	(vi) Outdoor Lighting	1,689	$426	
17	Total	162,945	($2,153)	
18	Net Recovery		$3,995,576	Line 10 + Line 17

Over/Under Recovered Costs

		Amount	
19	True-Up Amount for November 2017	($168,640)	Line 3 - Line 18

[1] Reflects the average for the month of November 2017.

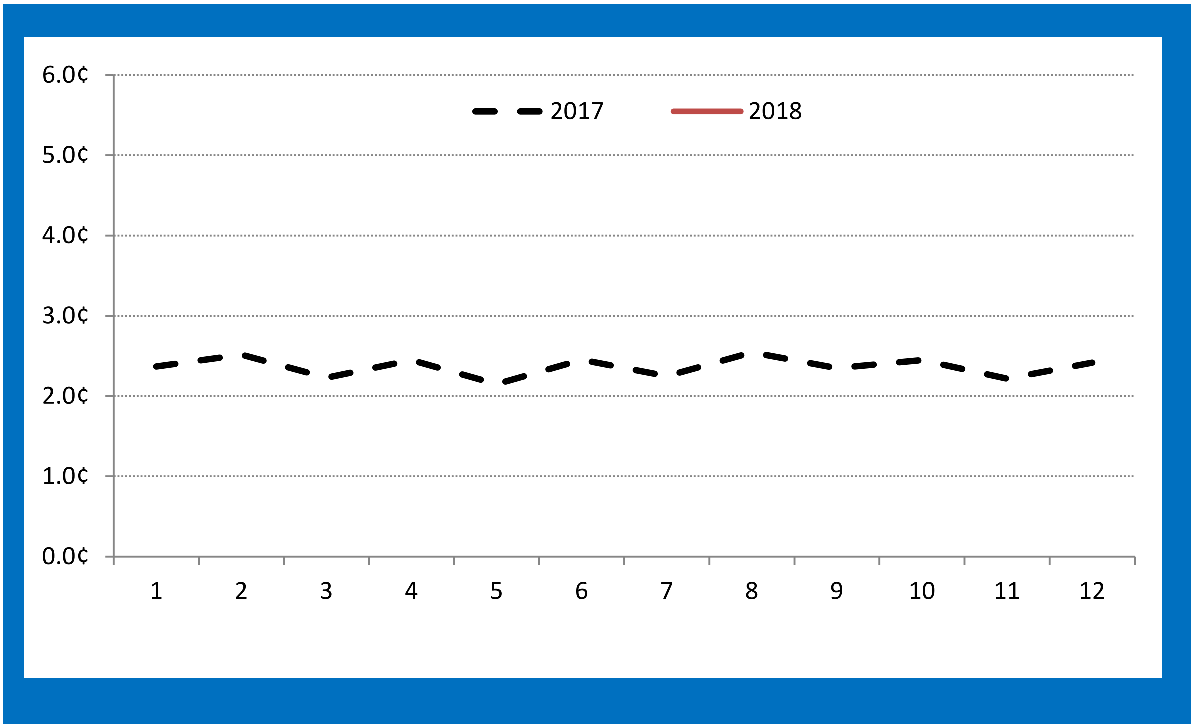
[2] Actual ND sales in month of November 2017.

Northern States Power Company
Electric Utility - State of North Dakota

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	$0	$0	$0	$0
13	**Cumulative**	**(6,744,868)**	**(173,528)**	**(282,261)**	**(7,200,656)**

Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges

		2017	Bill Impact[1]	2018	Bill Impact[1]
1	January	2.370¢	$17.78	2.341¢	$17.56
2	February	2.517¢	$18.88		
3	March	2.229¢	$16.72		
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	2.341¢	$17.56

[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	7-Month Total
1	Market Priced Cost	$377,734	$431,817	$609,372	$487,903	$538,579	$400,192	$360,301	$3,205,898
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	$9,766,732
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	$12,972,630
4	ND Billing Month Sales	168,757	169,300	181,331	193,840	167,968	169,768	162,945	1,213,909
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	23,859,135
6	ND Allocator (4)/(5)	5.42441%	4.88826%	4.98288%	4.99841%	4.99066%	5.01540%	5.40094%	5.08782%
7	Market Costs (1)	$377,734	$431,817	$609,372	$487,903	$538,579	$400,192	$360,301	$3,205,898
8	**ND Solar Gardens Allocation** (7)x(6)	**$20,490**	**$21,108**	**$30,364**	**$24,387**	**$26,879**	**$20,071**	**$19,460**	**$162,759**