414 Nicollet Mall
Minneapolis, Minnesota 55401

November 30, 2017

— Via Electronic Filing —

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

Re: December 2017 Fuel Cost Rider Rates
Case No. PU-17-12

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 December 2017.

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

December 2017	FCR rate/kWh
Residential	$0.02415
C & I Non-Demand	$0.02499
C & I Demand	$0.02467
C & I Demand Time of Day (On-Peak)	$0.03100
C & I Demand Time of Day (Off-Peak)	$0.01927
Outdoor Lighting	$0.01778

See Attachment A for the supporting calculations of these rates.

24 PU-17-12 Filed 11/30/2017 Pages: 15
December 2017 fuel cost adjustment
Northern States Power Company

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 December 2017 FCR the net MISO Day 2 costs for October 2017 as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is $8,083,005 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 December 2017 FCR rates the net MISO ASM costs for October 2017 as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is -$355,798, 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. October margins of $646,268 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 December FCR is $20,406. 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 reported during the current reporting period is $82,923. 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 2017 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 - December 2017

	System Fuel and Purchased Energy Costs	4 Month Total	
1	NSP System Fuel/Energy Costs (Retail)	$342,173,955	Att B, p. 1, line 6
2	MISO Charges	$24,214,726	Att B, p. 1, line 10
3	Disallowed Purchased Power Costs[1]	($17,197,331)	Att B, p. 1, line 14
4	Net NSP System Costs	$349,191,350	
	ND Fuel and Purchased Energy Costs	4 Month Total	
5	NSP System MWh Sales (Retail)	14,267,698	Att B, p. 1, line 16
6	Average NSP System Cost per kWh	2.447¢	line 4 / line 5/10
7	ND MWh Sales (Retail)	712,908	Att B, p. 1, line 18
8	ND Fuel & Purchased Energy Costs	$17,444,859	line 6 x line 7
	Credits and Other Adjustments Applicable to ND	October 2017	
9	Wholesale Margins	($666,674)	Att B, p. 1, line 20,21
10	REC Sales Proceeds	($82,923)	Att B, p. 1, line 22
11	Method Transition Adjustment[2]	$0	
12	Net Credits and Other	($749,597)	
	Over/Under Recovered Costs	Amount	
13	True-Up Amount for October 2017	$574,396	Att E, p.1, line 19
	ND Net FCR Costs	4 Month Total.	
14	Net FCR Costs	$17,269,658	line 8+line 12+line 13
15	Net FCR Cost per kWh	2.422¢	line 14 / line 7/10

Fuel Cost Rider Rate By Class

	Customer Class	ND Cost of Fuel/kWh	Cust. Class Ratio[3]	FCR Rate
16	Residential	2.422¢	0.99690	**2.415¢**
17	C & I Non-Demand	2.422¢	1.03180	**2.499¢**
18	C & I Demand Non-TOD	2.422¢	1.01840	**2.467¢**
19	C & I Demand TOD On-Peak	2.422¢	1.27980	**3.100¢**
20	C & I Demand TOD Off-Peak	2.422¢	0.79540	**1.927¢**
21	Outdoor Lighting	2.422¢	0.73410	**1.778¢**

[1] Excludes 17 wind and solar PPAs pursuant to March 9, 2016 Order Approving Settlement
[2] Temporary recovery adjustment to transition to new method for including offsetting proceeds in the FCR
[3] See Fuel Cost Rider Tariff

Northern States Power Company
Electric Utility - State of North Dakota

4 Month Fuel Cost Rider Costs - December 2017

		(A)	(B)	(C)	(D)	(E)
	Fuel & Purchased Energy Costs	Jul-17	Aug-17	Sep-17	Oct-17	4 Month Total
1	Account 151 - Fossil Fuel	$48,664,413	$41,926,846	$35,370,005	$33,417,119	$159,378,383
2	Account 518 - Nuclear Fuel	$10,193,117	$10,199,102	$9,534,887	$8,123,036	$38,050,142
3	Account 555 - Purchased Power[1]	$46,369,120	$40,822,769	$44,847,564	$48,094,374	$180,133,827
4	Sub-Total NSP Sys Energy Costs	$105,226,650	$92,948,716	$89,752,456	$89,634,529	$377,562,352
5	Exclude Costs of InterSystem Sales	($10,116,936)	($8,363,988)	($6,956,938)	($9,950,534)	($35,388,397)
6	Total Sys Fuel & Purch Energy	$95,109,714	$84,584,729	$82,795,518	$79,683,995	$342,173,955
	MISO Charges					
7	Day 2 Market	$5,481,308	$3,853,904	$4,823,302	$8,161,139	$22,319,653
8	Exclude Schedule 24 Plus Congest Refund	($63,879)	($90,918)	($90,739)	($78,134)	($323,670)
9	Ancillary Services Market	$2,420,656	$836,146	($682,262)	($355,798)	$2,218,742
10	Total MISO Charges	$7,838,085	$4,599,132	$4,050,301	$7,727,207	$24,214,726
	Disallowed PPAs[2]					
11	Exclude Costs of Disallowed PPAs	($7,296,762)	($5,701,437)	($6,529,285)	($6,490,223)	($26,017,707)
12	Exclude Related Curtailment Costs	$14,142	($6,492)	($15,135)	($51,721)	($59,206)
13	Replacement Energy Costs	$2,666,857	$1,687,861	$2,215,216	$2,309,648	$8,879,582
14	Net Disallowance	($4,615,762)	($4,020,068)	($4,329,205)	($4,232,296)	($17,197,331)
15	Net NSP System Costs	$98,332,037	$85,163,793	$82,516,614	$83,178,905	$349,191,350
	ND Fuel and Purchased Energy Costs	Jul-17	Aug-17	Sep-17	Oct-17	4 Month Total
16	NSP System Sales (Retail)	3,639,082	3,878,032	3,365,649	3,384,935	14,267,698
17	Avg. NSP System Cost per kWh	2.702¢	2.196¢	2.452¢	2.457¢	2.447¢
18	ND Sales (Retail)	181,331	193,840	167,969	169,768	712,908
19	ND Fuel & Purchased Energy Costs	$4,899,564	$4,256,726	$4,118,600	$4,171,200	$17,444,859
	Credits and True-Up					
20	Asset-Based Margins	($655,165)	($540,919)	($632,175)	($646,268)	($2,474,527)
21	Non-Asset-Based Margins	$2,222	($27,324)	$1,226	($20,406)	($44,282)
22	REC Sales Proceeds (100%)	($78,098)	($108,254)	($60,169)	($82,923)	($329,444)
23	Net Credits and Other	($731,041)	($676,497)	($691,118)	($749,597)	($2,848,253)

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 Attachment C
Electric Utility - State of North Dakota Page 1 of 3

MISO Day 2 Settlement Charges - December 2017

		FERC Account	Retail Expense (Rev)
	Energy and Losses		
1	Day Ahead Asset Energy - Energy	555	$9,965,167
2	Day Ahead Asset Energy - Losses	555	$2,114,833
3	Day Ahead Financial Bilateral Transaction Loss	555	($3,801)
4	Day Ahead Non-Asset Energy - Energy	555	($8,797,500)
5	Day Ahead Non-Asset Energy - Losses	555	$1,187,726
6	Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	$3,801
7	Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	$0
8	Real Time Asset Energy - Energy	555	$2,417,906
9	Real Time Asset Energy - Losses	555	$33,044
10	Real Time Distribution of Losses	555	($792,348)
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	($64,967)
14	Real Time Non-Asset Energy - Energy	555	$12,659
15	Real Time Non-Asset Energy - Losses	555	($506)
16	**Total Energy and Losses**		$6,076,013
	Congestion		
17	Day Ahead Asset Energy - Congestion	555	$2,747,803
18	Day Ahead Financial Bilateral Transaction - Congestion	555	($3,574)
19	Day Ahead Non-Asset Energy - Congestion	555	$1,799,301
20	Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	$3,574
21	Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	$0
22	Real Time Asset Energy - Congestion	555	$75,587
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	($26,745)
26	**Total Congestion-Related**		$4,595,946
	Financial Transmission Rights (FTR)		
27	FTR Hourly Allocation	555	($4,426,239)
28	FTR Monthly Allocation	555	($208,971)
29	FTR Transaction	555	$0
30	FTR Yearly Allocation	555	$0
31	FTR Full Funding Guarantee	555	($254,090)
32	FTR Guarantee Uplift	555	$258,311
33	FTR Monthly Transaction	555	$0
34	**Total Financial Transmission Rights Charges**		($4,630,990)

Northern States Power Company
Electric Utility - State of North Dakota

MISO Day 2 Settlement Charges - December 2017

		FERC Account	Retail Expense (Rev)
	Uplift		
35	Real-Time Revenue Neutrality Uplift	555	$1,301,794
36	**Total Uplift**		$1,301,794
	Revenue Sufficiency Guarantee (RSG)		
37	Day Ahead RSG Distribution	555	$79,029
38	Day Ahead RSG Make Whole Payment	555	($35,200)
39	Real time RSG First Pass Distribution	555	$242,005
40	Real Time RSG Make Whole Payment	555	($18,549)
41	Real Time Price Volatility Make Whole Payment	555	($423,493)
42	**Total Revenue Sufficiency Guarantee**	555	($156,208)
	Market Administration[1]		
43	Day Ahead Market Administration	575.7	$733,769
44	Real Time Market Administration	575.7	$55,787
45	FTR Market Administration	575.7	$27,509
46	**Total Market Administration**		$817,066
	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	($3,465,884)
52	ARR Stage 2 Distribution	555	($18,212)
53	ARR Monthly Infeasible Revenue	555	$28,488
54	**Total Auction Revenue Rights**		($36,569)
	Other Miscellaneous		
55	Real Time Miscellaneous	555	$115,953
56	Real Time Uninstructed Deviation	555	$0
57	**Total Other Miscellaneous**		$115,953
58	**Grand Total MISO Day 2 Charges**		**$8,083,005**

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

Northern States Power Company
Electric Utility - State of North Dakota

MISO Ancillary Services Markets (ASM) Charges - December 2017

		FERC Account	Retail Expense (Rev)
	Procurement		
1	Day Ahead Regulation	555	($261,288)
2	Day Ahead Spinning Reserve	555	($542,721)
3	Day Ahead Supplemental Reserve	555	($25,670)
4	Real Time Regulation	555	$125,329
5	Real Time Spinning Reserve	555	$427,724
6	Real Time Supplemental Reserve	555	$3,842
7	**Total Procurement**		($272,784)
	Resource Energy		
8	Real Time Excessive Energy	555	$11,338
9	Real Time Excessive Energy - Congestion	555	$0
10	Real Time Excessive Energy - Losses	555	$0
11	Real Time Non-Excessive Energy	555	($81,050)
12	Real Time Non-Excessive Energy - Congestion	555	($328,311)
13	Real Time Non-Excessive Energy - Losses	555	($60,663)
14	Real Time Net Regulation Adjustment	555	($47,684)
15	**Total Resource Energy**		($506,370)
	Cost Distribution		
16	Real Time Regulation Reserve Cost Distribution	555	$173,396
17	Real Time Spinning Reserve Cost Distribution	555	$156,539
18	Real Time Supplemental Reserve Cost Distribution	555	$32,868
19	**Total Cost Distribution**		$362,803
	Penalties		
20	Real Time Excessive/Deficient Energy Deployment	555	$56,110
21	Real Time Contingency Reserve Deployment Failure	555	$4,444
22	**Total Penalties**		$60,554
23	**Grand Total ASM Charges**		**($355,798)**

Northern States Power Company
Electric Utility - State of North Dakota

Derivation of October 2017 Replacement Costs for Disallowed PPAs

	Fuel & Purchased Energy Costs	NSP System	ND Allocation[1]	ND Jurisdiction	
1	Fuel & Purch Energy Costs (Retail)[2]	$87,411,202	5.0154%	$4,384,021	Att B, Col D, line 6+10
	Disallowed PPA Costs				
2	15 C-BED Wind PPAs	($4,610,852)	5.0154%	($231,253)	
3	6 Solar PPAs	($1,879,371)	5.0154%	($94,258)	
4	Wind Curtailment Payments	($51,721)	5.0154%	($2,594)	
5	Total Exclusion	($6,541,944)		($328,105)	
6	Adjusted Fuel & Purchased Energy Costs	$80,869,258	5.0154%	$4,055,916	Line 1 - line 5
	Energy Sales (Billing Mo.)				
		[a]	[b]	[c]	
7	MWh Energy Sales	3,384,935	5.0154%	169,768	[b]=[c]/[a]
8	Disallowed PPA MWh Energy Sales	(94,002)	5.0154%	(4,715)	
9	Adjusted MWh Sales (Billing Mo.)	3,290,933		165,053	
	Replacement Costs				
10	Avg. Cost ($/MWh) w/o Disallowed PPAs	$24.57		$24.57	Line 6 / line 9
11	Replacement Cost for Disallowed PPAs[3]	$2,309,629		$115,848	Line 8 x line 10
	Impact of Disallowance				
12	Net Impact of Disallowance	($4,232,315)		($212,257)	Line 5 + line 11
13	FCR Rate Impact of Disallowance /kWh			-0.125¢	Line 12 / line 7
14	Residential Monthly Bill Impact (750 kWh)			($0.94)	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 - October 2017

Cost to Recover in October 2017

		[a] Oct Sys Fuel Cost/kWh[1]	[b] Oct ND MWh Sales[2]	Amount	
1	Fuel & Purchased Energy Costs	2.457¢	169,768	$4,171,200	[a] x [b]
2	True Up Amount for August 2017			$667,139	
3	Net Costs			$4,838,338	Line 1 + Line 2

Cost Recovered in October 2017

		Sales	Amount	
	Fuel & Purchased Energy			
4	(i) Residential	48,550	$1,215,736	
5	(ii) C & I Non-Demand	7,788	$202,168	
6	(iii) C & I Demand Non-TOD	64,389	$1,649,360	
7	(iv) C & I Demand TOD On-Peak	18,667	$600,811	
8	(v) C & I Demand TOD Off-Peak	28,896	$578,049	
9	(vi) Outdoor Lighting	1,478	$27,481	
10	Total	169,768	$4,273,605	
	True-Up Obligation			
11	(i) Residential	48,550	($2,128)	
12	(ii) C & I Non-Demand	7,788	($659)	
13	(iii) C & I Demand Non-TOD	64,389	($3,077)	
14	(iv) C & I Demand TOD On-Peak	18,667	($1,581)	
15	(v) C & I Demand TOD Off-Peak	28,896	($1,774)	
16	(vi) Outdoor Lighting	1,478	($444)	
17	Total	169,768	($9,663)	
18	Net Recovery		$4,263,942	Line 10 + Line 17

Over/Under Recovered Costs

19	True-Up Amount for October 2017	$574,396	Line 3 - Line 18

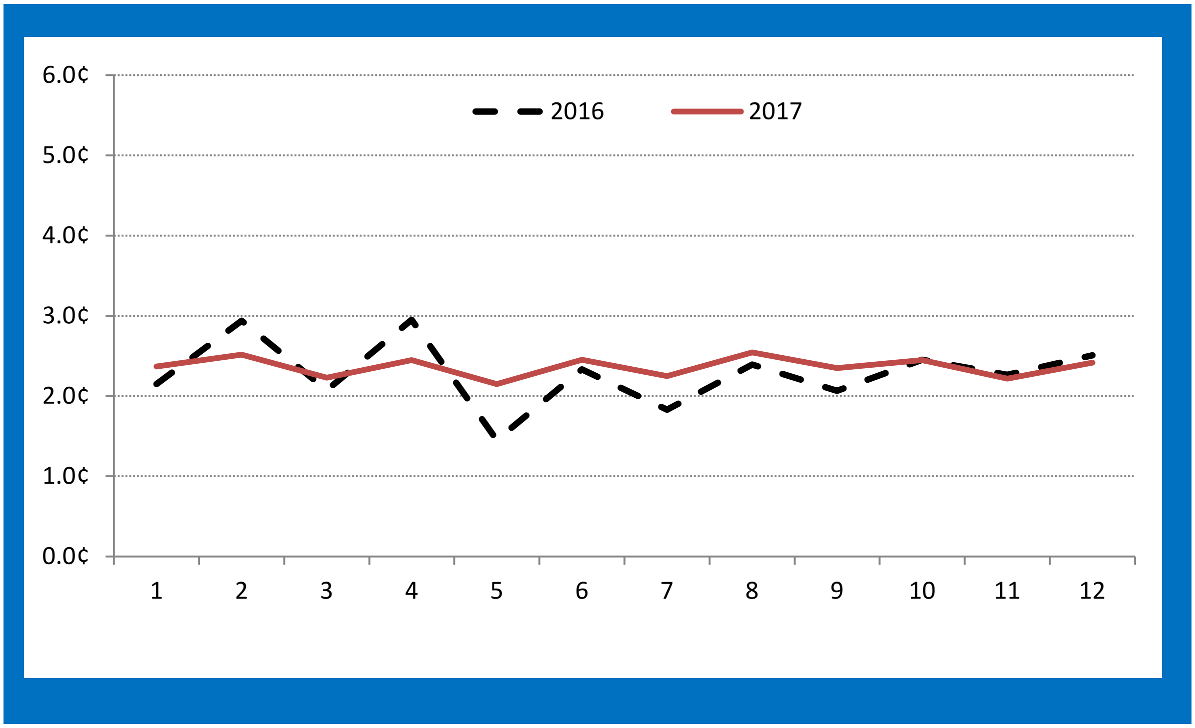
[1] Reflects the average for the month of October 2017.
[2] Actual ND sales in month of October 2017.

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	$0	$0	$0	$0
12	December	$0	$0	$0	$0
13	**Cumulative**	**(6,077,220)**	**(174,117)**	**(236,290)**	**(6,487,627)**

Historical Trend of FCR Charges (Residential)



	Residential Fuel Cost Charges	2016	Typical Bill Impact[1]	2017	Typical Bill Impact[1]
1	January	2.148¢	$16.11	2.370¢	$17.78
2	February	2.939¢	$22.04	2.517¢	$18.88
3	March	2.073¢	$15.55	2.229¢	$16.72
4	April	2.950¢	$22.13	2.448¢	$18.36
5	May	1.450¢	$10.88	2.148¢	$16.11
6	June	2.332¢	$17.49	2.452¢	$18.39
7	July	1.829¢	$13.72	2.248¢	$16.86
8	August	2.394¢	$17.96	2.545¢	$19.09
9	September	2.067¢	$15.50	2.349¢	$17.62
10	October	2.454¢	$18.41	2.449¢	$18.37
11	November	2.266¢	$17.00	2.218¢	$16.64
12	December	2.510¢	$18.83	2.415¢	$18.11
13	Average	2.284¢	$17.13	2.366¢	$17.74

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

Northern States Power Company
Electric Utility - State of North Dakota

Community Solar Garden Costs Allocated To North Dakota FCA

		May 2017	June 2017	July 2017	August 2017	September 2017	October 2017	Total
1	Market Priced Cost	$377,734.48	$431,817.32	$609,371.58	$487,902.59	$538,578.55	$400,191.80	$2,845,596.32
2	Above Market Cost	$1,302,630.78	$1,314,177.16	$1,545,018.43	$1,083,507.58	$1,403,783.15	$1,491,176.78	$8,140,293.88
3	Total Solar Gardens (1)+(2)	$1,680,365.26	$1,745,994.48	$2,154,390.01	$1,571,410.17	$1,942,361.70	$1,891,368.58	$10,985,890.20
4	ND Billing Month Sales	168,757	169,300	181,331	193,840	167,968	169,768	1,050,964
5	Billing Month System Sales	3,111,065	3,463,397	3,639,082	3,878,032	3,365,649	3,384,935	20,842,160
6	ND Allocator (4)/(5)	5.42441%	4.88826%	4.98288%	4.99841%	4.99066%	5.01540%	5.04249%
7	Market Costs (1)	$377,734.48	$431,817.32	$609,371.58	$487,902.59	$538,578.55	$400,191.80	$2,845,596.32
8	**ND Solar Gardens Allocation** (7)x(6)	**$20,489.88**	**$21,108.37**	**$30,364.24**	**$24,387.38**	**$26,878.61**	**$20,071.22**	**$143,299.70**