414 Nicollet Mall
Minneapolis, Minnesota 55401

February 28, 2019

— Via Electronic Filing —

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

Re: March 2019 Fuel Cost Rider Rates
Case No. PU-19-xxx

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 March 2019.

The table below shows the FCR rates by customer class:

March 2019	FCR rate/kWh
Residential	$0.02451
C & I Non-Demand	$0.02537
C & I Demand	$0.02504
C & I Demand Time of Day (On-Peak)	$0.03147
C & I Demand Time of Day (Off-Peak)	$0.01956
Outdoor Lighting	$0.01805

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 FCR the net MISO Day 2 costs for January as recorded in Account 555. The MISO Day 2 cost recovery included in this month's FCR is $13,173,608 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 FCR rates the net MISO ASM costs for December as recorded in Account 555. The MISO ASM cost recovery included in this month's FCR is $955,970, 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 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.[2] January margins of $799,396 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 2018 Non-Asset Based Margin amount applicable to the March FCR is $22,888. 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

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[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

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. The REC sales credit for the current reporting period is $158,376. See Attachments B and F.

Refund of NSP Gain on Inver Hills Asset Sale Flint Hill Resources Pine Bend, LLC
Pursuant to Commission Order dated February 6, 2019 under Case No. PU-18-118, the Company is granted a waiver to credit the entire North Dakota gain of $218,000 from the sale of certain assets at the Company's Inver Hills Generating plant in Inver Grove Heights, MN to Flint Hills Resources Pine Bend, LLC. to North Dakota customers through the Fuel Cost Rider. The Company has included this one time refund in March fuel cost charges in accordance with the 2013 test year customer class allocations proposed in Company's supplemental filing dated June 12, 2018.

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

3. North Star Solar PV (100 MW)[5]
4. Aurora Distributed Solar (100 MW)[6]

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. Beginning with September 2018, a new solar PPA, Dragonfly Solar is added to the exclusion list. 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)	18. Dragonfly Solar, LLC (0.8 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 FCR 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.

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 March FCR includes $61,587

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[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).

in termination cost recovery. The itemized cost recovery information is found in Attachment F.

MONTHLY FCR RATE CALCULATION AND SUPPORTING DOCUMENTS

This filing includes the following supporting documents:

- Attachment A – Summary of Calculation of the Monthly 2019 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 /

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 - March 2019

	System Fuel and Purchased Energy Costs	4 Month Total	
1	NSP System Fuel/Energy Costs (Retail)	$287,344,304	Att B, p. 1, line 6
2	MISO Charges	$44,098,978	Att B, p. 1, line 10
3	Disallowed Purchased Power Costs	($13,068,209)	Att B, p. 1, line 14
4	Net NSP System Costs	$318,375,072	
	ND Fuel and Purchased Energy Costs	4 Month Total	
5	NSP System MWh Sales (Retail)	13,465,160	Att B, p. 1, line 16
6	Average NSP System Cost per kWh	2.364¢	line 4 / line 5/10
7	ND MWh Sales (Retail)	764,253	Att B, p. 1, line 18
8	ND Fuel & Purchased Energy Costs	$18,066,941	line 6 x line 7
	Credits and Other Adjustments Applicable to ND	January 2019	
9	Wholesale Margins Credit	($822,284)	Att B, p. 1, line 20,21
10	REC Sales Proceeds Credit	($158,376)	Att B, p. 1, line 22
11	Biomass PPA Termination Costs	$61,587	Att B, p. 1, line 23
12	Net Credits and Other	($919,073)	
	Over/Under Recovered Costs	Amount	
13a	True-Up Amount for January 2019	$1,861,379	Att E, p.1, line 19
13b	Special One-Time Refund Gain on Inver Hills Asset Sale	($218,000)	Att B, p.1, line 25
	ND Net FCR Costs	4 Month Total.	
14	Net FCR Costs	$18,791,247	line 8+line 12+line 13ab
15	Net FCR Cost per kWh	2.459¢	line 14 / line 7/10

Fuel Cost Rider Rate By Class

	Customer Class	ND Cost of Fuel/kWh	Cust. Class Ratio[1]	FCR Rate
16	Residential	2.459¢	0.99690	**2.451¢**
17	C & I Non-Demand	2.459¢	1.03180	**2.537¢**
18	C & I Demand Non-TOD	2.459¢	1.01840	**2.504¢**
19	C & I Demand TOD On-Peak	2.459¢	1.27980	**3.147¢**
20	C & I Demand TOD Off-Peak	2.459¢	0.79540	**1.956¢**
21	Outdoor Lighting	2.459¢	0.73410	**1.805¢**

[1] See Fuel Cost Rider Tariff.

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Electric Utility - State of North Dakota

4 Month Fuel Cost Rider Costs - March 2019

		(A)	(B)	(C)	(D)	(E)
	Fuel & Purchased Energy Costs	Oct-18	Nov-18	Dec-18	Jan-19	4 Month Total
1	Account 151 - Fossil Fuel	$38,990,862	$45,454,418	$43,546,149	$46,075,337	$174,066,765
2	Account 518 - Nuclear Fuel	$7,591,733	$10,212,886	$10,920,319	$10,475,574	$39,200,512
3	Account 555 - Purchased Power[1]	$39,924,176	$29,477,456	$36,313,937	$40,005,397	$145,720,965
4	Sub-Total NSP Sys Energy Costs	$86,506,771	$85,144,760	$90,780,405	$96,556,307	$358,988,243
5	Exclude Costs of InterSystem Sales	($13,833,029)	($15,701,935)	($20,953,148)	($21,155,828)	($71,643,939)
6	Total Sys Fuel & Purch Energy	$72,673,742	$69,442,825	$69,827,257	$75,400,480	$287,344,304
	MISO Charges					
7	Day 2 Market	$10,493,511	$7,436,250	$7,176,376	$13,266,933	$38,373,071
8	Exclude Schedule 24	($101,812)	($105,958)	($96,697)	($93,325)	($397,793)
9	Ancillary Services Market	$2,750,673	$992,158	$1,424,899	$955,970	$6,123,700
10	Total MISO Charges	$13,142,373	$8,322,451	$8,504,577	$14,129,577	$44,098,978
	Disallowed PPA Costs[2]					
11	Exclude Costs of Disallowed PPAs	($5,851,321)	($4,810,315)	($4,567,866)	($5,463,320)	($20,692,821)
12	Exclude Related Curtailment Costs	($13,988)	($22,138)	($22,138)	($146,127)	($204,391)
13	Replacement Energy Costs	$2,103,515	$1,924,313	$1,636,081	$2,165,094	$7,829,003
14	Net Disallowance	($3,761,794)	($2,908,139)	($2,953,922)	($3,444,353)	($13,068,209)
15	Net NSP System Costs	$82,054,320	$74,857,136	$75,377,912	$86,085,704	$318,375,072
	ND Fuel and Purchased Energy Costs	Oct-18	Nov-18	Dec-18	Jan-19	4 Month Total
16	NSP System Sales (Retail)	3,450,768	2,945,898	3,412,341	3,656,153	13,465,160
17	Avg. NSP System Cost per kWh	2.378¢	2.541¢	2.209¢	2.355¢	2.364¢
18	ND Sales (Retail)	173,720	161,751	203,104	225,678	764,253
19	ND Fuel & Purchased Energy Costs	$4,131,062	$4,110,093	$4,486,567	$5,313,686	$18,066,941
	Other Adjustments and True-Up					
20	Asset-Based Margins	($613,055)	($965,465)	($718,434)	($799,396)	($3,096,350)
21	Non-Asset-Based Margins	($3,260)	($18,417)	($3,418)	($22,888)	($47,983)
22	REC Sales Proceeds (100%)	($108,486)	($238,292)	($80,275)	($158,376)	($585,429)
23	Biomass PPA Termination Costs[3]	$110,184	$108,018	$107,284	$61,587	$387,073
24	Net Credits and Other	($614,617)	($1,114,156)	($694,843)	($919,073)	($3,342,689)
	Special One-Time Refund					
25	Gain of Inver Hills Asset Sale[4]				($218,000)	($218,000)

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 dockets.

3 Benson, Laurentian and Pine Bend PPAs.

4 NSP FCA Waiver Approval, Case No. PU-18-118 dated February 6, 2019.

Northern States Power Company
Electric Utility - State of North Dakota

MISO Day 2 Settlement Charges - March 2019

		FERC Account	Retail Expense (Rev)
	Energy and Losses		
1	Day Ahead Asset Energy - Energy	555	$11,214,401
2	Day Ahead Asset Energy - Losses	555	$3,488,042
3	Day Ahead Financial Bilateral Transaction Loss	555	$1,798
4	Day Ahead Non-Asset Energy - Energy	555	($2,760,060)
5	Day Ahead Non-Asset Energy - Losses	555	$213,463
6	Day Ahead Losses Rebate on Carve-out Grandfathered Agreements	555	($1,798)
7	Day Ahead Losses Rebate on Option B Grandfathered Agreements	555	$0
8	Real Time Asset Energy - Energy	555	$952,621
9	Real Time Asset Energy - Losses	555	($81,323)
10	Real Time Distribution of Losses	555	($1,146,337)
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	($50,899)
14	Real Time Non-Asset Energy - Energy	555	$1,843
15	Real Time Non-Asset Energy - Losses	555	$0
16	**Total Energy and Losses**		$11,831,752
	Congestion		
17	Day Ahead Asset Energy - Congestion	555	$1,996,617
18	Day Ahead Financial Bilateral Transaction - Congestion	555	$11,651
19	Day Ahead Non-Asset Energy - Congestion	555	($35,883)
20	Day Ahead Congestion Rebate - Carve-out Grandfather Agreements	555	($11,651)
21	Day Ahead Congestion Rebate - Option B Grandfather Agreements	555	$0
22	Real Time Asset Energy - Congestion	555	($168,205)
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**		$1,792,528
	Financial Transmission Rights (FTR)		
27	FTR Hourly Allocation	555	($381,906)
28	FTR Monthly Allocation	555	($90,158)
29	FTR Transaction	555	$0
30	FTR Yearly Allocation	555	($426,288)
31	FTR Full Funding Guarantee	555	$435,503
32	FTR Guarantee Uplift	555	($473,347)
33	FTR Monthly Transaction	555	$0
34	**Total Financial Transmission Rights Charges**		($936,195)

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Electric Utility - State of North Dakota

MISO Day 2 Settlement Charges - March 2019

		FERC Account	Retail Expense (Rev)
	Uplift		
35	Real-Time Revenue Neutrality Uplift	555	$11,045
36	**Total Uplift**		$11,045
	Revenue Sufficiency Guarantee (RSG)		
37	Day Ahead RSG Distribution	555	$90,772
38	Day Ahead RSG Make Whole Payment	555	($32,639)
39	Real time RSG First Pass Distribution	555	$64,031
40	Real Time RSG Make Whole Payment	555	($120,267)
41	Real Time Price Volatility Make Whole Payment	555	($44,762)
42	**Total Revenue Sufficiency Guarantee**	555	($42,866)
	Market Administration[1]		
43	Day Ahead Market Administration	575.7	$398,079
44	Real Time Market Administration	575.7	$25,057
45	FTR Market Administration	575.7	$29,177
46	**Total Market Administration**		$452,313
	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	$1,791,300
51	ARR Monthly Revenue	555	($1,675,105)
52	ARR Stage 2 Distribution	555	($153,247)
53	ARR Monthly Infeasible Revenue	555	$42,390
54	**Total Auction Revenue Rights**		$5,338
	Other Miscellaneous		
55	Real Time Miscellaneous	555	$59,691
56	Real Time Uninstructed Deviation	555	$0
57	**Total Other Miscellaneous**		$59,691
58	**Grand Total MISO Day 2 Charges**		**$13,173,608**

[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 - March 2019

		FERC Account	Retail Expense (Rev)
	Procurement		
1	Day Ahead Regulation	555	($65,489)
2	Day Ahead Spinning Reserve	555	($147,034)
3	Day Ahead Supplemental Reserve	555	($94,408)
4	Real Time Regulation	555	($36,441)
5	Real Time Spinning Reserve	555	($69,968)
6	Real Time Supplemental Reserve	555	$142,127
7	**Total Procurement**		($271,214)
	Resource Energy		
8	Real Time Excessive Energy	555	($4,808)
9	Real Time Excessive Energy - Congestion	555	$0
10	Real Time Excessive Energy - Losses	555	$0
11	Real Time Non-Excessive Energy	555	$830,010
12	Real Time Non-Excessive Energy - Congestion	555	$140,707
13	Real Time Non-Excessive Energy - Losses	555	$5,458
14	Real Time Net Regulation Adjustment	555	($1,522)
15	**Total Resource Energy**		$969,846
	Cost Distribution		
16	Real Time Regulation Reserve Cost Distribution	555	$116,559
17	Real Time Spinning Reserve Cost Distribution	555	$100,795
18	Real Time Supplemental Reserve Cost Distribution	555	$14,041
19	**Total Cost Distribution**		$231,395
	Penalties		
20	Real Time Excessive/Deficient Energy Deployment	555	$25,942
21	Real Time Contingency Reserve Deployment Failure	555	$0
22	**Total Penalties**		$25,942
23	**Grand Total ASM Charges**		**$955,970**

Northern States Power Company
Electric Utility - State of North Dakota

Derivation of January 2019 Replacement Costs for Disallowed PPAs

	Fuel & Purchased Energy Costs	NSP System	ND Allocation[1]	ND Jurisdiction	
1	Fuel & Purch Energy Costs (Retail)[2]	$89,029,697	6.1726%	$5,495,406	Att B, Col D, line 6+10
	Disallowed PPA Costs				
2	15 C-BED Wind PPAs	($4,103,725)	6.1726%	($253,305)	
3	7 Solar PPAs	($1,359,595)	6.1726%	($83,922)	
4	Wind Curtailment Payments	($146,127)	6.1726%	($9,020)	
5	Total Exclusion	($5,609,447)		($346,246)	
6	Adjusted Fuel & Purchased Energy Costs	$83,420,250	6.1726%	$5,149,160	Line 1 - line 5
	Energy Sales (Billing Mo.)				
		[a]	[b]	[c]	
7	MWh Energy Sales	3,656,153	6.1726%	225,678	[b]=[c]/[a]
8	Disallowed PPA MWh Energy Sales	(92,522)	6.1726%	(5,711)	
9	Adjusted MWh Sales (Billing Mo.)	3,563,631		219,967	
	Replacement Costs				
10	Avg. Cost ($/MWh) w/o Disallowed PPAs	$23.41		$23.41	Line 6 / line 9
11	Replacement Cost for Disallowed PPAs[3]	$2,165,946		$133,695	Line 8 x line 10
	Impact of Disallowance				
12	Net Impact of Disallowance	($3,443,501)		($212,552)	Line 5 + line 11
13	FCR Rate Impact of Disallowance /kWh			-0.094¢	Line 12 / line 7
14	Residential Monthly Bill Impact (750 kWh)			($0.71)	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
Electric Utility - State of North Dakota

Derivation of FCR True-Up Adjustment - January 2019

Cost to Recover in January 2019

		[a] Jan Sys Fuel Cost/kWh[1]	[b] Jan ND MWh Sales[2]	Amount	
1	Fuel & Purchased Energy Costs	2.355¢	225,678	$5,314,717	
2	True Up Amount for November 2018			$1,988,704	
3	Net Costs			$7,303,421	Line 1 + Line 2

Cost Recovered in January 2019

	Fuel & Purchased Energy	Sales	Amount	
4	(i) Residential	93,551	$2,210,786	
5	(ii) C & I Non-Demand	12,120	$296,414	
6	(iii) C & I Demand Non-TOD	68,433	$1,651,661	
7	(iv) C & I Demand TOD On-Peak	17,737	$538,143	
8	(v) C & I Demand TOD Off-Peak	31,777	$599,207	
9	(vi) Outdoor Lighting	2,060	$35,791	
10	Total	225,678	$5,332,002	
	True-Up Obligation			
11	(i) Residential	93,551	$44,934	
12	(ii) C & I Non-Demand	12,120	$5,848	
13	(iii) C & I Demand Non-TOD	68,433	$32,624	
14	(iv) C & I Demand TOD On-Peak	17,737	$12,817	
15	(v) C & I Demand TOD Off-Peak	31,777	$14,254	
16	(vi) Outdoor Lighting	2,060	($437)	
17	Total	225,678	$110,040	
18	Net Recovery		$5,442,042	Line 10 + Line 17

Over/Under Recovered Costs

19	True-Up Amount for January 2019	$1,861,379	Line 3 - Line 18

Special One Time Refund

20	Inver Hill Asset Sales Refund	($218,000)

[1] Reflects the average for the month of January 2019.
[2] Actual ND sales in month of January 2019.
[3] Correction for August Recovery Data Entry Error in October FCR.

Northern States Power Company
Electric Utility - State of North Dakota

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

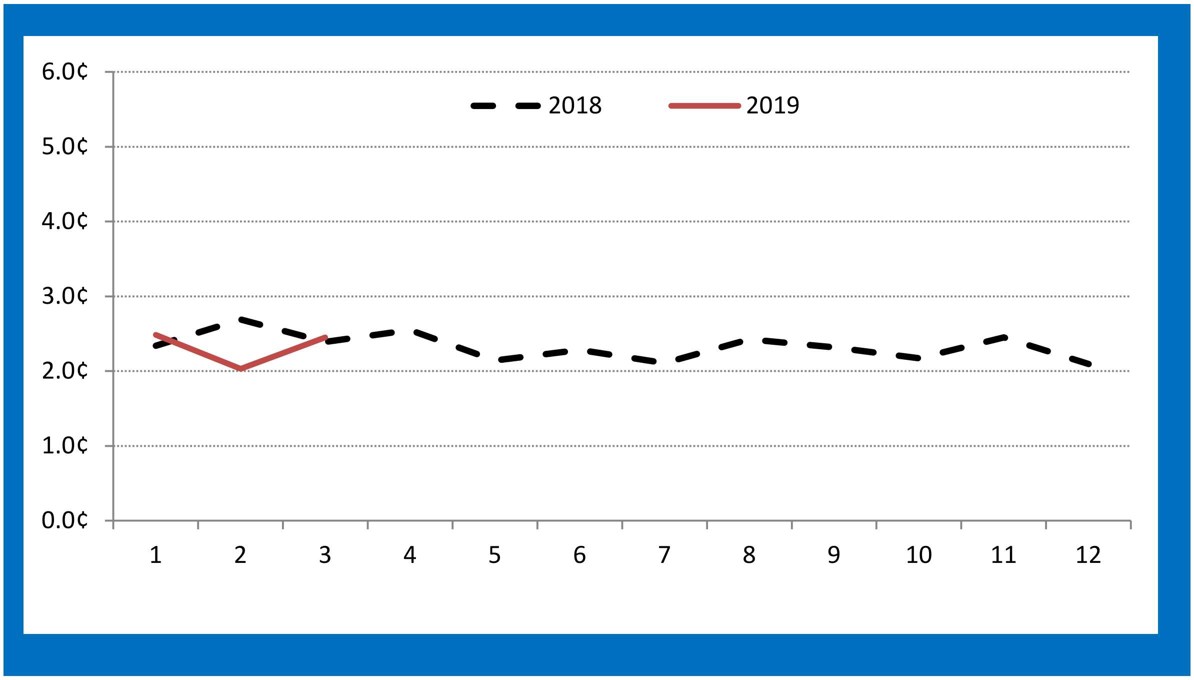
Margin Sharing and REC Sales Proceeds Credits

	Month	Asset Based Margins	Non-Asset Based Margins		Renewable Energy Credits	Total
1	January	($799,396)	($22,888)		($158,376)	($980,660)
2	February					
3	March					
4	April					
5	May					
6	June					
7	July					
8	August					
9	September					
10	October					
11	November					
12	December					
13	**Cumulative**	**($799,396)**	**($22,888)**		**($158,376)**	**($980,660)**

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	$22,349	$20,786	$8,123	$8,121	$0	$2,208	$61,587
15	February							
16	March							
17	April							
18	May							
19	June							
20	July							
21	August							
22	September							
23	October							
24	November							
25	December							
26	**Cumulative**	**$22,349**	**$20,786**	**$8,123**	**$8,121**	**$0**	**$2,208**	**$61,587**

Historical Trend of FCR Charges (Residential)



Residential Fuel Cost Charges

		2018	Bill Impact[1]	2019	Bill Impact[1]
1	January	2.341¢	$17.56	2.486¢	$18.65
2	February	2.691¢	$20.18	2.030¢	$15.23
3	March	2.392¢	$17.94	2.451¢	$18.38
4	April	2.548¢	$19.11		
5	May	2.144¢	$16.08		
6	June	2.282¢	$17.12		
7	July	2.108¢	$15.81		
8	August	2.426¢	$18.20		
9	September	2.318¢	$17.39		
10	October	2.171¢	$16.28		
11	November	2.451¢	$18.38		
12	December	2.093¢	$15.70		
13	Average	2.330¢	$17.48	2.322¢	$17.42

[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

	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	12-Month Total
1 Market Priced Cost	$708,550	$833,890	$1,403,964	$2,080,074	$1,591,746	$2,363,416	$2,082,538	$1,703,371	$1,342,849	($320,333)	$1,769,155	$1,043,793	$16,603,013
2 Above Market Cost	$1,910,837	$5,048,402	$5,548,760	$5,580,368	$5,026,916	$7,826,811	$4,911,139	$5,731,902	$5,050,152	$3,994,342	$2,828,022	$3,657,470	$57,115,121
3 Total Solar Gardens (1)+(2)	$2,619,387	$5,882,292	$6,952,724	$7,660,442	$6,618,662	$10,190,227	$6,993,677	$7,435,273	$6,393,000	$3,674,009	$4,597,177	$4,701,263	$73,718,134
4 ND Billing Month Sales	198,296	212,774	178,066	169,590	175,959	193,528	202,286	162,857	173,720	161,751	203,104	225,678	2,257,609
5 Billing Month System Sales	3,255,949	3,476,022	3,108,286	3,159,098	3,542,386	3,986,141	4,035,254	3,439,026	3,450,768	2,945,898	3,412,341	3,656,153	41,467,322
6 ND Allocator (4)/(5)	6.09027%	6.12119%	5.72875%	5.36830%	4.96725%	4.85502%	5.01297%	4.73556%	5.03424%	5.49072%	5.95204%	6.17255%	5.44431%
7 Market Costs (1)	$708,550	$833,890	$1,403,964	$2,080,074	$1,591,746	$2,363,416	$2,082,538	$1,703,371	$1,342,849	($320,333)	$1,769,155	$1,043,793	$16,603,013
8 **ND Solar Gardens Allocation** (7)x(6)	**$43,153**	**$51,044**	**$80,430**	**$111,665**	**$79,066**	**$114,744**	**$104,397**	**$80,664**	**$67,602**	**($17,589)**	**$105,301**	**$64,429**	**$884,905**