414 Nicollet Mall
Minneapolis, Minnesota 55401

— Via Electronic Filing —

April 29, 2016

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

Re: May 2016 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric fuel cost charge (FCC) for May 2016.

The table below shows the Fuel Cost Charge by customer class category:

May 2016	Fuel Cost Charge ($/kWh)
Residential	0.01450
C & I Non-Demand	0.01501
C & I Demand	0.01481
C & I Demand Time of Day On-Peak	0.01861
C & I Demand Time of Day Off-Peak	0.01157
Outdoor Lighting	0.01068

9 PU-16-12 Filed 04/29/2016 Pages: 15
May 2016 fuel cost adjustment
Northern States Power Company

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO) charges under the Day 2 Market. Pursuant to the Commission's April 6, 2005 Order in Case No. PU-05-147 and the Order in Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The current FCC also reflected the MISO Day 2 charge types including three Auction Revenue Rights (ARR) and three Financial Transmission Rights (FTR) charge types.[1] Consistent with this Order and the required "net" accounting of MISO Day 2 costs and revenues, we have included in the May 2016 FCC the net MISO Day 2 costs for March 2016 as recorded in Account 555. The MISO Day 2 cost recovery included in this May 2016 FCC is $4,609,584, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (ASM) on January 6, 2009, the net costs or revenues of 14 ASM charge types are included in the Fuel Cost Rider, 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 include in the May 2016 FCC the net MISO ASM costs for March 2016 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is $797,506, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

SPENT NUCLEAR FUEL DISPOSAL FEE

The Company received notification from the U.S. Department of Energy (DOE) on May 12, 2014 that the Spent Nuclear Fuel Disposal Fee, which was 1.0 mill per kilowatt hour of electricity generated and sold, would be discontinued effective May 16, 2014.[2] The Disposal Fee is an authorized component of FERC account 518. The charge had been collected from customers via a line item in our monthly Fuel Cost Charge filings. We no longer collect the Disposal Fee from customers and will not do so unless, of course, the DOE reinstates a fee.

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[1] Previously embedded in other FTR charge types.

[2] The Company submitted an informational filing to the Commission on May 21, 2014 regarding this charge in Case No. PU-14-012.

REFUNDS

Asset and Non-Asset Based Margins Sharing Refund

Under the terms of the Revised Second Amended Settlement adopted by the Commission[3] on February 26, 2014, retroactive to January 1, 2014, the Company began passing through 100 percent of wholesale asset based margins to North Dakota customers. The Asset Based Margin amount of $336,923 has been included as a credit to the May 2016 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the prior year retail share of the Non-Asset Based Margins has been credited to the monthly FCC over the following 12-month period only if the calendar year balance is positive. The realized North Dakota retail share of the 2015 Non-Asset Based Margin credit is $50,462 and this credit amount is distributed equally each month over the following 12-month period. The amount reflected in the May 2016 FCC is $22,159, or a credit of 0.014¢ per kWh. Attachment 3, page 2 contains the derivation of this refund amount.

Sales of Renewable Energy Credits

Pursuant to the Commission Order dated September 9, 2010 in Case No. PU-10-19, the Company is authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the net proceeds back to customers through the Fuel Cost Rider (FCR). Under the February 26, 2014 Settlement, instead of 90 percent, 100 percent of the North Dakota state jurisdictional share of revenue generated by the sale of RECs is credited to customers. (See Attachment 3, page 3). There were no REC sales during the current reporting period.

PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement (Case No. PU-12-813) the following procedural changes reflected in Revised Second Amended Settlement were intended 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 the Fuel Cost Charges. In addition, the Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year.
- Future renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will require approval of an Advance Determination of Prudence before included for recovery in the FCR; and

[3] Case Nos. PU-12-813, PU-13-706, PU-13-707 ,PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

- MISO market energy purchases are not subject to the above requirements.

For the March 2016 FCR reporting month there are no new renewable projects or purchases that require the above referenced reporting obligation. The Company will monitor and comply with these obligations under the Settlement going forward.

PRAIRIE ROSE WIND PPA

Pursuant to the Commission's December 21, 2012 Order in the Company's Advance Determination of Prudence application (Case No. PU-12-59), the energy and costs associated with the January 1, 2013 commencement of the Prairie Rose Wind (PRW) power purchase agreement (PPA) are being excluded from the calculation of the Company's monthly FCR.

As a result of the Revised Second Amended Settlement adopted by the Commission on February 26, 2014, the Prairie Rose Wind energy costs incurred on and after February 26, 2014 are included in the FCR calculation. The Company agreed to forego any unrecovered portion the Prairie Rose PPA incurred prior to that February date. As such, starting with the May 2014 FCC, the Company has included the Prairie Rose PPA costs in the computation.

NEGOTIATED AGREEMENT

Pursuant to the Commission's March 9, 2016 Order Accepting Settlement (Case Nos. PU-12-813, *et. al.*) the costs and volumes of fifteen Community-Based Energy Development (C-BED) and two small solar PPAs are to be excluded from the calculation of the Company's monthly FCR charge. This is the first monthly report that reflects the adjustments addressed in the Commission's Order. Please see Attachment 1, Page 5 for the details. The excluded C-BED and solar PPAs are as follows:

Community Based Energy Development (CBED) Wind

1. Jeffers Wind 20, LLC (50 MW)
2. Big Blue (36 MW)
3. Community Wind South (Zephyr) (30 MW)
4. Ridgewind Power Partners LLC (25 MW)
5. Adams Wind Generations (20 MW)
6. Danielson Wind Farms (20 MW)
7. Ewington Energy Systems LLC (20 MW)
8. Grant County Wind, LLC (20 MW)
9. North Community Turbines (15 MW)
10. North Wind Turbines (15 MW)
11. Valley View Transmission (10 MW)
12. Uilk Wind Farm (4.5 MW)

13. Hilltop Power (2 MW)
14. Winona County Wind (1.5 MW)
15. Woodstock Municipal Wind, LLC (0.8 MW)

Solar Contracts

1. Outland Solar (2 MW)
2. Best Power (St. Johns) (0.4 MW)

MONTHLY CALCULATIONS AND COMPARISONS

Attached is the calculation of the May 2016 FCC, as well as a statistical summary of energy sources and costs, compared to the previous month.

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist at 701-241-8632.

Sincerely,

/ s /

Amy S. Fredregill
RESOURCE PLANNING AND STRATEGY MANAGER

Enclosures
CC: David H. Sederquist

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for May-2016

May-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.02353**	**-$0.00248**	**-$0.00651**	**$0.01454**
Residential	**$0.02346**	**-$0.00247**	**-$0.00649**	**$0.01450**
C & I Non-Demand	**$0.02428**	**-$0.00255**	**-$0.00672**	**$0.01501**
C & I Demand Non-TOD	**$0.02396**	**-$0.00252**	**-$0.00663**	**$0.01481**
C & I Demand TOD On-Peak	**$0.03011**	**-$0.00317**	**-$0.00833**	**$0.01861**
C & I Demand TOD Off-Peak	**$0.01872**	**-$0.00197**	**-$0.00518**	**$0.01157**
Outdoor Lighting	**$0.01727**	**-$0.00182**	**-$0.00478**	**$0.01068**
Residential				
Residential Service	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
Residential TOD	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
Residential - Underground	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
Residential TOD - Underground	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
Energy Control - (Non-Demand)	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
Limit Off Peak	$ 0.02346	$ (0.00247)	$ (0.00649)	$ 0.01450
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Limit Off Peak	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Small General Service	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Small General TOD - Metered	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Small General TOD - Unmetered	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Fire and Civil Defense Siren	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
Direct Current (Closed)	$ 0.02428	$ (0.00255)	$ (0.00672)	$ 0.01501
C & I Demand				
General Service	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
General TOD - On Peak	$ 0.03011	$ (0.00317)	$ (0.00833)	$ 0.01861
General TOD - Off Peak	$ 0.01872	$ (0.00197)	$ (0.00518)	$ 0.01157
Peak Controlled (Closed)	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Peak Controlled TOD (Closed) - On Peak	$ 0.03011	$ (0.00317)	$ (0.00833)	$ 0.01861
Peak Controlled TOD (Closed) - Off Peak	$ 0.01872	$ (0.00197)	$ (0.00518)	$ 0.01157
Peak Controlled Tiered	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Peak Controlled Tiered TOD - On Peak	$ 0.03011	$ (0.00317)	$ (0.00833)	$ 0.01861
Peak Controlled Tiered TOD - Off Peak	$ 0.01872	$ (0.00197)	$ (0.00518)	$ 0.01157
Energy Controlled (Closed)	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Tier 1 Energy Controlled Rider	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Real Time Pricing - Firm - On Peak	$ 0.03011	$ (0.00317)	$ (0.00833)	$ 0.01861
Real Time Pricing - Firm - Off Peak	$ 0.01872	$ (0.00197)	$ (0.00518)	$ 0.01157
Real Time Pricing - Controllable - On Peak	$ 0.03011	$ (0.00317)	$ (0.00833)	$ 0.01861
Real Time Pricing - Controllable - Off Peak	$ 0.01872	$ (0.00197)	$ (0.00518)	$ 0.01157
Small Municipal Pumping	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Municipal Pumping	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Excess Energy - St. Anthony Falls	$ 0.02396	$ (0.00252)	$ (0.00663)	$ 0.01481
Outdoor Lighting				
Automatic Protective Lighting	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068
Street Lighting System	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068
Street Lighting Energy	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068
Street Lighting Energy - Metered	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068
Street Lighting Energy (Closed)	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068
Street Lighting - City of St. Paul	$ 0.01727	$ (0.00182)	$ (0.00478)	$ 0.01068

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Current Period Cost of Energy for May-2016

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Dec-15	Jan-16	Feb-16	Mar-16	**4 Month Total**
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$37,734,653	$45,029,964	$34,725,752	$27,324,375	$144,814,744
Account 518 - Nuclear Fuel	$7,947,135	$7,094,043	$7,279,561	$10,696,586	$33,017,325
Account 555 - Purchased Power[1]	$38,447,571	$38,195,938	$38,089,568	$38,591,082	$153,324,159
C-BED Wind & Solar PPA Costs	$0	$0	$0	($4,778,197)	($4,778,197)
C-BED Wind PPA Curtailment Payment	$0	$0	$0	($221,503)	($221,503)
Replacement Energy Costs	$0	$0	$0	$2,038,451	$2,038,451
Account 555 - With PPAs Adjustment[2]	$0	$0	$0	($2,961,249)	($2,961,249)
MISO Day 2 Charges	$3,620,382	$5,071,466	$6,341,748	$4,691,629	$19,725,226
MISO Day 2 - Schedule 24	($99,023)	($79,278)	($97,706)	($82,385)	($358,391)
MISO - ASM Charges	$3,158,072	$2,751,558	$1,132,280	$797,506	$7,839,416
Account 555 - Total MISO Charges	$6,679,432	$7,743,746	$7,376,322	$5,406,751	$27,206,251
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$90,808,790	$98,063,692	$87,471,203	$79,057,544	$355,401,230
Less Fuel Cost of InterSystem Sales	($9,646,144)	($7,335,842)	($6,168,145)	($6,558,736)	($29,708,866)
Net System Costs	$81,162,647	$90,727,850	$81,303,058	$72,498,808	$325,692,363
System MWH Sales					
Total NSP System Retail	3,447,524	3,530,598	3,376,930	3,486,859	13,841,911
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,447,524	3,530,598	3,376,930	3,486,859	13,841,911
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
System (Including All PPAs)	**2.354¢**	**2.570¢**	**2.408¢**	**2.164¢**	**2.374¢**
System (Adjusted for 17 PPAs Exclusion)	**2.354¢**	**2.570¢**	**2.408¢**	**2.079¢**	**2.353¢**
Class Ratio/TOD Ratio					
(i) Residential	0.9969	0.9969	0.9969	0.9969	0.9969
(ii) C & I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318
(iii) C & I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184
(iv) C & I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798
(v) C & I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954
(vi) Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341

North Dakota Fuel Cost Factor (FCF)

	Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential	2.353¢	0.9969	**2.346¢**
(ii) C & I Non-Demand	2.353¢	1.0318	**2.428¢**
(iii) C & I Demand Non-TOD	2.353¢	1.0184	**2.396¢**
(iv) C & I Demand TOD On-Peak	2.353¢	1.2798	**3.011¢**
(v) C & I Demand TOD Off-Peak	2.353¢	0.7954	**1.872¢**
(vi) Outdoor Lighting	2.353¢	0.7341	**1.727¢**

North Dakota Retail MWh Sales

	Dec-15	Jan-16	Feb-16	Mar-16	4 Month Total
(i) Residential	73,189	87,368	79,199	73,616	313,372
(ii) C & I Non-Demand	10,393	11,753	11,058	11,328	44,532
(iii) C & I Demand Non-TOD	68,396	66,866	64,747	73,347	273,356
(iv) C & I Demand TOD On-Peak	18,251	15,332	17,746	18,502	69,831
(v) C & I Demand TOD Off-Peak	29,775	29,416	28,781	28,824	116,796
(vi) Outdoor Lighting	1,968	2,093	1,956	1,703	7,720
(vii) Total	201,972	212,828	203,487	207,320	825,607

May-2016 Recovery Provision (True-up Factor) Calculation

Prior Unrecovered Expenses (Jan-16 Balance of Unrecovered Expenses)	Total
	Jan-16
	($1,119,846)

[1] Excludes demand-related expenses

[2] Excludes 17 PPAs pursuant to March 9, 2016 Order Approving Settlement

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Current Period Cost of Energy for May-2016

Prior Expenses Recovered in Mar-2016 [Billing Record]

	ND Billed MWh Sales	Prior Receovered Expenses
(i) Residential	73,616	($54,145)
(ii) C & I Non-Demand	11,328	($8,622)
(iii) C & I Demand Non-TOD	73,347	($57,031)
(iv) C & I Demand TOD On-Peak	18,502	($19,082)
(v) C & I Demand TOD Off-Peak	28,824	($18,697)
(vi) Outdoor Lighting	1,703	($610)
(vii) Total	207,320	($158,187)

Actual Cost Should Have Been Recovered in Mar-16

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.079¢	0.000¢	207,320	$4,310,183

Cost Recovered in Mar-16 [Billing Record]

	ND Billed MWh Sales	Actual Recovery
(i) Residential	73,616	$1,905,085
(ii) C & I Non-Demand	11,328	$303,632
(iii) C & I Demand Non-TOD	73,347	$1,941,126
(iv) C & I Demand TOD On-Peak	18,502	$614,881
(v) C & I Demand TOD Off-Peak	28,824	$595,427
(vi) Outdoor Lighting	1,703	$32,466
(vii) Total	207,320	$5,392,617

Total Balance of Unrecovered Expenses (May-16 Balance of Unrecovered Expenses)

May-2016 Recovery Provision	($2,044,093)
4 Month ND Retail Total MWh Sales	825,607
May-2016 Recovery Provision per KWH	**-0.248¢**

May-2016 Recovery Provision (True-up Factor) per kWh by Customer Category

	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	-0.248¢	**-0.247¢**
(ii) C & I Non-Demand	1.0318	-0.248¢	**-0.255¢**
(iii) C & I Demand Non-TOD	1.0184	-0.248¢	**-0.252¢**
(iv) C & I Demand TOD On-Peak	1.2798	-0.248¢	**-0.317¢**
(v) C & I Demand TOD Off-Peak	0.7954	-0.248¢	**-0.197¢**
(vi) Outdoor Lighting	0.7341	-0.248¢	**-0.182¢**

Refunds/Additional Charges

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	($336,923)	($22,159)	($708,279)	**($1,067,361)**
(i) Residential	-0.205¢	-0.013¢	-0.431¢	**-0.649¢**
(ii) C & I Non-Demand	-0.212¢	-0.014¢	-0.446¢	**-0.672¢**
(iii) C & I Demand Non-TOD	-0.209¢	-0.014¢	-0.440¢	**-0.663¢**
(iv) C & I Demand TOD On-Peak	-0.263¢	-0.017¢	-0.553¢	**-0.833¢**
(v) C & I Demand TOD Off-Peak	-0.163¢	-0.011¢	-0.344¢	**-0.518¢**
(vi) Outdoor Lighting	-0.151¢	-0.010¢	-0.317¢	**-0.478¢**

May-2016 Factors

	Total
(i) Residential	**1.450¢**
(ii) C & I Non-Demand	**1.501¢**
(iii) C & I Demand Non-TOD	**1.481¢**
(iv) C & I Demand TOD On-Peak	**1.861¢**
(v) C & I Demand TOD Off-Peak	**1.157¢**
(vi) Outdoor Lighting	**1.068¢**

Northern States Power Company
Electric Operations - State of North Dakota
FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -
Prior Month Compared to Current Month FCA

	FCA Application		Comparison		Generation Type by Percent		
			Differ-	Percent	FCA Application		Differ-
	Apr-16	May-16	ence	Change	Apr-16	May-16	ence
** COSTS (Millions) **							
1 Fossil	$152.8	$144.8	($8.0)	-5.2%	41.3%	40.7%	-0.6%
2 Nuclear	$28.3	$33.0	$4.7	16.6%	7.6%	9.3%	1.7%
3 Purchases	$156.6	$150.4	($6.2)	-4.0%	42.3%	42.3%	0.0%
MISO related Purchases	$32.7	$27.2	($5.5)	-16.7%	8.8%	7.7%	-1.1%
4 Total System Costs	370.4	355.4	($15.0)	-4.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	$28.3	$29.7	$1.4	4.9%	7.6%	8.4%	0.8%
6 Net System Costs	$342.1	$325.7	($16.4)	-4.8%	92.4%	91.6%	-0.8%
7							
8 ** GWH OUTPUT **							
9 Fossil	4,617	4,275	(342)	-7.4%	34.7%	35.7%	1.0%
10 Nuclear	3,514	4,057	543	15.5%	26.4%	33.9%	7.5%
11 Purchases	4,148	3,815	(333)	-8.0%	31.2%	31.9%	0.7%
12 Hydro & Other	3,199	3,431	232	7.3%	24.0%	28.7%	4.7%
13 Net Interchange	(2,166)	(3,603)	(1,437)	-66.3%	-16.3%	-30.1%	-13.8%
14 Total Output	13,312	11,975	(1,337)	-10.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,599	1,792	194	12.1%	12.0%	15.0%	3.0%
16 Native Requirement	11,713	10,183	(1,531)	-13.1%	88.0%	85.0%	-3.0%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.310	3.387	0.077	2.3%			
20 Nuclear	0.806	0.814	0.008	1.0%			
21 Purchases	3.776	3.941	0.166	4.4%			
22 Total System Costs	2.783	2.968	0.185	6.7%			
23 Intersystem Sales	1.772	1.658	-0.114	-6.4%			
24 Net System Costs	2.920	3.199	0.278	9.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,246	13,842	596	4.5%			
28							
29 COST per KWH SALES (¢)	2.583	2.353	-0.230	-8.9%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.030	-0.248	-0.218				
(i) Residential	-0.030	-0.247	-0.217				
(ii) C & I Non-Demand	-0.031	-0.255	-0.225				
(iii) C & I Demand Non-TOD	-0.031	-0.252	-0.222				
(iv) C & I Demand TOD On-Peak	-0.038	-0.317	-0.278				
(v) C & I Demand TOD Off-Peak	-0.024	-0.197	-0.173				
(vi) Outdoor Lighting	-0.022	-0.182	-0.160				
32 REFUND	0.406	-0.652	-1.058				
(i) Residential	0.407	-0.649					
(ii) C & I Non-Demand	0.417	-0.672					
(iii) C & I Demand Non-TOD	0.413	-0.663					
(iv) C & I Demand TOD On-Peak	0.523	-0.833					
(v) C & I Demand TOD Off-Peak	0.320	-0.518					
(vi) Outdoor Lighting	0.302	-0.478					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.959	1.453	-1.506	-50.9%			
(i) Residential	2.950	1.450	-1.500				
(ii) C & I Non-Demand	3.053	1.501					
(iii) C & I Demand Non-TOD	3.014	1.481					
(iv) C & I Demand TOD On-Peak	3.787	1.861					
(v) C & I Demand TOD Off-Peak	2.354	1.157					
(vi) Outdoor Lighting	2.172	1.068					

Calculations:

[4] = [1]+[2]+[3]	[21] = [3] / [11]
[6] = [4] - [5]	[22] = [4] / [14]
[14] = [9]+..+[13]	[23] = [5] / [15]
[16] = [14] - [15]	[24] = [6] / [16]
[19] = [1] / [9]	[29] = [6] / [27]
[20] = [2] / [10]	[33] = [29]+[31]

Residential BILL IMPACT ($'s)

kWh	Change from Previous Month
100	($1.50)
250	($3.75)
500	($7.50)
750	($11.25)
1,000	($15.00)

Some miscellaneous totals refer to so many terms that their formula would be too long. So intermediate totals are developed here, then an overall total is taken and is rounded, and finally it's simply referred to above.

	FCA Application	
	Apr-16	May-16
** GWH OUTPUT **		
Thermal	2,202,563	2,358,842
Disper gen	(85)	(55)
Hydro plus Wind	996,060	1,072,662
Hydro and Other	3,198,538	3,431,449
Rounded to nearest thousand:	3,199	3,431
Sales		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,598,754,000	1,792,390,000
Rounded to nearest million:	1598.754	1792.39

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Replacement Cost for the Designated Purchased Power Agreements
For Actual Month of March 2016

	PPAs Included	PPAs Excluded	Difference	Adjustment to ND Fuel Cost
PPAs Replacement Cost				
System Fuel Costs	$75,460,057	$75,460,057		
Less: PPAs Exclusion				
15 C-BED Wind PPAs	$0	($4,746,301)		
2 Solar PPAs	$0	($31,896)		
Wind Curtailment Payments	$0	($221,503)		
Total Exclusion	$0	($4,999,700)		
Net System Costs	$75,460,057	$70,460,357		
Billing Month System Sales	3486859	3486859		
Billing Month North Dakota Sales	207320	207320		
North Dakota Percentage	5.9458%	5.9458%		
Affected PPAs Volume (Ssyetm)	86632	86632		
Affected PPAs Volume (North Dakota's Share)	5151	5151		
Billing Month System Sales	3486859	3486859		
Less: Affected PPAs Volume		-86632		
Net System Billing Month Sales	3486859	3400227		
Billing Month North Dakota Sales	207320	207320		
Less: Affected PPAs Volume		-5151		
Net North Dakota Billing Month Sales	207320	202169		
System Fuel Costs	$75,460,057	$70,460,357		
North Dakota Percentage	5.9458%	5.9458%		
North Dakota Fuel Cost	$4,486,704	$4,189,432	($297,272)	
Affected PPAs Volume (System)		86632		
North Dakota Average System Cost ($/MWh)		$23.53		
North Dakota Replacement Cost	$0	$2,038,451		
Affected PPAs Volume (North Dakota's Share)		5151		
North Dakota Average System Cost ($/MWh)		$23.53		
North Dakota Replacement Cost	$0	$121,203	$121,203	
Adjusted PPA Cost Added to ND FCA Calculation				($176,069)
Fuel Cost Impact Due to PPA Exclsuion				($0.00087)
Residential Fuel Cost Charge Impact (750 kWh Use)				($0.65)

Northern States Power Company

Attachment 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Page 1

		System	Intersystem	Retail
September 2015 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$ 6,386,106.36	$ 5,544,813.92	$ 11,930,920.28
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$ 2,644,294.03	$ -	$ 2,644,294.03
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,269.94	$ -	$ 3,269.94
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$ (11,378,475.04)	$ -	$ (11,378,475.04)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$ 1,021,615.40	$ -	$ 1,021,615.40
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,269.94)	$ -	$ (3,269.94)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	$ (517,359.41)	$ 1,757,695.13	$ 1,240,335.72
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$ 57,163.18	$ -	$ 57,163.18
14	Real-Time Distribution of Losses Amount	$ (1,226,063.07)	$ -	$ (1,226,063.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 9,693.52	$ -	$ 9,693.52
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$ 8,595.58	$ -	$ 8,595.58
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$ (621.95)	$ -	$ (621.95)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$ 5,490,819.21	$ -	$ 5,490,819.21
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 17,359.37	$ -	$ 17,359.37
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$ 1,012,893.58	$ -	$ 1,012,893.58
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (17,359.37)	$ -	$ (17,359.37)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	$ 144,299.24	$ -	$ 144,299.24
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	$ (1,621.78)	$ -	$ (1,621.78)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,806,681.63)	$ -	$ (3,806,681.63)
30	Financial Transmission Rights Monthly Allocation Amount	$ (318,211.73)	$ -	$ (318,211.73)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (68,287.15)	$ -	$ (68,287.15)
37	Financial Transmission Guarantee Uplift Amount	$ 72,603.84	$ -	$ 72,603.84
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 529,022.80	$ -	$ 529,022.80
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 117,657.19	$ -	$ 117,657.19
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (108,124.53)	$ 50,832.92	$ (57,291.61)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 405,051.46	$ -	$ 405,051.46
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (307,907.79)	$ 138,699.53	$ (169,208.26)
43	Real-Time Price Volatility Make Whole Payment Amount	$ (255,207.60)	$ 12,911.09	$ (242,296.51)
Market Adminstration Charges				
4	Day-Ahead Market Administration Amount	$ 551,580.38	$ (15,954.74)	$ 535,625.64
19	Real-Time Market Administration Amount	$ 38,029.43	$ (5,571.65)	$ 32,457.78
29	Financial Transmission Rights Market Administration Amount	$ 25,266.24	$ -	$ 25,266.24
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,805.56	$ (2,534.81)	$ 85,270.75
34	Real -Time Schedule 24 Allocation Amount	$ (95,065.04)	$ 100,032.99	$ 4,967.95
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
Virtual Energy Charges				
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
Other MISO Charges				
20	Real-Time Miscellaneous Amount	$ (63,780.52)	$ 33,304.72	$ (30,475.80)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75	$ -	$ 2,850,841.75
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (400,833.24)	$ -	$ (400,833.24)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,528.16	$ -	$ 101,528.16
	TOTAL MISO CHARGES	**$ 147,395.25**	**$ 7,614,229.10**	**$ 7,761,624.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,238.70**
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)			**$ 7,671,385.65**

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
September 2015 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	$ (83,111.35)		$ (83,111.35)
2	Day-Ahead Spinning Reserve Amount	$ (113,495.74)		$ (113,495.74)
3	Day-Ahead Supplemental Reserve	$ (77,740.15)		$ (77,740.15)
4	Real-Time Regulation Amount	$ (83,439.17)	$ 74,644.60	$ (8,794.57)
5	Real-Time Spinning Reserve Amount	$ (21,084.57)	$ 46,369.39	$ 25,284.82
6	Real-Time Supplemental Reserve Amount.	$ 8,639.35	$ 4,644.03	$ 13,283.38
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ (7,170.29)		$ (7,170.29)
7b	Real Time Excessive Energy Congestion			$ -
7c	Real Time Excessive Energy Loss			$ -
8a	Real Time Non Excessive Energy Amount	$ 1,303,212.45		$ 1,303,212.45
8b	Real Time Non Excessive Energy Congestion	$ (383,403.66)		$ (383,403.66)
8c	Real Time Non Excessive Energy Loss	$ (99,174.40)		$ (99,174.40)
9	Real Time Net Regulation Adjustment Amount	$ 6,916.76	$ (4,245.50)	$ 2,671.26
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 99,820.24		$ 99,820.24
11	Real Time Spinnng Reserve Cost Distribution	$ 108,454.56		$ 108,454.56
12	Real Time Supplemental Reserve Cost Distribution	$ 76,350.94		$ 76,350.94
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	$ 42,317.50	$ (13,225.65)	$ 29,091.85
14	Real Time Contignecy Reserve Deployment Failure	$ 753.77	$ 339.03	$ 1,092.80
	TOTAL MISO ASM CHARGES	**$ 777,846.24**	**$ 108,525.90**	**$ 886,372.14**

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Asset Based Margin Sharing

#													
1	**Forecast Month**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-16**	**Feb-16**
2	**True-up Month**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
3													
4	Monthly Refund	(71,432)	(99,484)	(68,297)									
5													
6	Forecast North Dakota Sales	223,782	182,660	163,931	173,060	173,060	-	-	-	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.032)	(0.054)	(0.042)	-	-	-	-	-	-	-	-	-
9													
14	Expected Refund	(269,298)	210,125	(288,922)	164,765	(336,923)	-	-	-	-	-	-	-
15	Actual Refunded	(51,808)	(54,124)	(20,295)									
16	Deviation	(217,490)	264,249	(268,627)	164,765	(336,923)	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.097)	0.145	(0.164)	-	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	**(0.129)**	**0.090**	**(0.206)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.129)	0.090	(0.205)	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.133)	0.093	(0.212)	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.131)	0.092	(0.209)	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.165)	0.115	(0.263)	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.103)	0.072	(0.163)	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.095)	0.066	(0.151)	-	-	-	-	-	-	-	-	-

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Non-Asset Based Margin Sharing

1	**Forecast Month**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**
2	**True-up Month**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**
3													
4	Monthly Refund	(4,205)	(50,462)	4,205	0								
5													
6	Forecast North Dakota Sales	212,098	223,782	182,660	163,931								
7													
8	**Current Month Refund Factor**	(0.002)	(0.023)	0.002	-	-	-	-	-	-	-	-	-
13													
14	Expected Refund	(21,268)	(12,776)	(9,259)	(46,243)	-	-	-	-	-	-	-	-
15	Actual Refund	(16,214)	(16,995)	(10,609)	(24,084)								
16	Deviation	(5,054)	4,219	1,350	(22,159)	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.002)	0.002	0.001	(0.014)	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	**(0.004)**	**(0.021)**	**0.003**	**(0.014)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.004)	(0.021)	0.003	(0.013)	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.005)	(0.021)	0.003	(0.014)	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.004)	(0.021)	0.003	(0.014)	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.006)	(0.026)	0.004	(0.017)	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.003)	(0.016)	0.002	(0.011)	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.003)	(0.015)	0.002	(0.010)	-	-	-	-	-	-	-	-

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Sales of Renewable Energy Credits

#													
1	**Forecast Month**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-16**	**Feb-16**
2	**True-up Month**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**
3													
4	Monthly Refund	-	(13,210)	(157,823)									
5													
6	Forecast North Dakota Sales	223,782	182,660	163,931									
7													
8	**Current Month Refund Factor**	-	(0.007)	(0.096)	-	-	-	-	-	-	-	-	-
13													
14	Expected Refund	(487,641)	558,449	(478,452)	-	-	-	-	-	-	-	-	-
15	Actual Refund	(9,189)	(26,312)	72,004									
16	Deviation	(478,452)	584,761	(550,456)	-	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.214)	0.320	(0.336)	-	-	-	-	-	-	-	-	-
19													
20	**Realized Refund**	(0.214)	0.313	**(0.432)**	-	-	-	-	-	-	-	-	-
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.213)	0.312	(0.431)	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.221)	0.323	(0.446)	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.218)	0.319	(0.440)	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.274)	0.400	(0.553)	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.170)	0.249	(0.344)	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.157)	0.230	(0.317)	-	-	-	-	-	-	-	-	-