



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

January 29, 2016

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

Re: February 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 February 2016.

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

February 2016	Fuel Cost Charge (\$/kWh)
Residential	0.02939
C & I Non-Demand	0.03041
C & I Demand	0.03002
C & I Demand Time of Day On-Peak	0.03772
C & I Demand Time of Day Off-Peak	0.02345
Outdoor Lighting	0.02164

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 February 2016 FCC the net MISO Day 2 costs for December 2015 as recorded in Account 555. The MISO Day 2 cost recovery included in this February 2016 FCC is \$3,521,359, 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 February 2016 FCC the net MISO ASM costs for December 2015 as recorded in Account 555. The MISO ASM cost recovery included in the FCC is \$3,158,072, 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.

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 Commission³ 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 \$210,125 has been included as a charge to the February 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 refund reflected in the February 2016 FCC is \$9,259, or a credit of 0.004¢ per kWh (system basis). 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 Renewable Energy Credits was credited to customers. (See Attachment 3, page 3).

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 January 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 would be included in the FCR calculation, and the Company would forego any unrecovered portion the Prairie Rose PPA had incurred prior to that time. As such, starting with the May 2014 FCC, the Company has included the Prairie Rose PPA costs in the computation.

MONTHLY CALCULATIONS AND COMPARISONS

Attached is the calculation of the January 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 (2)
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 Feb-2016

Feb-2016 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02596	-\$0.00006	\$0.00358	\$0.02948
Residential	\$0.02588	-\$0.00006	\$0.00357	\$0.02939
C & I Non-Demand	\$0.02679	-\$0.00007	\$0.00369	\$0.03041
C & I Demand Non-TOD	\$0.02644	-\$0.00006	\$0.00365	\$0.03002
C & I Demand TOD On-Peak	\$0.03322	-\$0.00008	\$0.00458	\$0.03772
C & I Demand TOD Off-Peak	\$0.02065	-\$0.00005	\$0.00285	\$0.02345
Outdoor Lighting	\$0.01906	-\$0.00005	\$0.00263	\$0.02164
Residential				
Residential Service	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
Residential TOD	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
Residential - Underground	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
Residential TOD - Underground	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
Energy Control - (Non-Demand)	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
Limit Off Peak	\$ 0.02588	\$ (0.00006)	\$ 0.00357	\$ 0.02939
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Limit Off Peak	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Small General Service	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Small General TOD - Metered	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Small General TOD - Unmetered	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Fire and Civil Defense Siren	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
Direct Current (Closed)	\$ 0.02679	\$ (0.00007)	\$ 0.00369	\$ 0.03041
C & I Demand				
General Service	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
General TOD - On Peak	\$ 0.03322	\$ (0.00008)	\$ 0.00458	\$ 0.03772
General TOD - Off Peak	\$ 0.02065	\$ (0.00005)	\$ 0.00285	\$ 0.02345
Peak Controlled (Closed)	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Peak Controlled TOD (Closed) - On Peak	\$ 0.03322	\$ (0.00008)	\$ 0.00458	\$ 0.03772
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02065	\$ (0.00005)	\$ 0.00285	\$ 0.02345
Peak Controlled Tiered	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Peak Controlled Tiered TOD - On Peak	\$ 0.03322	\$ (0.00008)	\$ 0.00458	\$ 0.03772
Peak Controlled Tiered TOD - Off Peak	\$ 0.02065	\$ (0.00005)	\$ 0.00285	\$ 0.02345
Energy Controlled (Closed)	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Tier 1 Energy Controlled Rider	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Real Time Pricing - Firm - On Peak	\$ 0.03322	\$ (0.00008)	\$ 0.00458	\$ 0.03772
Real Time Pricing - Firm - Off Peak	\$ 0.02065	\$ (0.00005)	\$ 0.00285	\$ 0.02345
Real Time Pricing - Controllable - On Peak	\$ 0.03322	\$ (0.00008)	\$ 0.00458	\$ 0.03772
Real Time Pricing - Controllable - Off Peak	\$ 0.02065	\$ (0.00005)	\$ 0.00285	\$ 0.02345
Small Municipal Pumping	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Municipal Pumping	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Excess Energy - St. Anthony Falls	\$ 0.02644	\$ (0.00006)	\$ 0.00365	\$ 0.03002
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164
Street Lighting System	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164
Street Lighting Energy	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164
Street Lighting Energy - Metered	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164
Street Lighting Energy (Closed)	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164
Street Lighting - City of St. Paul	\$ 0.01906	\$ (0.00005)	\$ 0.00263	\$ 0.02164

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Sep-15	Oct-15	Nov-15	Dec-15	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$40,783,629	\$38,217,497	\$35,333,247	\$37,734,653	\$152,069,026
Account 518 - Nuclear Fuel	\$10,542,939	\$9,063,923	\$5,996,735	\$7,947,135	\$33,550,732
Account 555 - Purchased Power ¹	\$43,738,693	\$40,306,305	\$41,877,757	\$38,447,571	\$164,370,325
MISO Day 2 Charges	\$7,761,624	\$3,645,674	\$10,046,285	\$3,620,382	\$25,073,966
MISO Day 2 - Schedule 24	(\$90,239)	(\$88,223)	(\$73,445)	(\$99,023)	(\$350,929)
MISO - ASM Charges	\$886,033	\$1,630,903	\$886,033	\$3,158,072	\$6,561,042
Account 555 - Total MISO Charges	\$8,557,419	\$5,188,354	\$10,858,873	\$6,679,432	\$31,284,078
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$103,622,680	\$92,776,079	\$94,066,612	\$90,808,790	\$381,274,162
Less Fuel Cost of InterSystem Sales	(\$9,309,967)	(\$10,060,412)	(\$5,175,231)	(\$9,646,144)	(\$34,191,753)
Net System Costs	\$94,312,713	\$82,715,668	\$88,891,381	\$81,162,647	\$347,082,408
System MWh Sales					
Total NSP System Retail	3,665,023	3,365,965	2,890,835	3,447,524	13,369,347
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,665,023	3,365,965	2,890,835	3,447,524	13,369,347
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.573¢	2.457¢	3.075¢	2.354¢	2.596¢
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			2.596¢	0.9969	2.588¢
(ii) C & I Non-Demand			2.596¢	1.0318	2.679¢
(iii) C & I Demand Non-TOD			2.596¢	1.0184	2.644¢
(iv) C & I Demand TOD On-Peak			2.596¢	1.2798	3.322¢
(v) C & I Demand TOD Off-Peak			2.596¢	0.7954	2.065¢
(vi) Outdoor Lighting			2.596¢	0.7341	1.906¢
North Dakota Retail MWh Sales					
(i) Residential	57,422	50,103	45,184	73,189	225,898
(ii) C & I Non-Demand	8,324	8,075	7,195	10,393	33,987
(iii) C & I Demand Non-TOD	65,517	65,024	55,348	68,396	254,285
(iv) C & I Demand TOD On-Peak	20,010	18,112	16,463	18,251	72,836
(v) C & I Demand TOD Off-Peak	31,313	28,370	25,828	29,775	115,286
(vi) Outdoor Lighting	1,384	1,546	1,785	1,968	6,683
(vii) Total	183,970	171,230	151,803	201,972	708,975
Feb-2016 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Oct-15 Balance of Unrecovered Expenses)					Total
					Oct-15
					\$239,808

¹ Excludes demand-related expenses

Prior Expenses Recovered in Dec-2015 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	73,189	(\$88,289)
(ii) C & I Non-Demand	10,393	(\$12,988)
(iii) C & I Demand Non-TOD	68,396	(\$80,052)
(iv) C & I Demand TOD On-Peak	18,251	(\$26,631)
(v) C & I Demand TOD Off-Peak	29,775	(\$27,149)
(vi) Outdoor Lighting	1,968	(\$2,338)
(vii) Total	201,972	(\$237,447)

Actual Cost Should Have Been Recovered in Dec-15				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.354¢	0.000¢	201,972	\$4,754,421

Cost Recovered in Dec-15 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	73,189	\$1,904,343
(ii) C & I Non-Demand	10,393	\$280,297
(iii) C & I Demand Non-TOD	68,396	\$1,824,220
(iv) C & I Demand TOD On-Peak	18,251	\$610,950
(v) C & I Demand TOD Off-Peak	29,775	\$618,950
(vi) Outdoor Lighting	1,968	\$37,814
(vii) Total	201,972	\$5,276,574

Total Balance of Unrecovered Expenses (Feb-16 Balance of Unrecovered Expenses)	
Feb-2016 Recovery Provision	(\$44,898)
4 Month ND Retail Total MWh Sales	708,975
Feb-2016 Recovery Provision per KWH	-0.006¢

Feb-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	-0.006¢	-0.006¢
(ii) C & I Non-Demand	1.0318	-0.006¢	-0.007¢
(iii) C & I Demand Non-TOD	1.0184	-0.006¢	-0.006¢
(iv) C & I Demand TOD On-Peak	1.2798	-0.006¢	-0.008¢
(v) C & I Demand TOD Off-Peak	0.7954	-0.006¢	-0.005¢
(vi) Outdoor Lighting	0.7341	-0.006¢	-0.005¢

Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	\$210,125	(\$9,259)	\$558,449	\$759,315
(i) Residential	0.099¢	-0.004¢	0.262¢	0.357¢
(ii) C & I Non-Demand	0.102¢	-0.005¢	0.272¢	0.369¢
(iii) C & I Demand Non-TOD	0.101¢	-0.004¢	0.268¢	0.365¢
(iv) C & I Demand TOD On-Peak	0.127¢	-0.006¢	0.337¢	0.458¢
(v) C & I Demand TOD Off-Peak	0.079¢	-0.003¢	0.209¢	0.285¢
(vi) Outdoor Lighting	0.073¢	-0.003¢	0.193¢	0.263¢

Feb-2016 Factors	
	Total
(i) Residential	2.939¢
(ii) C & I Non-Demand	3.041¢
(iii) C & I Demand Non-TOD	3.002¢
(iv) C & I Demand TOD On-Peak	3.772¢
(v) C & I Demand TOD Off-Peak	2.345¢
(vi) Outdoor Lighting	2.164¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jan-16	Feb-16	Differ- ence	Percent Change	FCA Application Jan-16	Feb-16	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$158.1	\$152.1	(\$6.0)	-3.8%	39.6%	39.9%	0.3%
2 Nuclear	\$36.5	\$33.6	(\$3.0)	-8.1%	9.1%	8.8%	-0.3%
3 Purchases	\$169.3	\$164.4	(\$4.9)	-2.9%	42.4%	43.1%	0.7%
MISO related Purchases	\$35.3	\$31.3	(\$4.0)	-11.4%	8.8%	8.2%	-0.6%
4 Total System Costs	399.3	381.3	(\$18.0)	-4.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$32.3	\$34.2	\$1.9	5.7%	8.1%	9.0%	0.9%
6 Net System Costs	\$366.9	\$347.1	(\$19.8)	-5.4%	91.9%	91.0%	-0.9%
7							
8 ** GWH OUTPUT **							
9 Fossil	4,665	4,607	(58)	-1.2%	30.3%	28.7%	-1.6%
10 Nuclear	4,355	4,054	(301)	-6.9%	28.3%	25.3%	-3.0%
11 Purchases	3,607	4,272	665	18.4%	23.5%	26.6%	3.1%
12 Hydro & Other	2,403	2,745	342	14.2%	15.6%	17.1%	1.5%
13 Net Interchange	344	376	32	9.3%	2.2%	2.3%	0.1%
14 Total Output	15,374	16,054	680	4.4%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,610	1,842	232	14.4%	10.5%	11.5%	1.0%
16 Native Requirement	13,764	14,212	448	3.3%	89.5%	88.5%	-1.0%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.389	3.301	-0.088	-2.6%			
20 Nuclear	0.839	0.828	-0.011	-1.3%			
21 Purchases	4.694	3.848	-0.846	-18.0%			
22 Total System Costs	2.597	2.375	-0.222	-8.5%			
23 Intersystem Sales	2.008	1.857	-0.152	-7.6%			
24 Net System Costs	2.666	2.442	-0.224	-8.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,805	13,369	(436)	-3.2%			
28							
29 COST per KWH SALES (¢)	2.658	2.596	-0.062	-2.3%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.168	-0.006	0.162				
(i) Residential	-0.167	-0.006	0.161				
(ii) C & I Non-Demand	-0.173	-0.007	0.167				
(iii) C & I Demand Non-TOD	-0.171	-0.006	0.165				
(iv) C & I Demand TOD On-Peak	-0.215	-0.008	0.207				
(v) C & I Demand TOD Off-Peak	-0.134	-0.005	0.129				
(vi) Outdoor Lighting	-0.123	-0.005	0.119				
32 REFUND	-0.335	0.351	0.686				
(i) Residential	-0.336	0.357					
(ii) C & I Non-Demand	-0.344	0.369					
(iii) C & I Demand Non-TOD	-0.341	0.365					
(iv) C & I Demand TOD On-Peak	-0.432	0.458					
(v) C & I Demand TOD Off-Peak	-0.264	0.285					
(vi) Outdoor Lighting	-0.249	0.263					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.155	2.941	0.786	36.5%			
(i) Residential	2.148	2.939	0.791				
(ii) C & I Non-Demand	2.223	3.041					
(iii) C & I Demand Non-TOD	2.194	3.002					
(iv) C & I Demand TOD On-Peak	2.757	3.772					
(v) C & I Demand TOD Off-Peak	1.714	2.345					
(vi) Outdoor Lighting	1.582	2.164					

Residential BILL IMPACT (\$'s)

Calculations:

		Change from kWh Previous Month
[4] = [1]+[2]+[3]	[21] = [3] / [11]	
[6] = [4] - [5]	[22] = [4] / [14]	100
[14] = [9]+..+[13]	[23] = [5] / [15]	250
[16] = [14] - [15]	[24] = [6] / [16]	500
[19] = [1] / [9]	[29] = [6] / [27]	750
[20] = [2] / [10]	[33] = [29]+[31]	1,000
		\$0.79
		\$1.98
		\$3.95
		\$5.93
		\$7.91

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.

	<u>FCA Application</u>	
	Jan-16	Feb-16
** GWH OUTPUT **		
Thermal	1,811,406	1,968,590
Disper gen	(75)	(75)
<u>Hydro plus Wind</u>	591,255	776,198
Hydro and Other	2,402,586	2,744,713
Rounded to nearest thousand:	2,403	2,745
<u>Sales</u>		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,610,142,000	1,841,708,000
Rounded to nearest million:	1610.142	1841.708

		System	Intersystem	Retail
December 2015 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ (3,161,849.70)	\$ 7,138,201.73	\$ 3,976,352.03
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,276,066.79	\$ -	\$ 2,276,066.79
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 2,891.51	\$ -	\$ 2,891.51
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (5,904,338.05)	\$ -	\$ (5,904,338.05)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 431,685.77	\$ -	\$ 431,685.77
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (2,891.51)	\$ -	\$ (2,891.51)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (35,573.90)	\$ 790,783.22	\$ 755,209.32
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (1,960.06)	\$ -	\$ (1,960.06)
14	Real-Time Distribution of Losses Amount	\$ (687,512.97)	\$ -	\$ (687,512.97)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (40,441.71)	\$ -	\$ (40,441.71)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 505.06	\$ -	\$ 505.06
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 4.02	\$ -	\$ 4.02
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,259,584.78	\$ -	\$ 1,259,584.78
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 4,423.75	\$ -	\$ 4,423.75
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 676,085.05	\$ -	\$ 676,085.05
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (4,423.75)	\$ -	\$ (4,423.75)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 3,338.29	\$ -	\$ 3,338.29
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)	\$ (0.18)	\$ -	\$ (0.18)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (992,388.90)	\$ -	\$ (992,388.90)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (91,420.53)	\$ -	\$ (91,420.53)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (18,226.83)	\$ -	\$ (18,226.83)
37	Financial Transmission Guarantee Uplift Amount	\$ 4,048.29	\$ -	\$ 4,048.29
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 478,236.54	\$ -	\$ 478,236.54
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 44,692.68	\$ -	\$ 44,692.68
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (160,724.75)	\$ 19,411.64	\$ (141,313.11)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 69,340.38	\$ -	\$ 69,340.38
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (3,854.63)	\$ 1,886.63	\$ (1,968.00)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (239,720.33)	\$ 11,633.29	\$ (228,087.04)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 594,528.51	\$ (29,955.39)	\$ 564,573.12
19	Real-Time Market Administration Amount	\$ 52,570.68	\$ (3,278.41)	\$ 49,292.27
29	Financial Transmission Rights Market Administration Amount	\$ 27,410.96	\$ -	\$ 27,410.96
33	Day-Ahead Schedule 24 Allocation Amount	\$ 86,505.76	\$ (4,282.16)	\$ 82,223.60
34	Real-Time Schedule 24 Allocation Amount	\$ (92,003.82)	\$ 108,803.14	\$ 16,799.32
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	\$ 1,072,002.52	\$ 52,588.75	\$ 1,124,591.27
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 3,770,129.38	\$ -	\$ 3,770,129.38
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (3,771,745.17)	\$ 9,706.72	\$ (3,762,038.45)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (186,462.01)	\$ -	\$ (186,462.01)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 66,371.33	\$ -	\$ 66,371.33
TOTAL MISO CHARGES		\$ (4,475,116.75)	\$ 8,095,499.16	\$ 3,620,382.41
SCHEDULE 24 (FOR RETAIL)				\$ 99,022.92
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 3,521,359.49

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
December 2015 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (32,032.61)	\$ -	\$ (32,032.61)
2	Day-Ahead Spinning Reserve Amount	\$ (130,805.72)	\$ -	\$ (130,805.72)
3	Day-Ahead Supplemental Reserve	\$ (39,329.37)	\$ -	\$ (39,329.37)
4	Real-Time Regulation Amount	\$ (24,150.03)	\$ 14,298.72	\$ (9,851.31)
5	Real-Time Spinning Reserve Amount	\$ (2,307.80)	\$ 73,561.87	\$ 71,254.07
6	Real-Time Supplemental Reserve Amount.	\$ 621.51	\$ 1,293.78	\$ 1,915.29
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 43,903.07	\$ -	\$ 43,903.07
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,840,720.06	\$ -	\$ 2,840,720.06
8b	Real Time Non Excessive Energy Congestion	\$ 136,105.72	\$ -	\$ 136,105.72
8c	Real Time Non Excessive Energy Loss	\$ 64,750.07	\$ -	\$ 64,750.07
9	Real Time Net Regulation Adjustment Amount	\$ 2,826.77	\$ (824.36)	\$ 2,002.41
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 71,173.52	\$ -	\$ 71,173.52
11	Real Time Spinning Reserve Cost Distribution	\$ 78,292.63	\$ -	\$ 78,292.63
12	Real Time Supplemental Reserve Cost Distribution	\$ 40,390.87	\$ -	\$ 40,390.87
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 24,696.52	\$ (5,321.85)	\$ 19,374.67
14	Real Time Contignecy Reserve Deployment Failure	\$ 208.99	\$ -	\$ 208.99
TOTAL MISO ASM CHARGES		\$ 3,075,064.20	\$ 83,008.16	\$ 3,158,072.36

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-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16
2 True-up Month	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
3												
4 Monthly Refund	(58,150)	(58,410)	(63,921)	(11,298)	(31,343)	(34,586)	(41,850)	(56,080)	(64,244)	(66,982)	(22,819)	(56,547)
5												
6 Forecast North Dakota Sales	214,698	190,045	163,417	175,362	193,801	189,560	181,682	174,056	163,609	218,447	229,474	212,098
7												
8 Current Month Refund Factor	(0.027)	(0.031)	(0.039)	(0.006)	(0.016)	(0.018)	(0.023)	(0.032)	(0.039)	(0.031)	(0.010)	(0.027)
9												
14 Expected Refund	(240,764)	87,087	(225,701)	104,158	(229,020)	145,774	(208,331)	181,481	(225,260)	148,015	(288,648)	124,522
15 Actual Refunded	(73,213)	(75,480)	(60,602)	(52,914)	(52,032)	(70,293)	(24,921)	(22,614)	(856)	(43,489)	(42,169)	(142,150)
16 Deviation	(167,551)	162,567	(165,099)	157,072	(176,988)	216,067	(183,410)	204,095	(224,404)	191,504	(246,479)	266,672
17												
18 True-up Factor	(0.078)	0.086	(0.101)	0.090	(0.091)	0.114	(0.101)	0.117	(0.157)	0.088	(0.107)	0.126
19												
20 Realized Margin	(0.105)	0.055	(0.140)	0.083	(0.107)	0.096	(0.124)	0.085	(0.176)	0.057	(0.117)	0.099
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	(0.105)	0.055	(0.140)	0.083	(0.107)	0.095	(0.124)	0.085	(0.176)	0.057	(0.117)	0.099
32 C&I Non-Demand	(0.108)	0.057	(0.145)	0.086	(0.111)	0.099	(0.128)	0.088	(0.182)	0.059	(0.121)	0.102
33 C&I Demand Non-TOD	(0.107)	0.056	(0.143)	0.085	(0.109)	0.098	(0.126)	0.087	(0.180)	0.058	(0.120)	0.101
34 C&I Demand TOD On-Peak	(0.135)	0.070	(0.179)	0.106	(0.138)	0.123	(0.159)	0.109	(0.226)	0.073	(0.150)	0.127
35 C&I Demand TOD Off-Peak	(0.084)	0.044	(0.111)	0.066	(0.086)	0.076	(0.099)	0.068	(0.140)	0.045	(0.093)	0.079
36 Outdoor Lighting	(0.077)	0.040	(0.103)	0.061	(0.079)	0.070	(0.091)	0.062	(0.130)	0.042	(0.086)	0.073

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-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16
2 True-up Month	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
3												
4 Monthly Refund	-	-	-	-	-	-	-	-	(79,589)	-	-	-
5												
6 Forecast North Dakota Sales	214,698	190,045	163,417	175,362	193,801	189,560	181,682	174,056	163,609	218,447	229,474	212,098
7												
8 Current Month Refund Factor	-	-	-	-	-	-	-	-	(0.049)	-	-	-
9												
14 Expected Refund	(378,673)	240,848	(401,239)	314,753	(346,179)	351,946	(335,018)	398,064	(357,607)	384,436	(495,284)	385,971
15 Actual Refund	22,566	(73,905)	(55,060)	(37,193)	(11,161)	(46,118)	22,589	13,628	58,089	(1,535)	(7,643)	(172,478)
16 Deviation	(401,239)	314,753	(346,179)	351,946	(335,018)	398,064	(357,607)	384,436	(415,696)	385,971	(487,641)	558,449
17												
18 True-up Factor	(0.187)	0.166	(0.212)	0.201	(0.173)	0.210	(0.197)	0.221	(0.254)	0.177	(0.213)	0.263
19												
20 Realized Refund	(0.187)	0.166	(0.212)	0.201	(0.173)	0.210	(0.197)	0.221	(0.303)	0.177	(0.213)	0.263
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	(0.186)	0.165	(0.211)	0.200	(0.172)	0.209	(0.196)	0.220	(0.302)	0.176	(0.212)	0.262
32 C&I Non-Demand	(0.193)	0.171	(0.219)	0.207	(0.178)	0.217	(0.203)	0.228	(0.312)	0.182	(0.219)	0.272
33 C&I Demand Non-TOD	(0.190)	0.169	(0.216)	0.204	(0.176)	0.214	(0.200)	0.225	(0.308)	0.180	(0.216)	0.268
34 C&I Demand TOD On-Peak	(0.239)	0.212	(0.271)	0.257	(0.221)	0.269	(0.252)	0.283	(0.387)	0.226	(0.272)	0.337
35 C&I Demand TOD Off-Peak	(0.149)	0.132	(0.168)	0.160	(0.137)	0.167	(0.157)	0.176	(0.241)	0.141	(0.169)	0.209
36 Outdoor Lighting	(0.137)	0.122	(0.156)	0.147	(0.127)	0.154	(0.144)	0.162	(0.222)	0.130	(0.156)	0.193