



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

May 30, 2014

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

Re: June 2014 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 June 2014.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2012 rate proceeding (Case No. PU-12-813), the new rates were implemented on May 1, 2014. The new Service Category Ratios listed below also become effective:

Service Category Ratios	Current	Effective May 2014
Residential	1.0026	0.9969
C & I Non-Demand	1.0281	1.0318
C & I Demand	1.0170	1.0184
C & I Demand Time of Day On-Peak	1.2883	1.2798
C & I Demand Time of Day Off-Peak	0.7889	0.7954
Outdoor Lighting	0.7440	0.7341

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

June 2014	Fuel Cost Charge (\$/kWh)
Residential	0.03117
C & I Non-Demand	0.03211
C & I Demand	0.03172
C & I Demand Time of Day On-Peak	0.04003
C & I Demand Time of Day Off-Peak	0.02470
Outdoor Lighting	0.02304

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator, Inc.) 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 March 2009 FCC reflected the MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge types¹, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required "net" accounting of Day 2 costs and revenues, we have included in the June 2014 FCC the net MISO Day 2 costs for April 2014 as recorded in Account 555. The MISO Day 2 cost recovery included in this April 2014 FCC is \$12,145,898, 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

¹ Previously embedded in other FTR charge types.

in the June FCC the net MISO ASM costs for April 2014 as recorded in Account 555. The MISO ASM cost recovery included in this June FCC is \$2,087,053, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Asset and Non-Asset Based Margins Sharing Refund

Under the terms of the Revised Second Amended Settlement adopted by the Commission² 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 June 2014 Asset Based Margin amount of \$51,493 has been included as a credit, or offset, to the June 2014 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 2013 Non-Asset Based Margin credit is \$93,142 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the June 2014 FCC is \$10,029, or 0.006¢ 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).

EXCLUSION

Prairie Rose Wind PPA Exclusion

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 Fuel Cost Rider (FCR). Beginning with the March 2013 FCR filing, the Company has excluded the PRW PPA from any FCR calculations until the

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

Commission has completed a ratemaking proceeding and made a decision regarding the rate treatment for the PRW PPA.

As a result of the above-mentioned February 26, 2014 Settlement, the Commission agreed that 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, the Company has included the April 2014 Prairie Rose PPA costs in the computation of the June 2014 FCC.

Other Reporting Item

Attached is the calculation of the June 2014 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 in Fargo at 701-241-8632.

Sincerely,

/ s /

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Jun-2014

Jun-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02944	\$0.00049	\$0.00125	\$0.03117
Residential	\$0.02943	\$0.00049	\$0.00125	\$0.03117
C & I Non-Demand	\$0.03032	\$0.00050	\$0.00128	\$0.03211
C & I Demand Non-TOD	\$0.02996	\$0.00050	\$0.00127	\$0.03172
C & I Demand TOD On-Peak	\$0.03780	\$0.00063	\$0.00160	\$0.04003
C & I Demand TOD Off-Peak	\$0.02332	\$0.00039	\$0.00099	\$0.02470
Outdoor Lighting	\$0.02176	\$0.00036	\$0.00092	\$0.02304
Residential				
Residential Service	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
Residential TOD	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
Residential - Underground	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
Residential TOD - Underground	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
Energy Control - (Non-Demand)	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
Limit Off Peak	\$ 0.02943	\$ 0.00049	\$ 0.00125	\$ 0.03117
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Limit Off Peak	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Small General Service	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Small General TOD - Metered	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Small General TOD - Unmetered	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Fire and Civil Defense Siren	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
Direct Current (Closed)	\$ 0.03032	\$ 0.00050	\$ 0.00128	\$ 0.03211
C & I Demand				
General Service	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
General TOD - On Peak	\$ 0.03780	\$ 0.00063	\$ 0.00160	\$ 0.04003
General TOD - Off Peak	\$ 0.02332	\$ 0.00039	\$ 0.00099	\$ 0.02470
Peak Controlled (Closed)	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Peak Controlled TOD (Closed) - On Peak	\$ 0.03780	\$ 0.00063	\$ 0.00160	\$ 0.04003
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02332	\$ 0.00039	\$ 0.00099	\$ 0.02470
Peak Controlled Tiered	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Peak Controlled Tiered TOD - On Peak	\$ 0.03780	\$ 0.00063	\$ 0.00160	\$ 0.04003
Peak Controlled Tiered TOD - Off Peak	\$ 0.02332	\$ 0.00039	\$ 0.00099	\$ 0.02470
Energy Controlled (Closed)	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Tier 1 Energy Controlled Rider	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Real Time Pricing - Firm - On Peak	\$ 0.03780	\$ 0.00063	\$ 0.00160	\$ 0.04003
Real Time Pricing - Firm - Off Peak	\$ 0.02332	\$ 0.00039	\$ 0.00099	\$ 0.02470
Real Time Pricing - Controllable - On Peak	\$ 0.03780	\$ 0.00063	\$ 0.00160	\$ 0.04003
Real Time Pricing - Controllable - Off Peak	\$ 0.02332	\$ 0.00039	\$ 0.00099	\$ 0.02470
Small Municipal Pumping	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Municipal Pumping	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Excess Energy - St. Anthony Falls	\$ 0.02996	\$ 0.00050	\$ 0.00127	\$ 0.03172
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304
Street Lighting System	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304
Street Lighting Energy	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304
Street Lighting Energy - Metered	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304
Street Lighting Energy (Closed)	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304
Street Lighting - City of St. Paul	\$ 0.02176	\$ 0.00036	\$ 0.00092	\$ 0.02304

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jan-14	Feb-14	Mar-14	Apr-14	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$53,489,925	\$40,586,350	\$32,742,817	\$25,819,345	\$152,638,437
Account 518 - Nuclear Fuel	\$9,136,018	\$10,019,374	\$12,140,399	\$11,355,291	\$42,651,082
Account 555 - Purchased Power ¹	\$48,385,125	\$41,849,054	\$42,611,657	\$43,386,319	\$176,232,156
Account 555 - Pr. Rose PPA Adjustment	(\$168,834)	(\$100,484)	\$0	\$0	(\$269,318)
MISO Day 2 Charges	\$29,980,488	\$18,096,951	\$18,455,712	\$12,223,550	\$78,756,701
MISO Day 2 - Schedule 24	(\$86,462)	(\$82,302)	(\$85,137)	(\$77,652)	(\$331,552)
MISO - ASM Charges	(\$1,761,368)	(\$914,565)	(\$1,135,909)	\$2,087,053	(\$1,724,789)
Account 555 - Total MISO Charges	\$28,132,658	\$17,100,085	\$17,234,665	\$14,232,951	\$76,700,359
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$138,974,892	\$109,454,379	\$104,729,538	\$94,793,906	\$447,952,716
Less Fuel Cost of InterSystem Sales	(\$10,126,119)	(\$7,375,339)	(\$6,313,943)	(\$4,212,643)	(\$28,028,043)
Net System Costs	\$128,848,774	\$102,079,041	\$98,415,596	\$90,581,264	\$419,924,673
System MWh Sales					
Total NSP System Retail	4,065,686	3,389,319	3,618,588	3,188,674	14,262,267
Non-Gen Muni's/Load Pattern	1,687	-	-	-	1,687
Total NSP System MWh Sales	4,067,373	3,389,319	3,618,588	3,188,674	14,263,954
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	3.168¢	3.012¢	2.720¢	2.841¢	2.944¢
Class Ratio/TOD Ratio					
(i) Residential	1.0026	1.0026	0.9969	0.9969	0.9998
(ii) C & I Non-Demand	1.0281	1.0281	1.0318	1.0318	1.0300
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0184	1.0184	1.0177
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2798	1.2798	1.2841
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7954	0.7954	0.7922
(vi) Outdoor Lighting	0.7440	0.7440	0.7341	0.7341	0.7391
North Dakota Fuel Cost Factor (FCF)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			2.944¢	0.9998	2.943¢
(ii) C & I Non-Demand			2.944¢	1.0300	3.032¢
(iii) C & I Demand Non-TOD			2.944¢	1.0177	2.996¢
(iv) C & I Demand TOD On-Peak			2.944¢	1.2841	3.780¢
(v) C & I Demand TOD Off-Peak			2.944¢	0.7922	2.332¢
(vi) Outdoor Lighting			2.944¢	0.7391	2.176¢
North Dakota Retail MWh Sales					
(i) Residential	113,485	87,264	89,114	69,638	359,501
(ii) C & I Non-Demand	15,180	12,455	13,112	10,303	51,050
(iii) C & I Demand Non-TOD	77,600	61,389	74,497	58,503	271,989
(iv) C & I Demand TOD On-Peak	19,746	16,864	18,203	17,268	72,081
(v) C & I Demand TOD Off-Peak	35,851	27,058	28,670	28,162	119,741
(vi) Outdoor Lighting	2,075	2,108	1,752	1,616	7,551
(vii) Total	263,937	207,138	225,348	185,490	881,913
Jun-2014 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Feb-14 Balance of Unrecovered Expenses)					Total
					Feb-14
					\$1,412,238

¹ Excludes demand-related expenses and includes Prairie Rose Wind PPA expenses

Prior Expenses Recovered in Apr-2014 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	69,638	\$75,119
(ii) C & I Non-Demand	10,303	\$11,592
(iii) C & I Demand Non-TOD	58,503	\$66,928
(iv) C & I Demand TOD On-Peak	17,268	\$24,236
(v) C & I Demand TOD Off-Peak	28,162	\$24,525
(vi) Outdoor Lighting	1,616	\$1,015
(vii) Total	185,490	\$203,415

Actual Cost Should Have Been Recovered in Apr-14				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.841¢	0.000¢	185,490	\$5,269,771

Cost Recovered in Apr-14 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	69,638	\$2,276,522
(ii) C & I Non-Demand	10,303	\$345,160
(iii) C & I Demand Non-TOD	58,503	\$1,938,418
(iv) C & I Demand TOD On-Peak	17,268	\$725,217
(v) C & I Demand TOD Off-Peak	28,162	\$724,305
(vi) Outdoor Lighting	1,616	\$39,148
(vii) Total	185,490	\$6,048,770

Total Balance of Unrecovered Expenses (Jun-14 Balance of Unrecovered Expenses)	
Jun-2014 Recovery Provision	\$429,824
4 Month ND Retail Total MWh Sales	881,913
Jun-2014 Recovery Provision per KWH	0.049¢

Jun-2014 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9998	0.049¢	0.049¢
(ii) C & I Non-Demand	1.0300	0.049¢	0.050¢
(iii) C & I Demand Non-TOD	1.0177	0.049¢	0.050¢
(iv) C & I Demand TOD On-Peak	1.2841	0.049¢	0.063¢
(v) C & I Demand TOD Off-Peak	0.7922	0.049¢	0.039¢
(vi) Outdoor Lighting	0.7391	0.049¢	0.036¢

Jun-2014 Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$51,493)	(\$10,029)	\$269,885	\$218,392
(i) Residential	-0.031¢	-0.006¢	0.161¢	0.125¢
(ii) C & I Non-Demand	-0.032¢	-0.006¢	0.166¢	0.128¢
(iii) C & I Demand Non-TOD	-0.031¢	-0.006¢	0.164¢	0.127¢
(iv) C & I Demand TOD On-Peak	-0.040¢	-0.008¢	0.207¢	0.160¢
(v) C & I Demand TOD Off-Peak	-0.024¢	-0.005¢	0.128¢	0.099¢
(vi) Outdoor Lighting	-0.023¢	-0.004¢	0.119¢	0.092¢

Jun-2014 Factors	
	Total
(i) Residential	3.117¢
(ii) C & I Non-Demand	3.211¢
(iii) C & I Demand Non-TOD	3.172¢
(iv) C & I Demand TOD On-Peak	4.003¢
(v) C & I Demand TOD Off-Peak	2.470¢
(vi) Outdoor Lighting	2.304¢

	FCA Application		Comparison		Generation Type by Percent		
	May-14	Jun-14	Differ- ence	Percent Change	FCA Application May-14	Jun-14	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$179.3	\$152.6	(\$26.7)	-14.9%	37.7%	34.1%	-3.6%
2 Nuclear	\$39.1	\$42.7	\$3.6	9.1%	8.2%	9.5%	1.3%
3 Purchases	\$172.3	\$176.0	\$3.7	2.1%	36.3%	39.3%	3.0%
MISO related Purchases	\$84.5	\$76.7	(\$7.8)	-9.3%	17.8%	17.1%	-0.7%
4 Total System Costs	475.2	448.0	(\$27.3)	-5.7%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$26.2	\$28.0	\$1.8	7.1%	5.5%	6.3%	0.8%
6 Net System Costs	\$449.0	\$419.9	(\$29.1)	-6.5%	94.5%	93.7%	-0.8%
7							
** GWH OUTPUT **							
9 Fossil	5,641	4,995	(646)	-11.5%	34.2%	31.2%	-3.0%
10 Nuclear	4,110	4,453	343	8.3%	24.9%	27.9%	3.0%
11 Purchases	4,792	4,773	(19)	-0.4%	29.0%	29.9%	0.9%
12 Hydro & Other	1,245	1,088	(157)	-12.6%	7.5%	6.8%	-0.7%
13 Net Interchange	708	676	(32)	-4.5%	4.3%	4.2%	-0.1%
14 Total Output	16,496	15,985	(511)	-3.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	926	1,112	186	20.0%	5.6%	7.0%	1.4%
16 Native Requirement	15,570	14,873	(697)	-4.5%	94.4%	93.0%	-1.4%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.179	3.056	-0.123	-3.9%			
20 Nuclear	0.951	0.958	0.007	0.7%			
21 Purchases	3.595	3.687	0.092	2.5%			
22 Total System Costs	2.881	2.802	-0.078	-2.7%			
23 Intersystem Sales	2.827	2.521	-0.306	-10.8%			
24 Net System Costs	2.884	2.823	-0.061	-2.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,586	14,264	(322)	-2.2%			
28							
29 COST per KWH SALES (\$)	3.078	2.944	-0.134	-4.4%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.107	0.049	0.156				
(i) Residential	-0.107	0.049	0.156				
(ii) C & I Non-Demand	-0.110	0.050	0.160				
(iii) C & I Demand Non-TOD	-0.109	0.050	0.158				
(iv) C & I Demand TOD On-Peak	-0.138	0.063	0.200				
(v) C & I Demand TOD Off-Peak	-0.085	0.039	0.123				
(vi) Outdoor Lighting	-0.079	0.036	0.115				
32 REFUND	-0.409	0.124	0.533				
(i) Residential	-0.410	0.125					
(ii) C & I Non-Demand	-0.420	0.128					
(iii) C & I Demand Non-TOD	-0.416	0.127					
(iv) C & I Demand TOD On-Peak	-0.527	0.160					
(v) C & I Demand TOD Off-Peak	-0.323	0.099					
(vi) Outdoor Lighting	-0.304	0.092					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.562	3.117	0.555	21.7%			
(i) Residential	2.566	3.117	0.551				
(ii) C & I Non-Demand	2.637	3.211					
(iii) C & I Demand Non-TOD	2.607	3.172					
(iv) C & I Demand TOD On-Peak	3.296	4.003					
(v) C & I Demand TOD Off-Peak	2.026	2.470					
(vi) Outdoor Lighting	1.900	2.304					

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
		\$5.51

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	
	May-14	Jun-14
** GWH OUTPUT **		
Thermal	768,823	506,261
Disper gen	(97)	(92)
Hydro plus Wind	476,534	581,790
Hydro and Other	1,245,260	1,087,959
Rounded to nearest thousand:	1,245	1,088
Sales		
Non Gen Munic Total	3,107,000	1,687,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	926,202,000	1,111,729,000
Rounded to nearest million:	926.202	1111.729

		System	Intersystem	Retail
April 2014 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 16,486,143.10	\$ 2,077,106.80	\$ 18,563,249.90
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,691,888.08	\$ -	\$ 4,691,888.08
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 5,699.47	\$ -	\$ 5,699.47
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,495,808.07)	\$ -	\$ (13,495,808.07)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 942,287.10	\$ -	\$ 942,287.10
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (5,699.47)	\$ -	\$ (5,699.47)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (399,042.66)	\$ 942,706.07	\$ 543,663.41
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (7,169.10)	\$ -	\$ (7,169.10)
14	Real-Time Distribution of Losses Amount	\$ (1,346,050.39)	\$ -	\$ (1,346,050.39)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (110,094.79)	\$ -	\$ (110,094.79)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 8,648.33	\$ -	\$ 8,648.33
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (539.31)	\$ -	\$ (539.31)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 4,695,771.29	\$ -	\$ 4,695,771.29
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 2,606.83	\$ -	\$ 2,606.83
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 3,344,977.25	\$ -	\$ 3,344,977.25
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (2,606.83)	\$ -	\$ (2,606.83)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 154,916.15	\$ -	\$ 154,916.15
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)	\$ (1,823.04)	\$ -	\$ (1,823.04)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (6,352,319.79)	\$ -	\$ (6,352,319.79)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (259,404.68)	\$ -	\$ (259,404.68)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ (139,538.67)	\$ -	\$ (139,538.67)
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (741,204.60)	\$ -	\$ (741,204.60)
37	Financial Transmission Guarantee Uplift Amount	\$ 922,783.45	\$ -	\$ 922,783.45
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,481,500.14	\$ -	\$ 1,481,500.14
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 215,830.32	\$ -	\$ 215,830.32
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (129,710.80)	\$ 10,024.31	\$ (119,686.49)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ (628,858.88)	\$ -	\$ (628,858.88)
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (4,670.10)	\$ 227.28	\$ (4,442.82)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (321,838.06)	\$ 33,915.02	\$ (287,923.04)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 528,206.56	\$ (8,295.18)	\$ 519,911.38
19	Real-Time Market Administration Amount	\$ 33,638.03	\$ (3,519.89)	\$ 30,118.14
29	Financial Transmission Rights Market Administration Amount	\$ 31,495.84	\$ -	\$ 31,495.84
33	Day-Ahead Schedule 24 Allocation Amount	\$ 74,404.99	\$ (1,164.59)	\$ 73,240.40
34	Real-Time Schedule 24 Allocation Amount	\$ (143,939.31)	\$ 148,350.65	\$ 4,411.34
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	\$ 2,895.45	\$ -	\$ 2,895.45
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 4,332,578.48	\$ -	\$ 4,332,578.48
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (4,437,232.36)	\$ -	\$ (4,437,232.36)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (650,457.70)	\$ -	\$ (650,457.70)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 245,936.93	\$ -	\$ 245,936.93
TOTAL MISO CHARGES		\$ 9,024,199.18	\$ 3,199,350.47	\$ 12,223,549.65
SCHEDULE 24 (FOR RETAIL)				\$ 77,651.74
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 12,145,897.91

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
April 2014 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (453,749.67)	\$ -	\$ (453,749.67)
2	Day-Ahead Spinning Reserve Amount	\$ (235,167.07)	\$ -	\$ (235,167.07)
3	Day-Ahead Supplemental Reserve	\$ (71,155.57)	\$ -	\$ (71,155.57)
4	Real-Time Regulation Amount	\$ 223,539.47	\$ 161,824.05	\$ 385,363.52
5	Real-Time Spinning Reserve Amount	\$ 53,536.73	\$ 105,411.59	\$ 158,948.32
6	Real-Time Supplemental Reserve Amount.	\$ 23,577.16	\$ (901.44)	\$ 22,675.72
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ 65,551.65	\$ -	\$ 65,551.65
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,879,779.74	\$ -	\$ 1,879,779.74
8b	Real Time Non Excessive Energy Congestion	\$ (147,831.79)	\$ -	\$ (147,831.79)
8c	Real Time Non Excessive Energy Loss	\$ 71,537.96	\$ -	\$ 71,537.96
9	Real Time Net Regulation Adjustment Amount	\$ (12,394.93)	\$ 1,284.73	\$ (11,110.20)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 109,018.97	\$ -	\$ 109,018.97
11	Real Time Spinning Reserve Cost Distribution	\$ 128,615.11	\$ -	\$ 128,615.11
12	Real Time Supplemental Reserve Cost Distribution	\$ 73,707.68	\$ -	\$ 73,707.68
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 120,915.72	\$ (11,908.29)	\$ 109,007.43
14	Real Time Contignecy Reserve Deployment Failure	\$ 1,861.03	\$ -	\$ 1,861.03
TOTAL MISO ASM CHARGES		\$ 1,831,342.19	\$ 255,710.64	\$ 2,087,052.83

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

Forecast Month	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
True-up Month	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14
1	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)
2	198,863	204,151	186,753	165,759	167,300	-	-	-	-	-	-	-
3	(0,004)	(0,004)	(0,004)	(0,005)	(0,005)	(0,005)	(0,005)	(0,005)	(0,005)	(0,005)	(0,005)	(0,005)
4	(15,511)	(12,506)	(7,639)	(2,884)	(5,868)	-	-	-	-	-	-	-
5	(15,634)	(17,384)	(9,533)	(6,066)	(3,601)	-	-	-	-	-	-	-
6	123	4,878	1,894	3,182	(2,267)	-	-	-	-	-	-	-
7	0,000	0,002	0,001	0,002	(0,001)	-	-	-	-	-	-	-
8	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	-	-	-	-	-	-	-

Class Ratios	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand TOD On-Peak	C&I Demand TOD Off-Peak	Outdoor Lighting
14	1.0026	1.0026	1.0026	1.0012	0.9998	0.9983
15	1.0281	1.0281	1.0281	1.0290	1.0300	1.0309
16	1.0170	1.0170	1.0170	1.0174	1.0177	1.0181
17	1.2883	1.2883	1.2883	1.2862	1.2841	1.2819
18	0.7889	0.7889	0.7889	0.7905	0.7922	0.7938
19	0.7440	0.7440	0.7440	0.7415	0.7391	0.7366
20	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
21	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
22	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
23	(0,005)	(0,002)	(0,004)	(0,004)	(0,008)	(0,008)
24	(0,003)	(0,001)	(0,002)	(0,002)	(0,005)	(0,005)
25	(0,003)	(0,001)	(0,002)	(0,002)	(0,004)	(0,004)
26	0.9969	0.9969	0.9969	0.9983	0.9998	0.9969
27	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
28	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
29	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
30	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
31	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341

Realized Margin Adj for Class Ratios	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand TOD On-Peak	C&I Demand TOD Off-Peak	Outdoor Lighting
31	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
32	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
33	(0,004)	(0,001)	(0,003)	(0,003)	(0,006)	(0,006)
34	(0,005)	(0,002)	(0,004)	(0,004)	(0,008)	(0,008)
35	(0,003)	(0,001)	(0,002)	(0,002)	(0,005)	(0,005)
36	(0,003)	(0,001)	(0,002)	(0,002)	(0,004)	(0,004)

