



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

July 31, 2014

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

Re: August 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 August 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:

August 2014	Fuel Cost Charge (\$/kWh)
Residential	0.03089
C & I Non-Demand	0.03197
C & I Demand	0.03156
C & I Demand Time of Day On-Peak	0.03966
C & I Demand Time of Day Off-Peak	0.02465
Outdoor Lighting	0.02275

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 August 2014 FCC the net MISO Day 2 costs for June 2014 as recorded in Account 555. The MISO Day 2 cost recovery included in this June 2014 FCC is \$11,370,497, 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 August FCC the net MISO ASM costs for June 2014 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is \$5,744,170, 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 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. In future Fuel Cost Charge filings, we will no longer collect the Disposal Fee from North Dakota customers unless, of course, the DOE reinstates a fee again.

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 August 2014 Asset Based Margin amount of -\$136,839 has been included as a credit, or offset, to the August 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 August 2014 FCC is \$10,541, 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).

² Company submitted an informational filing to the commission on May 21, 2014 regarding this charge under Case No. PU-14-012

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

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 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, starting with the May 2014 FCC, the Company has included the March 2014 Prairie Rose PPA costs in the computation.

Other Reporting Item

Attached is the calculation of the August 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

Aug-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02824	\$0.00036	\$0.00239	\$0.03099
Residential	\$0.02815	\$0.00035	\$0.00239	\$0.03089
C & I Non-Demand	\$0.02914	\$0.00037	\$0.00247	\$0.03197
C & I Demand Non-TOD	\$0.02876	\$0.00036	\$0.00244	\$0.03156
C & I Demand TOD On-Peak	\$0.03614	\$0.00046	\$0.00306	\$0.03966
C & I Demand TOD Off-Peak	\$0.02246	\$0.00028	\$0.00190	\$0.02465
Outdoor Lighting	\$0.02073	\$0.00026	\$0.00176	\$0.02275
Residential				
Residential Service	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
Residential TOD	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
Residential - Underground	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
Residential TOD - Underground	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
Energy Control - (Non-Demand)	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
Limit Off Peak	\$ 0.02815	\$ 0.00035	\$ 0.00239	\$ 0.03089
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Limit Off Peak	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Small General Service	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Small General TOD - Metered	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Small General TOD - Unmetered	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Fire and Civil Defense Siren	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
Direct Current (Closed)	\$ 0.02914	\$ 0.00037	\$ 0.00247	\$ 0.03197
C & I Demand				
General Service	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
General TOD - On Peak	\$ 0.03614	\$ 0.00046	\$ 0.00306	\$ 0.03966
General TOD - Off Peak	\$ 0.02246	\$ 0.00028	\$ 0.00190	\$ 0.02465
Peak Controlled (Closed)	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Peak Controlled TOD (Closed) - On Peak	\$ 0.03614	\$ 0.00046	\$ 0.00306	\$ 0.03966
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02246	\$ 0.00028	\$ 0.00190	\$ 0.02465
Peak Controlled Tiered	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Peak Controlled Tiered TOD - On Peak	\$ 0.03614	\$ 0.00046	\$ 0.00306	\$ 0.03966
Peak Controlled Tiered TOD - Off Peak	\$ 0.02246	\$ 0.00028	\$ 0.00190	\$ 0.02465
Energy Controlled (Closed)	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Tier 1 Energy Controlled Rider	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Real Time Pricing - Firm - On Peak	\$ 0.03614	\$ 0.00046	\$ 0.00306	\$ 0.03966
Real Time Pricing - Firm - Off Peak	\$ 0.02246	\$ 0.00028	\$ 0.00190	\$ 0.02465
Real Time Pricing - Controllable - On Peak	\$ 0.03614	\$ 0.00046	\$ 0.00306	\$ 0.03966
Real Time Pricing - Controllable - Off Peak	\$ 0.02246	\$ 0.00028	\$ 0.00190	\$ 0.02465
Small Municipal Pumping	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Municipal Pumping	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Excess Energy - St. Anthony Falls	\$ 0.02876	\$ 0.00036	\$ 0.00244	\$ 0.03156
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275
Street Lighting System	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275
Street Lighting Energy	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275
Street Lighting Energy - Metered	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275
Street Lighting Energy (Closed)	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275
Street Lighting - City of St. Paul	\$ 0.02073	\$ 0.00026	\$ 0.00176	\$ 0.02275

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 Aug-2014

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Mar-14	Apr-14	May-14	Jun-14	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$32,742,817	\$25,819,345	\$43,692,932	\$41,774,382	\$144,029,476
Account 518 - Nuclear Fuel	\$12,140,399	\$11,355,291	\$10,758,687	\$10,460,693	\$44,715,070
Account 555 - Purchased Power ¹	\$42,611,657	\$43,386,319	\$38,458,789	\$36,725,487	\$161,182,253
MISO Day 2 Charges	\$18,455,712	\$12,223,550	\$3,670,045	\$11,445,777	\$45,795,083
MISO Day 2 - Schedule 24	(\$85,137)	(\$77,652)	(\$80,578)	(\$75,280)	(\$318,647)
MISO - ASM Charges	<u>(\$1,135,909)</u>	<u>\$2,087,053</u>	<u>\$4,218,919</u>	<u>\$5,744,170</u>	<u>\$10,914,232</u>
Account 555 - Total MISO Charges	\$17,234,665	\$14,232,951	\$7,808,385	\$17,114,666	\$56,390,668
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$104,729,538	\$94,793,906	\$100,718,793	\$106,075,229	\$406,317,466
Less Fuel Cost of InterSystem Sales	(\$6,313,943)	(\$4,212,643)	(\$15,144,193)	(\$6,792,146)	(\$32,462,925)
Net System Costs	<u>\$98,415,596</u>	<u>\$90,581,264</u>	<u>\$85,574,600</u>	<u>\$99,283,082</u>	<u>\$373,854,541</u>
System MWH Sales					
Total NSP System Retail	3,618,588	3,188,674	3,017,667	3,411,295	13,236,224
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	<u>3,618,588</u>	<u>3,188,674</u>	<u>3,017,667</u>	<u>3,411,295</u>	<u>13,236,224</u>
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	2.720¢	2.841¢	2.836¢	2.910¢	2.824¢
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			2.824¢	0.9969	2.815¢
(ii) C & I Non-Demand			2.824¢	1.0318	2.914¢
(iii) C & I Demand Non-TOD			2.824¢	1.0184	2.876¢
(iv) C & I Demand TOD On-Peak			2.824¢	1.2798	3.614¢
(v) C & I Demand TOD Off-Peak			2.824¢	0.7954	2.246¢
(vi) Outdoor Lighting			2.824¢	0.7341	2.073¢
North Dakota Retail MWh Sales					
(i) Residential	89,114	69,638	52,863	52,740	264,355
(ii) C & I Non-Demand	13,112	10,303	8,616	8,195	40,226
(iii) C & I Demand Non-TOD	74,497	58,503	59,965	61,779	254,744
(iv) C & I Demand TOD On-Peak	18,203	17,268	15,162	19,373	70,006
(v) C & I Demand TOD Off-Peak	28,670	28,162	24,609	27,624	109,065
(vi) Outdoor Lighting	1,752	1,616	1,348	1,254	5,970
(vii) Total	<u>225,348</u>	<u>185,490</u>	<u>162,563</u>	<u>170,965</u>	<u>744,366</u>
Aug-2014 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Apr-14 Balance of Unrecovered Expenses)					Total
					Apr-14
					\$429,824

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

Prior Expenses Recovered in Jun-2014 [Billing Record]			ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential			52,740	(\$19,557)
(ii) C & I Non-Demand			8,195	(\$3,164)
(iii) C & I Demand Non-TOD			61,779	(\$19,490)
(iv) C & I Demand TOD On-Peak			19,373	(\$8,713)
(v) C & I Demand TOD Off-Peak			27,624	(\$7,928)
(vi) Outdoor Lighting			1,254	(\$631)
(vii) Total			170,965	(\$59,483)

Actual Cost Should Have Been Recovered in Jun-14				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.910¢	0.000¢	170,965	\$4,975,082

Cost Recovered in Jun-14 [Billing Record]			ND Billed MWh Sales	Actual Recovery
(i) Residential			52,740	\$1,593,183
(ii) C & I Non-Demand			8,195	\$255,335
(iii) C & I Demand Non-TOD			61,779	\$1,904,717
(iv) C & I Demand TOD On-Peak			19,373	\$754,929
(v) C & I Demand TOD Off-Peak			27,624	\$662,832
(vi) Outdoor Lighting			1,254	\$28,341
(vii) Total			170,965	\$5,199,337

Total Balance of Unrecovered Expenses (Aug-14 Balance of Unrecovered Expenses)	
Aug-2014 Recovery Provision	\$265,052
4 Month ND Retail Total MWh Sales	744,366
Aug-2014 Recovery Provision per KWH	0.036¢

Aug-2014 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	0.036¢	0.035¢
(ii) C & I Non-Demand	1.0318	0.036¢	0.037¢
(iii) C & I Demand Non-TOD	1.0184	0.036¢	0.036¢
(iv) C & I Demand TOD On-Peak	1.2798	0.036¢	0.046¢
(v) C & I Demand TOD Off-Peak	0.7954	0.036¢	0.028¢
(vi) Outdoor Lighting	0.7341	0.036¢	0.026¢

Aug-2014 Refunds/Additional Charges				
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
	\$136,839	(\$10,541)	\$318,815	\$455,654
(i) Residential	0.073¢	-0.006¢	0.171¢	0.239¢
(ii) C & I Non-Demand	0.076¢	-0.006¢	0.177¢	0.247¢
(iii) C & I Demand Non-TOD	0.075¢	-0.006¢	0.175¢	0.244¢
(iv) C & I Demand TOD On-Peak	0.094¢	-0.007¢	0.219¢	0.306¢
(v) C & I Demand TOD Off-Peak	0.059¢	-0.005¢	0.136¢	0.190¢
(vi) Outdoor Lighting	0.054¢	-0.004¢	0.126¢	0.176¢

Aug-2014 Factors		Total
(i) Residential		3.089¢
(ii) C & I Non-Demand		3.197¢
(iii) C & I Demand Non-TOD		3.156¢
(iv) C & I Demand TOD On-Peak		3.966¢
(v) C & I Demand TOD Off-Peak		2.465¢
(vi) Outdoor Lighting		2.275¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jul-14	Aug-14	Differ- ence	Percent Change	FCA Application Jul-14	Aug-14	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$142.8	\$144.0	\$1.2	0.8%	34.9%	35.4%	0.5%
2 Nuclear	\$44.3	\$44.7	\$0.4	1.0%	10.8%	11.0%	0.2%
3 Purchases	\$166.2	\$161.2	(\$5.0)	-3.0%	40.6%	39.7%	-0.9%
MISO related Purchases	\$56.4	\$56.4	\$0.0	0.0%	13.8%	13.9%	0.1%
4 Total System Costs	409.7	406.3	(\$3.4)	-0.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$33.0	\$32.5	(\$0.6)	-1.8%	8.1%	8.0%	-0.1%
6 Net System Costs	\$376.7	\$373.9	(\$2.8)	-0.7%	91.9%	92.0%	0.1%
7							
** GWH OUTPUT **							
9 Fossil	4,526	4,248	(278)	-6.1%	29.3%	27.2%	-2.1%
10 Nuclear	4,629	4,706	77	1.7%	29.9%	30.2%	0.3%
11 Purchases	4,425	4,511	86	1.9%	28.6%	28.9%	0.3%
12 Hydro & Other	1,247	1,472	225	18.0%	8.1%	9.4%	1.3%
13 Net Interchange	633	657	24	3.8%	4.1%	4.2%	0.1%
14 Total Output	15,460	15,594	134	0.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,256	1,197	(60)	-4.7%	8.1%	7.7%	-0.4%
16 Native Requirement	14,204	14,397	194	1.4%	91.9%	92.3%	0.4%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.156	3.391	0.235	7.4%			
20 Nuclear	0.956	0.950	-0.006	-0.7%			
21 Purchases	3.756	3.573	-0.183	-4.9%			
22 Total System Costs	2.650	2.606	-0.044	-1.7%			
23 Intersystem Sales	2.630	2.713	0.082	3.1%			
24 Net System Costs	2.652	2.597	-0.055	-2.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,214	13,236	22	0.2%			
28							
29 COST per KWH SALES (\$)	2.850	2.825	-0.025	-0.9%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.208	0.036	0.244				
(i) Residential	-0.208	0.035	0.243				
(ii) C & I Non-Demand	-0.215	0.037	0.251				
(iii) C & I Demand Non-TOD	-0.212	0.036	0.248				
(iv) C & I Demand TOD On-Peak	-0.267	0.046	0.313				
(v) C & I Demand TOD Off-Peak	-0.165	0.028	0.194				
(vi) Outdoor Lighting	-0.153	0.026	0.180				
32 REFUND	-0.303	0.239	0.542				
(i) Residential	-0.304	0.239					
(ii) C & I Non-Demand	-0.312	0.247					
(iii) C & I Demand Non-TOD	-0.308	0.244					
(iv) C & I Demand TOD On-Peak	-0.390	0.306					
(v) C & I Demand TOD Off-Peak	-0.239	0.190					
(vi) Outdoor Lighting	-0.225	0.176					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.339	3.100	0.761	32.5%			
(i) Residential	2.334	3.089	0.755				
(ii) C & I Non-Demand	2.411	3.197					
(iii) C & I Demand Non-TOD	2.381	3.156					
(iv) C & I Demand TOD On-Peak	2.998	3.966					
(v) C & I Demand TOD Off-Peak	1.856	2.465					
(vi) Outdoor Lighting	1.722	2.275					

Residential BILL IMPACT (\$'s)

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]

kWh	Change from Previous Month
100	\$0.76
250	\$1.89
500	\$3.78
750	\$5.66
1,000	\$7.55

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>	
	Jul-14	Aug-14
** GWH OUTPUT **		
Thermal	596,362	744,592
Disper gen	(81)	(70)
<u>Hydro plus Wind</u>	650,799	727,147
Hydro and Other	1,247,080	1,471,669
Rounded to nearest thousand:	1,247	1,472
Sales		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,256,337,000	1,196,706,000
Rounded to nearest million:	1256.337	1196.706

Northern States Power Company, A Minnesota Corporation
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Attachment 2

Page 1

		System	Intersystem	Retail
June 2014 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 17,634,138.06	\$ 3,570,973.03	\$ 21,205,111.09
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 3,846,462.16	\$ -	\$ 3,846,462.16
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 5,258.06	\$ -	\$ 5,258.06
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (18,046,025.66)	\$ -	\$ (18,046,025.66)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,318,828.15	\$ -	\$ 1,318,828.15
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (5,258.06)	\$ -	\$ (5,258.06)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 837,156.00	\$ 1,231,775.37	\$ 2,068,931.37
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 129,035.81	\$ -	\$ 129,035.81
14	Real-Time Distribution of Losses Amount	\$ (1,371,173.68)	\$ -	\$ (1,371,173.68)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ (3.03)	\$ -	\$ (3.03)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ 3.03	\$ -	\$ 3.03
21	Real-time Net inadvertent Distribution	\$ 227,786.93	\$ -	\$ 227,786.93
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 138,980.33	\$ -	\$ 138,980.33
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 5,725.00	\$ -	\$ 5,725.00
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 363,549.24	\$ -	\$ 363,549.24
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (271.12)	\$ -	\$ (271.12)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 4,293,999.85	\$ -	\$ 4,293,999.85
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ 271.12	\$ -	\$ 271.12
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 312,331.74	\$ -	\$ 312,331.74
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ 17.27	\$ -	\$ 17.27
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (17.27)	\$ -	\$ (17.27)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (16,872.82)	\$ -	\$ (16,872.82)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,872,092.47)	\$ -	\$ (3,872,092.47)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (209,478.60)	\$ -	\$ (209,478.60)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (173,618.57)	\$ -	\$ (173,618.57)
37	Financial Transmission Guarantee Uplift Amount	\$ 191,862.24	\$ -	\$ 191,862.24
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 754,900.21	\$ -	\$ 754,900.21
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 263,839.91	\$ -	\$ 263,839.91
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (124,408.97)	\$ 73,607.69	\$ (50,801.28)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 273,895.92	\$ -	\$ 273,895.92
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (21,462.96)	\$ 264,504.78	\$ 243,041.82
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (177,412.48)	\$ 27,577.52	\$ (149,834.96)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 542,455.56	\$ (6,967.43)	\$ 535,488.13
19	Real-Time Market Administration Amount	\$ 42,367.30	\$ (2,446.47)	\$ 39,920.83
29	Financial Transmission Rights Market Administration Amount	\$ 44,151.84	\$ -	\$ 44,151.84
33	Day-Ahead Schedule 24 Allocation Amount	\$ 67,725.14	\$ (846.78)	\$ 66,878.36
34	Real-Time Schedule 24 Allocation Amount	\$ (36,153.53)	\$ 44,555.15	\$ 8,401.62
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	\$ (534,291.95)	\$ 32,597.09	\$ (501,694.86)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 7,267,335.64	\$ -	\$ 7,267,335.64
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (7,682,508.05)	\$ -	\$ (7,682,508.05)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (278,866.42)	\$ -	\$ (278,866.42)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 198,285.80	\$ -	\$ 198,285.80
TOTAL MISO CHARGES		\$ 6,210,446.67	\$ 5,235,329.95	\$ 11,445,776.62
SCHEDULE 24 (FOR RETAIL)				\$ 75,279.98
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 11,370,496.64

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
June 2014 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (320,457.41)	\$ -	\$ (320,457.41)
2	Day-Ahead Spinning Reserve Amount	\$ (103,638.76)	\$ -	\$ (103,638.76)
3	Day-Ahead Supplemental Reserve	\$ (47,583.40)	\$ -	\$ (47,583.40)
4	Real-Time Regulation Amount	\$ (7,640.93)	\$ 189,594.26	\$ 181,953.33
5	Real-Time Spinning Reserve Amount	\$ (33,399.02)	\$ 47,659.22	\$ 14,260.20
6	Real-Time Supplemental Reserve Amount.	\$ 12,238.83	\$ 90.18	\$ 12,329.01
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (24,607.61)	\$ -	\$ (24,607.61)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 5,674,892.21	\$ -	\$ 5,674,892.21
8b	Real Time Non Excessive Energy Congestion	\$ (82,472.95)	\$ -	\$ (82,472.95)
8c	Real Time Non Excessive Energy Loss	\$ 51,037.45	\$ -	\$ 51,037.45
9	Real Time Net Regulation Adjustment Amount	\$ 57,256.96	\$ (17,667.58)	\$ 39,589.38
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 117,953.96	\$ -	\$ 117,953.96
11	Real Time Spinning Reserve Cost Distribution	\$ 104,934.22	\$ -	\$ 104,934.22
12	Real Time Supplemental Reserve Cost Distribution	\$ 44,718.02	\$ -	\$ 44,718.02
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 109,380.43	\$ (33,758.58)	\$ 75,621.85
14	Real Time Contignecy Reserve Deployment Failure	\$ 5,640.10	\$ -	\$ 5,640.10
TOTAL MISO ASM CHARGES		\$ 5,558,252.10	\$ 185,917.50	\$ 5,744,169.60

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

Forecast Month	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15
True-up Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
1												
2												
3												
4	(280,361)	(232,398)	(191,441)	(106,644)	(91,428)	(52,490)						
5	204,151	186,753	165,759	167,300	190,371	186,036	182,561	176,353				
6												
7												
8	(0.137)	(0.124)	(0.115)	(0.064)	(0.048)	(0.028)						
9												
10	(68,557)	50,152	(306,819)	(172,630)	(373,518)	(51,493)	(219,413)	136,839				
11	(42,099)	(9,616)	(124,742)	(227,780)	(245,533)	(240,829)						
12	(26,458)	59,768	(182,077)	55,150	(127,985)	189,336	(219,413)	136,839				
13												
14	(0.013)	0.032	(0.110)	0.033	(0.067)	0.102						
15												
16	(0.150)	(0.092)	(0.225)	(0.031)	(0.115)	0.074						
17												
18	1.0026	1.0026	1.0012	0.9998	0.9983	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
19	1.0281	1.0281	1.0290	1.0300	1.0309	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
20	1.0170	1.0170	1.0174	1.0177	1.0181	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
21	1.2883	1.2883	1.2862	1.2841	1.2819	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
22	0.7889	0.7889	0.7905	0.7922	0.7938	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
23	0.7440	0.7440	0.7415	0.7391	0.7366	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
24												
25	(0.151)	(0.093)	(0.226)	(0.031)	(0.115)	0.073						
26	(0.155)	(0.095)	(0.232)	(0.032)	(0.119)	0.076						
27	(0.153)	(0.094)	(0.229)	(0.031)	(0.117)	0.075						
28	(0.194)	(0.119)	(0.290)	(0.040)	(0.148)	0.094						
29	(0.119)	(0.073)	(0.178)	(0.024)	(0.091)	0.059						
30	(0.112)	(0.069)	(0.167)	(0.023)	(0.085)	0.054						

21 Residential
22 C&I Non-Demand
23 C&I Demand Non-TOD
24 C&I Demand TOD On-Peak
25 C&I Demand TOD Off-Peak
26 Outdoor Lighting

27 Residential
28 C&I Non-Demand
29 C&I Demand Non-TOD
30 C&I Demand TOD On-Peak
31 C&I Demand TOD Off-Peak
32 Outdoor Lighting

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

	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15
1 Forecast 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	Dec-14
2 True-up Month													
3													
4 Monthly Refund			(39,728)		(72,037)	(23,952)							
5 Forecast North Dakota Sales	198,863	204,151	186,753	165,759	167,300	190,371	186,036						
6													
7													
8 Current Month Refund Factor			(0.021)		(0.043)	(0.013)							
9													
10 Expected Refund	98,806	(496,354)	260,871	(315,660)	333,838	(300,330)	269,885						
11													
12 Actual Refund	(162,065)	(180,694)	(112,695)	(15,330)	(8,084)	26,080	(48,930)						
13													
14 Deviation	260,871	(315,660)	373,566	(300,330)	341,922	(326,410)	318,815						
15													
16 True-up Factor	0.131	(0.155)	0.200	(0.181)	0.204	(0.171)	0.171						
17													
18													
19													
20 Realized Refund	0.131	(0.155)	0.179	(0.181)	0.161	(0.184)	0.171						
21													
22 Class Ratios													
23 Residential	1.0026	1.0026	1.0026	1.0012	0.9998	0.9983	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0281	1.0281	1.0281	1.0290	1.0300	1.0309	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0174	1.0177	1.0181	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2862	1.2841	1.2819	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7905	0.7922	0.7938	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7440	0.7440	0.7440	0.7415	0.7391	0.7366	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30 Realized Margin Adj for Class Ratios													
31 Residential	0.132	(0.155)	0.179	(0.181)	0.161	(0.184)	0.171						
32 C&I Non-Demand	0.135	(0.159)	0.184	(0.186)	0.166	(0.190)	0.177						
33 C&I Demand Non-TOD	0.133	(0.157)	0.182	(0.184)	0.164	(0.187)	0.175						
34 C&I Demand TOD On-Peak	0.169	(0.199)	0.230	(0.233)	0.207	(0.236)	0.219						
35 C&I Demand TOD Off-Peak	0.103	(0.122)	0.141	(0.143)	0.128	(0.146)	0.136						
36 Outdoor Lighting	0.098	(0.115)	0.133	(0.134)	0.119	(0.136)	0.126						