



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

September 28, 2012

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

Re: October 2012 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (“FCC”) for October 2012.

Pursuant to Commission authorization of the final compliance tariffs in the Company’s 2010 rate proceeding (Docket No. PU-10-657), the new rates were implemented on May 1, 2012. The new Service Category Ratios listed below also became effective:

Service Category Ratios	Current	Effective May 1, 2012
Residential	0.9956	1.0026
C & I Non-Demand	1.0548	1.0281
C & I Demand	1.0219	1.0170
C & I Demand Time of Day On-Peak	1.3135	1.2883
C & I Demand Time of Day Off-Peak	0.7726	0.7889
Outdoor Lighting	0.7088	0.7440

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

October 2012	Fuel Cost Charge (\$/kWh)
Residential	0.02896
C & I Non-Demand	0.02970
C & I Demand	0.02938
C & I Demand Time of Day On-Peak	0.03722
C & I Demand Time of Day Off-Peak	0.02279
Outdoor Lighting	0.02149

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent Transmission System Operator, Inc. (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s April 6, 2005 Order in Docket No. PU-05-147 and the Order in Docket No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (“ARR”) and 3 new 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 October 2012 FCC the net MISO Day 2 costs for August 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this October FCC is \$17,459,884, 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.

¹ Previously embedded in other FTR charge types.

MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (“ASM”) on January 6, 2009, the net costs or revenues of 14 new ASM charge types are included in the Fuel Cost Rider, pursuant to Commission guidance in Docket No. PU-09-016. Consistent with the MISO Order and the required “net” accounting of ASM costs and revenues, we include in the October FCC the net MISO ASM costs for August 2012 as recorded in Account 555. The MISO ASM cost recovery included in this October FCC is \$968,698, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Pursuant to the above referenced Order Adopting Settlement, the October 2012 Asset Based Margin amount of \$29,198 has been included in the October 2012 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 will be 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 2011 Non-Asset Based Margin credit is \$141,551 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the October FCC is \$9,304, or 0.005¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attached is the calculation of the October 2012 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, Compliance and Filings

Enclosures (2)
CC: David H. Sederquist

Oct-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02890	\$0.00020	-\$0.00022	\$0.02889
Residential	\$0.02898	\$0.00021	-\$0.00022	\$0.02896
C & I Non-Demand	\$0.02971	\$0.00021	-\$0.00022	\$0.02970
C & I Demand Non-TOD	\$0.02939	\$0.00021	-\$0.00022	\$0.02938
C & I Demand TOD On-Peak	\$0.03723	\$0.00026	-\$0.00028	\$0.03722
C & I Demand TOD Off-Peak	\$0.02280	\$0.00016	-\$0.00017	\$0.02279
Outdoor Lighting	\$0.02150	\$0.00015	-\$0.00016	\$0.02149
Residential				
Residential Service	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
Residential TOD	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
Residential - Underground	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
Residential TOD - Underground	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
Energy Control - (Non-Demand)	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
Limit Off Peak	\$ 0.02898	\$ 0.00021	\$ (0.00022)	\$ 0.02896
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Limit Off Peak	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Small General Service	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Small General TOD - Metered	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Small General TOD - Unmetered	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Fire and Civil Defense Siren	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
Direct Current (Closed)	\$ 0.02971	\$ 0.00021	\$ (0.00022)	\$ 0.02970
C & I Demand				
General Service	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
General TOD - On Peak	\$ 0.03723	\$ 0.00026	\$ (0.00028)	\$ 0.03722
General TOD - Off Peak	\$ 0.02280	\$ 0.00016	\$ (0.00017)	\$ 0.02279
Peak Controlled (Closed)	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Peak Controlled TOD (Closed) - On Peak	\$ 0.03723	\$ 0.00026	\$ (0.00028)	\$ 0.03722
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02280	\$ 0.00016	\$ (0.00017)	\$ 0.02279
Peak Controlled Tiered	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Peak Controlled Tiered TOD - On Peak	\$ 0.03723	\$ 0.00026	\$ (0.00028)	\$ 0.03722
Peak Controlled Tiered TOD - Off Peak	\$ 0.02280	\$ 0.00016	\$ (0.00017)	\$ 0.02279
Energy Controlled (Closed)	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Tier 1 Energy Controlled Rider	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Real Time Pricing - Firm - On Peak	\$ 0.03723	\$ 0.00026	\$ (0.00028)	\$ 0.03722
Real Time Pricing - Firm - Off Peak	\$ 0.02280	\$ 0.00016	\$ (0.00017)	\$ 0.02279
Real Time Pricing - Controllable - On Peak	\$ 0.03723	\$ 0.00026	\$ (0.00028)	\$ 0.03722
Real Time Pricing - Controllable - Off Peak	\$ 0.02280	\$ 0.00016	\$ (0.00017)	\$ 0.02279
Small Municipal Pumping	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Municipal Pumping	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Excess Energy - St. Anthony Falls	\$ 0.02939	\$ 0.00021	\$ (0.00022)	\$ 0.02938
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149
Street Lighting System	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149
Street Lighting Energy	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149
Street Lighting Energy - Metered	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149
Street Lighting Energy (Closed)	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149
Street Lighting - City of St. Paul	\$ 0.02150	\$ 0.00015	\$ (0.00016)	\$ 0.02149

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	May-12	Jun-12	Jul-12	Aug-12	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$30,820,668	\$33,749,949	\$58,790,048	\$46,184,773	\$169,545,438
Account 518 - Nuclear Fuel	\$7,637,776	\$10,844,492	\$11,470,923	\$9,668,555	\$39,621,746
Account 555 - Purchased Power ¹	\$38,192,993	\$39,647,383	\$41,035,251	\$38,850,330	\$157,725,957
Account 555 - MISO Day 2 Charges	\$19,036,986	\$24,234,400	\$23,257,210	\$17,553,245	\$84,081,841
Account 555 MISO Day 2 - Schedule 24	(\$102,572)	(\$111,383)	(\$119,841)	(\$93,360)	(\$427,157)
Account 555 MISO - ASM Charges	\$2,161,481	\$907,884	\$1,410,522	\$968,698	\$5,448,584
Total MISO Charges	\$21,095,895	\$25,030,901	\$24,547,891	\$18,428,582	\$89,103,268
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$97,747,332	\$109,272,725	\$135,844,112	\$113,132,240	\$455,996,409
Less Fuel Cost of InterSystem Sales	(\$2,927,370)	(\$4,659,393)	(\$4,726,025)	(\$3,716,520)	(\$16,029,308)
Net System Costs	\$94,819,962	\$104,613,332	\$131,118,087	\$109,415,720	\$439,967,101
System MWh Sales					
Total NSP System Retail	3,222,226	3,449,768	4,163,505	4,241,939	15,077,438
Non-Gen Muni's/Load Pattern	32,683	34,482	37,734	42,444	147,343
Total NSP System MWh Sales	3,254,909	3,484,250	4,201,239	4,284,383	15,224,781
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.913¢	3.002¢	3.121¢	2.554¢	2.890¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	1.0026	1.0026	1.0026	1.0026	1.0026
(ii) C & I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889
(vi) Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				1.0026	2.898¢
(ii) C & I Non-Demand				1.0281	2.971¢
(iii) C & I Demand Non-TOD				1.0170	2.939¢
(iv) C & I Demand TOD On-Peak				1.2883	3.723¢
(v) C & I Demand TOD Off-Peak				0.7889	2.280¢
(vi) Outdoor Lighting				0.7440	2.150¢
North Dakota Retail MWh Sales					
(i) Residential	48,899	50,195	67,595	70,089	236,778
(ii) C & I Non-Demand	8,481	8,199	9,298	9,627	35,605
(iii) C & I Demand Non-TOD	60,445	59,510	66,344	69,444	255,743
(iv) C & I Demand TOD On-Peak	18,151	16,999	19,710	20,606	75,466
(v) C & I Demand TOD Off-Peak	27,909	26,395	32,049	31,310	117,663
(vi) Outdoor Lighting	1,314	1,220	1,125	1,201	4,860
(vii) Total	165,199	162,518	196,121	202,277	726,115
Oct-2012 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Jun-12 Balance of Unrecovered Expenses)					Total
					Jun-12
					\$597,941

¹ Excludes demand-related expenses

Prior Expenses Recovered in Aug-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	70,089	\$36,506
(ii) C & I Non-Demand	9,627	\$4,883
(iii) C & I Demand Non-TOD	69,444	\$33,495
(iv) C & I Demand TOD On-Peak	20,606	\$12,469
(v) C & I Demand TOD Off-Peak	31,310	\$11,266
(vi) Outdoor Lighting	1,201	\$318
(vii) Total	202,277	\$98,937

Actual Cost Should Have Been Recovered in Aug-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.554¢	0.000¢	202,277	\$5,166,155

Cost Recovered in Aug-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	70,089	\$1,912,446
(ii) C & I Non-Demand	9,627	\$270,114
(iii) C & I Demand Non-TOD	69,444	\$1,919,372
(iv) C & I Demand TOD On-Peak	20,606	\$722,697
(v) C & I Demand TOD Off-Peak	31,310	\$667,976
(vi) Outdoor Lighting	1,201	\$23,906
(vii) Total	202,277	\$5,516,511

Total Balance of Unrecovered Expenses (Oct-12 Balance of Unrecovered Expenses)	
Oct-2012 Recovery Provision	\$148,648
4 Month ND Retail Total MWh Sales	726,115
Oct-2012 Recovery Provision per KWH	0.020¢

Oct-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.020¢	0.021¢
(ii) C & I Non-Demand	1.0281	0.020¢	0.021¢
(iii) C & I Demand Non-TOD	1.0170	0.020¢	0.021¢
(iv) C & I Demand TOD On-Peak	1.2883	0.020¢	0.026¢
(v) C & I Demand TOD Off-Peak	0.7889	0.020¢	0.016¢
(vi) Outdoor Lighting	0.7440	0.020¢	0.015¢

Oct-2012 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$29,198)	(\$9,304)	(\$38,502)
(i) Residential	-0.016¢	-0.005¢	-0.022¢
(ii) C & I Non-Demand	-0.017¢	-0.005¢	-0.022¢
(iii) C & I Demand Non-TOD	-0.017¢	-0.005¢	-0.022¢
(iv) C & I Demand TOD On-Peak	-0.021¢	-0.007¢	-0.028¢
(v) C & I Demand TOD Off-Peak	-0.013¢	-0.004¢	-0.017¢
(vi) Outdoor Lighting	-0.012¢	-0.004¢	-0.016¢

Oct-2012 Factors	
	Total
(i) Residential	2.896¢
(ii) C & I Non-Demand	2.970¢
(iii) C & I Demand Non-TOD	2.938¢
(iv) C & I Demand TOD On-Peak	3.722¢
(v) C & I Demand TOD Off-Peak	2.279¢
(vi) Outdoor Lighting	2.149¢

	FCA Application		Comparison		Generation Type by Percent		
	Sep-12	Oct-12	Difference	Percent Change	FCA Application Sep-12	FCA Application Oct-12	Difference
** COSTS (Millions) **							
1 Fossil	\$151.7	\$169.5	\$17.8	11.7%	35.6%	37.2%	1.6%
2 Nuclear	\$37.3	\$39.6	\$2.3	6.2%	8.8%	8.7%	-0.1%
3 Purchases	\$155.3	\$157.7	\$2.4	1.6%	36.5%	34.6%	-1.9%
MISO related Purchases	\$81.6	\$89.1	\$7.5	9.2%	19.2%	19.5%	0.3%
4 Total System Costs	426.0	456.0	\$30.0	7.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$14.5	\$16.0	\$1.5	10.5%	3.4%	3.5%	0.1%
6 Net System Costs	\$411.5	\$440.0	\$28.5	6.9%	96.6%	96.5%	-0.1%
7							
** GWH OUTPUT **							
9 Fossil	3,831	4,335	504	13.2%	22.9%	24.5%	1.6%
10 Nuclear	3,948	4,131	183	4.6%	23.6%	23.4%	-0.2%
11 Purchases	5,631	5,917	286	5.1%	33.7%	33.5%	-0.2%
12 Hydro & Other	2,659	2,610	(49)	-1.8%	15.9%	14.8%	-1.1%
13 Net Interchange	651	680	29	4.5%	3.9%	3.8%	-0.1%
14 Total Output	16,720	17,673	953	5.7%	100.0%	100.0%	0.0%
15 Intersystem Sales	796	826	30	3.7%	4.8%	4.7%	-0.1%
16 Native Requirement	15,924	16,847	923	5.8%	95.2%	95.3%	0.1%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.961	3.911	-0.050	-1.3%			
20 Nuclear	0.945	0.959	0.014	1.5%			
21 Purchases	2.758	2.666	-0.093	-3.4%			
22 Total System Costs	2.548	2.580	0.032	1.3%			
23 Intersystem Sales	1.821	1.940	0.119	6.5%			
24 Net System Costs	2.584	2.612	0.028	1.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,017	15,225	1,208	8.6%			
28							
29 COST per KWH SALES (\$)	2.936	2.890	-0.046	-1.6%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.161	0.020	-0.141				
(i) Residential	0.161	0.021	-0.141				
(ii) C & I Non-Demand	0.166	0.021	-0.145				
(iii) C & I Demand Non-TOD	0.164	0.021	-0.143				
(iv) C & I Demand TOD On-Peak	0.207	0.026	-0.181				
(v) C & I Demand TOD Off-Peak	0.127	0.016	-0.111				
(vi) Outdoor Lighting	0.120	0.015	-0.105				
32 REFUND	-0.066	-0.021	0.045				
(i) Residential	-0.066	-0.022					
(ii) C & I Non-Demand	-0.068	-0.022					
(iii) C & I Demand Non-TOD	-0.067	-0.022					
(iv) C & I Demand TOD On-Peak	-0.085	-0.028					
(v) C & I Demand TOD Off-Peak	-0.052	-0.017					
(vi) Outdoor Lighting	-0.049	-0.016					
33 SYSTEM FCC IMPACT (\$ / KWH)	3.031	2.889	-0.142	-4.7%			
(i) Residential	3.038	2.896	-0.142				
(ii) C & I Non-Demand	3.116	2.970					
(iii) C & I Demand Non-TOD	3.082	2.938					
(iv) C & I Demand TOD On-Peak	3.904	3.722					
(v) C & I Demand TOD Off-Peak	2.391	2.279					
(vi) Outdoor Lighting	2.255	2.149					

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	(\$0.14)
250	(\$0.35)
500	(\$0.71)
750	(\$1.06)
1,000	(\$1.42)

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	
	Sep-12	Oct-12
** GWH OUTPUT **		
Thermal	2,144,800	2,164,751
Disper gen	(54)	(83)
<u>Hydro plus Wind</u>	513,819	445,462
Hydro and Other	2,658,565	2,610,130
Rounded to nearest thousand:	2,659	2,610
Sales		
Non Gen Munic Total	140,469,000	147,343,000
Load Pattern Power	0	0
<u>Resale & Interchange (intersystem)</u>	796,464,000	826,208,000
Rounded to nearest million:	796.464	826.208

		System	Intersystem	Retail
August 2012 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 26,691,965.94	\$ 1,593,297.65	\$ 28,285,263.59
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,257,402.20	\$ -	\$ 2,257,402.20
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (16,532,355.35)	\$ -	\$ (16,532,355.35)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,861,954.33	\$ -	\$ 1,861,954.33
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ 855,557.62	\$ 651,364.68	\$ 1,506,922.30
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 45,688.97	\$ -	\$ 45,688.97
14	Real-Time Distribution of Losses Amount	\$ (1,504,324.04)	\$ -	\$ (1,504,324.04)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (72,184.95)	\$ -	\$ (72,184.95)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 90,019.30	\$ -	\$ 90,019.30
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (48,861.89)	\$ -	\$ (48,861.89)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 4,090,290.19	\$ -	\$ 4,090,290.19
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,675,450.67	\$ -	\$ 2,675,450.67
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (55,283.01)	\$ -	\$ (55,283.01)
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)	\$ 31,876.24	\$ -	\$ 31,876.24
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (5,029,369.33)	\$ -	\$ (5,029,369.33)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (395,574.50)	\$ -	\$ (395,574.50)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (32,439.99)	\$ -	\$ (32,439.99)
37	Financial Transmission Guarantee Uplift Amount	\$ 32,379.22	\$ -	\$ 32,379.22
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 583,211.64	\$ -	\$ 583,211.64
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 31,401.90	\$ -	\$ 31,401.90
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (47,014.67)	\$ 3,602.22	\$ (43,412.45)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ (9,112.91)	\$ -	\$ (9,112.91)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (122,719.93)	\$ 21,398.52	\$ (101,321.41)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (61,447.23)	\$ 8,090.23	\$ (53,357.00)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 461,743.32	\$ (3,229.89)	\$ 458,513.43
19	Real-Time Market Administration Amount	\$ 28,233.62	\$ (2,283.74)	\$ 25,949.88
29	Financial Transmission Rights Market Administration Amount	\$ 36,767.04	\$ -	\$ 36,767.04
33	Day-Ahead Schedule 24 Allocation Amount	\$ 88,987.03	\$ (619.48)	\$ 88,367.55
34	Real-Time Schedule 24 Allocation Amount	\$ 5,430.63	\$ (437.80)	\$ 4,992.83
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	\$ 0.19	\$ -	\$ 0.19
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,950,727.55	\$ -	\$ 2,950,727.55
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,979,909.40)	\$ -	\$ (2,979,909.40)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (656,923.82)	\$ -	\$ (656,923.82)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 10,495.85	\$ -	\$ 10,495.85
TOTAL MISO CHARGES		\$ 15,282,062.43	\$ 2,271,182.39	\$ 17,553,244.82
SCHEDULE 24 (FOR RETAIL)				\$ 93,360.38
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 17,459,884.44

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
August 2012 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (171,055.51)	\$ -	\$ (171,055.51)
2	Day-Ahead Spinning Reserve Amount	\$ (40,167.60)	\$ -	\$ (40,167.60)
3	Day-Ahead Supplemental Reserve	\$ (133,663.50)	\$ -	\$ (133,663.50)
4	Real-Time Regulation Amount	\$ (106,202.98)	\$ 119,765.90	\$ 13,562.92
5	Real-Time Spinning Reserve Amount	\$ (9,278.93)	\$ (24,688.76)	\$ (33,967.69)
6	Real-Time Supplemental Reserve Amount	\$ 570.62	\$ 41,271.23	\$ 41,841.85
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (37,655.10)		\$ (37,655.10)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 848,448.93		\$ 848,448.93
8b	Real Time Non Excessive Energy Congestion	\$ 8,428.76		\$ 8,428.76
8c	Real Time Non Excessive Energy Loss	\$ 41,172.00		\$ 41,172.00
9	Real Time Net Regulation Adjustment Amount	\$ 36,203.78	\$ (3,039.81)	\$ 33,163.97
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 220,155.05	\$ -	\$ 220,155.05
11	Real Time Spinning Reserve Cost Distribution	\$ 56,196.39	\$ -	\$ 56,196.39
12	Real Time Supplemental Reserve Cost Distribution	\$ 119,706.54	\$ -	\$ 119,706.54
Penalty Charges				
13	Real Time Excessive/Deficient Energy Deployment	\$ 3,029.75	\$ (499.21)	\$ 2,530.54
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 835,888.20	\$ 132,809.35	\$ 968,697.55

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-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Nov-12
True-up Month	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Sep-12
1 Monthly Refund	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)
2 Forecast North Dakota Sales	209,900	204,480	176,872	172,668	167,827	180,675	198,082	165,774	179,024	-	-	-	-
3 Current Month Refund Factor	(0.006)	(0.006)	(0.007)	(0.007)	(0.007)	(0.007)	(0.006)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)
4 Expected Refund	(1,271)	(7,850)	(9,247)	(15,472)	(13,816)	(15,506)	(13,246)	(13,482)	(11,314)	-	-	-	-
5 Actual Refund	(3,820)	(4,174)	(7,227)	(11,762)	(12,966)	(13,820)	(13,728)	(15,116)	(13,806)	-	-	-	-
6 Deviation	2,549	(3,676)	(2,020)	(3,710)	(1,450)	(1,666)	482	1,636	2,492	-	-	-	-
7 True-up Factor	0.001	(0.002)	(0.001)	(0.002)	(0.001)	(0.001)	0.000	0.001	0.001	0.001	0.001	0.001	0.001
8 Realized Margin	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	(0.006)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
9 Class Ratios													
10 Residential	0.9956	0.9956	0.9956	0.9974	0.9991	1.0009	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
11 C&I Non-Demand	1.0548	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
12 C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
13 C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
14 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
15 Outdoor Lighting	0.7088	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
16 Realized Margin Adj for Class Ratios													
17 Residential	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	(0.006)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
18 C&I Non-Demand	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
19 C&I Demand Non-TOD	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	(0.006)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
20 C&I Demand TOD On-Peak	(0.006)	(0.010)	(0.010)	(0.012)	(0.010)	(0.010)	(0.007)	(0.008)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)
21 C&I Demand TOD Off-Peak	(0.003)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	(0.005)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)
22 Outdoor Lighting	(0.003)	(0.005)	(0.005)	(0.006)	(0.006)	(0.005)	(0.004)	(0.005)	(0.004)	(0.004)	(0.004)	(0.004)	(0.004)