



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

April 29, 2011

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

Re: May 2011 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 May 2011.

Pursuant to the Commission authorization of the final compliance tariffs in the Company’s 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a “multi-class” fuel cost mechanism replaced the previous single-factor mechanism. The May 2011 system FCC is based on the average of the most recent four-month actual fuel cost plus a “true-up” factor, reflecting cost recovery deviations during the March 2011 calendar month.

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

May 2011	Fuel Cost Charge (\$/kWh)
Residential	0.02403
C & I Non-Demand	0.02546
C & I Demand	0.02466
C & I Demand Time of Day On-Peak	0.03170
C & I Demand Time of Day Off-Peak	0.01865
Outdoor Lighting	0.01711

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 Order (Docket No. PU-05-147) dated April 6, 2005 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 May 2011 FCC, the net MISO Day 2 costs for March 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this May FCC is \$18,172,232, 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 new ASM charge types are included in the Fuel Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent

¹ Previously embedded in other FTR charge types.

with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the May FCC, the net MISO ASM costs for March 2011 as recorded in Account 555. The MISO ASM cost recovery included in this May FCC is -\$1,143,120, 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 March 2011 Asset Based Margin amount of \$72,439 has been included in the May Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 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 2010 Non-Asset Based Margin credit is \$56,225 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the May FCC is \$8,362, 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 May 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 /

Phillip J. Zins
Manager, Pricing and Planning
Enclosures (2)
CC: David H. Sederquist

Electric Operations - State of North Dakota

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for May-2011

May-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02519	-\$0.00058	-\$0.00048	\$0.02413
Residential	\$0.02508	-\$0.00057	-\$0.00048	\$0.02403
C & I Non-Demand	\$0.02657	-\$0.00061	-\$0.00051	\$0.02546
C & I Demand Non-TOD	\$0.02574	-\$0.00059	-\$0.00049	\$0.02466
C & I Demand TOD On-Peak	\$0.03309	-\$0.00076	-\$0.00063	\$0.03170
C & I Demand TOD Off-Peak	\$0.01946	-\$0.00045	-\$0.00037	\$0.01865
Outdoor Lighting	\$0.01785	-\$0.00041	-\$0.00034	\$0.01711
Residential				
Residential Service	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
Residential TOD	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
Residential - Underground	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
Residential TOD - Underground	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
Energy Control - (Non-Demand)	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
Limit Off Peak	\$ 0.02508	\$ (0.00057)	\$ (0.00048)	\$ 0.02403
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Limit Off Peak	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Small General Service	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Small General TOD - Metered	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Small General TOD - Unmetered	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Fire and Civil Defense Siren	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
Direct Current (Closed)	\$ 0.02657	\$ (0.00061)	\$ (0.00051)	\$ 0.02546
C & I Demand				
General Service	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
General TOD - On Peak	\$ 0.03309	\$ (0.00076)	\$ (0.00063)	\$ 0.03170
General TOD - Off Peak	\$ 0.01946	\$ (0.00045)	\$ (0.00037)	\$ 0.01865
Peak Controlled (Closed)	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Peak Controlled TOD (Closed) - On Peak	\$ 0.03309	\$ (0.00076)	\$ (0.00063)	\$ 0.03170
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01946	\$ (0.00045)	\$ (0.00037)	\$ 0.01865
Peak Controlled Tiered	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Peak Controlled Tiered TOD - On Peak	\$ 0.03309	\$ (0.00076)	\$ (0.00063)	\$ 0.03170
Peak Controlled Tiered TOD - Off Peak	\$ 0.01946	\$ (0.00045)	\$ (0.00037)	\$ 0.01865
Energy Controlled (Closed)	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Tier 1 Energy Controlled Rider	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Real Time Pricing - Firm - On Peak	\$ 0.03309	\$ (0.00076)	\$ (0.00063)	\$ 0.03170
Real Time Pricing - Firm - Off Peak	\$ 0.01946	\$ (0.00045)	\$ (0.00037)	\$ 0.01865
Real Time Pricing - Controllable - On Peak	\$ 0.03309	\$ (0.00076)	\$ (0.00063)	\$ 0.03170
Real Time Pricing - Controllable - Off Peak	\$ 0.01946	\$ (0.00045)	\$ (0.00037)	\$ 0.01865
Small Municipal Pumping	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Municipal Pumping	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Excess Energy - St. Anthony Falls	\$ 0.02574	\$ (0.00059)	\$ (0.00049)	\$ 0.02466
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711
Street Lighting System	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711
Street Lighting Energy	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711
Street Lighting Energy - Metered	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711
Street Lighting Energy (Closed)	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711
Street Lighting - City of St. Paul	\$ 0.01785	\$ (0.00041)	\$ (0.00034)	\$ 0.01711

Electric Operations - State of North Dakota

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for May-2011

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Dec-10	Jan-11	Feb-11	Mar-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$42,930,204	\$45,110,406	\$38,537,323	\$43,721,305	\$170,299,238
Account 518 - Nuclear Fuel	\$10,688,880	\$10,741,550	\$9,532,671	\$7,780,334	\$38,743,435
Account 555 - Purchased Power ¹	\$34,161,906	\$41,752,106	\$40,007,408	\$38,906,437	\$154,827,856
Account 555 - MISO Day 2 Charges	\$13,438,358	\$12,635,170	\$12,934,596	\$18,257,815	\$57,265,938
Account 555 MISO Day 2 - Schedule 24	(\$95,443)	(\$90,163)	(\$81,156)	(\$85,583)	(\$352,345)
Account 555 MISO - ASM Charges	\$125,361	\$119,964	\$4,442,828	(\$1,143,120)	\$3,545,033
Total MISO Charges	\$13,468,276	\$12,664,972	\$17,296,268	\$17,029,112	\$60,458,626
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$101,249,265	\$110,269,033	\$105,373,669	\$107,437,188	\$424,329,155
Less Fuel Cost of InterSystem Sales	(\$9,477,298)	(\$17,097,148)	(\$13,188,195)	(\$14,210,295)	(\$53,972,937)
Net System Costs	\$91,771,967	\$93,171,886	\$92,185,474	\$93,226,893	\$370,356,219
System MWh Sales					
Total NSP System Retail	3,539,364	3,962,011	3,324,893	3,624,446	14,450,714
Non-Gen Muni's/Load Pattern	66,245	76,589	57,656	51,878	252,368
Total NSP System MWh Sales	3,605,609	4,038,600	3,382,549	3,676,324	14,703,082
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.545¢	2.307¢	2.725¢	2.536¢	2.519¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.508¢
(ii) C & I Non-Demand				1.0548	2.657¢
(iii) C & I Demand Non-TOD				1.0219	2.574¢
(iv) C & I Demand TOD On-Peak				1.3135	3.309¢
(v) C & I Demand TOD Off-Peak				0.7726	1.946¢
(vi) Outdoor Lighting				0.7088	1.785¢
North Dakota Retail MWh Sales					
(i) Residential	82,934	99,111	83,320	86,238	351,603
(ii) C & I Non-Demand	11,913	14,191	11,949	12,922	50,975
(iii) C & I Demand Non-TOD	62,705	72,443	57,938	70,769	263,855
(iv) C & I Demand TOD On-Peak	18,586	16,560	16,999	22,007	74,152
(v) C & I Demand TOD Off-Peak	30,313	29,313	27,539	32,833	119,998
(vi) Outdoor Lighting	1,951	2,237	1,948	1,700	7,836
(vii) Total	208,402	233,855	199,693	226,469	868,419
May-2011 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Jan-11 Balance of Unrecovered Expenses)					Total
					Jan-11
					(\$728,472)

¹ Excludes demand-related expenses

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for May-2011

Prior Expenses Recovered in Mar-2011 [Billing Record]			
		ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential		86,238	(\$59,988)
(ii) C & I Non-Demand		12,922	(\$9,193)
(iii) C & I Demand Non-TOD		70,769	(\$47,844)
(iv) C & I Demand TOD On-Peak		22,007	(\$17,762)
(v) C & I Demand TOD Off-Peak		32,833	(\$16,250)
(vi) Outdoor Lighting		1,700	(\$681)
(vii) Total		226,469	(\$151,718)
Actual Cost Should Have Been Recovered in Mar-11			
	Actual	Base	Actual ND MWh Sales
	2.536¢	0.000¢	226,469
			Expected Recovery \$5,743,254
Cost Recovered in Mar-11 [Billing Record]			
		ND Billed MWh Sales	Actual Recovery
(i) Residential		86,238	\$2,140,014
(ii) C & I Non-Demand		12,922	\$340,712
(iii) C & I Demand Non-TOD		70,769	\$1,803,808
(iv) C & I Demand TOD On-Peak		22,007	\$720,464
(v) C & I Demand TOD Off-Peak		32,833	\$632,265
(vi) Outdoor Lighting		1,700	\$29,856
(vii) Total		226,469	\$5,667,119
Total Balance of Unrecovered Expenses (May-11 Balance of Unrecovered Expenses)			
May-2011 Recovery Provision			(\$500,619)
4 Month ND Retail Total MWh Sales			868,419
May-2011 Recovery Provision per KWH			-0.058¢
May-2011 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.058¢	-0.057¢
(ii) C & I Non-Demand	1.0548	-0.058¢	-0.061¢
(iii) C & I Demand Non-TOD	1.0219	-0.058¢	-0.059¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.058¢	-0.076¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.058¢	-0.045¢
(vi) Outdoor Lighting	0.7088	-0.058¢	-0.041¢
May-2011 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$72,439)	(\$8,362)	(\$80,801)
(i) Residential	-0.043¢	-0.005¢	-0.048¢
(ii) C & I Non-Demand	-0.045¢	-0.005¢	-0.051¢
(iii) C & I Demand Non-TOD	-0.044¢	-0.005¢	-0.049¢
(iv) C & I Demand TOD On-Peak	-0.056¢	-0.007¢	-0.063¢
(v) C & I Demand TOD Off-Peak	-0.033¢	-0.004¢	-0.037¢
(vi) Outdoor Lighting	-0.030¢	-0.004¢	-0.034¢
May-2011 Factors			
			Total
(i) Residential			2.403¢
(ii) C & I Non-Demand			2.546¢
(iii) C & I Demand Non-TOD			2.466¢
(iv) C & I Demand TOD On-Peak			3.170¢
(v) C & I Demand TOD Off-Peak			1.865¢
(vi) Outdoor Lighting			1.711¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Apr-11	May-11	Differ- ence	Percent Change	FCA Application Apr-11	May-11	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$155.8	\$170.3	\$14.5	9.3%	37.6%	40.1%	2.5%
2 Nuclear	\$39.4	\$38.7	(\$0.7)	-1.7%	9.5%	9.1%	-0.4%
3 Purchases	\$156.3	\$154.8	(\$1.5)	-0.9%	37.7%	36.5%	-1.2%
MISO related Purchases	\$63.1	\$60.5	(\$2.6)	-4.2%	15.2%	14.2%	-1.0%
4 Total System Costs	414.6	424.3	\$9.7	2.3%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$51.6	\$54.0	\$2.3	4.5%	12.5%	12.7%	0.2%
6 Net System Costs	\$363.0	\$370.4	\$7.4	2.0%	87.5%	87.3%	-0.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,799	6,211	412	7.1%	34.3%	36.7%	2.4%
10 Nuclear	4,565	4,498	(67)	-1.5%	27.0%	26.6%	-0.4%
11 Purchases	4,663	4,219	(444)	-9.5%	27.5%	24.9%	-2.6%
12 Hydro & Other	1,046	1,136	90	8.6%	6.2%	6.7%	0.5%
13 Net Interchange	853	871	18	2.1%	5.0%	5.1%	0.1%
14 Total Output	16,926	16,935	9	0.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,801	1,127	(674)	-37.4%	10.6%	6.7%	-3.9%
16 Native Requirement	15,125	15,808	683	4.5%	89.4%	93.3%	3.9%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.687	2.742	0.055	2.0%			
20 Nuclear	0.863	0.861	-0.002	-0.2%			
21 Purchases	3.352	3.670	0.318	9.5%			
22 Total System Costs	2.450	2.506	0.056	2.3%			
23 Intersystem Sales	2.867	4.787	1.920	67.0%			
24 Net System Costs	2.400	2.343	-0.057	-2.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,187	14,703	516	3.6%			
28							
29 COST per KWH SALES (\$)	2.558	2.519	-0.039	-1.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.021	-0.058	-0.079				
(i) Residential	0.021	-0.057	-0.078				
(ii) C & I Non-Demand	0.022	-0.061	-0.083				
(iii) C & I Demand Non-TOD	0.022	-0.059	-0.080				
(iv) C & I Demand TOD On-Peak	0.028	-0.076	-0.103				
(v) C & I Demand TOD Off-Peak	0.016	-0.045	-0.061				
(vi) Outdoor Lighting	0.015	-0.041	-0.056				
32 REFUND	-0.018	0.000	0.018				
(i) Residential	-0.018	-0.048	-0.030				
(ii) C & I Non-Demand	-0.019	-0.051	-0.032				
(iii) C & I Demand Non-TOD	-0.018	-0.049	-0.031				
(iv) C & I Demand TOD On-Peak	-0.024	-0.063	-0.039				
(v) C & I Demand TOD Off-Peak	-0.014	-0.037	-0.023				
(vi) Outdoor Lighting	-0.013	-0.034	-0.021				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.561	2.461	-0.100	-3.9%			
(i) Residential	2.550	2.403	-0.147				
(ii) C & I Non-Demand	2.702	2.546	-0.156				
(iii) C & I Demand Non-TOD	2.617	2.466	-0.151				
(iv) C & I Demand TOD On-Peak	3.364	3.170	-0.194				
(v) C & I Demand TOD Off-Peak	1.979	1.865	-0.114				
(vi) Outdoor Lighting	1.815	1.711	-0.104				

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	(\$0.15)
250	(\$0.37)
500	(\$0.74)
750	(\$1.10)
1,000	(\$1.47)

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>	
	Apr-11	May-11
** GWH OUTPUT **		
Thermal	633,062	681,847
Disper gen	(83)	(85)
<u>Hydro plus Wind</u>	412,851	454,363
Hydro and Other	1,045,830	1,136,125
Rounded to nearest thousand:	1,046	1,136
<u>Sales</u>		
Non Gen Munic Total	263,314,000	252,368,000
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,801,172,000	1,127,488,000
Rounded to nearest million:	1801.172	1127.488

		System	Intersystem	Retail
March 2011 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 22,612,339.73	\$ 1,885,515.01	\$ 24,497,854.74
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,652,340.57	-	\$ 2,652,340.57
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (12,537,900.55)	-	\$ (12,537,900.55)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,318,345.25	-	\$ 1,318,345.25
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)	\$ 742,739.30	\$ 2,638,686.53	\$ 3,381,425.83
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 19,326.61	-	\$ 19,326.61
14	Real-Time Distribution of Losses Amount	\$ (1,592,210.64)	-	\$ (1,592,210.64)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (40,464.81)	-	\$ (40,464.81)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 14,056.56	-	\$ 14,056.56
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (772.06)	-	\$ (772.06)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,222,172.02	-	\$ 1,222,172.02
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,567,502.99	-	\$ 1,567,502.99
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)	\$ (43,432.18)	-	\$ (43,432.18)
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)	\$ (4,052.35)	-	\$ (4,052.35)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,032,098.14)	-	\$ (3,032,098.14)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (309,870.76)	-	\$ (309,870.76)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 75,138.69	-	\$ 75,138.69
37	Financial Transmission Guarantee Uplift Amount	\$ (75,382.26)	-	\$ (75,382.26)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 863,185.27	-	\$ 863,185.27
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 147,774.74	-	\$ 147,774.74
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (339,090.60)	\$ 19,690.23	\$ (319,400.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 349,926.18	-	\$ 349,926.18
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (89,269.29)	\$ 3,881.16	\$ (85,388.13)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (337,205.15)	\$ 20,740.24	\$ (316,464.91)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 667,986.17	\$ (6,945.95)	\$ 661,040.22
19	Real-Time Market Administration Amount	\$ 44,878.02	\$ (10,190.80)	\$ 34,687.22
29	Financial Transmission Rights Market Administration Amount	\$ 57,575.92	-	\$ 57,575.92
33	Day-Ahead Schedule 24 Allocation Amount	\$ 82,147.28	\$ (861.16)	\$ 81,286.12
34	Real-Time Schedule 24 Allocation Amount	\$ 5,551.07	\$ (1,254.18)	\$ 4,296.89
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	\$ 773.42	-	\$ 773.42
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,229,776.23	-	\$ 1,229,776.23
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,192,084.39)	-	\$ (1,192,084.39)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (446,000.55)	-	\$ (446,000.55)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 74,851.15	-	\$ 74,851.15
TOTAL MISO CHARGES		\$ 13,708,553.44	\$ 4,549,261.08	\$ 18,257,814.52
SCHEDULE 24 (FOR RETAIL)				\$ 85,583.01
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 18,172,231.51

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
March 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (350,915.02)	\$ -	\$ (350,915.02)
2	Day-Ahead Spinning Reserve Amount	\$ (173,560.07)	\$ -	\$ (173,560.07)
3	Day-Ahead Supplemental Reserve	\$ (92,043.63)	\$ -	\$ (92,043.63)
4	Real-Time Regulation Amount	\$ 55,131.20	\$ 82,061.12	\$ 137,192.32
5	Real-Time Spinning Reserve Amount	\$ 49,975.16	\$ 29,467.52	\$ 79,442.68
6	Real-Time Supplemental Reserve Amount	\$ 614.47	\$ 23,275.59	\$ 23,890.06
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (6,011.63)		\$ (6,011.63)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ (2,229,812.32)		\$ (2,229,812.32)
8b	Real Time Non Excessive Energy Congestion	\$ 837,002.93		\$ 837,002.93
8c	Real Time Non Excessive Energy Loss	\$ 146,318.93		\$ 146,318.93
9	Real Time Net Regulation Adjustment Amount	\$ 9,376.76	\$ (329.29)	\$ 9,047.47
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 224,857.74	\$ -	\$ 224,857.74
11	Real Time Spinning Reserve Cost Distribution	\$ 179,098.97	\$ -	\$ 179,098.97
12	Real Time Supplemental Reserve Cost Distribution	\$ 67,535.03	\$ -	\$ 67,535.03
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 5,886.93	\$ (1,050.13)	\$ 4,836.80
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ (1,276,544.55)	\$ 133,424.81	\$ (1,143,119.74)

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Asset Based Margin Sharing

Forecast Month	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
True-up Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
1	(72,651)	(19,186)	(84,041)									
2	203,850	171,035	168,639	174,150	172,841							
3												
4												
5												
6												
7												
8	(0,036)	(0,011)	(0,050)									
9	(25,037)	(44,836)	(29,737)	(32,785)	(72,439)							
14	(38,347)	(31,238)	(41,339)									
15	42,914	(13,399)	11,602	(32,785)	(72,439)							
16												
17	0,021	(0,006)	0,007									
18												
19												
20	(0,015)	(0,019)	(0,043)									
21												
22												
23	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956	0,9956
24	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548
25	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219
26	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135
27	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726
28	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088
29												
30												
31	(0,015)	(0,019)	(0,043)									
32	(0,015)	(0,020)	(0,045)									
33	(0,015)	(0,020)	(0,044)									
34	(0,019)	(0,025)	(0,050)									
35	(0,011)	(0,015)	(0,033)									
36	(0,010)	(0,014)	(0,030)									

Class Ratios	0,9956	1,0548	1,0219	1,3135	0,7726	0,7088
Residential	0,9956	1,0548	1,0219	1,3135	0,7726	0,7088
C&I Non-Demand	1,0548	1,0548	1,0548	1,0548	1,0548	1,0548
C&I Demand Non-TOD	1,0219	1,0219	1,0219	1,0219	1,0219	1,0219
C&I Demand TOD On-Peak	1,3135	1,3135	1,3135	1,3135	1,3135	1,3135
C&I Demand TOD Off-Peak	0,7726	0,7726	0,7726	0,7726	0,7726	0,7726
Outdoor Lighting	0,7088	0,7088	0,7088	0,7088	0,7088	0,7088
Realized Margin Adj for Class Ratios						
Residential	(0,015)	(0,019)	(0,043)			
C&I Non-Demand	(0,015)	(0,020)	(0,045)			
C&I Demand Non-TOD	(0,015)	(0,020)	(0,044)			
C&I Demand TOD On-Peak	(0,019)	(0,025)	(0,050)			
C&I Demand TOD Off-Peak	(0,011)	(0,015)	(0,033)			
Outdoor Lighting	(0,010)	(0,014)	(0,030)			

