



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

October 31, 2011

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

**Re: November 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 November 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 November 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 September 2011 calendar month.

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

<b>November 2011</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02616
<b>C &amp; I Non-Demand</b>	0.02772
<b>C &amp; I Demand</b>	0.02685
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03451
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02030
<b>Outdoor Lighting</b>	0.01862

## **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 types<sup>1</sup>, 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 November 2011 FCC, the net MISO Day 2 costs for September 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this November FCC is \$14,733,609, 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

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<sup>1</sup> 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 November FCC, the net MISO ASM costs for September 2011 as recorded in Account 555. The MISO ASM cost recovery included in this November FCC is \$769,417, 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 September 2011 Asset Based Margin amount of -\$30,303 has been included in the November 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 November FCC is \$-5,340, or -0.003¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attached is the calculation of the November 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

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  
 Current Period Cost of Energy for Nov-2011

Nov-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02670	-\$0.00021	-\$0.00021	\$0.02628
<b>Residential</b>	\$0.02658	-\$0.00021	-\$0.00021	\$0.02616
<b>C &amp; I Non-Demand</b>	\$0.02816	-\$0.00023	-\$0.00022	\$0.02772
<b>C &amp; I Demand Non-TOD</b>	\$0.02728	-\$0.00022	-\$0.00021	\$0.02685
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03507	-\$0.00028	-\$0.00028	\$0.03451
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02063	-\$0.00017	-\$0.00016	\$0.02030
<b>Outdoor Lighting</b>	\$0.01892	-\$0.00015	-\$0.00015	\$0.01862
<b>Residential</b>				
Residential Service	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
Residential TOD	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
Residential - Underground	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
Residential TOD - Underground	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
Energy Control - (Non-Demand)	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
Limit Off Peak	\$ 0.02658	\$ (0.00021)	\$ (0.00021)	\$ 0.02616
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Limit Off Peak	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Small General Service	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Small General TOD - Metered	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Small General TOD - Unmetered	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Fire and Civil Defense Siren	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
Direct Current (Closed)	\$ 0.02816	\$ (0.00023)	\$ (0.00022)	\$ 0.02772
<b>C &amp; I Demand</b>				
General Service	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
General TOD - On Peak	\$ 0.03507	\$ (0.00028)	\$ (0.00028)	\$ 0.03451
General TOD - Off Peak	\$ 0.02063	\$ (0.00017)	\$ (0.00016)	\$ 0.02030
Peak Controlled (Closed)	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Peak Controlled TOD (Closed) - On Peak	\$ 0.03507	\$ (0.00028)	\$ (0.00028)	\$ 0.03451
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02063	\$ (0.00017)	\$ (0.00016)	\$ 0.02030
Peak Controlled Tiered	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Peak Controlled Tiered TOD - On Peak	\$ 0.03507	\$ (0.00028)	\$ (0.00028)	\$ 0.03451
Peak Controlled Tiered TOD - Off Peak	\$ 0.02063	\$ (0.00017)	\$ (0.00016)	\$ 0.02030
Energy Controlled (Closed)	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Tier 1 Energy Controlled Rider	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Real Time Pricing - Firm - On Peak	\$ 0.03507	\$ (0.00028)	\$ (0.00028)	\$ 0.03451
Real Time Pricing - Firm - Off Peak	\$ 0.02063	\$ (0.00017)	\$ (0.00016)	\$ 0.02030
Real Time Pricing - Controllable - On Peak	\$ 0.03507	\$ (0.00028)	\$ (0.00028)	\$ 0.03451
Real Time Pricing - Controllable - Off Peak	\$ 0.02063	\$ (0.00017)	\$ (0.00016)	\$ 0.02030
Small Municipal Pumping	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Municipal Pumping	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
Excess Energy - St. Anthony Falls	\$ 0.02728	\$ (0.00022)	\$ (0.00021)	\$ 0.02685
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862
Street Lighting System	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862
Street Lighting Energy	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862
Street Lighting Energy - Metered	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862
Street Lighting Energy (Closed)	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862
Street Lighting - City of St. Paul	\$ 0.01892	\$ (0.00015)	\$ (0.00015)	\$ 0.01862

	Column (A) Jun-11	Column (B) Jul-11	Column (C) Aug-11	Column (D) Sep-11	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$37,703,245	\$59,929,940	\$49,469,418	\$32,381,294	\$179,483,897
Account 518 - Nuclear Fuel	\$8,998,877	\$11,208,057	\$11,630,399	\$11,598,307	\$43,435,640
Account 555 - Purchased Power <sup>1</sup>	\$44,306,074	\$44,383,414	\$41,249,223	\$36,633,495	\$166,572,207
Account 555 - MISO Day 2 Charges	\$17,352,507	\$22,767,976	\$21,897,056	\$14,825,965	\$76,843,504
Account 555 MISO Day 2 - Schedule 24	(\$99,973)	(\$109,686)	(\$101,787)	(\$92,356)	(\$403,802)
Account 555 MISO - ASM Charges	(\$704,521)	\$2,519,375	(\$2,154,021)	\$769,417	\$430,249
Total MISO Charges	\$16,548,012	\$25,177,665	\$19,641,248	\$15,503,027	\$76,869,952
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$107,556,209	\$140,699,077	\$121,990,288	\$96,116,123	\$466,361,697
Less Fuel Cost of InterSystem Sales	(\$13,538,555)	(\$13,090,852)	(\$13,873,929)	(\$10,853,061)	(\$51,356,397)
Net System Costs	\$94,017,654	\$127,608,225	\$108,116,359	\$85,263,062	\$415,005,300
<b>System MWh Sales</b>					
Total NSP System Retail	3,473,679	3,774,374	4,379,112	3,719,112	15,346,277
Non-Gen Muni's/Load Pattern	43,823	45,964	52,938	51,583	194,308
Total NSP System MWh Sales	3,517,502	3,820,338	4,432,050	3,770,695	15,540,585
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.673¢	3.340¢	2.439¢	2.261¢	2.670¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(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
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.658¢
(ii) C & I Non-Demand				1.0548	2.816¢
(iii) C & I Demand Non-TOD				1.0219	2.728¢
(iv) C & I Demand TOD On-Peak				1.3135	3.507¢
(v) C & I Demand TOD Off-Peak				0.7726	2.063¢
(vi) Outdoor Lighting				0.7088	1.892¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	51,748	57,265	65,506	55,310	229,829
(ii) C & I Non-Demand	8,668	8,378	9,049	8,910	35,005
(iii) C & I Demand Non-TOD	58,924	61,664	70,382	64,666	255,636
(iv) C & I Demand TOD On-Peak	19,267	18,395	20,455	21,042	79,159
(v) C & I Demand TOD Off-Peak	30,957	30,048	31,758	30,284	123,047
(vi) Outdoor Lighting	1,221	1,108	1,181	1,386	4,896
(vii) Total	170,785	176,858	198,331	181,598	727,572
<b>Nov-2011 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Jul-11 Balance of Unrecovered Expenses)					Total
					Jul-11
					\$1,196,988

<sup>1</sup> Excludes demand-related expenses

Prior Expenses Recovered in Sep-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Received Expenses
(i) Residential	55,310	\$84,928
(ii) C & I Non-Demand	8,910	\$14,105
(iii) C & I Demand Non-TOD	64,666	\$97,973
(iv) C & I Demand TOD On-Peak	21,042	\$41,858
(v) C & I Demand TOD Off-Peak	30,284	\$35,387
(vi) Outdoor Lighting	1,386	\$1,431
(vii) Total	181,598	\$275,682

Actual Cost Should Have Been Recovered in Sep-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.261¢	0.000¢	181,598	\$4,105,931

Cost Recovered in Sep-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	55,310	\$1,565,751
(ii) C & I Non-Demand	8,910	\$266,372
(iii) C & I Demand Non-TOD	64,666	\$1,874,258
(iv) C & I Demand TOD On-Peak	21,042	\$785,207
(v) C & I Demand TOD Off-Peak	30,284	\$664,518
(vi) Outdoor Lighting	1,386	\$27,444
(vii) Total	181,598	\$5,183,550

Total Balance of Unrecovered Expenses (Nov-11 Balance of Unrecovered Expenses)	
Nov-2011 Recovery Provision	(\$156,313)
4 Month ND Retail Total MWh Sales	727,572
Nov-2011 Recovery Provision per KWH	-0.021¢

Nov-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	-0.021¢	-0.021¢
(ii) C & I Non-Demand	1.0548	-0.021¢	-0.023¢
(iii) C & I Demand Non-TOD	1.0219	-0.021¢	-0.022¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.021¢	-0.028¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.021¢	-0.017¢
(vi) Outdoor Lighting	0.7088	-0.021¢	-0.015¢

Nov-2011 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$30,303)	(\$5,340)	(\$35,643)
(i) Residential	-0.018¢	-0.003¢	-0.021¢
(ii) C & I Non-Demand	-0.019¢	-0.003¢	-0.022¢
(iii) C & I Demand Non-TOD	-0.018¢	-0.003¢	-0.021¢
(iv) C & I Demand TOD On-Peak	-0.023¢	-0.004¢	-0.028¢
(v) C & I Demand TOD Off-Peak	-0.014¢	-0.002¢	-0.016¢
(vi) Outdoor Lighting	-0.013¢	-0.002¢	-0.015¢

Nov-2011 Factors	
	Total
(i) Residential	2.616¢
(ii) C & I Non-Demand	2.772¢
(iii) C & I Demand Non-TOD	2.685¢
(iv) C & I Demand TOD On-Peak	3.451¢
(v) C & I Demand TOD Off-Peak	2.030¢
(vi) Outdoor Lighting	1.862¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Oct-11	Nov-11	Differ- ence	Percent Change	FCA Application Oct-11	Nov-11	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$182.4	\$179.5	(\$2.9)	-1.6%	38.0%	38.5%	0.5%
2 Nuclear	\$35.8	\$43.4	\$7.7	21.5%	7.4%	9.3%	1.9%
3 Purchases	\$179.1	\$166.6	(\$12.5)	-7.0%	37.3%	35.7%	-1.6%
MISO related Purchases	\$83.1	\$76.9	(\$6.3)	-7.5%	17.3%	16.5%	-0.8%
4 Total System Costs	480.4	466.4	(\$14.0)	-2.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$57.3	\$51.4	(\$5.9)	-10.4%	11.9%	11.0%	-0.9%
6 Net System Costs	\$423.1	\$415.0	(\$8.1)	-1.9%	88.1%	89.0%	0.9%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	6,027	5,816	(211)	-3.5%	34.6%	33.3%	-1.3%
10 Nuclear	3,688	4,458	770	20.9%	21.2%	25.5%	4.3%
11 Purchases	5,661	5,250	(411)	-7.3%	32.5%	30.1%	-2.4%
12 Hydro & Other	1,454	1,361	(93)	-6.4%	8.3%	7.8%	-0.5%
13 Net Interchange	600	565	(35)	-5.8%	3.4%	3.2%	-0.2%
14 Total Output	17,430	17,450	20	0.1%	100.0%	100.0%	0.0%
15 Intersystem Sales	906	894	(12)	-1.3%	5.2%	5.1%	-0.1%
16 Native Requirement	16,524	16,556	32	0.2%	94.8%	94.9%	0.1%
17							
<b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.026	3.086	0.060	2.0%			
20 Nuclear	0.970	0.974	0.005	0.5%			
21 Purchases	3.164	3.173	0.009	0.3%			
22 Total System Costs	2.756	2.673	-0.083	-3.0%			
23 Intersystem Sales	6.326	5.744	-0.582	-9.2%			
24 Net System Costs	2.560	2.507	-0.054	-2.1%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,999	15,541	542	3.6%			
28							
29 COST per KWH SALES (\$)	2.821	2.670	-0.151	-5.4%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.035	-0.021	-0.056				
(i) Residential	0.034	-0.021	-0.056				
(ii) C & I Non-Demand	0.037	-0.023	-0.059				
(iii) C & I Demand Non-TOD	0.035	-0.022	-0.057				
(iv) C & I Demand TOD On-Peak	0.046	-0.028	-0.074				
(v) C & I Demand TOD Off-Peak	0.027	-0.017	-0.043				
(vi) Outdoor Lighting	0.025	-0.015	-0.040				
32 REFUND	-0.023	0.000	0.023				
(i) Residential	-0.023	-0.021					
(ii) C & I Non-Demand	-0.024	-0.022					
(iii) C & I Demand Non-TOD	-0.024	-0.021					
(iv) C & I Demand TOD On-Peak	-0.030	-0.028					
(v) C & I Demand TOD Off-Peak	-0.018	-0.016					
(vi) Outdoor Lighting	-0.016	-0.015					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.833	2.649	-0.184	-6.5%			
(i) Residential	2.820	2.616	-0.204				
(ii) C & I Non-Demand	2.988	2.772					
(iii) C & I Demand Non-TOD	2.895	2.685					
(iv) C & I Demand TOD On-Peak	3.721	3.451					
(v) C & I Demand TOD Off-Peak	2.188	2.030					
(vi) Outdoor Lighting	2.008	1.862					

**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	(\$0.20)
250	(\$0.51)
500	(\$1.02)
750	(\$1.53)
1,000	(\$2.04)

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>	
	Oct-11	Nov-11
<b>** GWH OUTPUT **</b>		
Thermal	976,546	976,770
Disper gen	(68)	(79)
<u>Hydro plus Wind</u>	477,807	383,954
Hydro and Other	1,454,285	1,360,645
Rounded to nearest thousand:	1,454	1,361
<b>Sales</b>		
Non Gen Munic Total	189,961,000	194,308,000
Load Pattern Power	0	0
<u>Resale &amp; Interchange (Intersystem)</u>	905,913,000	894,086,000
Rounded to nearest million:	905.913	894.086

		System	Intersystem	Retail
<b>September 2011 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 19,620,566.65	\$ 947,564.28	\$ 20,568,130.93
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,111,853.78	\$ -	\$ 2,111,853.78
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,068,812.11)	\$ -	\$ (13,068,812.11)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,180,683.82	\$ -	\$ 1,180,683.82
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)	\$ 2,045,318.20	\$ 642,209.32	\$ 2,687,527.52
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 8,232.57	\$ -	\$ 8,232.57
14	Real-Time Distribution of Losses Amount	\$ (274,855.11)	\$ -	\$ (274,855.11)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 545,425.19	\$ -	\$ 545,425.19
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (78,317.20)	\$ -	\$ (78,317.20)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 12,432.59	\$ -	\$ 12,432.59
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,163,694.49	\$ -	\$ 1,163,694.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,324,011.43	\$ -	\$ 1,324,011.43
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)	\$ 44,731.33	\$ -	\$ 44,731.33
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)	\$ (937.40)	\$ -	\$ (937.40)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,745,782.42)	\$ -	\$ (1,745,782.42)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (70,242.77)	\$ -	\$ (70,242.77)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (20,850.29)	\$ -	\$ (20,850.29)
37	Financial Transmission Guarantee Uplift Amount	\$ 20,850.29	\$ -	\$ 20,850.29
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (123,287.27)	\$ -	\$ (123,287.27)
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 144,373.76	\$ -	\$ 144,373.76
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (32,889.66)	\$ 12,073.67	\$ (20,815.99)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 438,556.71	\$ -	\$ 438,556.71
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (308,026.63)	\$ 83,287.15	\$ (224,739.48)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (307,460.26)	\$ 11,244.91	\$ (296,215.35)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 566,428.41	\$ (4,221.79)	\$ 562,206.62
19	Real-Time Market Administration Amount	\$ 32,456.03	\$ (3,026.67)	\$ 29,429.36
29	Financial Transmission Rights Market Administration Amount	\$ 57,250.08	\$ -	\$ 57,250.08
33	Day-Ahead Schedule 24 Allocation Amount	\$ 88,418.12	\$ (665.72)	\$ 87,752.40
34	Real-Time Schedule 24 Allocation Amount	\$ 5,077.34	\$ (473.95)	\$ 4,603.39
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
<b>Virtual Energy Charges</b>				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
<b>Other MISO Charges</b>				
20	Real-Time Miscellaneous Amount	\$ (1,967.65)	\$ -	\$ (1,967.65)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,344,341.78	\$ -	\$ 2,344,341.78
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,432,047.15)	\$ -	\$ (2,432,047.15)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (480,323.76)	\$ -	\$ (480,323.76)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 329,071.19	\$ -	\$ 329,071.19
<b>TOTAL MISO CHARGES</b>		<b>\$ 13,137,974.08</b>	<b>\$ 1,687,991.20</b>	<b>\$ 14,825,965.28</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 92,355.79</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 14,733,609.49</b>

## MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
<b>September 2011 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (213,165.84)	\$ -	\$ (213,165.84)
2	Day-Ahead Spinning Reserve Amount	\$ (60,382.63)	\$ -	\$ (60,382.63)
3	Day-Ahead Supplemental Reserve	\$ (118,135.20)	\$ -	\$ (118,135.20)
4	Real-Time Regulation Amount	\$ 37,243.57	\$ 16,537.07	\$ 53,780.64
5	Real-Time Spinning Reserve Amount	\$ (29,818.68)	\$ 17,248.20	\$ (12,570.48)
6	Real-Time Supplemental Reserve Amount.	\$ 1,509.98	\$ 45,785.05	\$ 47,295.03
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (36,993.54)		\$ (36,993.54)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 494,731.69		\$ 494,731.69
8b	Real Time Non Excessive Energy Congestion	\$ 85,606.97		\$ 85,606.97
8c	Real Time Non Excessive Energy Loss	\$ 70,000.82		\$ 70,000.82
9	Real Time Net Regulation Adjustment Amount	\$ 3,183.71	\$ (356.60)	\$ 2,827.11
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 229,943.36	\$ -	\$ 229,943.36
11	Real Time Spinning Reserve Cost Distribution	\$ 132,740.84	\$ -	\$ 132,740.84
12	Real Time Supplemental Reserve Cost Distribution	\$ 83,064.54	\$ -	\$ 83,064.54
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 5,903.37	\$ 872.42	\$ 6,775.79
14	Real Time Contignecy Reserve Deployment Failure	\$ 6,059.50	\$ (2,161.58)	\$ 3,897.92
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 691,492.46</b>	<b>\$ 77,924.56</b>	<b>\$ 769,417.02</b>

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 Monthly Refund	(72,651)	(19,186)	(84,041)	(55,415)	(21,946)	(18,191)	(43,511)	(59,944)	(17,866)			
2 Forecast North Dakota Sales	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	169,751	201,528	230,843	-
3 Current Month Refund Factor	(0.036)	(0.011)	(0.050)	(0.032)	(0.013)	(0.009)	(0.024)	(0.036)	(0.011)	-	-	-
4 Expected Refund	(25,037)	(44,836)	(29,737)	(32,785)	(72,439)	(59,388)	(44,704)	(12,248)	(34,464)	(38,522)	(30,303)	-
5 Actual Refunded	(38,347)	(31,238)	(41,339)	(28,812)	(49,681)	(65,331)	(53,751)	(33,670)	(22,027)			
6 Deviation	42,914	(13,599)	11,602	(3,973)	(22,758)	5,943	9,047	21,422	(12,437)	(38,522)	(30,303)	-
7 True-up Factor	0.021	(0.008)	0.007	(0.002)	(0.013)	0.003	0.005	0.013	(0.007)	-	-	-
8 Realized Margin	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	-	-	-
9 Class Ratios												
10 Residential	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
11 C&I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
12 C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
13 C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
14 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
15 Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
16 Realized Margin Adj for Class Ratios												
17 Residential	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	-	-	-
18 C&I Non-Demand	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	(0.020)	(0.024)	(0.019)	-	-	-
19 C&I Demand Non-TOD	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	(0.020)	(0.024)	(0.018)	-	-	-
20 C&I Demand TOD On-Peak	(0.019)	(0.025)	(0.050)	(0.045)	(0.034)	(0.008)	(0.025)	(0.030)	(0.023)	-	-	-
21 C&I Demand TOD Off-Peak	(0.011)	(0.015)	(0.033)	(0.026)	(0.020)	(0.005)	(0.015)	(0.018)	(0.014)	-	-	-
22 Outdoor Lighting	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	(0.014)	(0.016)	(0.013)	-	-	-

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  
 Non-Asset Based Margin Sharing

1	Forecast Month	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12
2	True-up Month	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
3		(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,685)	(4,686)	(4,686)	(4,686)	(4,686)	(4,686)
4	Monthly Refund				(14,881)								
5		203,291	203,850	171,035	168,639	174,150	172,841	198,618	180,254	167,256	169,751	201,528	230,843
6	Forecast North Dakota Sales												
7		(0.002)	(0.002)	(0.003)	(0.009)	(0.003)	(0.003)	(0.002)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)
8	Current Month Refund Factor												
13		(17,897)	(16,914)	(4,666)	7,377	2,316	(8,562)	(6,663)	(10,576)	(3,944)	(6,492)	30	(5,340)
14	Expected Refund												
15	Actual Refund	(17,916)	(18,780)	(11,666)	858	4,294	(2,471)	(7,404)	(8,770)	(8,660)	(5,838)		
16	Deviation	19	12,062	7,001	6,519	(1,978)	(5,891)	741	(1,806)	4,716	(654)	30	(5,340)
17		0.000	0.006	0.004	0.004	(0.001)	(0.003)	0.000	(0.001)	0.003	(0.000)	-	-
18	True-up Factor												
19		(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	-	-
20	Realized Margin												
21		0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
22	Class Ratios												
23	Residential	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
24	C&I Non-Demand	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
25	C&I Demand Non-TOD	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
26	C&I Demand TOD On-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
27	C&I Demand TOD Off-Peak	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
28	Outdoor Lighting												
29		(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	-	-
30	Realized Margin Adj for Class Ratios												
31	Residential	0.004	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	-	-
32	C&I Non-Demand	0.004	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	-	-
33	C&I Demand Non-TOD	0.005	0.005	0.002	(0.007)	(0.005)	(0.008)	(0.003)	(0.005)	0.000	(0.004)	-	-
34	C&I Demand TOD On-Peak	0.003	0.003	0.001	(0.004)	(0.003)	(0.005)	(0.002)	(0.003)	0.000	(0.002)	-	-
35	C&I Demand TOD Off-Peak	0.002	0.003	0.001	(0.004)	(0.003)	(0.005)	(0.002)	(0.003)	0.000	(0.002)	-	-
36	Outdoor Lighting	0.002	0.003	0.001	(0.004)	(0.003)	(0.004)	(0.001)	(0.003)	0.000	(0.002)	-	-