



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

June 29, 2010

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

**Re: July 2010 Fuel Cost Charge**

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits electric fuel cost charge (FCC) for July 2010.

Pursuant to the Commission authorization of the final compliance tariffs in Company's 2007 rate proceeding (Docket No. PU-07-776) to implement new rates beginning March 1, 2009, a "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The July 2010 system FCC is based on the average of the most recent four-month actual fuel cost plus the "True-up" factor, reflecting cost recovery deviations from the May 2010 calendar month.

The former system average monthly fuel cost charge is now differentiated into 6 customer class categories (see derivation of these factors on Attachment 1, page 2 to 4).

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

<b>July 2010</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02653
<b>C &amp; I Non-Demand</b>	0.02810
<b>C &amp; I Demand</b>	0.02723
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03499
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02058
<b>Outdoor Lighting</b>	0.01888

## **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 PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March FCC 2009 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 Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the July FCC, the net MISO Day 2 costs for May 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this July FCC is \$16,234,204.71, 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.

On May 6, 2009 FERC issued Order (Docket No. EL07-86-005, *et al.*) reversing portions of the prior decision (November 2008) on MISO RSG that resulted in a resettlement adjustment in FCC. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCC.

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<sup>1</sup> 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 charges types are included in the Fuel Cost Rider, pursuant to the 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 July FCC, the net MISO ASM costs for May 2010 as recorded in Account 555. The MISO ASM cost recovery included in this July FCC is \$3,111,926 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 May 2010 Asset Based Margin amount of \$157,164 has been included in the July Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2010, the 2009 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 2009 Non-Asset Based Margin credit is \$201,971 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the July FCC is \$17,278, or 0.009¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attachment is the calculation of the July 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 Jul-2010

Jul-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02628	\$0.00129	-\$0.00093	\$0.02664
<b>Residential</b>	\$0.02616	\$0.00128	-\$0.00092	\$0.02653
<b>C &amp; I Non-Demand</b>	\$0.02772	\$0.00136	-\$0.00098	\$0.02810
<b>C &amp; I Demand Non-TOD</b>	\$0.02686	\$0.00132	-\$0.00095	\$0.02723
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03452	\$0.00169	-\$0.00122	\$0.03499
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02030	\$0.00099	-\$0.00071	\$0.02058
<b>Outdoor Lighting</b>	\$0.01863	\$0.00091	-\$0.00066	\$0.01888
<b>Residential</b>				
Residential Service	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
Residential TOD	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
Residential - Underground	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
Residential TOD - Underground	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
Energy Control - (Non-Demand)	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
Limit Off Peak	\$ 0.02616	\$ 0.00128	\$ (0.00092)	\$ 0.02653
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Limit Off Peak	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Small General Service	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Small General TOD - Metered	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Small General TOD - Unmetered	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Fire and Civil Defense Siren	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
Direct Current (Closed)	\$ 0.02772	\$ 0.00136	\$ (0.00098)	\$ 0.02810
<b>C &amp; I Demand</b>				
General Service	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
General TOD - On Peak	\$ 0.03452	\$ 0.00169	\$ (0.00122)	\$ 0.03499
General TOD - Off Peak	\$ 0.02030	\$ 0.00099	\$ (0.00071)	\$ 0.02058
Peak Controlled (Closed)	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Peak Controlled TOD (Closed) - On Peak	\$ 0.03452	\$ 0.00169	\$ (0.00122)	\$ 0.03499
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02030	\$ 0.00099	\$ (0.00071)	\$ 0.02058
Peak Controlled Tiered	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Peak Controlled Tiered TOD - On Peak	\$ 0.03452	\$ 0.00169	\$ (0.00122)	\$ 0.03499
Peak Controlled Tiered TOD - Off Peak	\$ 0.02030	\$ 0.00099	\$ (0.00071)	\$ 0.02058
Energy Controlled (Closed)	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Tier 1 Energy Controlled Rider	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Real Time Pricing - Firm - On Peak	\$ 0.03452	\$ 0.00169	\$ (0.00122)	\$ 0.03499
Real Time Pricing - Firm - Off Peak	\$ 0.02030	\$ 0.00099	\$ (0.00071)	\$ 0.02058
Real Time Pricing - Controllable - On Peak	\$ 0.03452	\$ 0.00169	\$ (0.00122)	\$ 0.03499
Real Time Pricing - Controllable - Off Peak	\$ 0.02030	\$ 0.00099	\$ (0.00071)	\$ 0.02058
Small Municipal Pumping	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Municipal Pumping	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
Excess Energy - St. Anthony Falls	\$ 0.02686	\$ 0.00132	\$ (0.00095)	\$ 0.02723
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888
Street Lighting System	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888
Street Lighting Energy	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888
Street Lighting Energy - Metered	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888
Street Lighting Energy (Closed)	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888
Street Lighting - City of St. Paul	\$ 0.01863	\$ 0.00091	\$ (0.00066)	\$ 0.01888

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 Jul-2010

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Feb-10	Mar-10	Apr-10	May-10	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$38,278,709	\$27,468,130	\$28,892,464	\$42,295,040	\$136,934,343
Account 518 - Nuclear Fuel	\$8,941,917	\$9,775,774	\$8,045,935	\$7,461,565	\$34,225,190
Account 555 - Purchased Power <sup>1</sup>	\$28,152,883	\$34,011,198	\$32,827,975	\$46,251,093	\$141,243,149
Account 555 - MISO Day 2 Charges	\$14,484,703	\$20,208,392	\$18,780,094	\$16,331,544	\$69,804,732
Account 555 MISO Day 2 - Schedule 24	(\$86,498)	(\$86,548)	(\$86,104)	(\$97,339)	(\$356,488)
Account 555 MISO - ASM Charges	(\$214,099)	(\$1,583,580)	\$186,146	\$3,111,926	\$1,500,394
Total MISO Charges	\$14,184,106	\$18,538,264	\$18,880,137	\$19,346,131	\$70,948,637
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$89,557,614	\$89,793,366	\$88,646,511	\$115,353,828	\$383,351,319
Less Fuel Cost of InterSystem Sales	(\$7,919,136)	(\$7,682,321)	(\$7,335,161)	(\$14,193,013)	(\$37,129,631)
Net System Costs	\$81,638,478	\$82,111,045	\$81,311,350	\$101,160,815	\$346,221,688
<b>System MWH Sales</b>					
Total NSP System Retail	3,303,570	3,553,751	3,129,808	2,907,623	12,894,752
Non-Gen Muni's/Load Pattern	80,653	71,253	67,601	60,608	280,115
Total NSP System MWh Sales	3,384,223	3,625,004	3,197,409	2,968,231	13,174,867
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.412¢	2.265¢	2.543¢	3.408¢	2.628¢
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	2.616¢
(ii) C & I Non-Demand				1.0548	2.772¢
(iii) C & I Demand Non-TOD				1.0219	2.686¢
(iv) C & I Demand TOD On-Peak				1.3135	3.452¢
(v) C & I Demand TOD Off-Peak				0.7726	2.030¢
(vi) Outdoor Lighting				0.7088	1.863¢

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

North Dakota Retail MWh Sales					
(i) Residential	80,469	76,676	55,786	45,211	258,142
(ii) C & I Non-Demand	12,538	13,603	10,380	8,456	44,977
(iii) C & I Demand Non-TOD	58,775	67,572	54,120	48,522	228,989
(iv) C & I Demand TOD On-Peak	17,869	22,810	17,650	15,394	73,723
(v) C & I Demand TOD Off-Peak	28,482	36,695	27,666	23,067	115,910
(vi) Outdoor Lighting	1,654	1,989	1,569	1,263	6,475
(vii) Total	199,787	219,345	167,171	141,913	728,216

**Jul-2010 Recovery Provision (True-up Factor) Calculation**

Prior Unrecovered Expenses (Mar-10 Balance of Unrecovered Expenses)	Total
	Mar-10
	(\$537,269)

**Prior Expenses Recovered in May-2010**

	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Received Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	-0.064¢	45,211	(\$28,972)
(iii) C & I Demand Non-TOD	1.0548	-0.068¢	8,456	(\$5,741)
(iv) C & I Demand TOD On-Peak	1.0219	-0.066¢	48,522	(\$31,915)
(v) C & I Demand TOD Off-Peak	1.3135	-0.085¢	15,394	(\$13,014)
(vi) Outdoor Lighting	0.7726	-0.050¢	23,067	(\$11,471)
(vii) Total	0.7088	-0.046¢	141,913	(\$91,689)

**Actual Cost Should Have Been Recovered in May-10**

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.408¢	0.000¢	141,913	\$4,836,395

**Cost Recovered in May-10**

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.413¢	45,211	\$1,091,092
(ii) C & I Non-Demand	1.0548	2.557¢	8,456	\$216,206
(iii) C & I Demand Non-TOD	1.0219	2.477¢	48,522	\$1,201,932
(iv) C & I Demand TOD On-Peak	1.3135	3.184¢	15,394	\$490,133
(v) C & I Demand TOD Off-Peak	0.7726	1.873¢	23,067	\$431,995
(vi) Outdoor Lighting	0.7088	1.718¢	1,263	\$21,700
(vii) Total			141,913	\$3,453,058

**Total Balance of Unrecovered Expenses (Jul-10 Balance of Unrecovered Expenses)**

Jul-2010 Recovery Provision	\$937,757
4 Month ND Retail Total MWh Sales	728,216
Jul-2010 Recovery Provision per KWH	0.129¢

<b>Jul-2010 Recovery Provision (True-up Factor) per kWh by Customer Category</b>			
	<b>FAF Ratio</b>	<b>Recovery Provision Adjustment</b>	<b>Recovery Provision Adj by Class</b>
(i) Residential	0.9956	0.129¢	0.128¢
(ii) C & I Non-Demand	1.0548	0.129¢	0.136¢
(iii) C & I Demand Non-TOD	1.0219	0.129¢	0.132¢
(iv) C & I Demand TOD On-Peak	1.3135	0.129¢	0.169¢
(v) C & I Demand TOD Off-Peak	0.7726	0.129¢	0.099¢
(vi) Outdoor Lighting	0.7088	0.129¢	0.091¢

  

<b>Jul-2010 Margin Sharing Refunds</b>			
	<b>Asset Based Margin Sharing Refund</b>	<b>Non-Asset Based Margin Sharing Refund</b>	<b>Total</b>
<b>Refund/Special Charge Amount</b>	(\$157,164)	(\$17,278)	(\$174,442)
(i) Residential	-0.083¢	-0.009¢	-0.092¢
(ii) C & I Non-Demand	-0.088¢	-0.010¢	-0.098¢
(iii) C & I Demand Non-TOD	-0.085¢	-0.009¢	-0.095¢
(iv) C & I Demand TOD On-Peak	-0.110¢	-0.012¢	-0.122¢
(v) C & I Demand TOD Off-Peak	-0.064¢	-0.007¢	-0.071¢
(vi) Outdoor Lighting	-0.059¢	-0.006¢	-0.066¢

  

<b>Jul-2010 Factors</b>	
	<b>Total</b>
(i) Residential	2.653¢
(ii) C & I Non-Demand	2.810¢
(iii) C & I Demand Non-TOD	2.723¢
(iv) C & I Demand TOD On-Peak	3.499¢
(v) C & I Demand TOD Off-Peak	2.058¢
(vi) Outdoor Lighting	1.888¢

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -  
 Prior Month Compared to Current Month FCA

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jun-10	Jul-10	Differ- ence	Percent Change	FCA Application Jun-10	Jul-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$137.6	\$136.9	(\$0.7)	-0.5%	36.1%	35.7%	-0.4%
2 Nuclear	\$36.8	\$34.2	(\$2.6)	-7.0%	9.6%	8.9%	-0.7%
3 Purchases	\$136.3	\$141.2	\$4.9	3.6%	35.7%	36.8%	1.1%
MISO related Purchases	\$70.6	\$70.9	\$0.3	0.5%	18.5%	18.5%	0.0%
4 Total System Costs	381.3	383.4	\$2.0	0.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$41.4	\$37.1	(\$4.3)	-10.3%	10.9%	9.7%	-1.2%
6 Net System Costs	\$340.0	\$346.2	\$6.3	1.8%	89.1%	90.3%	1.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,207	5,063	(144)	-2.8%	15.8%	15.7%	-0.1%
10 Nuclear	4,585	4,210	(375)	-8.2%	13.9%	13.1%	-0.8%
11 Purchases	4,787	4,957	170	3.6%	14.5%	15.4%	0.9%
12 Hydro & Other	779	838	59	7.6%	2.4%	2.6%	0.2%
13 Net Interchange	17,575	17,104	(471)	-2.7%	53.4%	53.2%	-0.2%
14 Total Output	32,933	32,172	(761)	-2.3%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,525	1,515	(9)	-0.6%	4.6%	4.7%	0.1%
16 Native Requirement	31,408	30,657	(752)	-2.4%	95.4%	95.3%	-0.1%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.643	2.705	0.062	2.3%			
20 Nuclear	0.802	0.813	0.011	1.3%			
21 Purchases	2.848	2.849	0.002	0.1%			
22 Total System Costs	1.158	1.192	0.034	2.9%			
23 Intersystem Sales	2.714	2.450	-0.264	-9.7%			
24 Net System Costs	1.082	1.129	0.047	4.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,072	13,175	(897)	-6.4%			
28							
29 COST per KWH SALES (\$)	2.416	2.628	0.212	8.8%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.019	0.129	0.148				
(i) Residential	-0.019	0.128	0.148				
(ii) C & I Non-Demand	-0.021	0.136	0.156				
(iii) C & I Demand Non-TOD	-0.020	0.132	0.152				
(iv) C & I Demand TOD On-Peak	-0.026	0.169	0.195				
(v) C & I Demand TOD Off-Peak	-0.015	0.099	0.115				
(vi) Outdoor Lighting	-0.014	0.091	0.105				
32 REFUND	-0.024	-0.092	-0.068				
(i) Residential	-0.024	-0.092	-0.068				
(ii) C & I Non-Demand	-0.025	-0.098	-0.073				
(iii) C & I Demand Non-TOD	-0.025	-0.095	-0.070				
(iv) C & I Demand TOD On-Peak	-0.032	-0.122	-0.090				
(v) C & I Demand TOD Off-Peak	-0.019	-0.071	-0.052				
(vi) Outdoor Lighting	-0.017	-0.066	-0.049				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.373	2.665	0.292	12.3%			
(i) Residential	2.362	2.653	0.291				
(ii) C & I Non-Demand	2.503	2.810	0.307				
(iii) C & I Demand Non-TOD	2.425	2.723	0.298				
(iv) C & I Demand TOD On-Peak	3.117	3.499	0.382				
(v) C & I Demand TOD Off-Peak	1.833	2.058	0.225				
(vi) Outdoor Lighting	1.682	1.888	0.206				

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	\$0.29
250	\$0.73
500	\$1.45
750	\$2.18
1,000	\$2.91

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>	
	Jun-10	Jul-10
<b>** GWH OUTPUT **</b>		
Thermal	586,140	623,956
Wind plus disper gen	(65)	(55)
Hydro	193,073	214,151
Hydro and Other	779,148	838,052
Rounded to nearest thousand:	779	838
<b>Sales</b>		
Non Gen Munic Total	334,619,000	280,115,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,524,599,000	1,515,270,000
Rounded to nearest million:	1524.599	1515.27

		System	Intersystem	Retail
<b>May 2010 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 13,293,480.84	\$ 5,727,187.01	\$ 19,020,667.85
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,385,638.68	\$ -	\$ 2,385,638.68
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 4,935.06	\$ -	\$ 4,935.06
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,909,524.40)	\$ -	\$ (11,909,524.40)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,467,636.99	\$ -	\$ 1,467,636.99
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)	\$ 2,528,036.16	\$ 156,000.62	\$ 2,684,036.78
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 3,510.14	\$ -	\$ 3,510.14
14	Real-Time Distribution of Losses Amount	\$ (1,129,180.50)	\$ -	\$ (1,129,180.50)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (27,007.66)	\$ -	\$ (27,007.66)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 71,924.31	\$ -	\$ 71,924.31
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (321.25)	\$ -	\$ (321.25)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 1,586,733.99	\$ -	\$ 1,586,733.99
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (2,055.83)	\$ -	\$ (2,055.83)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,510,142.41	\$ -	\$ 1,510,142.41
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)	\$ 257,552.86	\$ -	\$ 257,552.86
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)	\$ 9,143.77	\$ -	\$ 9,143.77
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,044,098.90)	\$ -	\$ (1,044,098.90)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (124,031.08)	\$ -	\$ (124,031.08)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (463,435.33)	\$ -	\$ (463,435.33)
37	Financial Transmission Guarantee Uplift Amount	\$ 408,550.90	\$ -	\$ 408,550.90
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 904,763.70	\$ -	\$ 904,763.70
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 128,471.93	\$ -	\$ 128,471.93
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (240,476.82)	\$ 13,988.57	\$ (226,488.25)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 405,098.66	\$ -	\$ 405,098.66
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (278,953.67)	\$ 82,029.12	\$ (196,924.55)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (221,189.45)	\$ 1,488.79	\$ (219,700.66)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 797,745.76	\$ (19,882.56)	\$ 777,863.20
19	Real-Time Market Administration Amount	\$ 63,526.94	\$ (2,546.99)	\$ 60,979.95
29	Financial Transmission Rights Market Administration Amount	\$ 69,266.96	\$ -	\$ 69,266.96
33	Day-Ahead Schedule 24 Allocation Amount	\$ 92,558.42	\$ (2,351.26)	\$ 90,207.16
34	Real-Time Schedule 24 Allocation Amount	\$ 7,388.94	\$ (257.20)	\$ 7,131.74
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	\$ 376,057.40	\$ -	\$ 376,057.40
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 352,980.27	\$ -	\$ 352,980.27
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (298,456.49)	\$ -	\$ (298,456.49)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (610,526.14)	\$ -	\$ (610,526.14)
<b>TOTAL MISO CHARGES</b>		<b>\$ 10,375,887.51</b>	<b>\$ 5,955,656.10</b>	<b>\$ 16,331,543.61</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 97,338.90</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 16,234,204.71</b>

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

		System	Intersystem	Retail
May 2010 Actual				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (472,287.90)	\$ -	\$ (472,287.90)
2	Day-Ahead Spinning Reserve Amount	\$ (78,276.05)	\$ -	\$ (78,276.05)
3	Day-Ahead Supplemental Reserve	\$ (147,932.70)	\$ -	\$ (147,932.70)
4	Real-Time Regulation Amount	\$ 83,792.18	\$ 222,564.00	\$ 306,356.18
5	Real-Time Spinning Reserve Amount	\$ (44,679.10)	\$ 32,696.25	\$ (11,982.85)
6	Real-Time Supplemental Reserve Amount.	\$ 24,946.49	\$ 12,613.07	\$ 37,559.56
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (29,133.91)		\$ (29,133.91)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,019,443.05		\$ 2,019,443.05
8b	Real Time Non Excessive Energy Congestion	\$ 618,473.61		\$ 618,473.61
8c	Real Time Non Excessive Energy Loss	\$ 200,803.77		\$ 200,803.77
9	Real Time Net Regulation Adjustment Amount	\$ 10,419.91	\$ 1,325.88	\$ 11,745.79
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 275,763.22	\$ -	\$ 275,763.22
11	Real Time Spinning Reserve Cost Distribution	\$ 214,139.61	\$ -	\$ 214,139.61
12	Real Time Supplemental Reserve Cost Distribution	\$ 146,167.26	\$ -	\$ 146,167.26
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 14,880.75	\$ 6,120.96	\$ 21,001.71
14	Real Time Contignecy Reserve Deployment Failure	\$ (0.09)	\$ 85.79	\$ 85.70
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 2,836,520.10</b>	<b>\$ 275,405.95</b>	<b>\$ 3,111,926.05</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

1 Forecast Month	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11
2 True-up Month	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
3												
4 Monthly Refund	(161,371)	10,622	(54,285)	(21,836)	(155,670)							
5												
6 Forecast North Dakota Sales	194,554	163,606	164,425	165,070	188,515	188,034	169,302	-	-	-	-	-
7												
8 <b>Current Month Refund Factor</b>	(0.083)	0.006	(0.033)	(0.013)	(0.083)	-	-	-	-	-	-	-
9												
10 Forecasted North Dakota Sales	215,527	196,388	194,554	163,606	164,425	165,070	188,515	-	-	-	-	-
11 Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	-	-	-	-	-	-	-
12 Deviation	(6,727)	6,442	3,899	11,743	4,271	165,070	188,515	-	-	-	-	-
13												
14 Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	-	-	-	-	-
15 Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	-	-	-	-	-	-	-
16 Deviation	420	(2,682)	(3,226)	570	(1,494)	(21,266)	(157,164)	-	-	-	-	-
17												
18 <b>True-up Factor</b>	0.000	(0.002)	(0.002)	0.000	(0.001)	-	-	-	-	-	-	-
19												
20 <b>Realized Margin</b>	(0.083)	0.005	(0.035)	(0.013)	(0.083)	-	-	-	-	-	-	-
21												
22 <b>Class Ratios</b>												
23 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
24 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
25 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
26 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
27 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
28 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
29												
30 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.082)	0.005	(0.035)	(0.013)	(0.083)	-	-	-	-	-	-	-
32 C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	-	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	-	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	-	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	-	-	-	-	-	-	-
36 Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	-	-	-	-	-	-	-

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-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11
2 True-up Month			Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10
3												
4 Monthly Refund	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,831)	(16,830)
5												
6 Forecast North Dakota Sales	196,388	194,554	163,606	164,425	165,070	188,515	-	-	-	-	-	-
7												
8 <b>Current Month Refund Factor</b>	(0.009)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	-	-	-	-	-	-
9												
10 Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	-	-	-	-	-	-
11 Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	-	-	-	-	-	-
12 Deviation			6,442	3,899	11,743	4,271	-	-	-	-	-	-
13												
14 Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	-	-	-	-	-	-
15 Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	-	-	-	-	-	-
16 Deviation			(553)	(337)	(1,247)	(447)	-	-	-	-	-	-
17												
18 <b>True-up Factor</b>	-	-	(0.000)	(0.000)	(0.001)	(0.000)	-	-	-	-	-	-
19												
20 <b>Realized Margin</b>	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	-	-	-	-	-	-
21												
22 <b>Class Ratios</b>												
23 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
24 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
25 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
26 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
27 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
28 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
29												
30 <b>Realized Margin Adj for Class Ratios</b>												
31 Residential	(0.009)	(0.009)	(0.011)	(0.010)	(0.011)	(0.009)	-	-	-	-	-	-
32 C&I Non-Demand	(0.009)	(0.009)	(0.011)	(0.011)	(0.012)	(0.010)	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.009)	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.011)	(0.011)	(0.014)	(0.014)	(0.014)	(0.012)	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(0.007)	-	-	-	-	-	-
36 Outdoor Lighting	(0.006)	(0.006)	(0.008)	(0.007)	(0.008)	(0.006)	-	-	-	-	-	-