



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

December 29, 2010

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

**Re: January 2011 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 January 2011.

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 January 2011 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 November 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:

January 2011	Fuel Cost Charge (\$/kWh)
<b>Residential</b>	0.02496
<b>C &amp; I Non-Demand</b>	0.02644
<b>C &amp; I Demand</b>	0.02561
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03292
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01937
<b>Outdoor Lighting</b>	0.01777

## 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 January 2011 FCC, the net MISO Day 2 costs for November 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this January FCC is \$17,779,254, 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.

<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 January FCC, the net MISO ASM costs for November 2010 as recorded in Account 555. The MISO ASM cost recovery included in this January FCC is \$1,874,955, 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 November 2010 Asset Based Margin amount of \$25,037 has been included in the January 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 January FCC is \$16,914, or 0.008¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attachment is the calculation of the January 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 Jan-2011

Jan-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02548	-\$0.00022	-\$0.00019	\$0.02507
<b>Residential</b>	\$0.02537	-\$0.00022	-\$0.00019	\$0.02496
<b>C &amp; I Non-Demand</b>	\$0.02688	-\$0.00023	-\$0.00020	\$0.02644
<b>C &amp; I Demand Non-TOD</b>	\$0.02604	-\$0.00023	-\$0.00020	\$0.02561
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03347	-\$0.00029	-\$0.00025	\$0.03292
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.01969	-\$0.00017	-\$0.00015	\$0.01937
<b>Outdoor Lighting</b>	\$0.01806	-\$0.00016	-\$0.00014	\$0.01777
<b>Residential</b>				
Residential Service	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
Residential TOD	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
Residential - Underground	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
Residential TOD - Underground	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
Energy Control - (Non-Demand)	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
Limit Off Peak	\$ 0.02537	\$ (0.00022)	\$ (0.00019)	\$ 0.02496
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Limit Off Peak	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Small General Service	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Small General TOD - Metered	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Small General TOD - Unmetered	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Fire and Civil Defense Siren	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
Direct Current (Closed)	\$ 0.02688	\$ (0.00023)	\$ (0.00020)	\$ 0.02644
<b>C &amp; I Demand</b>				
General Service	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
General TOD - On Peak	\$ 0.03347	\$ (0.00029)	\$ (0.00025)	\$ 0.03292
General TOD - Off Peak	\$ 0.01969	\$ (0.00017)	\$ (0.00015)	\$ 0.01937
Peak Controlled (Closed)	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Peak Controlled TOD (Closed) - On Peak	\$ 0.03347	\$ (0.00029)	\$ (0.00025)	\$ 0.03292
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01969	\$ (0.00017)	\$ (0.00015)	\$ 0.01937
Peak Controlled Tiered	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Peak Controlled Tiered TOD - On Peak	\$ 0.03347	\$ (0.00029)	\$ (0.00025)	\$ 0.03292
Peak Controlled Tiered TOD - Off Peak	\$ 0.01969	\$ (0.00017)	\$ (0.00015)	\$ 0.01937
Energy Controlled (Closed)	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Tier 1 Energy Controlled Rider	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Real Time Pricing - Firm - On Peak	\$ 0.03347	\$ (0.00029)	\$ (0.00025)	\$ 0.03292
Real Time Pricing - Firm - Off Peak	\$ 0.01969	\$ (0.00017)	\$ (0.00015)	\$ 0.01937
Real Time Pricing - Controllable - On Peak	\$ 0.03347	\$ (0.00029)	\$ (0.00025)	\$ 0.03292
Real Time Pricing - Controllable - Off Peak	\$ 0.01969	\$ (0.00017)	\$ (0.00015)	\$ 0.01937
Small Municipal Pumping	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Municipal Pumping	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
Excess Energy - St. Anthony Falls	\$ 0.02604	\$ (0.00023)	\$ (0.00020)	\$ 0.02561
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777
Street Lighting System	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777
Street Lighting Energy	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777
Street Lighting Energy - Metered	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777
Street Lighting Energy (Closed)	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777
Street Lighting - City of St. Paul	\$ 0.01806	\$ (0.00016)	\$ (0.00014)	\$ 0.01777

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 Jan-2011

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Aug-10	Sep-10	Oct-10	Nov-10	4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$58,449,676	\$32,483,786	\$27,904,463	\$29,250,092	\$148,088,017
Account 518 - Nuclear Fuel	\$10,436,900	\$10,120,300	\$10,528,653	\$8,442,371	\$39,528,222
Account 555 - Purchased Power <sup>1</sup>	\$51,892,571	\$42,858,688	\$35,333,149	\$40,365,101	\$170,449,510
Account 555 - MISO Day 2 Charges	\$19,796,437	\$10,215,984	\$13,229,787	\$17,870,049	\$61,112,258
Account 555 MISO Day 2 - Schedule 24	(\$102,950)	(\$88,143)	(\$91,617)	(\$90,795)	(\$373,506)
Account 555 MISO - ASM Charges	<u>(\$1,843,516)</u>	<u>(\$465,255)</u>	<u>\$1,826,511</u>	<u>\$1,874,955</u>	<u>\$1,392,696</u>
Total MISO Charges	\$17,849,971	\$9,662,585	\$14,964,682	\$19,654,210	\$62,131,448
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	<u>\$138,629,117</u>	<u>\$95,125,359</u>	<u>\$88,730,947</u>	<u>\$97,711,774</u>	<u>\$420,197,197</u>
Less Fuel Cost of InterSystem Sales	(\$16,801,461)	(\$15,484,547)	(\$6,507,051)	(\$11,869,991)	(\$50,663,049)
Net System Costs	<u>\$121,827,656</u>	<u>\$79,640,812</u>	<u>\$82,223,896</u>	<u>\$85,841,783</u>	<u>\$369,534,148</u>
<b>System MWh Sales</b>					
Total NSP System Retail	4,249,406	3,737,306	3,133,138	3,097,598	14,217,448
Non-Gen Muni's/Load Pattern	77,837	80,260	64,086	62,824	285,007
Total NSP System MWh Sales	<u>4,327,243</u>	<u>3,817,566</u>	<u>3,197,224</u>	<u>3,160,422</u>	<u>14,502,455</u>
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.815¢	2.086¢	2.572¢	2.716¢	2.548¢
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	2.537¢
(ii) C & I Non-Demand				1.0548	2.688¢
(iii) C & I Demand Non-TOD				1.0219	2.604¢
(iv) C & I Demand TOD On-Peak				1.3135	3.347¢
(v) C & I Demand TOD Off-Peak				0.7726	1.969¢
(vi) Outdoor Lighting				0.7088	1.806¢

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

## Electric Operations - State of North Dakota

## Derivation of Adjustment for Fuel Clause Rider

## Current Period Cost of Energy for Jan-2011

**North Dakota Retail MWh Sales**

(i) Residential	66,473	53,979	44,866	51,416	216,734
(ii) C & I Non-Demand	10,272	9,169	8,175	8,696	36,312
(iii) C & I Demand Non-TOD	63,143	60,097	56,339	55,482	235,061
(iv) C & I Demand TOD On-Peak	20,271	19,488	18,625	17,620	76,004
(v) C & I Demand TOD Off-Peak	31,083	30,560	28,988	27,348	117,979
(vi) Outdoor Lighting	1,195	1,405	1,301	1,945	5,846
(vii) Total	192,437	174,698	158,294	162,507	687,936

**Jan-2011 Recovery Provision (True-up Factor) Calculation****Prior Unrecovered Expenses (Sep-10 Balance of Unrecovered Expenses)**

Total

Sep-10

(\$414,217)

**Prior Expenses Recovered in Nov-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	-0.057¢	51,416	(\$29,215)
(iii) C & I Demand Non-TOD	1.0548	-0.060¢	8,696	(\$5,235)
(iv) C & I Demand TOD On-Peak	1.0219	-0.058¢	55,482	(\$32,358)
(v) C & I Demand TOD Off-Peak	1.3135	-0.075¢	17,620	(\$13,208)
(vi) Outdoor Lighting	0.7726	-0.044¢	27,348	(\$12,059)
(vii) Total	0.7088	-0.040¢	1,945	(\$787)
			162,507	(\$92,862)

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

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.716¢	0.000¢	162,507	\$4,413,690

**Cost Recovered in Nov-10**

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.598¢	51,416	\$1,335,541
(ii) C & I Non-Demand	1.0548	2.752¢	8,696	\$239,312
(iii) C & I Demand Non-TOD	1.0219	2.666¢	55,482	\$1,479,226
(iv) C & I Demand TOD On-Peak	1.3135	3.427¢	17,620	\$603,824
(v) C & I Demand TOD Off-Peak	0.7726	2.016¢	27,348	\$551,257
(vi) Outdoor Lighting	0.7088	1.849¢	1,945	\$35,968
(vii) Total			162,507	\$4,245,128

**Total Balance of Unrecovered Expenses (Jan-11 Balance of Unrecovered Expenses)**

Jan-2011 Recovery Provision	(\$152,793)
4 Month ND Retail Total MWh Sales	687,936
Jan-2011 Recovery Provision per KWH	-0.022¢

<b>Jan-2011 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	-0.022¢	-0.022¢
(ii) C & I Non-Demand	1.0548	-0.022¢	-0.023¢
(iii) C & I Demand Non-TOD	1.0219	-0.022¢	-0.023¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.022¢	-0.029¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.022¢	-0.017¢
(vi) Outdoor Lighting	0.7088	-0.022¢	-0.016¢
<b>Jan-2011 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>	<b>(\$25,037)</b>	<b>(\$16,914)</b>	<b>(\$41,952)</b>
(i) Residential	-0.011¢	-0.008¢	-0.019¢
(ii) C & I Non-Demand	-0.012¢	-0.008¢	-0.020¢
(iii) C & I Demand Non-TOD	-0.012¢	-0.008¢	-0.020¢
(iv) C & I Demand TOD On-Peak	-0.015¢	-0.010¢	-0.025¢
(v) C & I Demand TOD Off-Peak	-0.009¢	-0.006¢	-0.015¢
(vi) Outdoor Lighting	-0.008¢	-0.005¢	-0.014¢
<b>Jan-2011 Factors</b>			
	<b>Total</b>		
(i) Residential	2.496¢		
(ii) C & I Non-Demand	2.644¢		
(iii) C & I Demand Non-TOD	2.561¢		
(iv) C & I Demand TOD On-Peak	3.292¢		
(v) C & I Demand TOD Off-Peak	1.937¢		
(vi) Outdoor Lighting	1.777¢		

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>		
	Dec-10	Jan-11	Differ- ence	Percent Change	FCA Application Dec-10	Jan-11	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$173.9	\$148.1	(\$25.8)	-14.8%	37.7%	35.2%	-2.5%
2 Nuclear	\$41.6	\$39.5	(\$2.1)	-4.9%	9.0%	9.4%	0.4%
3 Purchases	\$186.8	\$170.4	(\$16.3)	-8.7%	40.5%	40.6%	0.1%
MISO related Purchases	\$58.8	\$62.1	\$3.4	5.7%	12.7%	14.8%	2.1%
4 Total System Costs	461.0	420.2	(\$40.8)	-8.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$62.5	\$50.7	(\$11.9)	-19.0%	13.6%	12.1%	-1.5%
6 Net System Costs	\$398.5	\$369.5	(\$29.0)	-7.3%	86.4%	87.9%	1.5%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	5,431	4,981	(450)	-8.3%	29.9%	29.1%	-0.8%
10 Nuclear	4,705	4,453	(252)	-5.4%	25.9%	26.0%	0.1%
11 Purchases	5,590	5,663	73	1.3%	30.7%	33.0%	2.3%
12 Hydro & Other	1,730	1,353	(377)	-21.8%	9.5%	7.9%	-1.6%
13 Net Interchange	729	686	(43)	-5.9%	4.0%	4.0%	0.0%
14 Total Output	18,185	17,136	(1,049)	-5.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,855	1,879	24	1.3%	10.2%	11.0%	0.8%
16 Native Requirement	16,330	15,257	(1,073)	-6.6%	89.8%	89.0%	-0.8%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.202	2.973	-0.229	-7.2%			
20 Nuclear	0.884	0.888	0.004	0.4%			
21 Purchases	3.341	3.010	-0.332	-9.9%			
22 Total System Costs	2.535	2.452	-0.083	-3.3%			
23 Intersystem Sales	3.370	2.696	-0.673	-20.0%			
24 Net System Costs	2.440	2.422	-0.018	-0.8%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,251	14,502	(749)	-4.9%			
28							
29 COST per KWH SALES (\$)	2.613	2.548	-0.065	-2.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.034	-0.022	0.012				
(i) Residential	-0.034	-0.022	0.012				
(ii) C & I Non-Demand	-0.036	-0.023	0.013				
(iii) C & I Demand Non-TOD	-0.035	-0.023	0.012				
(iv) C & I Demand TOD On-Peak	-0.045	-0.029	0.016				
(v) C & I Demand TOD Off-Peak	-0.027	-0.017	0.009				
(vi) Outdoor Lighting	-0.024	-0.016	0.009				
32 REFUND	-0.028	0.000	0.028				
(i) Residential	-0.028	-0.019	0.009				
(ii) C & I Non-Demand	-0.030	-0.020	0.010				
(iii) C & I Demand Non-TOD	-0.029	-0.020	0.009				
(iv) C & I Demand TOD On-Peak	-0.037	-0.025	0.012				
(v) C & I Demand TOD Off-Peak	-0.022	-0.015	0.007				
(vi) Outdoor Lighting	-0.020	-0.014	0.006				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.551	2.526	-0.025	-1.0%			
(i) Residential	2.539	2.496	-0.043				
(ii) C & I Non-Demand	2.690	2.644	-0.046				
(iii) C & I Demand Non-TOD	2.606	2.561	-0.045				
(iv) C & I Demand TOD On-Peak	3.350	3.292	-0.058				
(v) C & I Demand TOD Off-Peak	1.970	1.937	-0.033				
(vi) Outdoor Lighting	1.808	1.777	-0.031				

**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	(\$0.04)
250	(\$0.11)
500	(\$0.22)
750	(\$0.33)
1,000	(\$0.43)

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>	
	Dec-10	Jan-11
<b>** GWH OUTPUT **</b>		
Thermal	1,292,022	916,639
Wind plus disper gen	(62)	(57)
Hydro	438,143	436,088
Hydro and Other	1,730,103	1,352,670
Rounded to nearest thousand:	1,730	1,353
<b>Sales</b>		
Non Gen Munic Total	290,159,000	285,007,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,855,081,000	1,878,888,000
Rounded to nearest million:	1855.081	1878.888

		System	Intersystem	Retail
<b>November 2010 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 21,174,986.81	\$ 1,126,612.69	\$ 22,301,599.50
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,667,853.62	\$ -	\$ 1,667,853.62
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,663,483.69)	\$ -	\$ (10,663,483.69)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,082,741.58	\$ -	\$ 1,082,741.58
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)	\$ 1,526,559.33	\$ 685,013.83	\$ 2,211,573.16
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (13,314.95)	\$ -	\$ (13,314.95)
14	Real-Time Distribution of Losses Amount	\$ (1,212,586.49)	\$ -	\$ (1,212,586.49)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (79,203.37)	\$ -	\$ (79,203.37)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 7,961.44	\$ -	\$ 7,961.44
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (662.19)	\$ -	\$ (662.19)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 713,208.43	\$ -	\$ 713,208.43
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,387,463.62	\$ -	\$ 1,387,463.62
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)	\$ 117,818.85	\$ -	\$ 117,818.85
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)	\$ (1,494.99)	\$ -	\$ (1,494.99)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,444,027.67)	\$ -	\$ (1,444,027.67)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (90,532.76)	\$ -	\$ (90,532.76)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (1,838.04)	\$ -	\$ (1,838.04)
37	Financial Transmission Guarantee Uplift Amount	\$ (19,385.37)	\$ -	\$ (19,385.37)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 571,071.94	\$ -	\$ 571,071.94
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 83,196.15	\$ -	\$ 83,196.15
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (21,001.31)	\$ 4,940.77	\$ (16,060.54)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 1,212,047.63	\$ -	\$ 1,212,047.63
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (29,826.75)	\$ 16,499.22	\$ (13,327.53)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (424,963.11)	\$ 12,070.50	\$ (412,892.61)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 700,431.96	\$ (5,565.17)	\$ 694,866.79
19	Real-Time Market Administration Amount	\$ 52,945.50	\$ (4,296.62)	\$ 48,648.88
29	Financial Transmission Rights Market Administration Amount	\$ 48,999.84	\$ -	\$ 48,999.84
33	Day-Ahead Schedule 24 Allocation Amount	\$ 85,533.60	\$ (676.00)	\$ 84,857.60
34	Real-Time Schedule 24 Allocation Amount	\$ 6,460.70	\$ (523.30)	\$ 5,937.40
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	\$ (7,179.58)	\$ -	\$ (7,179.58)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 964,693.19	\$ -	\$ 964,693.19
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,035,574.92)	\$ -	\$ (1,035,574.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (448,731.09)	\$ -	\$ (448,731.09)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 125,805.54	\$ -	\$ 125,805.54
<b>TOTAL MISO CHARGES</b>		<b>\$ 16,035,973.45</b>	<b>\$ 1,834,075.92</b>	<b>\$ 17,870,049.37</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 90,795.00</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 17,779,254.37</b>

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

		System	Intersystem	Retail
<b>November 2010 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (258,338.51)	\$ -	\$ (258,338.51)
2	Day-Ahead Spinning Reserve Amount	\$ (45,935.69)	\$ -	\$ (45,935.69)
3	Day-Ahead Supplemental Reserve	\$ (90,268.95)	\$ -	\$ (90,268.95)
4	Real-Time Regulation Amount	\$ (23,009.69)	\$ 124,496.61	\$ 101,486.92
5	Real-Time Spinning Reserve Amount	\$ (20,673.22)	\$ 18,493.29	\$ (2,179.93)
6	Real-Time Supplemental Reserve Amount.	\$ 1,274.92	\$ 32,754.99	\$ 34,029.91
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (14,387.00)		\$ (14,387.00)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 485,926.27		\$ 485,926.27
8b	Real Time Non Excessive Energy Congestion	\$ 974,594.85		\$ 974,594.85
8c	Real Time Non Excessive Energy Loss	\$ 240,054.58		\$ 240,054.58
9	Real Time Net Regulation Adjustment Amount	\$ 7,422.56	\$ (688.96)	\$ 6,733.60
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 254,576.47	\$ -	\$ 254,576.47
11	Real Time Spinning Reserve Cost Distribution	\$ 119,787.41	\$ -	\$ 119,787.41
12	Real Time Supplemental Reserve Cost Distribution	\$ 63,002.47	\$ -	\$ 63,002.47
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,363.89	\$ (490.97)	\$ 5,872.92
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 1,700,390.36</b>	<b>\$ 174,564.96</b>	<b>\$ 1,874,955.32</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)	(141,793)	(89,740)	(93,985)	(46,840)	(35,659)	(24,794)	
5												
6 Forecast North Dakota Sales	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	210,810	218,526	201,248
7												
8 <b>Current Month Refund Factor</b>	(0.083)	0.006	(0.033)	(0.013)	(0.083)	(0.075)	(0.053)	(0.052)	(0.025)	(0.017)	(0.011)	-
9												
10 Forecasted North Dakota Sales	215,527	196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205	210,810
11 Actual North Dakota Sales (Cal. Mo.)	222,254	189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	167,662	186,288	-
12 Deviation	(6,727)	6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	11,753	917	210,810
13												
14 Expected Refund	(13,480)	(81,774)	(160,951)	7,940	(57,511)	(21,266)	(157,164)	(141,482)	(83,589)	(89,219)	(49,824)	(41,503)
15 Actual Refund	(13,900)	(79,092)	(157,725)	7,370	(56,017)	(21,577)	(163,315)	(146,248)	(80,605)	(83,375)	(49,581)	-
16 Deviation	420	(2,682)	(3,226)	570	(1,494)	311	6,151	4,766	(2,984)	(5,844)	(243)	(41,503)
17												
18 <b>True-up Factor</b>	0.000	(0.002)	(0.002)	0.000	(0.001)	0.000	0.004	0.003	(0.002)	(0.003)	(0.000)	-
19												
20 <b>Realized Margin</b>	(0.083)	0.005	(0.035)	(0.013)	(0.083)	(0.075)	(0.050)	(0.050)	(0.027)	(0.020)	(0.011)	-
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)	(0.075)	(0.050)	(0.050)	(0.026)	(0.020)	(0.011)	-
32 C&I Non-Demand	(0.087)	0.005	(0.037)	(0.014)	(0.088)	(0.079)	(0.052)	(0.052)	(0.028)	(0.021)	(0.012)	-
33 C&I Demand Non-TOD	(0.085)	0.005	(0.036)	(0.013)	(0.085)	(0.077)	(0.051)	(0.051)	(0.027)	(0.020)	(0.012)	-
34 C&I Demand TOD On-Peak	(0.109)	0.006	(0.046)	(0.017)	(0.110)	(0.099)	(0.065)	(0.065)	(0.035)	(0.026)	(0.015)	-
35 C&I Demand TOD Off-Peak	(0.064)	0.004	(0.027)	(0.010)	(0.064)	(0.058)	(0.038)	(0.038)	(0.021)	(0.015)	(0.009)	-
36 Outdoor Lighting	(0.059)	0.003	(0.025)	(0.009)	(0.059)	(0.053)	(0.035)	(0.035)	(0.019)	(0.014)	(0.008)	-

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	188,034	168,026	179,415	187,205	210,810	218,526
7												
8 <b>Current Month Refund Factor</b>	(0.009)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	(0.008)
9												
10 Forecasted North Dakota Sales			196,388	194,554	163,606	164,425	165,070	188,515	188,034	168,026	179,415	187,205
11 Actual North Dakota Sales (Cal. Mo.)			189,946	190,655	151,863	160,154	167,487	195,892	194,367	162,030	167,662	186,288
12 Deviation			6,442	3,899	11,743	4,271	(2,417)	(7,377)	(6,333)	5,996	11,753	917
13												
14 Expected Refund			(16,831)	(16,831)	(17,384)	(17,168)	(18,078)	(17,278)	(16,567)	(16,155)	(16,272)	(17,407)
15 Actual Refund			(16,278)	(16,494)	(16,137)	(16,722)	(18,342)	(17,954)	(17,126)	(15,579)	(15,207)	(17,323)
16 Deviation			(553)	(337)	(1,247)	(447)	264	676	559	(576)	(1,066)	(84)
17												
18 <b>True-up Factor</b>	-	-	(0.000)	(0.000)	(0.001)	(0.000)	0.000	0.000	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)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	(0.008)
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)	(0.009)	(0.010)	(0.009)	(0.009)	(0.008)	(0.008)
32 C&I Non-Demand	(0.009)	(0.009)	(0.011)	(0.011)	(0.012)	(0.010)	(0.009)	(0.010)	(0.010)	(0.010)	(0.009)	(0.008)
33 C&I Demand Non-TOD	(0.009)	(0.009)	(0.011)	(0.011)	(0.011)	(0.009)	(0.009)	(0.010)	(0.009)	(0.010)	(0.009)	(0.008)
34 C&I Demand TOD On-Peak	(0.011)	(0.011)	(0.014)	(0.014)	(0.014)	(0.012)	(0.012)	(0.013)	(0.012)	(0.012)	(0.011)	(0.010)
35 C&I Demand TOD Off-Peak	(0.007)	(0.007)	(0.008)	(0.008)	(0.008)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	(0.007)	(0.006)
36 Outdoor Lighting	(0.006)	(0.006)	(0.008)	(0.007)	(0.008)	(0.006)	(0.006)	(0.007)	(0.006)	(0.007)	(0.006)	(0.005)