



—Via Electronic Filing—

December 29, 2009

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

**Re: January 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 January 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 new "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The January 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 November 2009 calendar month.

The former system average monthly fuel cost adjustment factor 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>January 2010</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02423
<b>C &amp; I Non-Demand</b>	0.02567
<b>C &amp; I Demand</b>	0.02487
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03196
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.01880
<b>Outdoor Lighting</b>	0.01725

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent System Operator (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005, Xcel Energy is authorized to recover on an interim basis, subject to refund, the MISO Day 2 costs. The March 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 Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the January FCC, the net MISO Day 2 costs for November 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this January FCC is \$15,211,491, 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 FCA. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCA.

<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. 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 2009 as recorded in Account 555. The MISO ASM cost recovery included in this January FCC is \$155,862, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## **REFUNDS**

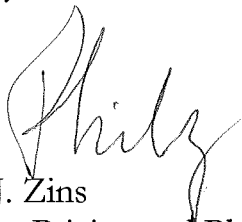
Pursuant to the above referenced Order Adopting Settlement, the November 2009 Asset Based Margin amount of \$13,480 has been included in the January Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined after the close of the calendar year and will be credited to the FCC during 2010.

## **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,



Phillip J. Zins *ch.*  
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-2010

Jan-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02462	-\$0.00022	-\$0.00006	\$0.02434
<b>Residential</b>	\$0.02451	-\$0.00022	-\$0.00006	\$0.02423
C & I Non-Demand	\$0.02597	-\$0.00023	-\$0.00007	\$0.02567
C & I Demand Non-TOD	\$0.02516	-\$0.00023	-\$0.00006	\$0.02487
C & I Demand TOD On-Peak	\$0.03234	-\$0.00029	-\$0.00008	\$0.03196
C & I Demand TOD Off-Peak	\$0.01902	-\$0.00017	-\$0.00005	\$0.01880
Outdoor Lighting	\$0.01745	-\$0.00016	-\$0.00004	\$0.01725
<b>Residential</b>				
Residential Service	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
Residential TOD	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
Residential - Underground	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
Residential TOD - Underground	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
Energy Control - (Non-Demand)	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
Limit Off Peak	\$ 0.02451	\$ (0.00022)	\$ (0.00006)	\$ 0.02423
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Limit Off Peak	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Small General Service	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Small General TOD - Metered	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Small General TOD - Unmetered	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Fire and Civil Defense Siren	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
Direct Current (Closed)	\$ 0.02597	\$ (0.00023)	\$ (0.00007)	\$ 0.02567
<b>C &amp; I Demand</b>				
General Service	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
General TOD - On Peak	\$ 0.03234	\$ (0.00029)	\$ (0.00008)	\$ 0.03196
General TOD - Off Peak	\$ 0.01902	\$ (0.00017)	\$ (0.00005)	\$ 0.01880
Peak Controlled (Closed)	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Peak Controlled TOD (Closed) - On Peak	\$ 0.03234	\$ (0.00029)	\$ (0.00008)	\$ 0.03196
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01902	\$ (0.00017)	\$ (0.00005)	\$ 0.01880
Peak Controlled Tiered	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Peak Controlled Tiered TOD - On Peak	\$ 0.03234	\$ (0.00029)	\$ (0.00008)	\$ 0.03196
Peak Controlled Tiered TOD - Off Peak	\$ 0.01902	\$ (0.00017)	\$ (0.00005)	\$ 0.01880
Energy Controlled (Closed)	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Tier 1 Energy Controlled Rider	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Real Time Pricing - Firm - On Peak	\$ 0.03234	\$ (0.00029)	\$ (0.00008)	\$ 0.03196
Real Time Pricing - Firm - Off Peak	\$ 0.01902	\$ (0.00017)	\$ (0.00005)	\$ 0.01880
Real Time Pricing - Controllable - On Peak	\$ 0.03234	\$ (0.00029)	\$ (0.00008)	\$ 0.03196
Real Time Pricing - Controllable - Off Peak	\$ 0.01902	\$ (0.00017)	\$ (0.00005)	\$ 0.01880
Small Municipal Pumping	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Municipal Pumping	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
Excess Energy - St. Anthony Falls	\$ 0.02516	\$ (0.00023)	\$ (0.00006)	\$ 0.02487
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725
Street Lighting System	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725
Street Lighting Energy	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725
Street Lighting Energy - Metered	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725
Street Lighting Energy (Closed)	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725
Street Lighting - City of St. Paul	\$ 0.01745	\$ (0.00016)	\$ (0.00004)	\$ 0.01725

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-2010

	Column (A) Aug-09	Column (B) Sep-09	Column (C) Oct-09	Column (D) Nov-09	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$37,083,990	\$37,932,723	\$33,768,296	\$32,464,309	\$141,249,318
Account 518 - Nuclear Fuel	\$8,753,879	\$6,826,856	\$6,097,905	\$5,827,515	\$27,506,154
Account 555 - Purchased Power <sup>1</sup>	\$48,107,021	\$34,174,573	\$33,897,312	\$30,349,302	\$146,528,208
Account 555 - MISO Day 2 Charges	\$11,227,373	\$12,205,549	\$16,893,303	\$15,304,176	\$55,630,400
Account 555 MISO Day 2 - Schedule 24	(\$97,286)	(\$95,853)	(\$93,342)	(\$92,685)	(\$379,166)
Account 555 MISO - ASM Charges	\$2,374,116	\$926,518	(\$1,061,115)	\$155,862	\$2,395,380
Total MISO Charges	\$13,504,203	\$13,036,213	\$15,738,845	\$15,367,352	\$57,646,614
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$107,449,093	\$91,970,365	\$89,502,358	\$84,008,478	\$372,930,294
Less Fuel Cost of InterSystem Sales	(\$14,341,684)	(\$5,238,676)	(\$7,920,494)	(\$6,075,292)	(\$33,576,146)
Net System Costs	\$93,107,409	\$86,731,689	\$81,581,864	\$77,933,186	\$339,354,148
<b>System MWh Sales</b>					
Total NSP System Retail	3,521,273	3,510,437	3,392,905	2,948,740	13,373,355
Non-Gen Muni's/Load Pattern	102,634	102,098	99,178	103,791	407,701
Total NSP System MWh Sales	3,623,907	3,612,535	3,492,083	3,052,531	13,781,056
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.569¢	2.401¢	2.336¢	2.553¢	2.462¢
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	2.451¢
(ii) C & I Non-Demand				1.0548	2.597¢
(iii) C & I Demand Non-TOD				1.0219	2.516¢
(iv) C & I Demand TOD On-Peak				1.3135	3.234¢
(v) C & I Demand TOD Off-Peak				0.7726	1.902¢
(vi) Outdoor Lighting				0.7088	1.745¢

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

North Dakota Retail MWh Sales					
(i) Residential	50,529	52,742	54,084	51,439	208,794
(ii) C & I Non-Demand	9,225	10,129	9,638	8,994	37,986
(iii) C & I Demand Non-TOD	56,576	54,590	56,461	47,302	214,929
(iv) C & I Demand TOD On-Peak	18,500	16,772	22,100	17,858	75,230
(v) C & I Demand TOD Off-Peak	28,364	27,621	32,420	26,371	114,776
(vi) Outdoor Lighting	1,173	1,372	1,546	1,749	5,840
(vii) Total	164,367	163,226	176,249	153,713	657,555

Jan-2010 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Sep-09 Balance of Unrecovered Expenses)	Total Sep-09 (\$408,119)

Prior Expenses Recovered in Nov-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9956	-0.060¢	51,439	(\$31,012)
(iii) C & I Demand Non-TOD	1.0548	-0.064¢	8,994	(\$5,745)
(iv) C & I Demand TOD On-Peak	1.0219	-0.062¢	47,302	(\$29,271)
(v) C & I Demand TOD Off-Peak	1.3135	-0.080¢	17,858	(\$14,204)
(vi) Outdoor Lighting	0.7726	-0.047¢	26,371	(\$12,338)
(vii) Total	0.7088	-0.043¢	1,749	(\$751)
			153,713	(\$93,321)

Actual Cost Should Have Been Recovered in Nov-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.553¢	0.000¢	153,713	\$3,924,293

Cost Recovered in Nov-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.426¢	51,439	\$1,248,053
(ii) C & I Non-Demand	1.0548	2.571¢	8,994	\$231,195
(iii) C & I Demand Non-TOD	1.0219	2.490¢	47,302	\$1,177,995
(iv) C & I Demand TOD On-Peak	1.3135	3.201¢	17,858	\$571,635
(v) C & I Demand TOD Off-Peak	0.7726	1.883¢	26,371	\$496,520
(vi) Outdoor Lighting	0.7088	1.727¢	1,749	\$30,211
(vii) Total			153,713	\$3,755,608

Total Balance of Unrecovered Expenses (Jan-10 Balance of Unrecovered Expenses)	
Jan-2010 Recovery Provision	(\$146,114)
4 Month ND Retail Total MWh Sales	657,555
Jan-2010 Recovery Provision per KWH	-0.022¢

<b>Jan-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	-0.022¢	-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-2010 Margin Sharing Refunds</b>			
	<b>Asset Based Margin Sharing Refund</b>		<b>Total</b>
<b>Refund/Special Charge Amount</b>	(\$13,480)		(\$13,480)
(i) Residential	-0.006¢		-0.006¢
(ii) C & I Non-Demand	-0.007¢		-0.007¢
(iii) C & I Demand Non-TOD	-0.006¢		-0.006¢
(iv) C & I Demand TOD On-Peak	-0.008¢		-0.008¢
(v) C & I Demand TOD Off-Peak	-0.005¢		-0.005¢
(vi) Outdoor Lighting	-0.004¢		-0.004¢
<b>Jan-2010 Factors</b>			
			<b>Total</b>
(i) Residential			2.423¢
(ii) C & I Non-Demand			2.567¢
(iii) C & I Demand Non-TOD			2.487¢
(iv) C & I Demand TOD On-Peak			3.196¢
(v) C & I Demand TOD Off-Peak			1.880¢
(vi) Outdoor Lighting			1.725¢

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-09	Jan-10	Differ- ence	Percent Change	FCA Application Dec-09	Jan-10	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$143.7	\$141.2	(\$2.4)	-1.7%	37.0%	37.9%	0.9%
2 Nuclear	\$30.4	\$27.5	(\$2.9)	-9.6%	7.8%	7.4%	-0.4%
3 Purchases	\$157.5	\$146.5	(\$11.0)	-7.0%	40.5%	39.3%	-1.2%
MISO related Purchases	\$57.1	\$57.6	\$0.6	1.0%	14.7%	15.5%	0.8%
4 Total System Costs	388.7	372.9	(\$15.7)	-4.1%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$38.5	\$33.6	(\$4.9)	-12.7%	9.9%	9.0%	-0.9%
6 Net System Costs	\$350.2	\$339.4	(\$10.9)	-3.1%	90.1%	91.0%	0.9%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	6,280	6,074	(206)	-3.3%	29.0%	29.1%	0.1%
10 Nuclear	4,133	3,808	(325)	-7.9%	19.1%	18.2%	-0.9%
11 Purchases	5,877	5,479	(398)	-6.8%	27.1%	26.2%	-0.9%
12 Hydro & Other	643	738	95	14.8%	3.0%	3.5%	0.5%
13 Net Interchange	4,758	4,779	21	0.4%	21.9%	22.9%	1.0%
14 Total Output	21,691	20,878	(813)	-3.7%	100.0%	100.0%	0.0%
15 Intersystem Sales	2,372	1,962	(410)	-17.3%	10.9%	9.4%	-1.5%
16 Native Requirement	19,319	18,916	(403)	-2.1%	89.1%	90.6%	1.5%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	2.288	2.325	0.038	1.6%			
20 Nuclear	0.736	0.722	-0.014	-1.9%			
21 Purchases	2.680	2.674	-0.006	-0.2%			
22 Total System Costs	1.792	1.786	-0.006	-0.3%			
23 Intersystem Sales	1.621	1.712	0.091	5.6%			
24 Net System Costs	1.813	1.794	-0.019	-1.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,550	13,781	(769)	-5.3%			
28							
29 COST per KWH SALES (\$)	2.407	2.462	0.055	2.3%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.117	-0.022	0.095				
(i) Residential	-0.117	-0.022	0.094				
(ii) C & I Non-Demand	-0.124	-0.023	0.100				
(iii) C & I Demand Non-TOD	-0.120	-0.023	0.097				
(iv) C & I Demand TOD On-Peak	-0.154	-0.029	0.125				
(v) C & I Demand TOD Off-Peak	-0.090	-0.017	0.073				
(vi) Outdoor Lighting	-0.083	-0.016	0.067				
32 REFUND	-0.016	-0.006	0.010				
(i) Residential	-0.016	-0.006					
(ii) C & I Non-Demand	-0.017	-0.007					
(iii) C & I Demand Non-TOD	-0.016	-0.006					
(iv) C & I Demand TOD On-Peak	-0.021	-0.008					
(v) C & I Demand TOD Off-Peak	-0.012	-0.005					
(vi) Outdoor Lighting	-0.011	-0.004					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.274	2.434	0.160	7.0%			
(i) Residential	2.264	2.423	0.159				
(ii) C & I Non-Demand	2.399	2.567					
(iii) C & I Demand Non-TOD	2.324	2.487					
(iv) C & I Demand TOD On-Peak	2.987	3.196					
(v) C & I Demand TOD Off-Peak	1.757	1.880					
(vi) Outdoor Lighting	1.612	1.725					

**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	\$0.16
250	\$0.40
500	\$0.79
750	\$1.19
1,000	\$1.59

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-09	Jan-10
<b>** GWH OUTPUT **</b>		
Thermal	506,614	574,336
Wind plus disper gen	(81)	(75)
Hydro	136,707	163,946
Hydro and Other	643,240	738,207
Rounded to nearest thousand:	643	738
<b>Sales</b>		
Non Gen Munic Total	405,884,000	407,701,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	2,371,982,000	1,961,608,000
Rounded to nearest million:	2371.982	1961.608

Northern States Power Company, A Minnesota Corporation  
**MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES**

Attachment 2

Page 1

		System	Intersystem	Retail
<b>November 2009 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 16,900,196.86	\$ 1,189,695.57	\$ 18,089,892.43
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,867,547.20	\$ -	\$ 1,867,547.20
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 4,102.65	\$ -	\$ 4,102.65
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (7,791,586.58)	\$ -	\$ (7,791,586.58)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 853,931.54	\$ -	\$ 853,931.54
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)	\$ 1,636,547.18	\$ 702,387.43	\$ 2,338,934.61
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (52,869.49)	\$ -	\$ (52,869.49)
14	Real-Time Distribution of Losses Amount	\$ (1,191,461.86)	\$ -	\$ (1,191,461.86)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 49,229.53	\$ -	\$ 49,229.53
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 16,060.26	\$ -	\$ 16,060.26
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (1,350.01)	\$ -	\$ (1,350.01)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 795,191.26	\$ -	\$ 795,191.26
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (480.05)	\$ -	\$ (480.05)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 103,862.06	\$ -	\$ 103,862.06
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)	\$ (100,098.23)	\$ -	\$ (100,098.23)
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)	\$ 11,223.33	\$ -	\$ 11,223.33
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (849,343.15)	\$ -	\$ (849,343.15)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (26,079.96)	\$ -	\$ (26,079.96)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (148,021.99)	\$ -	\$ (148,021.99)
37	Financial Transmission Guarantee Uplift Amount	\$ 152,352.70	\$ -	\$ 152,352.70
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 703,726.05	\$ -	\$ 703,726.05
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 117,561.57	\$ -	\$ 117,561.57
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (118,377.22)	\$ 11,042.38	\$ (107,334.84)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 238,448.35	\$ -	\$ 238,448.35
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (58,799.85)	\$ 2,339.92	\$ (56,459.93)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (178,291.03)	\$ 9,727.47	\$ (168,563.56)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 619,541.55	\$ (5,583.52)	\$ 613,958.03
19	Real-Time Market Administration Amount	\$ 52,582.47	\$ (5,524.33)	\$ 47,058.14
29	Financial Transmission Rights Market Administration Amount	\$ 71,826.40	\$ -	\$ 71,826.40
33	Day-Ahead Schedule 24 Allocation Amount	\$ 86,895.04	\$ (806.27)	\$ 86,088.77
34	Real-Time Schedule 24 Allocation Amount	\$ 7,376.35	\$ (779.67)	\$ 6,596.68
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	\$ 3,469.22	\$ -	\$ 3,469.22
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,133,951.39	\$ -	\$ 1,133,951.39
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,056,931.67)	\$ -	\$ (1,056,931.67)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (450,254.81)	\$ -	\$ (450,254.81)
<b>TOTAL MISO CHARGES</b>		<b>\$ 13,401,677.06</b>	<b>\$ 1,902,498.98</b>	<b>\$ 15,304,176.04</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 92,685.45</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 15,211,490.59</b>

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

		System	Intersystem	Retail
<b>November 2009 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (361,312.51)	\$ -	\$ (361,312.51)
2	Day-Ahead Spinning Reserve Amount	\$ (41,809.82)	\$ -	\$ (41,809.82)
3	Day-Ahead Supplemental Reserve	\$ (24,202.35)	\$ -	\$ (24,202.35)
4	Real-Time Regulation Amount	\$ 120,340.19	\$ 95,987.21	\$ 216,327.40
5	Real-Time Spinning Reserve Amount	\$ (19,599.67)	\$ 14,244.36	\$ (5,355.31)
6	Real-Time Supplemental Reserve Amount.	\$ 219.96	\$ 9,247.59	\$ 9,467.55
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (22,387.00)	\$ -	\$ (22,387.00)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 154,443.17	\$ -	\$ 154,443.17
8b	Real Time Non Excessive Energy Congestion	\$ (176,298.81)	\$ -	\$ (176,298.81)
8c	Real Time Non Excessive Energy Loss	\$ (56,392.05)	\$ -	\$ (56,392.05)
9	Real Time Net Regulation Adjustment Amount	\$ 456.80	\$ (105.64)	\$ 351.16
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 247,079.33	\$ -	\$ 247,079.33
11	Real Time Spinning Reserve Cost Distribution	\$ 181,169.08	\$ -	\$ 181,169.08
12	Real Time Supplemental Reserve Cost Distribution	\$ 12,263.62	\$ -	\$ 12,263.62
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 20,509.18	\$ (2,796.71)	\$ 17,712.47
14	Real Time Contignecy Reserve Deployment Failure	\$ 4,805.73	\$ -	\$ 4,805.73
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 39,284.85</b>	<b>\$ 116,576.81</b>	<b>\$ 155,861.66</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

	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10
1 Forecast Month												
2 True-up Month												
3												
4 Monthly Refund	(173,372)	(82,316)	(64,153)	(156)	(45,284)	7,115	(47,027)	(24,155)	(18,585)	(33,710)	(13,126)	
5 Forecast North Dakota Sales	191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550	181,835	204,705	215,527	196,388
6												
7												
8 <b>Current Month Refund Factor</b>	<b>(0.090)</b>	<b>(0.047)</b>	<b>(0.038)</b>	<b>(0.000)</b>	<b>(0.025)</b>	<b>0.004</b>	<b>(0.026)</b>	<b>(0.014)</b>	<b>(0.010)</b>	<b>(0.016)</b>	<b>(0.006)</b>	-
9												
10 Forecasted North Dakota Sales			191,827	174,423	167,216	169,094	182,677	182,651	177,780	169,550	181,835	204,705
11 Actual North Dakota Sales (Cal. Mo.)			268,578	165,328	160,677	156,178	176,480	172,835	160,737	176,921	179,066	-
12 Deviation			(76,751)	9,095	6,539	12,916	6,197	9,816	17,043	(7,371)	2,769	204,705
13												
14 Expected Refund			(173,372)	(82,316)	5,213	(4,449)	(45,081)	6,775	(48,556)	(23,790)	(23,241)	(32,675)
15 Actual Refund			(242,738)	(78,023)	5,010	(4,109)	(43,552)	6,410	(43,900)	(24,826)	(22,886)	-
16 Deviation			69,366	(4,293)	203	(340)	(1,529)	365	(4,656)	1,035	(354)	(32,675)
17												
18 <b>True-up Factor</b>	-	-	0.041	(0.003)	0.000	(0.000)	(0.001)	0.000	(0.003)	0.001	(0.000)	-
19												
20 <b>Realized Margin</b>	<b>(0.090)</b>	<b>(0.047)</b>	<b>0.003</b>	<b>(0.003)</b>	<b>(0.025)</b>	<b>0.004</b>	<b>(0.027)</b>	<b>(0.014)</b>	<b>(0.013)</b>	<b>(0.016)</b>	<b>(0.006)</b>	-
21												
22 <b>Class Ratios</b>												
23 Residential	0.9989	0.9978	0.9967	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
24 C&I Non-Demand	1.0137	1.0274	1.0411	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
25 C&I Demand Non-TOD	1.0055	1.0110	1.0164	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	1.0784	1.1568	1.2351	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	0.9432	0.8863	0.8295	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
28 Outdoor Lighting	0.9272	0.8544	0.7816	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	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	(0.013)	(0.016)	(0.006)	-
32 C&I Non-Demand	(0.092)	(0.048)	0.003	(0.003)	(0.026)	0.004	(0.029)	(0.015)	(0.013)	(0.017)	(0.007)	-
33 C&I Demand Non-TOD	(0.091)	(0.048)	0.003	(0.003)	(0.025)	0.004	(0.028)	(0.014)	(0.013)	(0.016)	(0.006)	-
34 C&I Demand TOD On-Peak	(0.097)	(0.055)	0.004	(0.003)	(0.032)	0.005	(0.036)	(0.018)	(0.017)	(0.021)	(0.008)	-
35 C&I Demand TOD Off-Peak	(0.085)	(0.042)	0.003	(0.002)	(0.019)	0.003	(0.021)	(0.011)	(0.010)	(0.012)	(0.005)	-
36 Outdoor Lighting	(0.084)	(0.040)	0.002	(0.002)	(0.017)	0.003	(0.019)	(0.010)	(0.009)	(0.011)	(0.004)	-