



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

January 29, 2010

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

Re: February 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 February 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 February 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 December 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:

February 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02360
C & I Non-Demand	0.02500
C & I Demand	0.02422
C & I Demand Time of Day On-Peak	0.03113
C & I Demand Time of Day Off-Peak	0.01831
Outdoor Lighting	0.01680

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 types¹, 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 February FCC, the net MISO Day 2 costs for December 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this February FCC is \$18,894,912, 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.

MISO ASM Charges

¹ Previously embedded in other FTR charge types.

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 February FCC, the net MISO ASM costs for December 2009 as recorded in Account 555. The MISO ASM cost recovery included in this February FCC is \$364,562 which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

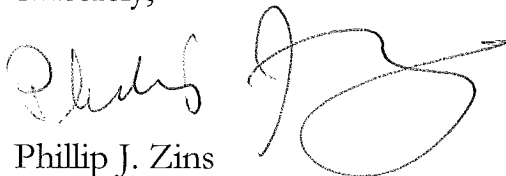
Pursuant to the above referenced Order Adopting Settlement, the December 2009 Asset Based Margin amount of \$81,774 has been included in the February Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2010, the 2009 retail share of the Non-Asset Based 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 February FCC is \$16,831 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 February 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
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 Feb-2010

Feb-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02460	-\$0.00040	-\$0.00042	\$0.02379
Residential	\$0.02449	-\$0.00040	-\$0.00050	\$0.02360
C & I Non-Demand	\$0.02595	-\$0.00042	-\$0.00053	\$0.02500
C & I Demand Non-TOD	\$0.02514	-\$0.00041	-\$0.00051	\$0.02422
C & I Demand TOD On-Peak	\$0.03231	-\$0.00052	-\$0.00066	\$0.03113
C & I Demand TOD Off-Peak	\$0.01901	-\$0.00031	-\$0.00039	\$0.01831
Outdoor Lighting	\$0.01744	-\$0.00028	-\$0.00036	\$0.01680
Residential				
Residential Service	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
Residential TOD	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
Residential - Underground	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
Residential TOD - Underground	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
Energy Control - (Non-Demand)	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
Limit Off Peak	\$ 0.02449	\$ (0.00040)	\$ (0.00050)	\$ 0.02360
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Limit Off Peak	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Small General Service	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Small General TOD - Metered	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Small General TOD - Unmetered	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Fire and Civil Defense Siren	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
Direct Current (Closed)	\$ 0.02595	\$ (0.00042)	\$ (0.00053)	\$ 0.02500
C & I Demand				
General Service	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
General TOD - On Peak	\$ 0.03231	\$ (0.00052)	\$ (0.00066)	\$ 0.03113
General TOD - Off Peak	\$ 0.01901	\$ (0.00031)	\$ (0.00039)	\$ 0.01831
Peak Controlled (Closed)	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Peak Controlled TOD (Closed) - On Peak	\$ 0.03231	\$ (0.00052)	\$ (0.00066)	\$ 0.03113
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01901	\$ (0.00031)	\$ (0.00039)	\$ 0.01831
Peak Controlled Tiered	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Peak Controlled Tiered TOD - On Peak	\$ 0.03231	\$ (0.00052)	\$ (0.00066)	\$ 0.03113
Peak Controlled Tiered TOD - Off Peak	\$ 0.01901	\$ (0.00031)	\$ (0.00039)	\$ 0.01831
Energy Controlled (Closed)	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Tier 1 Energy Controlled Rider	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Real Time Pricing - Firm - On Peak	\$ 0.03231	\$ (0.00052)	\$ (0.00066)	\$ 0.03113
Real Time Pricing - Firm - Off Peak	\$ 0.01901	\$ (0.00031)	\$ (0.00039)	\$ 0.01831
Real Time Pricing - Controllable - On Peak	\$ 0.03231	\$ (0.00052)	\$ (0.00066)	\$ 0.03113
Real Time Pricing - Controllable - Off Peak	\$ 0.01901	\$ (0.00031)	\$ (0.00039)	\$ 0.01831
Small Municipal Pumping	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Municipal Pumping	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Excess Energy - St. Anthony Falls	\$ 0.02514	\$ (0.00041)	\$ (0.00051)	\$ 0.02422
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680
Street Lighting System	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680
Street Lighting Energy	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680
Street Lighting Energy - Metered	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680
Street Lighting Energy (Closed)	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680
Street Lighting - City of St. Paul	\$ 0.01744	\$ (0.00028)	\$ (0.00036)	\$ 0.01680

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 Feb-2010

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Sep-09	Oct-09	Nov-09	Dec-09	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$37,932,723	\$33,768,296	\$32,464,309	\$38,057,196	\$142,222,524
Account 518 - Nuclear Fuel	\$6,826,856	\$6,097,905	\$5,827,515	\$10,825,157	\$29,577,432
Account 555 - Purchased Power ¹	\$34,174,573	\$33,897,312	\$30,349,302	\$37,855,140	\$136,276,327
Account 555 - MISO Day 2 Charges	\$12,205,549	\$16,893,303	\$15,304,176	\$18,990,451	\$63,393,478
Account 555 MISO Day 2 - Schedule 24	(\$95,853)	(\$93,342)	(\$92,685)	(\$95,539)	(\$377,419)
Account 555 MISO - ASM Charges	\$926,518	(\$1,061,115)	\$155,862	\$364,562	\$385,826
Total MISO Charges	\$13,036,213	\$15,738,845	\$15,367,352	\$19,259,474	\$63,401,885
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$91,970,365	\$89,502,358	\$84,008,478	\$105,996,967	\$371,478,168
Less Fuel Cost of InterSystem Sales	(\$5,238,676)	(\$7,920,494)	(\$6,075,292)	(\$13,102,962)	(\$32,337,424)
Net System Costs	\$86,731,689	\$81,581,864	\$77,933,186	\$92,894,005	\$339,140,744
System MWh Sales					
Total NSP System Retail	3,510,437	3,392,905	2,948,740	3,532,758	13,384,840
Non-Gen Muni's/Load Pattern	102,098	99,178	103,791	97,380	402,447
Total NSP System MWh Sales	3,612,535	3,492,083	3,052,531	3,630,138	13,787,287
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.401¢	2.336¢	2.553¢	2.559¢	2.460¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
Class Ratio/TOD Ratio					
(i) Residential	0.9956	0.9956	0.9956	0.9956	0.9956
(ii) C & I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548
(iii) C & I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219
(iv) C & I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135
(v) C & I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726
(vi) Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9956	2.449¢
(ii) C & I Non-Demand				1.0548	2.595¢
(iii) C & I Demand Non-TOD				1.0219	2.514¢
(iv) C & I Demand TOD On-Peak				1.3135	3.231¢
(v) C & I Demand TOD Off-Peak				0.7726	1.901¢
(vi) Outdoor Lighting				0.7088	1.744¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	52,742	54,084	51,439	78,441	236,706
(ii) C & I Non-Demand	10,129	9,638	8,994	12,512	41,273
(iii) C & I Demand Non-TOD	54,590	56,461	47,302	62,568	220,921
(iv) C & I Demand TOD On-Peak	16,772	22,100	17,858	16,314	73,044
(v) C & I Demand TOD Off-Peak	27,621	32,420	26,371	26,194	112,606
(vi) Outdoor Lighting	1,372	1,546	1,749	1,698	6,365
(vii) Total	163,226	176,249	153,713	197,727	690,915

Feb-2010 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Oct-09 Balance of Unrecovered Expenses)	Total
	Oct-09
	(\$798,507)

Prior Expenses Recovered in Dec-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	-0.117¢	78,441	(\$91,450)
(iii) C & I Demand Non-TOD	1.0548	-0.124¢	12,512	(\$15,454)
(iv) C & I Demand TOD On-Peak	1.0219	-0.120¢	62,568	(\$74,871)
(v) C & I Demand TOD Off-Peak	1.3135	-0.154¢	16,314	(\$25,093)
(vi) Outdoor Lighting	0.7726	-0.090¢	26,194	(\$23,698)
(vii) Total	0.7088	-0.083¢	1,698	(\$1,409)
			197,727	(\$231,975)

Actual Cost Should Have Been Recovered in Dec-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.559¢	0.000¢	197,727	\$5,059,834

Cost Recovered in Dec-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.396¢	78,441	\$1,879,767
(ii) C & I Non-Demand	1.0548	2.539¢	12,512	\$317,668
(iii) C & I Demand Non-TOD	1.0219	2.460¢	62,568	\$1,538,993
(iv) C & I Demand TOD On-Peak	1.3135	3.162¢	16,314	\$515,783
(v) C & I Demand TOD Off-Peak	0.7726	1.860¢	26,194	\$487,116
(vi) Outdoor Lighting	0.7088	1.706¢	1,698	\$28,969
(vii) Total			197,727	\$4,768,296

Total Balance of Unrecovered Expenses (Feb-10 Balance of Unrecovered Expenses)	
Feb-2010 Recovery Provision	(\$274,994)
4 Month ND Retail Total MWh Sales	690,915
Feb-2010 Recovery Provision per KWH	-0.040¢

Feb-2010 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.040¢	-0.040¢
(ii) C & I Non-Demand	1.0548	-0.040¢	-0.042¢
(iii) C & I Demand Non-TOD	1.0219	-0.040¢	-0.041¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.040¢	-0.052¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.040¢	-0.031¢
(vi) Outdoor Lighting	0.7088	-0.040¢	-0.028¢
Feb-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$81,774)	(\$16,831)	(\$98,605)
(i) Residential	-0.041¢	-0.009¢	-0.050¢
(ii) C & I Non-Demand	-0.044¢	-0.009¢	-0.053¢
(iii) C & I Demand Non-TOD	-0.043¢	-0.009¢	-0.051¢
(iv) C & I Demand TOD On-Peak	-0.055¢	-0.011¢	-0.066¢
(v) C & I Demand TOD Off-Peak	-0.032¢	-0.007¢	-0.039¢
(vi) Outdoor Lighting	-0.030¢	-0.006¢	-0.036¢
Feb-2010 Factors			
	Total		
(i) Residential	2.360¢		
(ii) C & I Non-Demand	2.500¢		
(iii) C & I Demand Non-TOD	2.422¢		
(iv) C & I Demand TOD On-Peak	3.113¢		
(v) C & I Demand TOD Off-Peak	1.831¢		
(vi) Outdoor Lighting	1.680¢		

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>		
	Jan-10	Feb-10	Differ- ence	Percent Change	FCA Application Jan-10	Feb-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$141.2	\$142.2	\$1.0	0.7%	37.9%	38.3%	0.4%
2 Nuclear	\$27.5	\$29.6	\$2.1	7.5%	7.4%	8.0%	0.6%
3 Purchases	\$146.5	\$136.3	(\$10.3)	-7.0%	39.3%	36.7%	-2.6%
MISO related Purchases	\$57.6	\$63.4	\$5.8	10.0%	15.5%	17.1%	1.6%
4 Total System Costs	372.9	371.5	(\$1.5)	-0.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$33.6	\$32.3	(\$1.2)	-3.7%	9.0%	8.7%	-0.3%
6 Net System Costs	\$339.4	\$339.1	(\$0.2)	-0.1%	91.0%	91.3%	0.3%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,074	6,178	104	1.7%	29.1%	29.3%	0.2%
10 Nuclear	3,808	3,850	42	1.1%	18.2%	18.3%	0.1%
11 Purchases	5,479	4,880	(599)	-10.9%	26.2%	23.2%	-3.0%
12 Hydro & Other	738	778	40	5.4%	3.5%	3.7%	0.2%
13 Net Interchange	4,779	5,372	593	12.4%	22.9%	25.5%	2.6%
14 Total Output	20,878	21,058	180	0.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,962	1,561	(400)	-20.4%	9.4%	7.4%	-2.0%
16 Native Requirement	18,916	19,497	580	3.1%	90.6%	92.6%	2.0%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.325	2.302	-0.023	-1.0%			
20 Nuclear	0.722	0.768	0.046	6.4%			
21 Purchases	2.674	2.793	0.118	4.4%			
22 Total System Costs	1.786	1.764	-0.022	-1.2%			
23 Intersystem Sales	1.712	2.071	0.359	21.0%			
24 Net System Costs	1.794	1.739	-0.054	-3.0%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,781	13,787	6	0.0%			
28							
29 COST per KWH SALES (\$)	2.462	2.460	-0.002	-0.1%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.022	-0.040	-0.018				
(i) Residential	-0.022	-0.040	-0.018				
(ii) C & I Non-Demand	-0.023	-0.042	-0.019				
(iii) C & I Demand Non-TOD	-0.023	-0.041	-0.018				
(iv) C & I Demand TOD On-Peak	-0.029	-0.052	-0.023				
(v) C & I Demand TOD Off-Peak	-0.017	-0.031	-0.014				
(vi) Outdoor Lighting	-0.016	-0.028	-0.012				
32 REFUND	-0.006	-0.051	-0.045				
(i) Residential	-0.006	-0.050	-0.044				
(ii) C & I Non-Demand	-0.006	-0.053	-0.047				
(iii) C & I Demand Non-TOD	-0.006	-0.051	-0.045				
(iv) C & I Demand TOD On-Peak	-0.008	-0.066	-0.058				
(v) C & I Demand TOD Off-Peak	-0.005	-0.039	-0.034				
(vi) Outdoor Lighting	-0.004	-0.036	-0.032				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.434	2.369	-0.065	-2.7%			
(i) Residential	2.423	2.360	-0.063				
(ii) C & I Non-Demand	2.567	2.500	-0.067				
(iii) C & I Demand Non-TOD	2.487	2.422	-0.065				
(iv) C & I Demand TOD On-Peak	3.196	3.113	-0.083				
(v) C & I Demand TOD Off-Peak	1.880	1.831	-0.049				
(vi) Outdoor Lighting	1.725	1.680	-0.045				

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	(\$0.06)
250	(\$0.16)
500	(\$0.32)
750	(\$0.48)
1,000	(\$0.63)

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>	
	Jan-10	Feb-10
** GWH OUTPUT **		
Thermal	574,336	613,159
Wind plus disper gen	(75)	(88)
Hydro	163,946	165,088
Hydro and Other	738,207	778,159
Rounded to nearest thousand:	738	778
Sales		
Non Gen Munic Total	407,701,000	402,447,000
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,961,608,000	1,561,449,000
Rounded to nearest million:	1961.608	1561.449

		System	Intersystem	Retail
December 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 18,088,520.38	\$ 4,783,283.35	\$ 22,871,803.73
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,091,085.24	\$ -	\$ 4,091,085.24
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 10,614.68	\$ -	\$ 10,614.68
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,547,717.06)	\$ -	\$ (11,547,717.06)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 837,134.97	\$ -	\$ 837,134.97
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)	\$ 1,729,614.00	\$ 900,465.91	\$ 2,630,079.91
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 21,332.89	\$ -	\$ 21,332.89
14	Real-Time Distribution of Losses Amount	\$ (1,940,223.26)	\$ -	\$ (1,940,223.26)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 21,623.75	\$ -	\$ 21,623.75
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 111,034.72	\$ -	\$ 111,034.72
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (170.53)	\$ -	\$ (170.53)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 833,946.32	\$ -	\$ 833,946.32
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 32.58	\$ -	\$ 32.58
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 101,843.49	\$ -	\$ 101,843.49
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)	\$ 30,724.70	\$ -	\$ 30,724.70
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)	\$ 9,788.83	\$ -	\$ 9,788.83
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (643,327.34)	\$ -	\$ (643,327.34)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (43,348.57)	\$ -	\$ (43,348.57)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ (86,898.96)	\$ -	\$ (86,898.96)
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (253,752.09)	\$ -	\$ (253,752.09)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 253,389.83	\$ -	\$ 253,389.83
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 767,401.79	\$ -	\$ 767,401.79
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 187,292.47	\$ -	\$ 187,292.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (108,474.46)	\$ 24,718.06	\$ (83,756.40)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 359,003.17	\$ -	\$ 359,003.17
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (316,966.86)	\$ 10,496.48	\$ (306,470.38)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (66,372.00)	\$ 1,110.69	\$ (65,261.31)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 775,366.02	\$ (15,616.33)	\$ 759,749.69
19	Real-Time Market Administration Amount	\$ 52,936.54	\$ (3,772.43)	\$ 49,164.11
29	Financial Transmission Rights Market Administration Amount	\$ 112,308.00	\$ -	\$ 112,308.00
33	Day-Ahead Schedule 24 Allocation Amount	\$ 91,590.33	\$ (1,842.50)	\$ 89,747.83
34	Real-Time Schedule 24 Allocation Amount	\$ 6,233.17	\$ (442.18)	\$ 5,790.99
35	Schedule 24 Admin Allocation	\$ -	\$ -	\$ -
Virtual Energy Charges				
12	Day-Ahead Virtual Energy Amount	\$ -	\$ -	\$ -
27	Real-Time Virtual Energy Amount	\$ -	\$ -	\$ -
Other MISO Charges				
20	Real-Time Miscellaneous Amount	\$ 26,279.15	\$ -	\$ 26,279.15
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 180,839.99	\$ -	\$ 180,839.99
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (201,409.27)	\$ -	\$ (201,409.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (199,226.78)	\$ -	\$ (199,226.78)
TOTAL MISO CHARGES		\$ 13,292,049.83	\$ 5,698,401.05	\$ 18,990,450.88

SCHEDULE 24 (FOR RETAIL) **\$ 95,538.82**

TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL) **\$ 18,894,912.06**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
December 2009 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (348,041.88)	\$ -	\$ (348,041.88)
2	Day-Ahead Spinning Reserve Amount	\$ (31,736.64)	\$ -	\$ (31,736.64)
3	Day-Ahead Supplemental Reserve	\$ (24,071.70)	\$ -	\$ (24,071.70)
4	Real-Time Regulation Amount	\$ 133,606.04	\$ 70,206.60	\$ 203,812.64
5	Real-Time Spinning Reserve Amount	\$ (25,690.07)	\$ 23,972.35	\$ (1,717.72)
6	Real-Time Supplemental Reserve Amount.	\$ 1,093.21	\$ 9,503.14	\$ 10,596.35
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (55,265.94)		\$ (55,265.94)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ (43,893.00)		\$ (43,893.00)
8b	Real Time Non Excessive Energy Congestion	\$ 109,543.44		\$ 109,543.44
8c	Real Time Non Excessive Energy Loss	\$ 49,462.69		\$ 49,462.69
9	Real Time Net Regulation Adjustment Amount	\$ 22,964.62	\$ (7,845.44)	\$ 15,119.18
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 292,126.50	\$ -	\$ 292,126.50
11	Real Time Spinning Reserve Cost Distribution	\$ 162,325.54	\$ -	\$ 162,325.54
12	Real Time Supplemental Reserve Cost Distribution	\$ 15,090.11	\$ -	\$ 15,090.11
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 19,831.09	\$ (8,618.84)	\$ 11,212.25
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 277,344.01	\$ 87,217.81	\$ 364,561.82

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-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10
2 True-up Month			Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
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)	(82,620)
5												
6 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
7												
8 Current Month Refund Factor	(0.090)	(0.047)	(0.038)	(0.000)	(0.025)	0.004	(0.026)	(0.014)	(0.010)	(0.016)	(0.006)	(0.042)
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	210,003
12 Deviation			(76,751)	9,095	6,539	12,916	6,197	9,816	17,043	(7,371)	2,769	(5,298)
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)	(33,521)
16 Deviation			69,366	(4,293)	203	(340)	(1,529)	365	(4,656)	1,035	(354)	846
17												
18 True-up Factor	-	-	0.041	(0.003)	0.000	(0.000)	(0.001)	0.000	(0.003)	0.001	(0.000)	0.000
19												
20 Realized Margin	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	(0.013)	(0.016)	(0.006)	(0.042)
21												
22 Class Ratios												
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 Realized Margin Adj for Class Ratios												
31 Residential	(0.090)	(0.047)	0.003	(0.003)	(0.025)	0.004	(0.027)	(0.014)	(0.013)	(0.016)	(0.006)	(0.041)
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)	(0.044)
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)	(0.043)
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)	(0.055)
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)	(0.032)
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)	(0.030)

