



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

November 31, 2011

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

**Re: December 2011 Fuel Cost Charge**

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (“FCC”) for December 2011.

Pursuant to the Commission authorization of the final compliance tariffs in the Company’s 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a “multi-class” fuel cost mechanism replaced the previous single-factor mechanism. The December 2011 system FCC is based on the average of the most recent four-month actual fuel cost plus a “true-up” factor, reflecting cost recovery deviations during the October 2011 calendar month.

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

<b>December 2011</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02638
<b>C &amp; I Non-Demand</b>	0.02795
<b>C &amp; I Demand</b>	0.02708
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03480
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02047
<b>Outdoor Lighting</b>	0.01878

## **MISO CHARGES IMPLEMENTATION**

### MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent Transmission System Operator, Inc. (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005 and the Order in Docket No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (“ARR”) and 3 new Financial Transmission Rights (“FTR”) charge types<sup>1</sup>, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the December 2011 FCC, the net MISO Day 2 costs for October 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this December FCC is \$16,655,444, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

### MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (“ASM”) on January 6, 2009, the net costs or revenues of 14 new ASM charge types are included in the Fuel Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent

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<sup>1</sup> Previously embedded in other FTR charge types.

with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the December FCC, the net MISO ASM costs for October 2011 as recorded in Account 555. The MISO ASM cost recovery included in this December FCC is \$2,516,975, 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 October 2011 Asset Based Margin amount of -\$29,566 has been included in the November Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 retail share of the Non-Asset Based Margins will be credited to the monthly FCC over the following 12-month period only if the calendar year balance is positive. The realized North Dakota retail share of 2010 Non-Asset Based Margin credit is \$56,225 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the November FCC is \$-1,271, or -0.001¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attached is the calculation of the December 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  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Dec-2011

Dec-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02688	-\$0.00023	-\$0.00015	\$0.02650
<b>Residential</b>	\$0.02676	-\$0.00023	-\$0.00015	\$0.02638
<b>C &amp; I Non-Demand</b>	\$0.02835	-\$0.00024	-\$0.00016	\$0.02795
<b>C &amp; I Demand Non-TOD</b>	\$0.02747	-\$0.00024	-\$0.00016	\$0.02708
<b>C &amp; I Demand TOD On-Peak</b>	\$0.03531	-\$0.00030	-\$0.00020	\$0.03480
<b>C &amp; I Demand TOD Off-Peak</b>	\$0.02077	-\$0.00018	-\$0.00012	\$0.02047
<b>Outdoor Lighting</b>	\$0.01905	-\$0.00016	-\$0.00011	\$0.01878
<b>Residential</b>				
Residential Service	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
Residential TOD	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
Residential - Underground	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
Residential TOD - Underground	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
Energy Control - (Non-Demand)	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
Limit Off Peak	\$ 0.02676	\$ (0.00023)	\$ (0.00015)	\$ 0.02638
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Limit Off Peak	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Small General Service	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Small General TOD - Metered	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Small General TOD - Unmetered	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Fire and Civil Defense Siren	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
Direct Current (Closed)	\$ 0.02835	\$ (0.00024)	\$ (0.00016)	\$ 0.02795
<b>C &amp; I Demand</b>				
General Service	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
General TOD - On Peak	\$ 0.03531	\$ (0.00030)	\$ (0.00020)	\$ 0.03480
General TOD - Off Peak	\$ 0.02077	\$ (0.00018)	\$ (0.00012)	\$ 0.02047
Peak Controlled (Closed)	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Peak Controlled TOD (Closed) - On Peak	\$ 0.03531	\$ (0.00030)	\$ (0.00020)	\$ 0.03480
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02077	\$ (0.00018)	\$ (0.00012)	\$ 0.02047
Peak Controlled Tiered	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Peak Controlled Tiered TOD - On Peak	\$ 0.03531	\$ (0.00030)	\$ (0.00020)	\$ 0.03480
Peak Controlled Tiered TOD - Off Peak	\$ 0.02077	\$ (0.00018)	\$ (0.00012)	\$ 0.02047
Energy Controlled (Closed)	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Tier 1 Energy Controlled Rider	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Real Time Pricing - Firm - On Peak	\$ 0.03531	\$ (0.00030)	\$ (0.00020)	\$ 0.03480
Real Time Pricing - Firm - Off Peak	\$ 0.02077	\$ (0.00018)	\$ (0.00012)	\$ 0.02047
Real Time Pricing - Controllable - On Peak	\$ 0.03531	\$ (0.00030)	\$ (0.00020)	\$ 0.03480
Real Time Pricing - Controllable - Off Peak	\$ 0.02077	\$ (0.00018)	\$ (0.00012)	\$ 0.02047
Small Municipal Pumping	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Municipal Pumping	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
Excess Energy - St. Anthony Falls	\$ 0.02747	\$ (0.00024)	\$ (0.00016)	\$ 0.02708
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878
Street Lighting System	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878
Street Lighting Energy	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878
Street Lighting Energy - Metered	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878
Street Lighting Energy (Closed)	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878
Street Lighting - City of St. Paul	\$ 0.01905	\$ (0.00016)	\$ (0.00011)	\$ 0.01878

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Current Period Cost of Energy for Dec-2011

	Column (A) Jul-11	Column (B) Aug-11	Column (C) Sep-11	Column (D) Oct-11	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$59,929,940	\$49,469,418	\$32,381,294	\$31,618,275	\$173,398,927
Account 518 - Nuclear Fuel	\$11,208,057	\$11,630,399	\$11,598,307	\$8,393,084	\$42,829,847
Account 555 - Purchased Power <sup>1</sup>	\$44,383,414	\$41,249,223	\$36,633,495	\$41,852,828	\$164,118,961
Account 555 - MISO Day 2 Charges	\$22,767,976	\$21,897,056	\$14,825,965	\$16,752,659	\$76,243,657
Account 555 MISO Day 2 - Schedule 24	(\$109,686)	(\$101,787)	(\$92,356)	(\$97,215)	(\$401,043)
Account 555 MISO - ASM Charges	\$2,519,375	(\$2,154,021)	\$769,417	\$2,516,975	\$3,651,746
Total MISO Charges	\$25,177,665	\$19,641,248	\$15,503,027	\$19,172,420	\$79,494,360
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$140,699,077	\$121,990,288	\$96,116,123	\$101,036,607	\$459,842,095
Less Fuel Cost of InterSystem Sales	(\$13,090,852)	(\$13,873,929)	(\$10,853,061)	(\$10,740,247)	(\$48,558,090)
Net System Costs	\$127,608,225	\$108,116,359	\$85,263,062	\$90,296,359	\$411,284,005
<b>System MWh Sales</b>					
Total NSP System Retail	3,774,374	4,379,112	3,719,112	3,234,963	15,107,561
Non-Gen Muni's/Load Pattern	45,964	52,938	51,583	44,858	195,343
Total NSP System MWh Sales	3,820,338	4,432,050	3,770,695	3,279,821	15,302,904
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	3.340¢	2.439¢	2.261¢	2.753¢	2.688¢
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	2.676¢
(ii) C & I Non-Demand				1.0548	2.835¢
(iii) C & I Demand Non-TOD				1.0219	2.747¢
(iv) C & I Demand TOD On-Peak				1.3135	3.531¢
(v) C & I Demand TOD Off-Peak				0.7726	2.077¢
(vi) Outdoor Lighting				0.7088	1.905¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	57,265	65,506	55,310	46,473	224,554
(ii) C & I Non-Demand	8,378	9,049	8,910	8,004	34,341
(iii) C & I Demand Non-TOD	61,664	70,382	64,666	60,842	257,554
(iv) C & I Demand TOD On-Peak	18,395	20,455	21,042	18,046	77,938
(v) C & I Demand TOD Off-Peak	30,048	31,758	30,284	27,619	119,709
(vi) Outdoor Lighting	1,108	1,181	1,386	1,541	5,216
(vii) Total	176,858	198,331	181,598	162,525	719,312
<b>Dec-2011 Recovery Provision (True-up Factor) Calculation</b>					
<b>Prior Unrecovered Expenses (Aug-11 Balance of Unrecovered Expenses)</b>					<b>Total</b>
					Aug-11
					\$247,616

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

Prior Expenses Recovered in Oct-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	46,473	\$48,062
(ii) C & I Non-Demand	8,004	\$9,279
(iii) C & I Demand Non-TOD	60,842	\$68,250
(iv) C & I Demand TOD On-Peak	18,046	\$26,206
(v) C & I Demand TOD Off-Peak	27,619	\$23,793
(vi) Outdoor Lighting	1,541	\$1,513
(vii) Total	162,525	\$177,103

Actual Cost Should Have Been Recovered in Oct-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.753¢	0.000¢	162,525	\$4,474,313

Cost Recovered in Oct-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	46,473	\$1,337,197
(ii) C & I Non-Demand	8,004	\$244,079
(iii) C & I Demand Non-TOD	60,842	\$1,795,196
(iv) C & I Demand TOD On-Peak	18,046	\$685,055
(v) C & I Demand TOD Off-Peak	27,619	\$616,973
(vi) Outdoor Lighting	1,541	\$31,925
(vii) Total	162,525	\$4,710,425

Total Balance of Unrecovered Expenses (Dec-11 Balance of Unrecovered Expenses)	
Dec-2011 Recovery Provision	(\$165,599)
4 Month ND Retail Total MWh Sales	719,312
Dec-2011 Recovery Provision per KWH	-0.023¢

Dec-2011 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.023¢	-0.023¢
(ii) C & I Non-Demand	1.0548	-0.023¢	-0.024¢
(iii) C & I Demand Non-TOD	1.0219	-0.023¢	-0.024¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.023¢	-0.030¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.023¢	-0.018¢
(vi) Outdoor Lighting	0.7088	-0.023¢	-0.016¢

Dec-2011 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$29,566)	(\$1,271)	(\$30,837)
(i) Residential	-0.015¢	-0.001¢	-0.015¢
(ii) C & I Non-Demand	-0.015¢	-0.001¢	-0.016¢
(iii) C & I Demand Non-TOD	-0.015¢	-0.001¢	-0.016¢
(iv) C & I Demand TOD On-Peak	-0.019¢	-0.001¢	-0.020¢
(v) C & I Demand TOD Off-Peak	-0.011¢	0.000¢	-0.012¢
(vi) Outdoor Lighting	-0.010¢	0.000¢	-0.011¢

Dec-2011 Factors	
	Total
(i) Residential	2.638¢
(ii) C & I Non-Demand	2.795¢
(iii) C & I Demand Non-TOD	2.708¢
(iv) C & I Demand TOD On-Peak	3.480¢
(v) C & I Demand TOD Off-Peak	2.047¢
(vi) Outdoor Lighting	1.878¢

	FCA Application		Comparison		Generation Type by Percent		
	Nov-11	Dec-11	Differ- ence	Percent Change	FCA Application Nov-11	Dec-11	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$179.5	\$173.4	(\$6.1)	-3.4%	38.5%	37.7%	-0.8%
2 Nuclear	\$43.4	\$42.8	(\$0.6)	-1.4%	9.3%	9.3%	0.0%
3 Purchases	\$166.6	\$164.1	(\$2.5)	-1.5%	35.7%	35.7%	0.0%
MISO related Purchases	\$76.9	\$79.5	\$2.6	3.4%	16.5%	17.3%	0.8%
4 Total System Costs	466.4	459.8	(\$6.5)	-1.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$51.4	\$48.6	(\$2.8)	-5.4%	11.0%	10.6%	-0.4%
6 Net System Costs	\$415.0	\$411.3	(\$3.7)	-0.9%	89.0%	89.4%	0.4%
7							
<b>** GWH OUTPUT **</b>							
9 Fossil	5,816	5,562	(254)	-4.4%	33.3%	32.4%	-0.9%
10 Nuclear	4,458	4,438	(20)	-0.4%	25.5%	25.9%	0.4%
11 Purchases	5,250	5,238	(12)	-0.2%	30.1%	30.5%	0.4%
12 Hydro & Other	1,361	1,358	(3)	-0.2%	7.8%	7.9%	0.1%
13 Net Interchange	565	551	(14)	-2.5%	3.2%	3.2%	0.0%
14 Total Output	17,450	17,147	(303)	-1.7%	100.0%	100.0%	0.0%
15 Intersystem Sales	894	889	(5)	-0.6%	5.1%	5.2%	0.1%
16 Native Requirement	16,556	16,258	(298)	-1.8%	94.9%	94.8%	-0.1%
17							
<b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.086	3.118	0.032	1.0%			
20 Nuclear	0.974	0.965	-0.009	-1.0%			
21 Purchases	3.173	3.133	-0.040	-1.2%			
22 Total System Costs	2.673	2.682	0.009	0.3%			
23 Intersystem Sales	5.744	5.464	-0.280	-4.9%			
24 Net System Costs	2.507	2.530	0.023	0.9%			
25							
26							
27 TOTAL SYSTEM GWH SALES	15,541	15,303	(238)	-1.5%			
28							
29 COST per KWH SALES (\$)	2.670	2.688	0.018	0.7%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.021	-0.023	-0.002				
(i) Residential	-0.021	-0.023	-0.002				
(ii) C & I Non-Demand	-0.023	-0.024	-0.002				
(iii) C & I Demand Non-TOD	-0.022	-0.024	-0.002				
(iv) C & I Demand TOD On-Peak	-0.028	-0.030	-0.002				
(v) C & I Demand TOD Off-Peak	-0.017	-0.018	-0.001				
(vi) Outdoor Lighting	-0.015	-0.016	-0.001				
32 REFUND	-0.021	-0.016	0.005				
(i) Residential	-0.021	-0.015	0.005				
(ii) C & I Non-Demand	-0.022	-0.016	0.005				
(iii) C & I Demand Non-TOD	-0.021	-0.016	0.005				
(iv) C & I Demand TOD On-Peak	-0.028	-0.020	0.008				
(v) C & I Demand TOD Off-Peak	-0.016	-0.012	0.004				
(vi) Outdoor Lighting	-0.015	-0.011	0.004				
33 SYSTEM FCC IMPACT (\$ / KWH)	2.628	2.649	0.021	0.8%			
(i) Residential	2.616	2.638	0.022				
(ii) C & I Non-Demand	2.772	2.795	0.023				
(iii) C & I Demand Non-TOD	2.685	2.708	0.023				
(iv) C & I Demand TOD On-Peak	3.451	3.480	0.029				
(v) C & I Demand TOD Off-Peak	2.030	2.047	0.017				
(vi) Outdoor Lighting	1.862	1.878	0.016				

**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	\$0.02
250	\$0.06
500	\$0.11
750	\$0.17
1,000	\$0.22

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.

	FCA Application	
	Nov-11	Dec-11
<b>** GWH OUTPUT **</b>		
Thermal	976,770	962,793
Disper gen	(79)	(89)
Hydro plus Wind	383,954	395,585
Hydro and Other	1,360,645	1,358,289
Rounded to nearest thousand:	1,361	1,358
<b>Sales</b>		
Non Gen Munic Total	194,308,000	195,343,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	894,086,000	888,642,000
Rounded to nearest million:	894,086	888,642

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 Derivation of Adjustment for Fuel Clause Rider  
 Asset Based Margin Shading

Forecast Month	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
True-up Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
1	(72,651)	(19,186)	(84,041)	(55,415)	(21,946)	(18,191)	(43,511)	(59,944)	(17,866)	(24,427)		
2	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	169,751	201,528	230,843	209,900
3	(0.036)	(0.011)	(0.050)	(0.032)	(0.013)	(0.009)	(0.024)	(0.056)	(0.011)	(0.012)		
4	(25,037)	(44,836)	(29,737)	(32,785)	(72,439)	(59,388)	(44,704)	(12,248)	(34,464)	(38,522)	(30,303)	(29,566)
5	(38,347)	(31,238)	(41,339)	(28,812)	(49,681)	(65,331)	(53,751)	(33,670)	(22,027)	(33,383)		
6	42,914	(13,599)	11,602	(3,973)	(22,758)	5,943	9,047	21,422	(12,437)	(5,139)	(30,303)	(29,566)
7	0.021	(0.008)	0.007	(0.002)	(0.013)	0.003	0.005	0.013	(0.007)	(0.003)		
8	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	(0.015)		
9	0.9956	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
10	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
11	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
12	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
13	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
14	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	(0.015)		
15	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	(0.020)	(0.024)	(0.019)	(0.015)		
16	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	(0.020)	(0.024)	(0.018)	(0.015)		
17	(0.019)	(0.025)	(0.056)	(0.045)	(0.034)	(0.008)	(0.025)	(0.030)	(0.023)	(0.019)		
18	(0.011)	(0.015)	(0.033)	(0.026)	(0.020)	(0.005)	(0.015)	(0.018)	(0.014)	(0.011)		
19	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	(0.014)	(0.016)	(0.013)	(0.010)		
20	0.9956	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
21	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
22	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
23	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
24	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
25	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	(0.015)		
26	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	(0.020)	(0.024)	(0.019)	(0.015)		
27	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	(0.020)	(0.024)	(0.018)	(0.015)		
28	(0.019)	(0.025)	(0.056)	(0.045)	(0.034)	(0.008)	(0.025)	(0.030)	(0.023)	(0.019)		
29	(0.011)	(0.015)	(0.033)	(0.026)	(0.020)	(0.005)	(0.015)	(0.018)	(0.014)	(0.011)		
30	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	(0.014)	(0.016)	(0.013)	(0.010)		
31	0.9956	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
32	1.0548	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
33	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
34	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
35	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
36	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	(0.019)	(0.023)	(0.018)	(0.015)		
37	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	(0.020)	(0.024)	(0.019)	(0.015)		
38	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	(0.020)	(0.024)	(0.018)	(0.015)		
39	(0.019)	(0.025)	(0.056)	(0.045)	(0.034)	(0.008)	(0.025)	(0.030)	(0.023)	(0.019)		
40	(0.011)	(0.015)	(0.033)	(0.026)	(0.020)	(0.005)	(0.015)	(0.018)	(0.014)	(0.011)		
41	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	(0.014)	(0.016)	(0.013)	(0.010)		

Northern States Power Company, A Minnesota Corporation  
Electric Operations - State of North Dakota  
Derivation of Adjustment for Fuel Clause Rider  
Non-Asset Based Margin Sharing

1	Forecast Month	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12
2	True-up Month	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11
3	Monthly Refund	(4,685)	(4,685)	(4,685)	(14,881)	(4,685)	(4,685)	(4,685)	(4,685)	(4,686)	(4,686)	(4,686)	(4,686)
5	Forecast North Dakota Sales	203,291	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	169,751	201,528	230,843
7	Current Month Refund Factor	(0.002)	(0.002)	(0.003)	(0.009)	(0.003)	(0.003)	(0.002)	(0.003)	(0.003)	(0.003)	(0.002)	-
13	Expected Refund	(17,897)	(16,914)	(4,666)	7,377	2,316	(8,362)	(6,663)	(10,576)	(3,944)	(6,492)	30	(5,340)
14	Actual Refund	(17,916)	(18,780)	(11,666)	858	4,294	(2,471)	(7,404)	(8,770)	(8,660)	(5,838)	(3,385)	(5,340)
16	Deviation	19	12,062	7,001	6,519	(1,978)	(5,891)	741	(1,806)	4,716	(654)	3,415	(5,340)
17	True-up Factor	0.000	0.006	0.004	0.004	(0.001)	(0.003)	0.000	(0.001)	0.003	(0.000)	0.002	-
19	Realized Margin	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
21	Class Ratios	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
22	Residential	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
23	C&I Non-Demand	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
24	C&I Demand Non-TOD	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
25	C&I Demand TOD On-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
26	C&I Demand TOD Off-Peak	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
27	Outdoor Lighting	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
29	Realized Margin Adj for Class Ratios	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
31	Residential	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
32	C&I Non-Demand	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
33	C&I Demand Non-TOD	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	(0.004)	0.000	(0.003)	(0.001)	-
34	C&I Demand TOD On-Peak	(0.003)	0.005	0.002	(0.007)	(0.005)	(0.008)	(0.003)	(0.005)	0.000	(0.004)	(0.001)	-
35	C&I Demand TOD Off-Peak	(0.002)	0.003	0.001	(0.004)	(0.003)	(0.005)	(0.002)	(0.003)	0.000	(0.002)	(0.000)	-
36	Outdoor Lighting	(0.002)	0.003	0.001	(0.004)	(0.003)	(0.004)	(0.001)	(0.003)	0.000	(0.002)	(0.000)	-

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

Attachment 2

Page 1

		System	Intersystem	Retail
<b>October 2011 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 22,571,167.54	\$ 1,146,557.13	\$ 23,717,724.67
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,216,479.35	\$ -	\$ 2,216,479.35
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,357,961.51)	\$ -	\$ (13,357,961.51)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,589,446.78	\$ -	\$ 1,589,446.78
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)	\$ 1,029,508.58	\$ 272,503.09	\$ 1,302,011.67
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (36,980.05)	\$ -	\$ (36,980.05)
14	Real-Time Distribution of Losses Amount	\$ (1,529,878.59)	\$ -	\$ (1,529,878.59)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (353,188.40)	\$ -	\$ (353,188.40)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (17,083.78)	\$ -	\$ (17,083.78)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 1,561.65	\$ -	\$ 1,561.65
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 4,451,551.62	\$ -	\$ 4,451,551.62
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 3,018,374.50	\$ -	\$ 3,018,374.50
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)	\$ (66,891.88)	\$ -	\$ (66,891.88)
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)	\$ (12,002.53)	\$ -	\$ (12,002.53)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (5,406,382.08)	\$ -	\$ (5,406,382.08)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (463,207.51)	\$ -	\$ (463,207.51)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (220,373.63)	\$ -	\$ (220,373.63)
37	Financial Transmission Guarantee Uplift Amount	\$ 220,373.63	\$ -	\$ 220,373.63
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,131,409.45	\$ -	\$ 1,131,409.45
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 123,252.31	\$ -	\$ 123,252.31
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (86,671.25)	\$ 3,250.98	\$ (83,420.27)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 312,672.54	\$ -	\$ 312,672.54
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (80,981.90)	\$ 13,269.58	\$ (67,712.32)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (351,562.72)	\$ 7,496.56	\$ (344,066.16)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 672,137.24	\$ (4,981.49)	\$ 667,155.75
19	Real-Time Market Administration Amount	\$ 46,666.05	\$ (1,387.83)	\$ 45,278.22
29	Financial Transmission Rights Market Administration Amount	\$ 55,771.92	\$ -	\$ 55,771.92
33	Day-Ahead Schedule 24 Allocation Amount	\$ 91,685.50	\$ (668.59)	\$ 91,016.91
34	Real-Time Schedule 24 Allocation Amount	\$ 6,380.10	\$ (182.23)	\$ 6,197.87
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	\$ 527.58	\$ -	\$ 527.58
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,344,341.78	\$ -	\$ 2,344,341.78
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,432,047.15)	\$ -	\$ (2,432,047.15)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (480,364.45)	\$ -	\$ (480,364.45)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 329,071.19	\$ -	\$ 329,071.19
<b>TOTAL MISO CHARGES</b>		<b>\$ 15,316,801.88</b>	<b>\$ 1,435,857.20</b>	<b>\$ 16,752,659.08</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 97,214.78</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 16,655,444.30</b>

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

		System	Intersystem	Retail
<b>October 2011 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (188,711.76)	\$ -	\$ (188,711.76)
2	Day-Ahead Spinning Reserve Amount	\$ (61,304.55)	\$ -	\$ (61,304.55)
3	Day-Ahead Supplemental Reserve	\$ (80,071.50)	\$ -	\$ (80,071.50)
4	Real-Time Regulation Amount	\$ 1,074.96	\$ 36,678.57	\$ 37,753.53
5	Real-Time Spinning Reserve Amount	\$ (2,667.57)	\$ 21,225.10	\$ 18,557.53
6	Real-Time Supplemental Reserve Amount.	\$ 1,602.52	\$ 17,784.30	\$ 19,386.82
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (19,472.22)	\$ -	\$ (19,472.22)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,567,829.10	\$ -	\$ 1,567,829.10
8b	Real Time Non Excessive Energy Congestion	\$ 590,171.93	\$ -	\$ 590,171.93
8c	Real Time Non Excessive Energy Loss	\$ 178,425.30	\$ -	\$ 178,425.30
9	Real Time Net Regulation Adjustment Amount	\$ (8,679.51)	\$ (362.76)	\$ (9,042.27)
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 210,196.39	\$ -	\$ 210,196.39
11	Real Time Spinning Reserve Cost Distribution	\$ 178,391.78	\$ -	\$ 178,391.78
12	Real Time Supplemental Reserve Cost Distribution	\$ 69,768.91	\$ -	\$ 69,768.91
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 5,425.52	\$ (329.11)	\$ 5,096.41
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 2,441,979.30</b>	<b>\$ 74,996.10</b>	<b>\$ 2,516,975.40</b>