



414 Nicollet Mall  
Minneapolis, Minnesota 55401

—Via Electronic Filing—

July 31, 2012

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

**Re: August 2012 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 August 2012.

Pursuant to Commission authorization of the final compliance tariffs in the Company’s 2010 rate proceeding (Docket No. PU-10-657), the new rates were implemented on May 1, 2012. The new Service Category Ratios listed below also became effective:

<b>Service Category Ratios</b>	<b>Current</b>	<b>Effective May 1, 2012</b>
<b>Residential</b>	0.9956	1.0026
<b>C &amp; I Non-Demand</b>	1.0548	1.0281
<b>C &amp; I Demand</b>	1.0219	1.0170
<b>C &amp; I Demand Time of Day On-Peak</b>	1.3135	1.2883
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.7726	0.7889
<b>Outdoor Lighting</b>	0.7088	0.7440

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

<b>August 2012</b>	<b>Fuel Cost Charge (\$/kWh)</b>
<b>Residential</b>	0.02860
<b>C &amp; I Non-Demand</b>	0.02933
<b>C &amp; I Demand</b>	0.02901
<b>C &amp; I Demand Time of Day On-Peak</b>	0.03675
<b>C &amp; I Demand Time of Day Off-Peak</b>	0.02251
<b>Outdoor Lighting</b>	0.02123

## **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 April 6, 2005 Order in Docket No. PU-05-147 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 August 2012 FCC the net MISO Day 2 costs for June 2012 as recorded in Account 555. The MISO Day 2 cost recovery included in this August FCC is \$24,123,061, 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.

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

## MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (“ASM”) on January 6, 2009, the net costs or revenues of 14 new ASM charge types are included in the Fuel Cost Rider, pursuant to 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 August FCC the net MISO ASM costs for June 2012 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is \$907,884, 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 August 2012 Asset Based Margin amount of \$19,991 has been included in the August 2012 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the prior year 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 the 2011 Non-Asset Based Margin credit is \$141,551 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the August FCC is \$11,314, or 0.006¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

## **OTHER REPORTING ITEM**

Attached is the calculation of the August 2012 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 /

Paul J Lehman  
Manager, Compliance and Filings

Enclosures (2)  
CC: David H. Sederquist

Aug-2012 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	<b>\$0.02781</b>	<b>\$0.00088</b>	<b>-\$0.00016</b>	<b>\$0.02853</b>
<b>Residential</b>	<b>\$0.02788</b>	<b>\$0.00088</b>	<b>-\$0.00016</b>	<b>\$0.02860</b>
<b>C &amp; I Non-Demand</b>	<b>\$0.02859</b>	<b>\$0.00090</b>	<b>-\$0.00016</b>	<b>\$0.02933</b>
<b>C &amp; I Demand Non-TOD</b>	<b>\$0.02828</b>	<b>\$0.00089</b>	<b>-\$0.00016</b>	<b>\$0.02901</b>
<b>C &amp; I Demand TOD On-Peak</b>	<b>\$0.03583</b>	<b>\$0.00113</b>	<b>-\$0.00020</b>	<b>\$0.03675</b>
<b>C &amp; I Demand TOD Off-Peak</b>	<b>\$0.02194</b>	<b>\$0.00069</b>	<b>-\$0.00012</b>	<b>\$0.02251</b>
<b>Outdoor Lighting</b>	<b>\$0.02069</b>	<b>\$0.00065</b>	<b>-\$0.00012</b>	<b>\$0.02123</b>
<b>Residential</b>				
Residential Service	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
Residential TOD	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
Residential - Underground	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
Residential TOD - Underground	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
Energy Control - (Non-Demand)	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
Limit Off Peak	\$ 0.02788	\$ 0.00088	\$ (0.00016)	\$ 0.02860
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Limit Off Peak	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Small General Service	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Small General TOD - Metered	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Small General TOD - Unmetered	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Fire and Civil Defense Siren	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
Direct Current (Closed)	\$ 0.02859	\$ 0.00090	\$ (0.00016)	\$ 0.02933
<b>C &amp; I Demand</b>				
General Service	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
General TOD - On Peak	\$ 0.03583	\$ 0.00113	\$ (0.00020)	\$ 0.03675
General TOD - Off Peak	\$ 0.02194	\$ 0.00069	\$ (0.00012)	\$ 0.02251
Peak Controlled (Closed)	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Peak Controlled TOD (Closed) - On Peak	\$ 0.03583	\$ 0.00113	\$ (0.00020)	\$ 0.03675
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02194	\$ 0.00069	\$ (0.00012)	\$ 0.02251
Peak Controlled Tiered	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Peak Controlled Tiered TOD - On Peak	\$ 0.03583	\$ 0.00113	\$ (0.00020)	\$ 0.03675
Peak Controlled Tiered TOD - Off Peak	\$ 0.02194	\$ 0.00069	\$ (0.00012)	\$ 0.02251
Energy Controlled (Closed)	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Tier 1 Energy Controlled Rider	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Real Time Pricing - Firm - On Peak	\$ 0.03583	\$ 0.00113	\$ (0.00020)	\$ 0.03675
Real Time Pricing - Firm - Off Peak	\$ 0.02194	\$ 0.00069	\$ (0.00012)	\$ 0.02251
Real Time Pricing - Controllable - On Peak	\$ 0.03583	\$ 0.00113	\$ (0.00020)	\$ 0.03675
Real Time Pricing - Controllable - Off Peak	\$ 0.02194	\$ 0.00069	\$ (0.00012)	\$ 0.02251
Small Municipal Pumping	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Municipal Pumping	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
Excess Energy - St. Anthony Falls	\$ 0.02828	\$ 0.00089	\$ (0.00016)	\$ 0.02901
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123
Street Lighting System	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123
Street Lighting Energy	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123
Street Lighting Energy - Metered	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123
Street Lighting Energy (Closed)	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123
Street Lighting - City of St. Paul	\$ 0.02069	\$ 0.00065	\$ (0.00012)	\$ 0.02123

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 Aug-2012

	Column (A) Mar-12	Column (B) Apr-12	Column (C) May-12	Column (D) Jun-12	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$29,391,806	\$28,380,422	\$30,820,668	\$33,749,949	\$122,342,845
Account 518 - Nuclear Fuel	\$7,698,699	\$7,343,050	\$7,637,776	\$10,844,492	\$33,524,017
Account 555 - Purchased Power <sup>1</sup>	\$33,730,196	\$36,446,713	\$38,192,993	\$39,647,383	\$148,017,285
Account 555 - MISO Day 2 Charges	\$17,066,042	\$10,754,829	\$19,036,986	\$24,234,400	\$71,092,256
Account 555 MISO Day 2 - Schedule 24	(\$94,518)	(\$100,028)	(\$102,572)	(\$111,383)	(\$408,502)
Account 555 MISO - ASM Charges	\$220,051	\$286,197	\$2,161,481	\$907,884	\$3,575,613
Total MISO Charges	\$17,191,574	\$10,940,998	\$21,095,895	\$25,030,901	\$74,259,368
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$88,012,275	\$83,111,183	\$97,747,332	\$109,272,725	\$378,143,515
Less Fuel Cost of InterSystem Sales	(\$162,610)	(\$2,189,732)	(\$2,927,370)	(\$4,659,393)	(\$9,939,105)
Net System Costs	\$87,849,665	\$80,921,452	\$94,819,962	\$104,613,332	\$368,204,410
<b>System MWh Sales</b>					
Total NSP System Retail	3,386,762	3,040,761	3,222,226	3,449,768	13,099,517
Non-Gen Muni's/Load Pattern	36,800	35,570	32,683	34,482	139,535
Total NSP System MWh Sales	3,423,562	3,076,331	3,254,909	3,484,250	13,239,052
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.566¢	2.630¢	2.913¢	3.002¢	2.781¢
Base Fuel Cost Included in Rates	0.000¢	0.000¢	0.000¢	0.000¢	0.000¢
<b>Class Ratio/TOD Ratio</b>					
(i) Residential	1.0026	1.0026	1.0026	1.0026	1.0026
(ii) C & I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889
(vi) Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440
<b>North Dakota Fuel Cost Factor (FCF)</b>					
				FCF Ratio	4 Month Average
(i) Residential				1.0026	2.788¢
(ii) C & I Non-Demand				1.0281	2.859¢
(iii) C & I Demand Non-TOD				1.0170	2.828¢
(iv) C & I Demand TOD On-Peak				1.2883	3.583¢
(v) C & I Demand TOD Off-Peak				0.7889	2.194¢
(vi) Outdoor Lighting				0.7440	2.069¢
<b>North Dakota Retail MWh Sales</b>					
(i) Residential	70,777	50,015	48,899	50,195	219,886
(ii) C & I Non-Demand	10,982	8,822	8,481	8,199	36,484
(iii) C & I Demand Non-TOD	64,672	56,699	60,445	59,510	241,326
(iv) C & I Demand TOD On-Peak	18,251	16,169	18,151	16,999	69,570
(v) C & I Demand TOD Off-Peak	29,309	25,449	27,909	26,395	109,062
(vi) Outdoor Lighting	1,686	1,577	1,314	1,220	5,797
(vii) Total	195,677	158,731	165,199	162,518	682,125
<b>Aug-2012 Recovery Provision (True-up Factor) Calculation</b>					
Prior Unrecovered Expenses (Apr-12 Balance of Unrecovered Expenses)					Total
					Apr-12
					(\$97,486)

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

Prior Expenses Recovered in Jun-2012 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	50,195	(\$14,185)
(ii) C & I Non-Demand	8,199	(\$2,452)
(iii) C & I Demand Non-TOD	59,510	(\$16,931)
(iv) C & I Demand TOD On-Peak	16,999	(\$6,600)
(v) C & I Demand TOD Off-Peak	26,395	(\$6,052)
(vi) Outdoor Lighting	1,220	(\$311)
(vii) Total	162,518	(\$46,531)

Actual Cost Should Have Been Recovered in Jun-12				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.002¢	0.000¢	162,518	\$4,878,790

Cost Recovered in Jun-12 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	50,195	\$1,299,799
(ii) C & I Non-Demand	8,199	\$222,397
(iii) C & I Demand Non-TOD	59,510	\$1,575,737
(iv) C & I Demand TOD On-Peak	16,999	\$575,823
(v) C & I Demand TOD Off-Peak	26,395	\$533,311
(vi) Outdoor Lighting	1,220	\$22,827
(vii) Total	162,518	\$4,229,894

Total Balance of Unrecovered Expenses (Aug-12 Balance of Unrecovered Expenses)	
Aug-2012 Recovery Provision	\$597,941
4 Month ND Retail Total MWh Sales	682,125
Aug-2012 Recovery Provision per KWH	0.088¢

Aug-2012 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.088¢	0.088¢
(ii) C & I Non-Demand	1.0281	0.088¢	0.090¢
(iii) C & I Demand Non-TOD	1.0170	0.088¢	0.089¢
(iv) C & I Demand TOD On-Peak	1.2883	0.088¢	0.113¢
(v) C & I Demand TOD Off-Peak	0.7889	0.088¢	0.069¢
(vi) Outdoor Lighting	0.7440	0.088¢	0.065¢

Aug-2012 Margin Sharing Refunds			
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
	(\$19,991)	(\$11,314)	(\$31,305)
(i) Residential	-0.010¢	-0.006¢	-0.016¢
(ii) C & I Non-Demand	-0.010¢	-0.006¢	-0.016¢
(iii) C & I Demand Non-TOD	-0.010¢	-0.006¢	-0.016¢
(iv) C & I Demand TOD On-Peak	-0.013¢	-0.007¢	-0.020¢
(v) C & I Demand TOD Off-Peak	-0.008¢	-0.005¢	-0.012¢
(vi) Outdoor Lighting	-0.008¢	-0.004¢	-0.012¢

Aug-2012 Factors	
	Total
(i) Residential	2.860¢
(ii) C & I Non-Demand	2.933¢
(iii) C & I Demand Non-TOD	2.901¢
(iv) C & I Demand TOD On-Peak	3.675¢
(v) C & I Demand TOD Off-Peak	2.251¢
(vi) Outdoor Lighting	2.123¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jul-12	Aug-12	Differ- ence	Percent Change	FCA Application Jul-12	Aug-12	Differ- ence
<b>** COSTS (Millions) **</b>							
1 Fossil	\$129.0	\$122.3	(\$6.6)	-5.1%	35.6%	32.4%	-3.2%
2 Nuclear	\$32.2	\$33.5	\$1.3	4.2%	8.9%	8.9%	0.0%
3 Purchases	\$141.4	\$148.0	\$6.6	4.7%	39.0%	39.1%	0.1%
MISO related Purchases	\$59.7	\$74.3	\$14.6	24.5%	16.5%	19.6%	3.1%
4 Total System Costs	\$362.2	\$378.1	\$15.9	4.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$10.7	\$9.9	(\$0.8)	-7.5%	3.0%	2.6%	-0.4%
6 Net System Costs	\$351.5	\$368.2	\$16.7	4.8%	97.0%	97.4%	0.4%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	3,378	3,114	(264)	-7.8%	22.8%	20.4%	-2.4%
10 Nuclear	3,506	3,606	100	2.9%	23.7%	23.7%	0.0%
11 Purchases	5,189	5,616	427	8.2%	35.0%	36.8%	1.8%
12 Hydro & Other	2,165	2,321	156	7.2%	14.6%	15.2%	0.6%
13 Net Interchange	572	588	16	2.8%	3.9%	3.9%	0.0%
14 Total Output	14,810	15,245	435	2.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	818	696	(121)	-14.8%	5.5%	4.6%	-0.9%
16 Native Requirement	13,992	14,549	556	4.0%	94.5%	95.4%	0.9%
17							
18 <b>** COST per KWH OUTPUT (\$) **</b>							
19 Fossil	3.817	3.929	0.111	2.9%			
20 Nuclear	0.918	0.930	0.012	1.3%			
21 Purchases	2.725	2.636	-0.090	-3.3%			
22 Total System Costs	2.446	2.480	0.035	1.4%			
23 Intersystem Sales	1.313	1.427	0.114	8.7%			
24 Net System Costs	2.512	2.531	0.019	0.8%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,154	13,239	85	0.6%			
28							
29 COST per KWH SALES (\$)	2.672	2.781	0.109	4.1%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.019	0.088	0.069				
(i) Residential	0.019	0.088	0.069				
(ii) C & I Non-Demand	0.020	0.090	0.070				
(iii) C & I Demand Non-TOD	0.019	0.089	0.070				
(iv) C & I Demand TOD On-Peak	0.025	0.113	0.088				
(v) C & I Demand TOD Off-Peak	0.015	0.069	0.054				
(vi) Outdoor Lighting	0.014	0.065	0.051				
32 REFUND	-0.022	-0.016	0.006				
(i) Residential	-0.022	-0.016					
(ii) C & I Non-Demand	-0.023	-0.016					
(iii) C & I Demand Non-TOD	-0.022	-0.016					
(iv) C & I Demand TOD On-Peak	-0.028	-0.020					
(v) C & I Demand TOD Off-Peak	-0.017	-0.012					
(vi) Outdoor Lighting	-0.016	-0.012					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.669	2.853	0.184	6.9%			
(i) Residential	2.671	2.860	0.189				
(ii) C & I Non-Demand	2.761	2.933					
(iii) C & I Demand Non-TOD	2.717	2.901					
(iv) C & I Demand TOD On-Peak	3.454	3.675					
(v) C & I Demand TOD Off-Peak	2.094	2.251					
(vi) Outdoor Lighting	1.962	2.123					

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	\$0.19
250	\$0.47
500	\$0.95
750	\$1.42
1,000	\$1.89

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>	
	Jul-12	Aug-12
<b>** GWH OUTPUT **</b>		
Thermal	1,659,725	1,768,430
Disper gen	(37)	(45)
<u>Hydro plus Wind</u>	505,301	552,589
Hydro and Other	2,164,989	2,320,974
Rounded to nearest thousand:	2,165	2,321
<u>Sales</u>		
Non Gen Munic Total	156,278,000	139,535,000
Load Pattern Power	0	0
<u>Resale &amp; Interchange (Intersystem)</u>	817,669,000	696,289,000
Rounded to nearest million:	817.669	696.289

		System	Intersystem	Retail
<b>June 2012 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 26,907,328.79	\$ 1,192,717.13	\$ 28,100,045.92
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,805,566.63	\$ -	\$ 2,805,566.63
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (14,516,292.19)	\$ -	\$ (14,516,292.19)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,203,519.41	\$ -	\$ 1,203,519.41
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)	\$ 3,071,568.83	\$ 138,639.33	\$ 3,210,208.16
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 52,741.04	\$ -	\$ 52,741.04
14	Real-Time Distribution of Losses Amount	\$ (1,470,984.03)	\$ -	\$ (1,470,984.03)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (27,927.43)	\$ -	\$ (27,927.43)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (29,836.23)	\$ -	\$ (29,836.23)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 4,611.10	\$ -	\$ 4,611.10
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 4,954,548.35	\$ -	\$ 4,954,548.35
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 3,399,136.39	\$ -	\$ 3,399,136.39
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)	\$ 352,180.57	\$ -	\$ 352,180.57
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)	\$ 3,822.77	\$ -	\$ 3,822.77
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (4,586,282.91)	\$ -	\$ (4,586,282.91)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (122,163.88)	\$ -	\$ (122,163.88)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (882,145.85)	\$ -	\$ (882,145.85)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 882,145.85	\$ -	\$ 882,145.85
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,124,206.81	\$ -	\$ 1,124,206.81
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 133,758.65	\$ -	\$ 133,758.65
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (55,825.33)	\$ 3,149.81	\$ (52,675.52)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 166,847.03	\$ -	\$ 166,847.03
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (675,392.98)	\$ 15,837.95	\$ (659,555.03)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (70,500.38)	\$ 1,763.07	\$ (68,737.31)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 641,168.06	\$ (2,999.82)	\$ 638,168.24
19	Real-Time Market Administration Amount	\$ 46,273.04	\$ (422.84)	\$ 45,850.20
29	Financial Transmission Rights Market Administration Amount	\$ 43,460.16	\$ -	\$ 43,460.16
33	Day-Ahead Schedule 24 Allocation Amount	\$ 104,429.78	\$ (504.25)	\$ 103,925.53
34	Real-Time Schedule 24 Allocation Amount	\$ 7,534.69	\$ (76.75)	\$ 7,457.94
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	\$ 3,369.04	\$ -	\$ 3,369.04
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,950,727.55	\$ -	\$ 2,950,727.55
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,886,210.18)	\$ -	\$ (2,886,210.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (658,322.42)	\$ -	\$ (658,322.42)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 9,235.55	\$ -	\$ 9,235.55
<b>TOTAL MISO CHARGES</b>		<b>\$ 22,886,296.28</b>	<b>\$ 1,348,103.63</b>	<b>\$ 24,234,399.91</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 111,383.47</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 24,123,016.44</b>

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

		System	Intersystem	Retail
June 2012 Actual				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (135,539.38)	\$ -	\$ (135,539.38)
2	Day-Ahead Spinning Reserve Amount	\$ (30,965.95)	\$ -	\$ (30,965.95)
3	Day-Ahead Supplemental Reserve	\$ (88,881.30)	\$ -	\$ (88,881.30)
4	Real-Time Regulation Amount	\$ (120,092.43)	\$ 119,941.06	\$ (151.37)
5	Real-Time Spinning Reserve Amount	\$ (35,112.97)	\$ 6,738.01	\$ (28,374.96)
6	Real-Time Supplemental Reserve Amount	\$ 16,886.45	\$ 21,620.95	\$ 38,507.40
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (39,486.41)		\$ (39,486.41)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ 1,330,359.15		\$ 1,330,359.15
8b	Real Time Non Excessive Energy Congestion	\$ (609,171.68)		\$ (609,171.68)
8c	Real Time Non Excessive Energy Loss	\$ 49,814.38		\$ 49,814.38
9	Real Time Net Regulation Adjustment Amount	\$ 30,321.41	\$ (1,578.62)	\$ 28,742.79
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 188,255.88	\$ -	\$ 188,255.88
11	Real Time Spinning Reserve Cost Distribution	\$ 120,564.25	\$ -	\$ 120,564.25
12	Real Time Supplemental Reserve Cost Distribution	\$ 75,023.08	\$ -	\$ 75,023.08
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 9,031.55	\$ (974.05)	\$ 8,057.50
14	Real Time Contingency Reserve Deployment Failure	\$ 1,130.84	\$ -	\$ 1,130.84
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ 762,136.87</b>	<b>\$ 145,747.35</b>	<b>\$ 907,884.22</b>

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

	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13
1 Forecast Month	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12
2 True-up Month												
3												
4 Monthly Refund	(37,060)	(46,106)	(20,853)	(21,116)	(45,351)	(9,986)						
5												
6 Forecast North Dakota Sales	204,480	176,872	172,668	167,827	180,675	198,082	166,509	179,078	-	-	-	-
7												
8 Current Month Refund Factor	(0.018)	(0.027)	(0.012)	(0.013)	(0.023)	(0.005)	-	-	-	-	-	-
9												
14 Expected Refund	(30,199)	(42,867)	(36,737)	(58,058)	(20,317)	(39,456)	(27,680)	(19,991)	-	-	-	-
15 Actual Refunded	(30,522)	(32,915)	(37,073)	(39,718)	(38,188)	(28,551)						
16 Deviation	323	(9,952)	336	(18,340)	17,671	(10,905)	(27,680)	(19,991)	-	-	-	-
17												
18 True-up Factor	0.000	(0.006)	0.000	(0.011)	0.010	(0.006)	-	-	-	-	-	-
19												
20 Realized Margin	(0.018)	(0.033)	(0.012)	(0.024)	(0.015)	(0.010)	-	-	-	-	-	-
21												
22 Class Ratios												
23 Residential	0.9956	0.9956	0.9974	0.9991	1.0009	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24 C&I Non-Demand	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25 C&I Demand Non-TOD	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26 C&I Demand TOD On-Peak	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28 Outdoor Lighting	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.018)	(0.033)	(0.012)	(0.023)	(0.015)	(0.010)	-	-	-	-	-	-
32 C&I Non-Demand	(0.019)	(0.035)	(0.012)	(0.024)	(0.016)	(0.010)	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.018)	(0.034)	(0.012)	(0.024)	(0.016)	(0.010)	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.024)	(0.043)	(0.016)	(0.031)	(0.020)	(0.013)	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.014)	(0.025)	(0.009)	(0.018)	(0.012)	(0.008)	-	-	-	-	-	-
36 Outdoor Lighting	(0.013)	(0.023)	(0.009)	(0.017)	(0.011)	(0.008)	-	-	-	-	-	-

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

	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13
	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12
1 Forecast Month												
2 True-up Month	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)	(11,796)
3												
4 Monthly Refund	205,900	204,480	176,872	172,668	167,827	180,675	198,082	-	-	-	-	-
5 Forecast North Dakota Sales												
6 Current Month Refund Factor	(0.006)	(0.006)	(0.007)	(0.007)	(0.007)	(0.007)	(0.006)	-	-	-	-	-
7												
8 Expected Refund	(1,271)	(7,850)	(9,247)	(15,472)	(13,816)	(15,506)	(13,246)	-	-	-	-	-
9 Actual Refund	(3,820)	(4,174)	(7,227)	(11,762)	(12,366)	(13,820)	(13,728)	-	-	-	-	-
10 Deviation	2,549	(3,676)	(2,020)	(3,710)	(1,450)	(1,686)	482	-	-	-	-	-
11												
12 True-up Factor	0.001	(0.002)	(0.001)	(0.002)	(0.001)	(0.001)	0.000	-	-	-	-	-
13												
14 Realized Margin	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	-	-	-	-	-
15												
16 Class Ratios												
17 Residential	0.9956	0.9956	0.9956	0.9974	0.9991	1.0009	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
18 C&I Non-Demand	1.0548	1.0548	1.0548	1.0481	1.0415	1.0348	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
19 C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0207	1.0195	1.0182	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
20 C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3072	1.3009	1.2946	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
21 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7767	0.7808	0.7848	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
22 Outdoor Lighting	0.7088	0.7088	0.7088	0.7176	0.7264	0.7352	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
23												
24 Realized Margin Adj for Class Ratios												
25 Residential	(0.004)	(0.008)	(0.008)	(0.009)	(0.008)	(0.007)	(0.006)	-	-	-	-	-
26 C&I Non-Demand	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	-	-	-	-	-
27 C&I Demand Non-TOD	(0.005)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	-	-	-	-	-
28 C&I Demand TOD On-Peak	(0.006)	(0.010)	(0.010)	(0.012)	(0.010)	(0.010)	(0.007)	-	-	-	-	-
29 C&I Demand TOD Off-Peak	(0.003)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	-	-	-	-	-
30 Outdoor Lighting	(0.003)	(0.005)	(0.006)	(0.006)	(0.006)	(0.005)	(0.004)	-	-	-	-	-