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AUG 01 2011

PUBLIC SERVICE COMMISSION

—Via Electronic Filing—

July 28, 2011

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

Re: August 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 August 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 August 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 June 2011 calendar month.

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

August 2011	Fuel Cost Charge (\$/kWh)
Residential	0.02855
C & I Non-Demand	0.03025
C & I Demand	0.02931
C & I Demand Time of Day On-Peak	0.03767
C & I Demand Time of Day Off-Peak	0.02216
Outdoor Lighting	0.02033

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 types¹, 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 2011 FCC, the net MISO Day 2 costs for June 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this August FCC is \$17,252,534, 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

¹ 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 August FCC, the net MISO ASM costs for June 2011 as recorded in Account 555. The MISO ASM cost recovery included in this August FCC is \$-704,521, 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 June 2011 Asset Based Margin amount of \$12,248 has been included in the August 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 August FCC is \$3,944, or 0.002¢ 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 FCC, as well as a statistical summary of energy sources and costs, compared to the previous month.

If you have any questions regarding the information contained in this filing, please contact Dave Sederquist in Fargo at 701-241-8632.

Sincerely,

/ S /

Phillip J. Zins
Manager, Pricing and Planning
Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Aug-2011

Aug-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02739	\$0.00137	-\$0.00008	\$0.02868
Residential	\$0.02727	\$0.00136	-\$0.00008	\$0.02855
C & I Non-Demand	\$0.02889	\$0.00145	-\$0.00009	\$0.03025
C & I Demand Non-TOD	\$0.02799	\$0.00140	-\$0.00008	\$0.02931
C & I Demand TOD On-Peak	\$0.03598	\$0.00180	-\$0.00011	\$0.03767
C & I Demand TOD Off-Peak	\$0.02116	\$0.00106	-\$0.00006	\$0.02216
Outdoor Lighting	\$0.01941	\$0.00097	-\$0.00006	\$0.02033
Residential				
Residential Service	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
Residential TOD	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
Residential - Underground	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
Residential TOD - Underground	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
Energy Control - (Non-Demand)	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
Limit Off Peak	\$ 0.02727	\$ 0.00136	\$(0.00008)	\$ 0.02855
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Limit Off Peak	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Small General Service	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Small General TOD - Metered	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Small General TOD - Unmetered	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Fire and Civil Defense Siren	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
Direct Current (Closed)	\$ 0.02889	\$ 0.00145	\$(0.00009)	\$ 0.03025
C & I Demand				
General Service	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
General TOD - On Peak	\$ 0.03598	\$ 0.00180	\$(0.00011)	\$ 0.03767
General TOD - Off Peak	\$ 0.02116	\$ 0.00106	\$(0.00006)	\$ 0.02216
Peak Controlled (Closed)	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Peak Controlled TOD (Closed) - On Peak	\$ 0.03598	\$ 0.00180	\$(0.00011)	\$ 0.03767
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02116	\$ 0.00106	\$(0.00006)	\$ 0.02216
Peak Controlled Tiered	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Peak Controlled Tiered TOD - On Peak	\$ 0.03598	\$ 0.00180	\$(0.00011)	\$ 0.03767
Peak Controlled Tiered TOD - Off Peak	\$ 0.02116	\$ 0.00106	\$(0.00006)	\$ 0.02216
Energy Controlled (Closed)	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Tier 1 Energy Controlled Rider	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Real Time Pricing - Firm - On Peak	\$ 0.03598	\$ 0.00180	\$(0.00011)	\$ 0.03767
Real Time Pricing - Firm - Off Peak	\$ 0.02116	\$ 0.00106	\$(0.00006)	\$ 0.02216
Real Time Pricing - Controllable - On Peak	\$ 0.03598	\$ 0.00180	\$(0.00011)	\$ 0.03767
Real Time Pricing - Controllable - Off Peak	\$ 0.02116	\$ 0.00106	\$(0.00006)	\$ 0.02216
Small Municipal Pumping	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Municipal Pumping	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Excess Energy - St. Anthony Falls	\$ 0.02799	\$ 0.00140	\$(0.00008)	\$ 0.02931
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033
Street Lighting System	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033
Street Lighting Energy	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033
Street Lighting Energy - Metered	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033
Street Lighting Energy (Closed)	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033
Street Lighting - City of St. Paul	\$ 0.01941	\$ 0.00097	\$(0.00006)	\$ 0.02033

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 Aug-2011

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Mar-11	Apr-11	May-11	Jun-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$43,721,305	\$28,258,842	\$35,283,583	\$37,703,245	\$144,966,975
Account 518 - Nuclear Fuel	\$7,780,334	\$6,778,412	\$3,922,509	\$8,998,877	\$27,480,132
Account 555 - Purchased Power ¹	\$38,906,437	\$47,631,320	\$49,169,423	\$44,306,074	\$180,013,255
Account 555 - MISO Day 2 Charges	\$18,257,815	\$23,401,459	\$21,065,785	\$17,352,507	\$80,077,565
Account 555 MISO Day 2 - Schedule 24	(\$85,583)	(\$82,110)	(\$82,724)	(\$99,973)	(\$350,390)
Account 555 MISO - ASM Charges	(\$1,143,120)	\$1,953,522	\$770,873	(\$704,521)	\$876,754
Total MISO Charges	\$17,029,112	\$25,272,871	\$21,753,935	\$16,548,012	\$80,603,930
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$107,437,188	\$107,941,445	\$110,129,450	\$107,556,209	\$433,064,292
Less Fuel Cost of InterSystem Sales	(\$14,210,295)	(\$17,536,970)	(\$16,801,539)	(\$13,538,555)	(\$62,087,359)
Net System Costs	\$93,226,893	\$90,404,475	\$93,327,911	\$94,017,654	\$370,976,932
System MWh Sales					
Total NSP System Retail	3,624,446	3,070,703	3,181,530	3,473,679	13,350,358
Non-Gen Muni's/Load Pattern	51,878	51,955	47,236	43,823	194,892
Total NSP System MWh Sales	3,676,324	3,122,658	3,228,766	3,517,502	13,545,250
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.536¢	2.895¢	2.891¢	2.673¢	2.739¢
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	2.727¢
(ii) C & I Non-Demand				1.0548	2.889¢
(iii) C & I Demand Non-TOD				1.0219	2.799¢
(iv) C & I Demand TOD On-Peak				1.3135	3.598¢
(v) C & I Demand TOD Off-Peak				0.7726	2.116¢
(vi) Outdoor Lighting				0.7088	1.941¢
North Dakota Retail MWh Sales					
(i) Residential	86,238	59,524	53,251	51,748	250,761
(ii) C & I Non-Demand	12,922	9,574	10,155	8,668	41,319
(iii) C & I Demand Non-TOD	70,769	53,152	58,714	58,924	241,559
(iv) C & I Demand TOD On-Peak	22,007	18,572	17,438	19,267	77,284
(v) C & I Demand TOD Off-Peak	32,833	27,669	27,857	30,957	119,316
(vi) Outdoor Lighting	1,700	1,574	1,312	1,221	5,807
(vii) Total	226,469	170,065	168,727	170,785	736,046
Aug-2011 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Apr-11 Balance of Unrecovered Expenses)					Total
					Apr-11
					\$838,605

¹ Excludes demand-related expenses

Prior Expenses Recovered in Jun-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	51,748	\$9,604
(ii) C & I Non-Demand	8,668	\$1,300
(iii) C & I Demand Non-TOD	58,924	\$9,772
(iv) C & I Demand TOD On-Peak	19,267	\$3,577
(v) C & I Demand TOD Off-Peak	30,957	\$3,394
(vi) Outdoor Lighting	1,221	(\$172)
(vii) Total	170,785	\$27,475

Actual Cost Should Have Been Recovered in Jun-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.673¢	0.000¢	170,785	\$4,565,083

Cost Recovered in Jun-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	51,748	\$1,316,799
(ii) C & I Non-Demand	8,668	\$233,465
(iii) C & I Demand Non-TOD	58,924	\$1,538,181
(iv) C & I Demand TOD On-Peak	19,267	\$646,314
(v) C & I Demand TOD Off-Peak	30,957	\$610,920
(vi) Outdoor Lighting	1,221	\$21,973
(vii) Total	170,785	\$4,367,652

Total Balance of Unrecovered Expenses (Aug-11 Balance of Unrecovered Expenses)	
Aug-2011 Recovery Provision	\$1,008,561
4 Month ND Retail Total MWh Sales	736,046
Aug-2011 Recovery Provision per KWH	0.137¢

Aug-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	0.137¢	0.136¢
(ii) C & I Non-Demand	1.0548	0.137¢	0.145¢
(iii) C & I Demand Non-TOD	1.0219	0.137¢	0.140¢
(iv) C & I Demand TOD On-Peak	1.3135	0.137¢	0.180¢
(v) C & I Demand TOD Off-Peak	0.7726	0.137¢	0.106¢
(vi) Outdoor Lighting	0.7088	0.137¢	0.097¢

Aug-2011 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$12,248)	(\$3,944)	(\$16,192)
(i) Residential	-0.006¢	-0.002¢	-0.008¢
(ii) C & I Non-Demand	-0.007¢	-0.002¢	-0.009¢
(iii) C & I Demand Non-TOD	-0.006¢	-0.002¢	-0.008¢
(iv) C & I Demand TOD On-Peak	-0.008¢	-0.003¢	-0.011¢
(v) C & I Demand TOD Off-Peak	-0.005¢	-0.002¢	-0.006¢
(vi) Outdoor Lighting	-0.004¢	-0.001¢	-0.006¢

Aug-2011 Factors	
	Total
(i) Residential	2.855¢
(ii) C & I Non-Demand	3.025¢
(iii) C & I Demand Non-TOD	2.931¢
(iv) C & I Demand TOD On-Peak	3.767¢
(v) C & I Demand TOD Off-Peak	2.216¢
(vi) Outdoor Lighting	2.033¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jul-11	Aug-11	Differ- ence	Percent Change	FCA Application Jul-11	Aug-11	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$145.8	\$145.0	(\$0.8)	-0.6%	33.8%	33.5%	-0.3%
2 Nuclear	\$28.0	\$27.5	(\$0.5)	-1.9%	6.5%	6.3%	-0.2%
3 Purchases	\$175.7	\$180.0	\$4.3	2.4%	40.8%	41.6%	0.8%
MISO related Purchases	\$81.4	\$80.6	(\$0.7)	-0.9%	18.9%	18.6%	-0.3%
4 Total System Costs	430.9	433.1	\$2.2	0.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$61.7	\$62.1	\$0.4	0.6%	14.3%	14.3%	0.0%
6 Net System Costs	\$369.1	\$371.0	\$1.8	0.5%	85.7%	85.7%	0.0%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,380	5,417	37	0.7%	34.5%	34.8%	0.3%
10 Nuclear	3,170	2,974	(196)	-6.2%	20.3%	19.1%	-1.2%
11 Purchases	5,230	5,434	204	3.9%	33.6%	34.9%	1.3%
12 Hydro & Other	1,083	1,032	(51)	-4.7%	7.0%	6.6%	-0.4%
13 Net Interchange	717	730	13	1.8%	4.6%	4.7%	0.1%
14 Total Output	15,580	15,587	7	0.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	809	492	(317)	-39.2%	5.2%	3.2%	-2.0%
16 Native Requirement	14,771	15,095	324	2.2%	94.8%	96.8%	2.0%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.710	2.676	-0.034	-1.3%			
20 Nuclear	0.884	0.924	0.040	4.6%			
21 Purchases	3.360	3.313	-0.047	-1.4%			
22 Total System Costs	2.786	2.778	0.013	0.5%			
23 Intersystem Sales	7.634	12.619	4.986	65.3%			
24 Net System Costs	2.499	2.458	-0.041	-1.7%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,410	13,545	135	1.0%			
28							
29 COST per KWH SALES (\$) **	2.753	2.739	-0.014	-0.5%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.015	0.137	0.122				
(i) Residential	0.014	0.136	0.122				
(ii) C & I Non-Demand	0.015	0.145	0.129				
(iii) C & I Demand Non-TOD	0.015	0.140	0.125				
(iv) C & I Demand TOD On-Peak	0.019	0.180	0.161				
(v) C & I Demand TOD Off-Peak	0.011	0.106	0.095				
(vi) Outdoor Lighting	0.010	0.097	0.087				
32 REFUND	-0.032	0.000	0.032				
(i) Residential	-0.032	-0.008					
(ii) C & I Non-Demand	-0.034	-0.009					
(iii) C & I Demand Non-TOD	-0.033	-0.008					
(iv) C & I Demand TOD On-Peak	-0.042	-0.011					
(v) C & I Demand TOD Off-Peak	-0.025	-0.006					
(vi) Outdoor Lighting	-0.023	-0.006					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.736	2.876	0.140	5.1%			
(i) Residential	2.724	2.855	0.131				
(ii) C & I Non-Demand	2.885	3.025					
(iii) C & I Demand Non-TOD	2.795	2.931					
(iv) C & I Demand TOD On-Peak	3.593	3.767					
(v) C & I Demand TOD Off-Peak	2.113	2.216					
(vi) Outdoor Lighting	1.939	2.033					

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	\$0.13
250	\$0.33
500	\$0.66
750	\$0.98
1,000	\$1.31

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-11	Aug-11
** GWH OUTPUT **		
Thermal	457,407	418,857
Disper gen	(60)	(55)
Hydro plus Wind	625,250	612,790
Hydro and Other	1,082,597	1,031,592
Rounded to nearest thousand:	1,083	1,032
Sales		
Non Gen Munic Total	206,725,000	194,892,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	808,738,000	492,004,000
Rounded to nearest million:	808,738	492,004

		June 2011 Actual		
		System	Intersystem	Retail
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 26,536,849.38	\$ 645,041.80	\$ 27,181,891.18
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,642,486.87	\$ -	\$ 2,642,486.87
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (19,659,050.65)	\$ -	\$ (19,659,050.65)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,673,980.91	\$ -	\$ 2,673,980.91
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)	\$ 3,720,032.47	\$ 1,095,006.33	\$ 4,815,038.80
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 81,957.26	\$ -	\$ 81,957.26
14	Real-Time Distribution of Losses Amount	\$ (1,310,810.03)	\$ -	\$ (1,310,810.03)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (78,730.63)	\$ -	\$ (78,730.63)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 71,302.27	\$ -	\$ 71,302.27
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 412.32	\$ -	\$ 412.32
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (1,792,172.54)	\$ -	\$ (1,792,172.54)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 6,317,818.39	\$ -	\$ 6,317,818.39
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)	\$ 107,707.48	\$ -	\$ 107,707.48
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)	\$ 5,025.32	\$ -	\$ 5,025.32
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (3,907,650.01)	\$ -	\$ (3,907,650.01)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (140,290.55)	\$ -	\$ (140,290.55)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 11,700.05	\$ -	\$ 11,700.05
37	Financial Transmission Guarantee Uplift Amount	\$ (25,553.39)	\$ -	\$ (25,553.39)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (206,156.67)	\$ -	\$ (206,156.67)
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 195,841.82	\$ -	\$ 195,841.82
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (311,515.58)	\$ 10,725.75	\$ (300,789.83)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 463,202.15	\$ -	\$ 463,202.15
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (333,302.90)	\$ 46,013.22	\$ (287,289.74)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (187,736.10)	\$ 9,037.54	\$ (178,698.62)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 816,578.49	\$ (3,609.68)	\$ 812,968.81
19	Real-Time Market Administration Amount	\$ 60,969.94	\$ (4,637.70)	\$ 56,332.24
29	Financial Transmission Rights Market Administration Amount	\$ 58,073.12	\$ -	\$ 58,073.12
33	Day-Ahead Schedule 24 Allocation Amount	\$ 93,912.71	\$ (410.36)	\$ 93,502.35
34	Real-Time Schedule 24 Allocation Amount	\$ 6,999.45	\$ (528.57)	\$ 6,470.88
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	\$ (2,909.21)	\$ -	\$ (2,909.21)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 2,832,430.59	\$ -	\$ 2,832,430.59
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (2,913,019.77)	\$ -	\$ (2,913,019.77)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (371,731.44)	\$ -	\$ (371,731.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 99,217.14	\$ -	\$ 99,217.14
TOTAL MISO CHARGES		\$ 15,555,868.54	\$ 1,796,638.33	\$ 17,352,506.87

SCHEDULE 24 (FOR RETAIL)	\$ 99,973.23
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TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)	\$ 17,252,533.64
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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

	System	Intersystem	Retail
June 2011 Actual			
Procurement Charges			
1 Day-Ahead Regulation Amount	\$ (291,484.04)	\$ -	\$ (291,484.04)
2 Day-Ahead Spinning Reserve Amount	\$ (147,841.88)	\$ -	\$ (147,841.88)
3 Day-Ahead Supplemental Reserve	\$ (156,103.35)	\$ -	\$ (156,103.35)
4 Real-Time Regulation Amount	\$ 22,672.89	\$ 141,933.72	\$ 164,606.61
5 Real-Time Spinning Reserve Amount	\$ (50.72)	\$ 108,827.75	\$ 108,777.03
6 Real-Time Supplemental Reserve Amount	\$ 80,114.55	\$ 43,644.22	\$ 123,758.77
Resource Energy Charges			
7a Real Time Excessive Energy Amount	\$ (15,278.28)	\$ -	\$ (15,278.28)
7b Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a Real Time Non Excessive Energy Amount	\$ (661,881.71)	\$ -	\$ (661,881.71)
8b Real Time Non Excessive Energy Congestion	\$ (293,841.34)	\$ -	\$ (293,841.34)
8c Real Time Non Excessive Energy Loss	\$ (43,458.53)	\$ -	\$ (43,458.53)
9 Real Time Net Regulation Adjustment Amount	\$ 43,737.58	\$ (5,517.80)	\$ 38,219.78
Cost Distribution Charges			
10 Real Time Regulation Reserve Cost Distribution Amount	\$ 224,668.95	\$ -	\$ 224,668.95
11 Real Time Spinning Reserve Cost Distribution	\$ 161,484.98	\$ -	\$ 161,484.98
12 Real Time Supplemental Reserve Cost Distribution	\$ 75,406.99	\$ -	\$ 75,406.99
Penalty Charges			
13 Real Time Excessive/Dificient Energy Deployment	\$ 11,439.54	\$ (2,994.98)	\$ 8,444.56
14 Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES	\$ (990,414.37)	\$ 285,892.91	\$ (704,521.46)

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-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12
2 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
3												
4 Monthly Refund	(72,651)	(19,186)	(84,041)	(55,415)	(21,946)	(18,191)						
5												
6 Forecast North Dakota Sales	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	-	-	-	-
7												
8 Current Month Refund Factor	(0.036)	(0.011)	(0.050)	(0.032)	(0.013)	(0.009)	-	-	-	-	-	-
9												
14 Expected Refund	(25,037)	(44,836)	(29,737)	(32,785)	(72,439)	(59,388)	(44,704)	(12,248)	-	-	-	-
15 Actual Refunded	(38,347)	(31,238)	(41,339)	(28,812)	(49,681)	(65,331)						
16 Deviation	42,914	(13,599)	11,602	(3,973)	(22,758)	5,943	(44,704)	(12,248)	-	-	-	-
17												
18 True-up Factor	0.021	(0.008)	0.007	(0.002)	(0.013)	0.003	-	-	-	-	-	-
19												
20 Realized Margin	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	-	-	-	-	-	-
21												
22 Class Ratios												
23 Residential	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
24 C&I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
25 C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
26 C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
27 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
28 Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.015)	(0.019)	(0.043)	(0.034)	(0.026)	(0.006)	-	-	-	-	-	-
32 C&I Non-Demand	(0.015)	(0.020)	(0.045)	(0.036)	(0.027)	(0.007)	-	-	-	-	-	-
33 C&I Demand Non-TOD	(0.015)	(0.020)	(0.044)	(0.035)	(0.026)	(0.006)	-	-	-	-	-	-
34 C&I Demand TOD On-Peak	(0.019)	(0.025)	(0.056)	(0.045)	(0.034)	(0.008)	-	-	-	-	-	-
35 C&I Demand TOD Off-Peak	(0.011)	(0.013)	(0.033)	(0.026)	(0.020)	(0.005)	-	-	-	-	-	-
36 Outdoor Lighting	(0.010)	(0.014)	(0.030)	(0.024)	(0.018)	(0.004)	-	-	-	-	-	-

Northern States Power Company, A Minnesota Corporation & Wholly Owned Subsidiary of Xcel Energy Inc.
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Non-Asset Based Margin Sharing

1 Forecast Month	Feb-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												
4 Monthly Refund	(4,685)	(4,685)	(4,685)	(14,881)	(4,685)	(4,685)	(4,685)	(4,686)	(4,686)	(4,686)	(4,686)	(4,686)
5												
6 Forecast North Dakota Sales	203,291	203,850	171,035	168,639	174,150	172,841	198,618	180,234	167,256	170,405	202,792	-
7												
8 Current Month Refund Factor	(0.002)	(0.002)	(0.003)	(0.009)	(0.003)	(0.003)	(0.002)	-	-	-	-	-
9												
10 Expected Refund	(17,897)	(16,914)	(4,666)	7,377	2,316	(8,362)	(6,663)	(10,576)	(3,944)	(15,262)	(8,630)	(19,948)
11 Actual Refund	(17,916)	(18,780)	(11,666)	858	4,294	(2,471)	(7,404)					
12 Deviation	19	12,062	7,001	6,519	(1,978)	(5,891)	741	(10,576)	(3,944)	(15,262)	(8,630)	(19,948)
13												
14 True-up Factor	0.000	0.006	0.004	0.004	(0.001)	(0.003)	0.000	-	-	-	-	-
15												
16 Realized Margin	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	-	-	-	-	-
17												
18 Class Ratios												
19 Residential	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956	0.9956
20 C&I Non-Demand	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548	1.0548
21 C&I Demand Non-TOD	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
22 C&I Demand TOD On-Peak	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135	1.3135
23 C&I Demand TOD Off-Peak	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726	0.7726
24 Outdoor Lighting	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088	0.7088
25												
26 Realized Margin Adj for Class Ratios												
27 Residential	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	-	-	-	-	-
28 C&I Non-Demand	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	-	-	-	-	-
29 C&I Demand Non-TOD	(0.002)	0.004	0.001	(0.005)	(0.004)	(0.006)	(0.002)	-	-	-	-	-
30 C&I Demand TOD On-Peak	(0.003)	0.005	0.002	(0.007)	(0.005)	(0.008)	(0.003)	-	-	-	-	-
31 C&I Demand TOD Off-Peak	(0.002)	0.003	0.001	(0.004)	(0.003)	(0.005)	(0.002)	-	-	-	-	-
32 Outdoor Lighting	(0.002)	0.003	0.001	(0.004)	(0.003)	(0.004)	(0.001)	-	-	-	-	-