



—Via Electronic Filing—

June 30, 2009

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

**Re: July 2009 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 July 2009.

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 July 2009 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 May 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:

July 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02325
C & I Non-Demand	0.02463
C & I Demand	0.02387
C & I Demand Time of Day On-Peak	0.03068
C & I Demand Time of Day Off-Peak	0.01804
Outdoor Lighting	0.01655

## MISO CHARGES IMPLEMENTATION

### MISO Day 2 Charges

This filing includes our reporting of the Midwest Independent System Operator (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005, Xcel Energy is authorized to recover on an interim basis, subject to refund, the MISO Day 2 costs. The March FCC reflected the new MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 new Financial Transmission Rights (FTR) charge types<sup>1</sup>, to be reflected in Fuel Cost Rider. Consistent with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the July FCC, the net MISO Day 2 costs for May 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this July FCC is \$10,239,222, which is the net of many items. Pursuant to the above mentioned Orders, the Company also provides more detailed records in Attachment 2, page 1 to support the calculation of the MISO Day 2 costs.

On May 6, 2009 FERC issued Order (Docket No. EL07-86-005, *et al.*) reversing portions of the prior decision (November 2008) on MISO RSG that resulted in a resettlement adjustment in FCA. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCA.

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

## MISO ASM Charges

With the implementation of the MISO Ancillary Services Market (ASM) on January 6, 2009, the net costs or revenues of 14 new ASM charges types are included in the Fuel Cost Rider. Consistent with the MISO order and the required "net" accounting of ASM costs and revenues, we include in the July FCC, the net MISO ASM costs for May 2009 as recorded in Account 555. The MISO ASM cost recovery included in this July FCC is \$-213,104, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

## **REFUNDS**

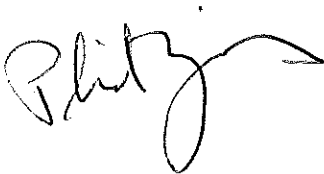
Pursuant to the above referenced Order Adopting Settlement, the May 2009 Asset Based Margin amount of \$45,081 has been included in the July Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined after the close of the calendar year and will be credited to the FCC during 2010.

## **OTHER REPORTING ITEM**

Attachment is the calculation of the July 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 Jul-2009

Jul-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
<b>System</b>	\$0.02421	-\$0.00061	-\$0.00025	\$0.02335
<b>Residential</b>	\$0.02410	-\$0.00061	-\$0.00025	\$0.02325
C & I Non-Demand	\$0.02554	-\$0.00064	-\$0.00026	\$0.02463
C & I Demand Non-TOD	\$0.02474	-\$0.00062	-\$0.00025	\$0.02387
C & I Demand TOD On-Peak	\$0.03180	-\$0.00080	-\$0.00032	\$0.03068
C & I Demand TOD Off-Peak	\$0.01870	-\$0.00047	-\$0.00019	\$0.01804
Outdoor Lighting	\$0.01716	-\$0.00043	-\$0.00017	\$0.01655
<b>Residential</b>				
Residential Service	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
Residential TOD	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
Residential - Underground	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
Residential TOD - Underground	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
Energy Control - (Non-Demand)	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
Limit Off Peak	\$ 0.02410	\$ (0.00061)	\$ (0.00025)	\$ 0.02325
<b>C &amp; I Non-Demand</b>				
Energy Controlled - (Non-Demand)	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Limit Off Peak	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Small General Service	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Small General TOD - Metered	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Small General TOD - Unmetered	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Fire and Civil Defense Siren	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
Direct Current (Closed)	\$ 0.02554	\$ (0.00064)	\$ (0.00026)	\$ 0.02463
<b>C &amp; I Demand</b>				
General Service	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
General TOD - On Peak	\$ 0.03180	\$ (0.00080)	\$ (0.00032)	\$ 0.03068
General TOD - Off Peak	\$ 0.01870	\$ (0.00047)	\$ (0.00019)	\$ 0.01804
Peak Controlled (Closed)	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Peak Controlled TOD (Closed) - On Peak	\$ 0.03180	\$ (0.00080)	\$ (0.00032)	\$ 0.03068
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01870	\$ (0.00047)	\$ (0.00019)	\$ 0.01804
Peak Controlled Tiered	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Peak Controlled Tiered TOD - On Peak	\$ 0.03180	\$ (0.00080)	\$ (0.00032)	\$ 0.03068
Peak Controlled Tiered TOD - Off Peak	\$ 0.01870	\$ (0.00047)	\$ (0.00019)	\$ 0.01804
Energy Controlled (Closed)	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Tier 1 Energy Controlled Rider	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Real Time Pricing - Firm - On Peak	\$ 0.03180	\$ (0.00080)	\$ (0.00032)	\$ 0.03068
Real Time Pricing - Firm - Off Peak	\$ 0.01870	\$ (0.00047)	\$ (0.00019)	\$ 0.01804
Real Time Pricing - Controllable - On Peak	\$ 0.03180	\$ (0.00080)	\$ (0.00032)	\$ 0.03068
Real Time Pricing - Controllable - Off Peak	\$ 0.01870	\$ (0.00047)	\$ (0.00019)	\$ 0.01804
Small Municipal Pumping	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Municipal Pumping	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
Excess Energy - St. Anthony Falls	\$ 0.02474	\$ (0.00062)	\$ (0.00025)	\$ 0.02387
<b>Outdoor Lighting</b>				
Automatic Protective Lighting	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655
Street Lighting System	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655
Street Lighting Energy	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655
Street Lighting Energy - Metered	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655
Street Lighting Energy (Closed)	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655
Street Lighting - City of St. Paul	\$ 0.01716	\$ (0.00043)	\$ (0.00017)	\$ 0.01655

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 Jul-2009

	Column (A) Feb-09	Column (B) Mar-09	Column (C) Apr-09	Column (D) May-09	Column (E) 4 Month Total
<b>Fuel and Purchased Power Costs</b>					
Account 151 - Fossil Fuel	\$40,519,694	\$44,289,260	\$38,470,249	\$31,165,671	\$154,444,874
Account 518 - Nuclear Fuel	\$7,173,261	\$6,562,615	\$5,445,252	\$6,882,519	\$26,063,647
Account 555 - Purchased Power <sup>1</sup>	\$33,961,134	\$39,969,637	\$32,424,378	\$37,336,051	\$143,691,200
Account 555 - MISO Day 2 Charges	\$10,449,675	\$8,880,133	\$9,567,159	\$10,327,685	\$39,224,652
Account 555 MISO Day 2 - Schedule 24	(\$93,039)	(\$95,992)	(\$88,819)	(\$88,464)	(\$366,313)
Account 555 MISO - ASM Charges	(\$1,111,922)	\$378,801	(\$2,293,179)	(\$213,104)	(\$3,239,405)
Total MISO Charges	\$9,244,713	\$9,162,943	\$7,185,161	\$10,026,117	\$35,618,934
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$90,898,802	\$99,984,454	\$83,525,040	\$85,410,358	\$359,818,655
Less Fuel Cost of InterSystem Sales	(\$9,812,213)	(\$9,290,280)	(\$5,646,290)	(\$10,380,755)	(\$35,129,538)
Net System Costs	\$81,086,589	\$90,694,174	\$77,878,750	\$75,029,603	\$324,689,117
<b>System MWh Sales</b>					
Total NSP System Retail	3,373,718	3,504,517	3,177,135	2,929,354	12,984,724
Non-Gen Muni's/Load Pattern	116,434	106,377	107,030	99,454	429,295
Total NSP System MWh Sales	3,490,152	3,610,894	3,284,165	3,028,808	13,414,019
<b>Average Unit Cost of Fuel and Purchased Power</b>					
Fuel Cost per kWh for NSP System	2.323¢	2.512¢	2.371¢	2.477¢	2.421¢
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	2.410¢	
(ii) C & I Non-Demand			1.0548	2.554¢	
(iii) C & I Demand Non-TOD			1.0219	2.474¢	
(iv) C & I Demand TOD On-Peak			1.3135	3.180¢	
(v) C & I Demand TOD Off-Peak			0.7726	1.870¢	
(vi) Outdoor Lighting			0.7088	1.716¢	

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

North Dakota Retail MWh Sales					
(i) Residential	84,551	81,182	64,544	49,122	279,399
(ii) C & I Non-Demand	13,462	13,734	11,046	9,216	47,458
(iii) C & I Demand Non-TOD	56,351	64,180	51,340	53,507	225,378
(iv) C & I Demand TOD On-Peak	22,074	18,857	17,941	15,235	74,107
(v) C & I Demand TOD Off-Peak	36,055	29,201	29,717	23,091	118,064
(vi) Outdoor Lighting	2,089	1,609	1,568	1,297	6,563
(vii) Total	214,582	208,763	176,156	151,468	750,969

Jul-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Mar-09 Balance of Unrecovered Expenses)	Total
	Mar-09
	(\$438,398)

Prior Expenses Recovered in May-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9967	-0.050¢	49,122	(\$24,587)
(iii) C & I Demand Non-TOD	1.0411	-0.052¢	9,216	(\$4,818)
(iv) C & I Demand TOD On-Peak	1.0164	-0.051¢	53,507	(\$27,311)
(v) C & I Demand TOD Off-Peak	1.2351	-0.062¢	15,235	(\$9,449)
(vi) Outdoor Lighting	0.8295	-0.042¢	23,091	(\$9,619)
(vii) Total	0.7816	-0.039¢	1,297	(\$509)
			151,468	(\$76,293)

Actual Cost Should Have Been Recovered in May-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.477¢	0.000¢	151,468	\$3,751,862

Cost Recovered in May-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9967	2.524¢	49,122	\$1,239,664
(ii) C & I Non-Demand	1.0411	2.636¢	9,216	\$242,940
(iii) C & I Demand Non-TOD	1.0164	2.574¢	53,507	\$1,377,016
(iv) C & I Demand TOD On-Peak	1.2351	3.127¢	15,235	\$476,440
(v) C & I Demand TOD Off-Peak	0.8295	2.100¢	23,091	\$484,979
(vi) Outdoor Lighting	0.7816	1.979¢	1,297	\$25,668
(vii) Total			151,468	\$3,846,707

Total Balance of Unrecovered Expenses (Jul-09 Balance of Unrecovered Expenses)	
Jul-2009 Recovery Provision	(\$456,949)
4 Month ND Retail Total MWh Sales	750,969
Jul-2009 Recovery Provision per KWH	-0.061¢

<b>Jul-2009 Recovery Provision (True-up Factor) per kWh by Customer Category</b>			
	<b>FAF Ratio</b>	<b>Recovery Provision Adjustment</b>	<b>Recovery Provision Adj by Class</b>
(i) Residential	0.9956	-0.061¢	-0.061¢
(ii) C & I Non-Demand	1.0548	-0.061¢	-0.064¢
(iii) C & I Demand Non-TOD	1.0219	-0.061¢	-0.062¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.061¢	-0.080¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.061¢	-0.047¢
(vi) Outdoor Lighting	0.7088	-0.061¢	-0.043¢
<b>Jul-2009 Margin Sharing Refunds</b>			
	<b>Asset Based Margin Sharing Refund</b>		<b>Total</b>
<b>Refund/Special Charge Amount</b>	(\$45,081)		(\$45,081)
(i) Residential	-0.025¢		-0.025¢
(ii) C & I Non-Demand	-0.026¢		-0.026¢
(iii) C & I Demand Non-TOD	-0.025¢		-0.025¢
(iv) C & I Demand TOD On-Peak	-0.032¢		-0.032¢
(v) C & I Demand TOD Off-Peak	-0.019¢		-0.019¢
(vi) Outdoor Lighting	-0.017¢		-0.017¢
<b>Jul-2009 Factors</b>			
			<b>Total</b>
(i) Residential			2.325¢
(ii) C & I Non-Demand			2.463¢
(iii) C & I Demand Non-TOD			2.387¢
(iv) C & I Demand TOD On-Peak			3.068¢
(v) C & I Demand TOD Off-Peak			1.804¢
(vi) Outdoor Lighting			1.655¢

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

	FCA Application		Comparison		Generation Type by Percent		
	Jun-09	Jul-09	Difference	Percent Change	FCA Application Jun-09	FCA Application Jul-09	Difference
<b>** COSTS (Millions) **</b>							
1 Fossil	\$170.4	\$154.4	(\$16.0)	-9.4%	43.8%	42.9%	-0.9%
2 Nuclear	\$27.0	\$26.1	(\$0.9)	-3.4%	6.9%	7.2%	0.3%
3 Purchases	\$147.2	\$143.7	(\$3.5)	-2.4%	37.9%	39.9%	2.0%
MISO related Purchases	\$44.0	\$35.6	(\$8.4)	-19.1%	11.3%	9.9%	-1.4%
4 Total System Costs	388.6	359.8	(\$28.8)	-7.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$34.0	\$35.1	\$1.1	3.3%	8.7%	9.8%	1.1%
6 Net System Costs	\$354.6	\$324.7	(\$30.0)	-8.4%	91.3%	90.2%	-1.1%
7							
8 <b>** GWH OUTPUT **</b>							
9 Fossil	6,483	5,960	(523)	-8.1%	39.2%	37.3%	-1.9%
10 Nuclear	4,059	3,779	(280)	-6.9%	24.6%	23.6%	-1.0%
11 Purchases	4,666	5,017	351	7.5%	28.2%	31.4%	3.2%
12 Hydro & Other	613	654	41	6.7%	3.7%	4.1%	0.4%
13 Net Interchange	698	587	(111)	-15.9%	4.2%	3.7%	-0.5%
14 Total Output	16,519	15,997	(522)	-3.2%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,638	1,909	271	16.6%	9.9%	11.9%	2.0%
16 Native Requirement	14,881	14,088	(793)	-5.3%	90.1%	88.1%	-2.0%
17							
18 <b>** COST per KWH OUTPUT (\$)</b>							
19 Fossil	2.629	2.591	-0.037	-1.4%			
20 Nuclear	0.665	0.690	0.025	3.8%			
21 Purchases	3.155	2.864	-0.291	-9.2%			
22 Total System Costs	2.353	2.249	-0.103	-4.4%			
23 Intersystem Sales	2.076	1.840	-0.235	-11.3%			
24 Net System Costs	2.383	2.305	-0.078	-3.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,392	13,414	(978)	-6.8%			
28							
29 COST per KWH SALES (\$)	2.464	2.421	-0.043	-1.7%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.188	-0.061	0.127				
(i) Residential	-0.187	-0.061	0.127				
(ii) C & I Non-Demand	-0.198	-0.064	0.134				
(iii) C & I Demand Non-TOD	-0.192	-0.062	0.130				
(iv) C & I Demand TOD On-Peak	-0.247	-0.080	0.167				
(v) C & I Demand TOD Off-Peak	-0.145	-0.047	0.098				
(vi) Outdoor Lighting	-0.133	-0.043	0.090				
32 REFUND	-0.003	-0.025	-0.022				
(i) Residential	-0.003	-0.025					
(ii) C & I Non-Demand	-0.003	-0.026					
(iii) C & I Demand Non-TOD	-0.003	-0.025					
(iv) C & I Demand TOD On-Peak	-0.003	-0.032					
(v) C & I Demand TOD Off-Peak	-0.002	-0.019					
(vi) Outdoor Lighting	-0.002	-0.017					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.273	2.335	0.062	2.7%			
(i) Residential	2.263	2.325	0.062				
(ii) C & I Non-Demand	2.398	2.463					
(iii) C & I Demand Non-TOD	2.323	2.387					
(iv) C & I Demand TOD On-Peak	2.986	3.068					
(v) C & I Demand TOD Off-Peak	1.756	1.804					
(vi) Outdoor Lighting	1.611	1.655					

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	\$0.31
750	\$0.47
1,000	\$0.62

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	
	Jun-09	Jul-09
<b>** GWH OUTPUT **</b>		
Thermal	360,714	399,128
Wind plus disper gen	(83)	(74)
Hydro	252,597	255,135
Hydro and Other	613,228	654,189
Rounded to nearest thousand:	613	654
<b>Sales</b>		
Non Gen. Munic Total	467,756,000	429,295,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,637,662,000	1,908,885,000
Rounded to nearest million:	1637.662	1908.885

		System	Intersystem	Retail
<b>May 2009 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 15,242,885.92	\$ 4,904,019.33	\$ 20,146,905.25
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 976,455.93	\$ -	\$ 976,455.93
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 3,620.26	\$ -	\$ 3,620.26
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (14,838,287.21)	\$ -	\$ (14,838,287.21)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 2,385,729.12	\$ -	\$ 2,385,729.12
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)	\$ 1,215,373.61	\$ 914,837.07	\$ 2,130,210.68
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (28,928.74)	\$ -	\$ (28,928.74)
14	Real-Time Distribution of Losses Amount	\$ (1,013,420.25)	\$ -	\$ (1,013,420.25)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 356,537.99	\$ -	\$ 356,537.99
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 131,673.18	\$ -	\$ 131,673.18
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (31,378.78)	\$ -	\$ (31,378.78)
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (1,168,501.75)	\$ -	\$ (1,168,501.75)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (40.68)	\$ -	\$ (40.68)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 2,001,955.45	\$ -	\$ 2,001,955.45
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)	\$ (56,582.00)	\$ -	\$ (56,582.00)
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)	\$ (58,600.04)	\$ -	\$ (58,600.04)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (661,438.14)	\$ -	\$ (661,438.14)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (127,346.91)	\$ -	\$ (127,346.91)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (2,414.11)	\$ -	\$ (2,414.11)
37	Financial Transmission Guarantee Uplift Amount	\$ 21,319.98	\$ -	\$ 21,319.98
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (843,077.78)	\$ -	\$ (843,077.78)
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 87,962.54	\$ -	\$ 87,962.54
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (68,867.37)	\$ -	\$ (68,867.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 499,584.42	\$ -	\$ 499,584.42
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (20,423.17)	\$ 373,666.84	\$ 353,243.67
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (260,185.86)	\$ 44,147.23	\$ (216,038.63)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 707,710.50	\$ (35,818.05)	\$ 671,892.45
19	Real-Time Market Administration Amount	\$ 68,622.71	\$ (7,196.05)	\$ 61,426.66
29	Financial Transmission Rights Market Administration Amount	\$ 81,730.00	\$ -	\$ 81,730.00
33	Day-Ahead Schedule 24 Allocation Amount	\$ 85,373.01	\$ (4,299.13)	\$ 81,073.88
34	Real-Time Schedule 24 Allocation Amount	\$ 8,256.22	\$ (866.12)	\$ 7,390.10
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	\$ (34,937.40)	\$ -	\$ (34,937.40)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ (100.43)	\$ (100.43)
<b>Auction Revenue Rights (ARR)</b>				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,221,945.90	\$ -	\$ 1,221,945.90
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,220,548.94)	\$ -	\$ (1,220,548.94)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (522,462.81)	\$ -	\$ (522,462.81)
<b>TOTAL MISO CHARGES</b>		<b>\$ 4,139,294.80</b>	<b>\$ 6,188,390.69</b>	<b>\$ 10,327,685.49</b>
<b>SCHEDULE 24 (FOR RETAIL)</b>				<b>\$ 88,463.98</b>
<b>TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)</b>				<b>\$ 10,239,221.51</b>

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

		System	Intersystem	Retail
<b>May 2009 Actual</b>				
<b>Procurement Charges</b>				
1	Day-Ahead Regulation Amount	\$ (333,569.26)	\$ (325,427.47)	\$ (658,996.73)
2	Day-Ahead Spinning Reserve Amount	\$ (62,445.72)	\$ (26,616.75)	\$ (89,062.47)
3	Day-Ahead Supplemental Reserve	\$ (19,926.90)	\$ (24,021.25)	\$ (43,948.15)
4	Real-Time Regulation Amount	\$ 32,093.62	\$ 181,271.83	\$ 213,365.45
5	Real-Time Spinning Reserve Amount	\$ (59,868.28)	\$ 44,005.44	\$ (15,862.84)
6	Real-Time Supplemental Reserve Amount.	\$ 393.39	\$ 14,406.66	\$ 14,800.05
<b>Resource Energy Charges</b>				
7a	Real Time Excessive Energy Amount	\$ (16,914.75)		\$ (16,914.75)
7b	Real Time Excessive Energy Congestion	\$ -		\$ -
7c	Real Time Excessive Energy Loss	\$ -		\$ -
8a	Real Time Non Excessive Energy Amount	\$ (276,107.82)		\$ (276,107.82)
8b	Real Time Non Excessive Energy Congestion	\$ 122,252.44		\$ 122,252.44
8c	Real Time Non Excessive Energy Loss	\$ (224,320.16)		\$ (224,320.16)
9	Real Time Net Regulation Adjustment Amount	\$ 16,132.71	\$ 9,817.29	\$ 25,950.00
<b>Cost Distribution Charges</b>				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 281,409.16	\$ 213,067.13	\$ 494,476.29
11	Real Time Spinning Reserve Cost Distribution	\$ 150,229.65	\$ 34,966.25	\$ 185,195.90
12	Real Time Supplemental Reserve Cost Distribution	\$ 15,787.43	\$ 13,291.60	\$ 29,079.03
<b>Penalty Charges</b>				
13	Real Time Excessive/Dificient Energy Deployment	\$ 32,199.74	\$ (5,210.84)	\$ 26,988.90
14	Real Time Contignecy Reserve Deployment Failure	\$ 0.59	\$ (0.16)	\$ 0.43
<b>TOTAL MISO ASM CHARGES</b>		<b>\$ (342,654.16)</b>	<b>\$ 129,549.73</b>	<b>\$ (213,104.43)</b>

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

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
True-up 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
1 Forecast Month	(173,372)	(82,316)	(64,153)	(156)	(45,284)							
2 True-up Month	191,827	174,423	167,216	169,094	182,677	182,681	177,780					
3 Monthly Refund												
4 Forecast North Dakota Sales												
5 Current Month Refund Factor	(0.090)	(0.047)	(0.038)	(0.000)	(0.025)							
6 Forecasted North Dakota Sales	191,827	174,423	191,827	174,423	167,216	169,094	182,677					
7 Actual North Dakota Sales (Cal. Mo.)	268,578	165,328	268,578	165,328	160,677	-	-					
8 Deviation	(76,751)	9,095	(76,751)	9,095	6,539	169,094	182,677					
9 Expected Refund	(173,372)	(82,316)	(173,372)	(82,316)	5,213	(4,449)	(45,081)					
10 Actual Refund	(242,738)	(78,023)	(242,738)	(78,023)	5,010	-	-					
11 Deviation	69,366	(4,293)	69,366	(4,293)	203	(4,449)	(45,081)					
12 True-up Factor			0.041	(0.003)	0.000							
13 Realized Margin	(0.090)	(0.047)	0.003	(0.003)	(0.025)							
14 Class Ratios												
15 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
16 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
17 C&I Demand Non-TOD	1.0955	1.0110	1.0164	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219	1.0219
18 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
19 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
20 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
21 Realized Margin Adj for Class Ratios												
22 Residential	(0.090)	(0.047)	0.003	(0.003)	(0.025)							
23 C&I Non-Demand	(0.092)	(0.048)	0.003	(0.003)	(0.026)							
24 C&I Demand Non-TOD	(0.091)	(0.048)	0.003	(0.003)	(0.025)							
25 C&I Demand TOD On-Peak	(0.097)	(0.055)	0.004	(0.003)	(0.032)							
26 C&I Demand TOD Off-Peak	(0.085)	(0.042)	0.003	(0.002)	(0.019)							
27 Outdoor Lighting	(0.084)	(0.040)	0.002	(0.002)	(0.017)							