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Minneapolis, Minnesota 55401-1993

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January 30, 2009

PUBLIC SERVICE COMMISSION

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

**Re: February 2009 Fuel Clause Adjustment**

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits electric fuel clause adjustment (FCA) for February 2009.

The average cost of fuel reflected in this adjustment was 2.625¢ per kWh, which was 0.122¢ lower than last month.

Combined with the recovery provision adjustment, the net adjustment to base fuel rates is 1.371¢ per kWh. The estimated FCA impact to the monthly electric bill of a residential customer using 750 kWh is approximately \$10.28, or \$2.40 less than previous month.

#### **MISO DAY 2 IMPLEMENTATION**

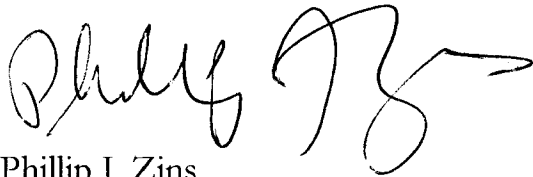
This filing includes our reporting of the Midwest Independent System Operator (“MISO”) charges under the Day 2 Market. Pursuant to the Commission’s Order (Docket No. PU-05-147) dated April 6, 2005, Xcel Energy is authorized to recover on an interim basis, subject to refund, the MISO Day 2 costs. In compliance with this Order and the required “net” accounting of Day 2 costs and revenues, we have included in the February FCA, the net MISO Day 2 costs for December 2008 as recorded in Account 555. The MISO Day 2 cost recovery included in this February FCA is \$16,032,432, which is the net of many items. Pursuant to the above mentioned Order, the Company

also provides in Exhibit 1, which contains more detailed records supporting the calculation of the MISO costs included.

Attached is the calculation of the February FCA, 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,

A handwritten signature in black ink, appearing to read "Phillip J. Zins", with a long horizontal flourish extending to the right.

Phillip J. Zins  
Manager, Pricing and Planning

Enclosures (2)  
CC: David H. Sederquist

**Northern States Power Company, A Minnesota Corporation**  
**Generation Fuel and Purchased Power Costs Per KWH (Sep-2008 - Dec-2008)**  
**North Dakota Retail - Applied in Billing Month of Feb-2009**

	Sep-2008	Oct-2008	Nov-2008	Dec-2008	Four Month Total
<u>Fuel and Purchased Power Costs</u>	(A)	(B)	(C)	(D)	(E)
1 Account 151 - Fossil Fuel	\$33,361,860	\$24,644,851	\$33,208,997	\$49,160,776	\$140,376,484
2 Account 518 - Nuclear Fuel *	\$4,707,997	\$4,964,190	\$7,360,886	\$7,964,041	\$24,997,114
3 Account 555 - Purchased Power <sup>1</sup>	\$44,982,065	\$36,792,004	\$41,092,713	\$48,506,144	\$171,372,926
Account 555 - MISO Day 2 Charges	\$29,191,592	\$30,481,109	\$18,566,013	\$16,032,432	\$94,271,146
4 Financial Instruments	\$0	\$0	\$0	\$0	\$0
5 Total System Costs	\$112,243,514	\$96,882,155	\$100,228,608	\$121,663,393	\$431,017,670
6 Less Fuel Cost of InterSystem Sales	(\$14,134,706)	(\$4,220,821)	(\$13,467,554)	(\$19,948,985)	(\$51,772,066)
7 Net System Costs	<u>\$98,108,808</u>	<u>\$92,661,334</u>	<u>\$86,761,054</u>	<u>\$101,714,408</u>	<u>\$379,245,604</u>
<b><u>Mwh Sales</u></b>					
8 Total NSP System Retail	3,889,783	3,493,004	2,865,421	3,715,105	13,963,313
9 Non-Gen Muni's/Load Pattern	126,772	119,170	117,780	122,434	486,156
10 Total NSP System Mwh Sales	<u>4,016,555</u>	<u>3,612,174</u>	<u>2,983,201</u>	<u>3,837,539</u>	<u>14,449,469</u>
11 NSP-ND Retail Mwh Sales	184,231	168,428	136,652	220,312	709,623

**Average Unit Cost of Fuel and Purchased Power**

12 Fuel Cost per Kwh for NSP System <sup>2</sup>	<u>2.443¢</u>	<u>2.565¢</u>	<u>2.908¢</u>	<u>2.651¢</u>	<u>2.625¢</u>
13 Base Fuel Cost included in rates					<u>1.092¢</u>
14 Fuel Cost in excess of Base Fuel Cost	[12E - 13E]				<u>1.533¢</u>

**Feb-2009 Recovery Provision Calculation**

15 Dec-2008 Actual cost per Kwh:	2.651¢	[12D]
16 Dec-2008 Expenses recovered per Kwh:	<u>2.942¢</u>	[Dec-2008 12E]
17 Dec-2008 Unrecovered expenses per Kwh:	-0.291¢	[line 15 - line 16]
18 Prior Unrecovered Expenses:	(\$736,955)	[Dec-2008 line 21]
19 Prior Expenses recovered in Dec-2008	(\$231,328)	[11D X Dec-2008 line 22]
20 Dec-2008 Unrecovered Expenses:	<u>(\$641,108)</u>	[11D X line 17]
21 Balance of Unrecovered Expenses	(\$1,146,735)	[line 18 - line 19 + line 20]
22 Recovery Provision adjustment per Kwh:	<u>-0.162¢</u>	[line 21 / 11E]

**Feb-2009 Fuel Clause Adjustment Factor**

23 Fuel cost adjustment per Kwh:	1.533¢	[14E]
24 Recovery provision adjustment per Kwh:	<u>-0.162¢</u>	[line 22]
25 Total Fuel Clause Adjustment per Kwh:	<u>1.371¢</u>	[line 23 + line 24]
26 Special Adjustment	<u>0.000¢</u>	
27 Adjusted Fuel Clause Factor	<u>1.371¢</u>	[line 25 + line 26]

Notes:

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

<sup>2</sup> Line 7 divided by line 10

Northern States Power Company, A Minnesota Corporation  
 Electric Operations - State of North Dakota  
 FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -  
 Prior Month Compared to Current Month FCA

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Jan-2009	Feb-2009	Differ- ence	Percent Change	FCA Application Jan-2009	Feb-2009	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$134.8	\$140.4	\$5.6	4.1%	30.3%	32.6%	2.3%
2 Nuclear	\$23.8	\$25.0	\$1.2	4.9%	5.4%	5.8%	0.4%
3 Purchases	\$177.0	\$171.4	(\$5.6)	-3.2%	39.8%	39.8%	0.0%
MISO 2 related Purchases	\$108.7	\$94.3	(\$14.4)	-13.3%	24.5%	21.9%	-2.6%
4 Total System Costs	444.3	431.0	(\$13.3)	-3.0%	100.0%	100.0%	0.0%
3 Intersystem Sales	\$44.1	\$51.8	\$7.7	17.4%	9.9%	12.0%	2.1%
6 Net System Costs	\$400.2	\$379.2	(\$21.0)	-5.2%	90.1%	88.0%	-2.1%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,986	6,094	108	1.8%	35.5%	36.0%	0.5%
10 Nuclear	3,930	4,008	78	2.0%	23.3%	23.7%	0.4%
11 Purchases	5,892	5,688	(204)	-3.5%	35.0%	33.6%	-1.4%
12 Hydro & Other	192	205	13	6.8%	1.1%	1.2%	0.1%
13 Net Interchange	840	912	72	8.6%	5.0%	5.4%	0.4%
14 Total Output	16,840	16,907	67	0.4%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,449	1,646	196	13.6%	8.6%	9.7%	1.1%
16 Native Requirement	15,391	15,261	(129)	-0.8%	91.4%	90.3%	-1.1%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	2.252	2.304	0.052	2.3%			
20 Nuclear	0.606	0.624	0.018	2.9%			
21 Purchases	3.004	3.013	0.009	0.3%			
22 Total System Costs	2.639	2.549	-0.089	-3.4%			
23 Intersystem Sales	3.042	3.146	0.104	3.4%			
24 Net System Costs	2.601	2.485	-0.116	-4.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,570	14,449	(121)	-0.8%			
28							
29 COST per KWH SALES (¢)	2.747	2.625	-0.122	-4.4%			
30							
31 RECOVERY PROV (¢ / KWH)	0.036	-0.162	-0.198				
32 REFUND	0.000	0	0.000				
33 TOTAL FCA IMPACT (¢ / KWH)	2.783	2.463	-0.320	-11.5%			

BILL IMPACT (\$'s)

Calculations:

[ 4 ] = [1]+[2]+[3]  
 [ 6 ] = [4] - [5]  
 [14] = [9]+..+[13]  
 [16] = [14] - [15]  
 [19] = [1] / [9]  
 [20] = [2] / [10]

[21] = [3] / [11]  
 [22] = [4] / [14]  
 [23] = [5] / [15]  
 [24] = [6] / [16]  
 [29] = [6] / [27]  
 [33] = [29]+[31]

kWh	Change from Previous Month
100	(\$0.32)
250	(\$0.80)
500	(\$1.60)
750	(\$2.40)
1,000	(\$3.20)

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

Exhibit 1  
 Page 1 of 1

		System	Intersystem	Retail
<b>December 2008 Actual</b>				
<b>Energy and Loss Charges</b>				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 20,334,852.60	\$ 9,343,569.90	\$ 29,678,422.50
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 5,718,109.82	\$ -	\$ 5,718,109.82
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 9,490.54	\$ -	\$ 9,490.54
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (15,001,734.57)	\$ -	\$ (15,001,734.57)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 491,486.43	\$ -	\$ 491,486.43
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)	\$ (1,148,348.51)	\$ (965,287.51)	\$ (2,113,636.02)
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 617,472.82	\$ -	\$ 617,472.82
14	Real-Time Distribution of Losses Amount	\$ (2,582,418.57)	\$ -	\$ (2,582,418.57)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 34,051.56	\$ -	\$ 34,051.56
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 2,232,135.65	\$ -	\$ 2,232,135.65
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 429.62	\$ -	\$ 429.62
<b>Congestion Related Charges</b>				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 3,944,046.12	\$ -	\$ 3,944,046.12
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 1,775.72	\$ -	\$ 1,775.72
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ (3,761,676.34)	\$ -	\$ (3,761,676.34)
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)	\$ (547,471.82)	\$ -	\$ (547,471.82)
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)	\$ (794.59)	\$ -	\$ (794.59)
<b>FTR Related Charges</b>				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (1,144,214.32)	\$ -	\$ (1,144,214.32)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (53,564.24)	\$ -	\$ (53,564.24)
31	Financial Transmission Rights Transaction Amount	\$ (2,656.46)	\$ -	\$ (2,656.46)
32	Financial Transmission Rights Yearly Allocation Amount	\$ (1,288,320.07)	\$ -	\$ (1,288,320.07)
<b>Uplift Charges</b>				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 959,254.51	\$ -	\$ 959,254.51
<b>Revenue Sufficiency Guarantee (RSG) Charges</b>				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 75,435.21	\$ -	\$ 75,435.21
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (38,302.99)	\$ -	\$ (38,302.99)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 506,472.54	\$ -	\$ 506,472.54
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (3,044,208.90)	\$ 711,698.60	\$ (2,332,510.30)
<b>Market Administration Charges</b>				
4	Day-Ahead Market Administration Amount	\$ 558,805.25	\$ (15,339.53)	\$ 543,465.72
19	Real-Time Market Administration Amount	\$ 52,447.57	\$ (7,690.13)	\$ 44,757.44
29	Financial Transmission Rights Market Administration Amount	\$ 65,067.37	\$ -	\$ 65,067.37
<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	\$ (53,862.25)	\$ -	\$ (53,862.25)
26	Real-Time Uninstructed Deviation Amount	\$ 32,722.24	\$ (1,001.48)	\$ 31,720.76
<b>TOTAL MISO CHARGES</b>		<b>\$ 6,966,481.94</b>	<b>\$ 9,065,949.85</b>	<b>\$ 16,032,431.79</b>