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MAR 31 2009

March 31, 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: April 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 April 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 April 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 February 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:

April 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02383
C & I Non-Demand	0.02454
C & I Demand	0.02414
C & I Demand Time of Day On-Peak	0.02763
C & I Demand Time of Day Off-Peak	0.02117
Outdoor Lighting	0.02040

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 types¹, 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 April FCC, the net MISO Day 2 costs for February 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this April FCC is \$10,356,635, 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 charges types are included in the Fuel

¹ Previously embedded in other FTR charge types.

Cost Rider. Consistent with the MISO order and the required "net" accounting of ASM costs and revenues, we include in the April FCC, the net MISO ASM costs for February 2009 as recorded in Account 555. The MISO ASM cost recovery included in this April FCC is \$-1,111,922, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

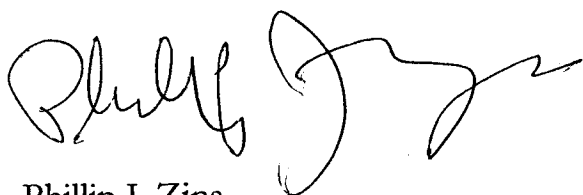
Pursuant to the above referenced Order Adopting Settlement, the February 2009 Asset Based Margin amount of \$82,316 has been included in the April Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined 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 April 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,

A handwritten signature in black ink, appearing to read "Phillip J. Zins". The signature is fluid and cursive, with a long horizontal stroke at the end.

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 Apr-2009

Apr-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02616	-\$0.00181	-\$0.00047	\$0.02388
Residential	\$0.02610	-\$0.00180	-\$0.00047	\$0.02383
C & I Non-Demand	\$0.02688	-\$0.00186	-\$0.00048	\$0.02454
C & I Demand Non-TOD	\$0.02645	-\$0.00183	-\$0.00048	\$0.02414
C & I Demand TOD On-Peak	\$0.03026	-\$0.00209	-\$0.00055	\$0.02763
C & I Demand TOD Off-Peak	\$0.02319	-\$0.00160	-\$0.00042	\$0.02117
Outdoor Lighting	\$0.02235	-\$0.00154	-\$0.00040	\$0.02040
Residential				
Residential Service	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
Residential TOD	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
Residential - Underground	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
Residential TOD - Underground	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
Energy Control - (Non-Demand)	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
Limit Off Peak	\$ 0.02610	\$ (0.00180)	\$ (0.00047)	\$ 0.02383
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Limit Off Peak	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Small General Service	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Small General TOD - Metered	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Small General TOD - Unmetered	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Fire and Civil Defense Siren	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
Direct Current (Closed)	\$ 0.02688	\$ (0.00186)	\$ (0.00048)	\$ 0.02454
C & I Demand				
General Service	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
General TOD - On Peak	\$ 0.03026	\$ (0.00209)	\$ (0.00055)	\$ 0.02763
General TOD - Off Peak	\$ 0.02319	\$ (0.00160)	\$ (0.00042)	\$ 0.02117
Peak Controlled (Closed)	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Peak Controlled TOD (Closed) - On Peak	\$ 0.03026	\$ (0.00209)	\$ (0.00055)	\$ 0.02763
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02319	\$ (0.00160)	\$ (0.00042)	\$ 0.02117
Peak Controlled Tiered	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Peak Controlled Tiered TOD - On Peak	\$ 0.03026	\$ (0.00209)	\$ (0.00055)	\$ 0.02763
Peak Controlled Tiered TOD - Off Peak	\$ 0.02319	\$ (0.00160)	\$ (0.00042)	\$ 0.02117
Energy Controlled (Closed)	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Tier 1 Energy Controlled Rider	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Real Time Pricing - Firm - On Peak	\$ 0.03026	\$ (0.00209)	\$ (0.00055)	\$ 0.02763
Real Time Pricing - Firm - Off Peak	\$ 0.02319	\$ (0.00160)	\$ (0.00042)	\$ 0.02117
Real Time Pricing - Controllable - On Peak	\$ 0.03026	\$ (0.00209)	\$ (0.00055)	\$ 0.02763
Real Time Pricing - Controllable - Off Peak	\$ 0.02319	\$ (0.00160)	\$ (0.00042)	\$ 0.02117
Small Municipal Pumping	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Municipal Pumping	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Excess Energy - St. Anthony Falls	\$ 0.02645	\$ (0.00183)	\$ (0.00048)	\$ 0.02414
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040
Street Lighting System	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040
Street Lighting Energy	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040
Street Lighting Energy - Metered	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040
Street Lighting Energy (Closed)	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040
Street Lighting - City of St. Paul	\$ 0.02235	\$ (0.00154)	\$ (0.00040)	\$ 0.02040

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 Apr-2009

	Column (A) Nov-08	Column (B) Dec-08	Column (C) Jan-09	Column (D) Feb-09	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$33,208,997	\$49,160,776	\$47,129,747	\$40,519,694	\$170,019,214
Account 518 - Nuclear Fuel	\$7,360,886	\$7,964,041	\$7,798,706	\$7,173,261	\$30,296,894
Account 555 - Purchased Power ¹	\$41,092,713	\$48,506,144	\$40,860,947	\$33,961,134	\$164,420,937
Account 555 - MISO Day 2 Charges	\$18,566,013	\$16,032,432	\$19,476,624	\$10,449,675	\$64,524,743
Account 555 MISO Day 2 - Schedule 24	\$0	\$0	(\$102,992)	(\$93,039)	(\$196,031)
Account 555 MISO - ASM Charges	\$0	\$0	(\$928,519)	(\$1,111,922)	(\$2,040,441)
Total MISO Charges	\$18,566,013	\$16,032,432	\$18,445,114	\$9,244,713	\$62,288,271
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$100,228,608	\$121,663,393	\$114,234,514	\$90,898,802	\$427,025,317
Less Fuel Cost of InterSystem Sales	(\$13,467,554)	(\$19,948,985)	(\$9,244,507)	(\$9,812,213)	(\$52,473,259)
Net System Costs	\$86,761,054	\$101,714,408	\$104,990,007	\$81,086,589	\$374,552,058
System MWH Sales					
Total NSP System Retail	2,865,421	3,715,105	3,869,018	3,373,718	13,823,262
Non-Gen Muni's/Load Pattern	117,780	122,434	137,915	116,434	494,563
Total NSP System MWh Sales	2,983,201	3,837,539	4,006,933	3,490,152	14,317,825
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.908¢	2.651¢	2.620¢	2.323¢	2.616¢
Base Fuel Cost Included in Rates	1.092¢	1.092¢	0.000¢	0.000¢	0.546¢
Class Ratio/TOD Ratio					
(i) Residential	1.0000	1.0000	0.9956	0.9956	0.9978
(ii) C & I Non-Demand	1.0000	1.0000	1.0548	1.0548	1.0274
(iii) C & I Demand Non-TOD	1.0000	1.0000	1.0219	1.0219	1.0110
(iv) C & I Demand TOD On-Peak	1.0000	1.0000	1.3135	1.3135	1.1568
(v) C & I Demand TOD Off-Peak	1.0000	1.0000	0.7726	0.7726	0.8863
(vi) Outdoor Lighting	1.0000	1.0000	0.7088	0.7088	0.8544
North Dakota Fuel Cost Factor (FCF)					
				FCF Ratio	4 Month Average
(i) Residential				0.9978	2.610¢
(ii) C & I Non-Demand				1.0274	2.688¢
(iii) C & I Demand Non-TOD				1.0110	2.645¢
(iv) C & I Demand TOD On-Peak				1.1568	3.026¢
(v) C & I Demand TOD Off-Peak				0.8863	2.319¢
(vi) Outdoor Lighting				0.8544	2.235¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	-	-	101,992	84,551	
(ii) C & I Non-Demand	-	-	17,159	13,462	
(iii) C & I Demand Non-TOD	-	-	63,019	56,351	
(iv) C & I Demand TOD On-Peak	-	-	16,065	22,074	
(v) C & I Demand TOD Off-Peak	-	-	29,158	36,055	
(vi) Outdoor Lighting	-	-	1,939	2,089	
(vii) Total	136,652	220,312	229,332	214,582	800,878

Apr-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Dec-08 Balance of Unrecovered Expenses)	Total Dec-08
	(\$1,446,735)

Prior Expenses Recovered in Feb-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	1.0000	-0.162¢	84,551	(\$136,973)
(iii) C & I Demand Non-TOD	1.0000	-0.162¢	13,462	(\$21,808)
(iv) C & I Demand TOD On-Peak	1.0000	-0.162¢	56,351	(\$91,289)
(v) C & I Demand TOD Off-Peak	1.0000	-0.162¢	22,074	(\$35,760)
(vi) Outdoor Lighting	1.0000	-0.162¢	36,055	(\$58,409)
(vii) Total	1.0000	-0.162¢	2,089	(\$3,384)
			214,582	(\$347,623)

Actual Cost Should Have Been Recovered in Feb-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.323¢	1.092¢	214,582	\$2,641,504

Cost Recovered in Feb-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	1.0000	1.533¢	84,551	\$1,296,167
(ii) C & I Non-Demand	1.0000	1.533¢	13,462	\$206,372
(iii) C & I Demand Non-TOD	1.0000	1.533¢	56,351	\$863,861
(iv) C & I Demand TOD On-Peak	1.0000	1.533¢	22,074	\$338,394
(v) C & I Demand TOD Off-Peak	1.0000	1.533¢	36,055	\$552,723
(vi) Outdoor Lighting	1.0000	1.533¢	2,089	\$32,024
(vii) Total			214,582	\$3,289,542

Total Balance of Unrecovered Expenses (Apr-09 Balance of Unrecovered Expenses)	
Apr-2009 Recovery Provision	(\$1,447,150)
4 Month ND Retail Total MWh Sales	800,878
Apr-2009 Recovery Provision per KWH	-0.181¢

Apr-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9978	-0.181¢	-0.180¢
(ii) C & I Non-Demand	1.0274	-0.181¢	-0.186¢
(iii) C & I Demand Non-TOD	1.0110	-0.181¢	-0.183¢
(iv) C & I Demand TOD On-Peak	1.1568	-0.181¢	-0.209¢
(v) C & I Demand TOD Off-Peak	0.8863	-0.181¢	-0.160¢
(vi) Outdoor Lighting	0.8544	-0.181¢	-0.154¢

Apr-2009 Margin Sharing Refunds		
	Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$82,316)	(\$82,316)
(i) Residential	-0.047¢	-0.047¢
(ii) C & I Non-Demand	-0.048¢	-0.048¢
(iii) C & I Demand Non-TOD	-0.048¢	-0.048¢
(iv) C & I Demand TOD On-Peak	-0.055¢	-0.055¢
(v) C & I Demand TOD Off-Peak	-0.042¢	-0.042¢
(vi) Outdoor Lighting	-0.040¢	-0.040¢

Apr-2009 Factors	
	Total
(i) Residential	2.383¢
(ii) C & I Non-Demand	2.454¢
(iii) C & I Demand Non-TOD	2.414¢
(iv) C & I Demand TOD On-Peak	2.763¢
(v) C & I Demand TOD Off-Peak	2.117¢
(vi) Outdoor Lighting	2.040¢

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		
	Mar-09	Apr-09	Difference	Percent Change	FCA Application Mar-09	FCA Application Apr-09	Difference
** COSTS (Millions) **							
1 Fossil	\$154.1	\$170.0	\$15.9	10.3%	35.6%	39.8%	4.2%
2 Nuclear	\$28.1	\$30.3	\$2.2	7.9%	6.5%	7.1%	0.6%
3 Purchases	\$167.3	\$164.4	(\$2.8)	-1.7%	38.6%	38.5%	-0.1%
MISO related Purchases	\$83.5	\$62.3	(\$21.2)	-25.4%	19.3%	14.6%	-4.7%
4 Total System Costs	433.0	427.0	(\$6.0)	-1.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$46.9	\$52.5	\$5.6	11.9%	10.8%	12.3%	1.5%
6 Net System Costs	\$386.1	\$374.6	(\$11.6)	-3.0%	89.2%	87.7%	-1.5%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,494	6,888	394	6.1%	37.3%	39.4%	2.1%
10 Nuclear	4,436	4,720	284	6.4%	25.5%	27.0%	1.5%
11 Purchases	5,299	4,745	(554)	-10.5%	30.4%	27.1%	-3.3%
12 Hydro & Other	244	232	(12)	-4.9%	1.4%	1.3%	-0.1%
13 Net Interchange	948	901	(47)	-5.0%	5.4%	5.2%	-0.2%
14 Total Output	17,421	17,486	65	0.4%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,741	1,886	145	8.3%	10.0%	10.8%	0.8%
16 Native Requirement	15,680	15,600	(80)	-0.5%	90.0%	89.2%	-0.8%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.374	2.468	0.095	4.0%			
20 Nuclear	0.633	0.642	0.009	1.4%			
21 Purchases	3.156	3.465	0.309	9.8%			
22 Total System Costs	2.486	2.442	-0.043	-1.7%			
23 Intersystem Sales	2.692	2.782	0.089	3.3%			
24 Net System Costs	2.463	2.401	-0.062	-2.5%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,440	14,318	(122)	-0.8%			
28							
29 COST per KWH SALES (\$)	2.674	2.616	-0.058	-2.2%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.018	-0.181	-0.163				
(i) Residential	-0.018	-0.180	-0.163				
(ii) C & I Non-Demand	-0.018	-0.186	-0.168				
(iii) C & I Demand Non-TOD	-0.018	-0.183	-0.165				
(iv) C & I Demand TOD On-Peak	-0.019	-0.209	-0.190				
(v) C & I Demand TOD Off-Peak	-0.017	-0.160	-0.144				
(vi) Outdoor Lighting	-0.016	-0.154	-0.138				
32 REFUND	-0.192	-0.047	0.145				
(i) Residential	-0.192	-0.047					
(ii) C & I Non-Demand	-0.194	-0.048					
(iii) C & I Demand Non-TOD	-0.193	-0.048					
(iv) C & I Demand TOD On-Peak	-0.199	-0.055					
(v) C & I Demand TOD Off-Peak	-0.187	-0.042					
(vi) Outdoor Lighting	-0.186	-0.040					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.464	2.388	-0.076	-3.1%			
(i) Residential	2.461	2.383	-0.078				
(ii) C & I Non-Demand	2.499	2.454					
(iii) C & I Demand Non-TOD	2.478	2.414					
(iv) C & I Demand TOD On-Peak	2.665	2.763					
(v) C & I Demand TOD Off-Peak	2.318	2.117					
(vi) Outdoor Lighting	2.277	2.040					

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	(\$0.08)
250	(\$0.20)
500	(\$0.39)
750	(\$0.59)
1,000	(\$0.78)

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	
	Mar-09	Apr-09
** GWH OUTPUT **		
Thermal	23,742	24,337
Wind plus disper gen	(110)	(103)
Hydro	220,320	208,089
Hydro and Other	243,952	232,323
Rounded to nearest thousand:	244	232
Sales		
Non Gen Munic Total	497,299,000	494,563,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,741,240,000	1,886,491,000
Rounded to nearest million:	1741.24	1886.491

		February 2009 Actual		
		System	Intersystem	Retail
Energy-Related Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 9,032,960.08	\$ 4,304,920.98	\$ 13,337,881.06
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 3,012,136.66	\$ -	\$ 3,012,136.66
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 9,340.23	\$ -	\$ 9,340.23
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (10,197,700.20)	\$ -	\$ (10,197,700.20)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,195,231.04	\$ -	\$ 1,195,231.04
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)	\$ 4,239,386.05	\$ 635,534.99	\$ 4,874,921.04
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (2,775.25)	\$ -	\$ (2,775.25)
14	Real-Time Distribution of Losses Amount	\$ (1,587,390.01)	\$ -	\$ (1,587,390.01)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 17,437.60	\$ -	\$ 17,437.60
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 40,715.21	\$ -	\$ 40,715.21
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 15,492.34	\$ -	\$ 15,492.34
Congestion-Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (264,455.02)	\$ -	\$ (264,455.02)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 168.42	\$ -	\$ 168.42
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 243,736.23	\$ -	\$ 243,736.23
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)	\$ (73,516.96)	\$ -	\$ (73,516.96)
15	Real-Time Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ 9,748.43	\$ -	\$ 9,748.43
FTR-Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ 103,869.91	\$ -	\$ 103,869.91
30	Financial Transmission Rights Monthly Allocation Amount	\$ (100,765.29)	\$ -	\$ (100,765.29)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 29,557.88	\$ -	\$ 29,557.88
37	Financial Transmission Guarantee Uplift Amount	\$ (37,049.57)	\$ -	\$ (37,049.57)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (699,427.96)	\$ -	\$ (699,427.96)
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 32,624.16	\$ -	\$ 32,624.16
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (89,919.06)	\$ -	\$ (89,919.06)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 643,444.14	\$ -	\$ 643,444.14
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (222,976.67)	\$ 85,066.71	\$ (137,909.96)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (91,023.97)	\$ 41,229.52	\$ (49,794.45)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 656,980.93	\$ (12,575.22)	\$ 644,405.71
19	Real-Time Market Administration Amount	\$ 44,755.40	\$ (3,515.42)	\$ 41,239.98
29	Financial Transmission Rights Market Administration Amount	\$ 61,628.68	\$ -	\$ 61,628.68
33	Day-Ahead Schedule 24 Allocation Amount	\$ 89,174.84	\$ (1,653.55)	\$ 87,521.29
34	Real-Time Schedule 24 Allocation Amount	\$ 5,998.04	\$ (480.24)	\$ 5,517.80
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	\$ (2,147.37)	\$ -	\$ (2,147.37)
26	Real-Time Uninstructed Deviation Amount	\$ 907.85	\$ 22.57	\$ 930.42
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,256,381.80	\$ -	\$ 1,256,381.80
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,253,289.11)	\$ -	\$ (1,253,289.11)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (718,115.31)	\$ -	\$ (718,115.31)
TOTAL MISO CHARGES		\$ 5,401,124.17	\$ 5,048,550.34	\$ 10,449,674.51
SCHEDULE 24 (FOR RETAIL)				\$ 93,039.09
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 10,356,635.42

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

	System	Intersystem	Retail
February 2009 Actual			
Procurement Charges			
1 Day-Ahead Regulation Amount	\$ (379,590.61)	\$ 290,498.38	\$ (89,092.23)
2 Day-Ahead Spinning Reserve Amount	\$ (77,880.69)	\$ 32,717.69	\$ (45,163.00)
3 Day-Ahead Supplemental Reserve	\$ (23,454.00)	\$ 22,934.25	\$ (519.75)
4 Real-Time Regulation Amount	\$ 31,077.02	\$ 18,952.75	\$ 50,029.77
5 Real-Time Spinning Reserve Amount	\$ (17,977.45)	\$ 15,658.95	\$ (2,318.50)
6 Real-Time Supplemental Reserve Amount	\$ 1,568.69	\$ (862.07)	\$ 706.62
Resource Energy Charges			
7 Real Time Excessive Energy Amount	\$ 246,080.69	\$ -	\$ 246,080.69
8 Real Time Non Excessive Enrgy Amount	\$ (1,693,850.46)	\$ -	\$ (1,693,850.46)
9 Real Time Net Regulation Adjustment Amount	\$ 3,878.99	\$ (1,954.18)	\$ 1,924.81
Cost Distribution Charges			
10 Real Time Regulation Reserve Cost Distribution Amount	\$ 368,932.07	\$ (210,724.61)	\$ 158,207.46
11 Real Time Spinning Reserve Cost Distribution	\$ 266,207.69	\$ (31,640.56)	\$ 234,567.13
12 Real Time Supplemental Reserve Cost Distribution	\$ 13,793.08	\$ (13,367.81)	\$ 425.27
Penalty Charges			
13 Real Time Excessive/Dificient Energy Deployment	\$ 38,276.77	\$ (11,196.92)	\$ 27,079.85
14 Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES	\$ (1,222,938.21)	\$ 111,015.87	\$ (1,111,922.34)

