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MAY 29 2009

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May 29, 2009

PUBLIC SERVICE COMMISSION

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

Re: June 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 June 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 June 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 April 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:

June 2009	Fuel Cost Charge (\$/kWh)
Residential	0.02263
C & I Non-Demand	0.02398
C & I Demand	0.02323
C & I Demand Time of Day On-Peak	0.02986
C & I Demand Time of Day Off-Peak	0.01756
Outdoor Lighting	0.01611

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 June FCC, the net MISO Day 2 costs for April 2009 as recorded in Account 555. The MISO Day 2 cost recovery included in this June FCC is \$9,478,340, 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.

¹ 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 June FCC, the net MISO ASM costs for April 2009 as recorded in Account 555. The MISO ASM cost recovery included in this May FCC is \$-2,293,179, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

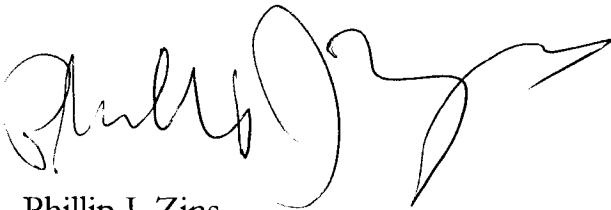
Pursuant to the above referenced Order Adopting Settlement, the April 2009 Asset Based Margin amount of \$4,449 has been included in the June Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. The 2009 North Dakota retail share of the Non-Asset Based Margins will be determined 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 June 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', with a long, sweeping horizontal stroke extending to the right.

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 Jun-2009

Jun-2009 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02464	-\$0.00188	-\$0.00003	\$0.02273
Residential	\$0.02453	-\$0.00187	-\$0.00003	\$0.02263
C & I Non-Demand	\$0.02599	-\$0.00198	-\$0.00003	\$0.02398
C & I Demand Non-TOD	\$0.02518	-\$0.00192	-\$0.00003	\$0.02323
C & I Demand TOD On-Peak	\$0.03236	-\$0.00247	-\$0.00003	\$0.02986
C & I Demand TOD Off-Peak	\$0.01904	-\$0.00145	-\$0.00002	\$0.01756
Outdoor Lighting	\$0.01746	-\$0.00133	-\$0.00002	\$0.01611
Residential				
Residential Service	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
Residential TOD	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
Residential - Underground	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
Residential TOD - Underground	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
Energy Control - (Non-Demand)	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
Limit Off Peak	\$ 0.02453	\$ (0.00187)	\$ (0.00003)	\$ 0.02263
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Limit Off Peak	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Small General Service	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Small General TOD - Metered	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Small General TOD - Unmetered	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Fire and Civil Defense Siren	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
Direct Current (Closed)	\$ 0.02599	\$ (0.00198)	\$ (0.00003)	\$ 0.02398
C & I Demand				
General Service	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
General TOD - On Peak	\$ 0.03236	\$ (0.00247)	\$ (0.00003)	\$ 0.02986
General TOD - Off Peak	\$ 0.01904	\$ (0.00145)	\$ (0.00002)	\$ 0.01756
Peak Controlled (Closed)	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Peak Controlled TOD (Closed) - On Peak	\$ 0.03236	\$ (0.00247)	\$ (0.00003)	\$ 0.02986
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01904	\$ (0.00145)	\$ (0.00002)	\$ 0.01756
Peak Controlled Tiered	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Peak Controlled Tiered TOD - On Peak	\$ 0.03236	\$ (0.00247)	\$ (0.00003)	\$ 0.02986
Peak Controlled Tiered TOD - Off Peak	\$ 0.01904	\$ (0.00145)	\$ (0.00002)	\$ 0.01756
Energy Controlled (Closed)	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Tier 1 Energy Controlled Rider	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Real Time Pricing - Firm - On Peak	\$ 0.03236	\$ (0.00247)	\$ (0.00003)	\$ 0.02986
Real Time Pricing - Firm - Off Peak	\$ 0.01904	\$ (0.00145)	\$ (0.00002)	\$ 0.01756
Real Time Pricing - Controllable - On Peak	\$ 0.03236	\$ (0.00247)	\$ (0.00003)	\$ 0.02986
Real Time Pricing - Controllable - Off Peak	\$ 0.01904	\$ (0.00145)	\$ (0.00002)	\$ 0.01756
Small Municipal Pumping	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Municipal Pumping	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Excess Energy - St. Anthony Falls	\$ 0.02518	\$ (0.00192)	\$ (0.00003)	\$ 0.02323
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611
Street Lighting System	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611
Street Lighting Energy	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611
Street Lighting Energy - Metered	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611
Street Lighting Energy (Closed)	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611
Street Lighting - City of St. Paul	\$ 0.01746	\$ (0.00133)	\$ (0.00002)	\$ 0.01611

Electric Operations - State of North Dakota

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for Jun-2009

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jan-09	Feb-09	Mar-09	Apr-09	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$47,129,747	\$40,519,694	\$44,289,260	\$38,470,249	\$170,408,950
Account 518 - Nuclear Fuel	\$7,798,706	\$7,173,261	\$6,562,615	\$5,445,252	\$26,979,834
Account 555 - Purchased Power ¹	\$40,860,947	\$33,961,134	\$39,969,637	\$32,424,378	\$147,216,096
Account 555 - MISO Day 2 Charges	\$19,476,624	\$10,449,675	\$8,880,133	\$9,567,159	\$48,373,591
Account 555 MISO Day 2 - Schedule 24	(\$102,992)	(\$93,039)	(\$95,992)	(\$88,819)	(\$380,841)
Account 555 MISO - ASM Charges	(\$928,519)	(\$1,111,922)	\$378,801	(\$2,293,179)	(\$3,954,819)
Total MISO Charges	\$18,445,114	\$9,244,713	\$9,162,943	\$7,185,161	\$44,037,931
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$114,234,514	\$90,898,802	\$99,984,454	\$83,525,040	\$388,642,811
Less Fuel Cost of InterSystem Sales	(\$9,244,507)	(\$9,812,213)	(\$9,290,280)	(\$5,646,290)	(\$33,993,290)
Net System Costs	\$104,990,007	\$81,086,589	\$90,694,174	\$77,878,750	\$354,649,521
System MWh Sales					
Total NSP System Retail	3,869,018	3,373,718	3,504,517	3,177,135	13,924,388
Non-Gen Muni's/Load Pattern	137,915	116,434	106,377	107,030	467,756
Total NSP System MWh Sales	4,006,933	3,490,152	3,610,894	3,284,165	14,392,144
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.620¢	2.323¢	2.512¢	2.371¢	2.464¢
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	2.453¢
(ii) C & I Non-Demand				1.0548	2.599¢
(iii) C & I Demand Non-TOD				1.0219	2.518¢
(iv) C & I Demand TOD On-Peak				1.3135	3.236¢
(v) C & I Demand TOD Off-Peak				0.7726	1.904¢
(vi) Outdoor Lighting				0.7088	1.746¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
(i) Residential	101,992	84,551	81,182	64,544	332,269
(ii) C & I Non-Demand	17,159	13,462	13,734	11,046	55,401
(iii) C & I Demand Non-TOD	63,019	56,351	64,180	51,340	234,890
(iv) C & I Demand TOD On-Peak	16,065	22,074	18,857	17,941	74,937
(v) C & I Demand TOD Off-Peak	29,158	36,055	29,201	29,717	124,131
(vi) Outdoor Lighting	1,939	2,089	1,609	1,568	7,205
(vii) Total	229,332	214,582	208,763	176,156	828,833

Jun-2009 Recovery Provision (True-up Factor) Calculation	
Prior Unrecovered Expenses (Feb-09 Balance of Unrecovered Expenses)	Total Feb-09 (\$1,447,150)

Prior Expenses Recovered in Apr-2009				
	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
(i) Residential				
(ii) C & I Non-Demand	0.9978	-0.180¢	64,544	(\$116,371)
(iii) C & I Demand Non-TOD	1.0274	-0.186¢	11,046	(\$20,506)
(iv) C & I Demand TOD On-Peak	1.0110	-0.183¢	51,340	(\$93,789)
(v) C & I Demand TOD Off-Peak	1.1568	-0.209¢	17,941	(\$37,502)
(vi) Outdoor Lighting	0.8863	-0.160¢	29,717	(\$47,592)
(vii) Total	0.8544	-0.154¢	176,156	(\$318,181)

Actual Cost Should Have Been Recovered in Apr-09				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.371¢	0.000¢	176,156	\$4,176,659

Cost Recovered in Apr-09				
	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9978	2.610¢	64,544	\$1,684,757
(ii) C & I Non-Demand	1.0274	2.688¢	11,046	\$296,881
(iii) C & I Demand Non-TOD	1.0110	2.645¢	51,340	\$1,357,828
(iv) C & I Demand TOD On-Peak	1.1568	3.026¢	17,941	\$542,929
(v) C & I Demand TOD Off-Peak	0.8863	2.319¢	29,717	\$689,007
(vi) Outdoor Lighting	0.8544	2.235¢	1,568	\$35,047
(vii) Total			176,156	\$4,606,447

Total Balance of Unrecovered Expenses (Jun-09 Balance of Unrecovered Expenses)	
Jun-2009 Recovery Provision	(\$1,558,757)
4 Month ND Retail Total MWh Sales	828,833
Jun-2009 Recovery Provision per KWH	-0.188¢

Jun-2009 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.188¢	-0.187¢
(ii) C & I Non-Demand	1.0548	-0.188¢	-0.198¢
(iii) C & I Demand Non-TOD	1.0219	-0.188¢	-0.192¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.188¢	-0.247¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.188¢	-0.145¢
(vi) Outdoor Lighting	0.7088	-0.188¢	-0.133¢
Jun-2009 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund		Total
Refund/Special Charge Amount	(\$4,449)		(\$4,449)
(i) Residential	-0.003¢		-0.003¢
(ii) C & I Non-Demand	-0.003¢		-0.003¢
(iii) C & I Demand Non-TOD	-0.003¢		-0.003¢
(iv) C & I Demand TOD On-Peak	-0.003¢		-0.003¢
(v) C & I Demand TOD Off-Peak	-0.002¢		-0.002¢
(vi) Outdoor Lighting	-0.002¢		-0.002¢
Jun-2009 Factors			
			Total
(i) Residential			2.263¢
(ii) C & I Non-Demand			2.398¢
(iii) C & I Demand Non-TOD			2.323¢
(iv) C & I Demand TOD On-Peak			2.986¢
(v) C & I Demand TOD Off-Peak			1.756¢
(vi) Outdoor Lighting			1.611¢

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		
	May-09	Jun-09	Differ- ence	Percent Change	FCA Application May-09	Jun-09	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$181.1	\$170.4	(\$10.7)	-5.9%	42.4%	43.8%	1.4%
2 Nuclear	\$29.5	\$27.0	(\$2.5)	-8.5%	6.9%	6.9%	0.0%
3 Purchases	\$163.3	\$147.2	(\$16.1)	-9.8%	38.3%	37.9%	-0.4%
MISO related Purchases	\$52.9	\$44.0	(\$8.8)	-16.7%	12.4%	11.3%	-1.1%
4 Total System Costs	426.8	388.6	(\$38.1)	-8.9%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$48.3	\$34.0	(\$14.3)	-29.6%	11.3%	8.7%	-2.6%
6 Net System Costs	\$378.5	\$354.6	(\$23.8)	-6.3%	88.7%	91.3%	2.6%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,934	6,483	(451)	-6.5%	39.5%	39.2%	-0.3%
10 Nuclear	4,541	4,059	(482)	-10.6%	25.9%	24.6%	-1.3%
11 Purchases	4,789	4,666	(123)	-2.6%	27.3%	28.2%	0.9%
12 Hydro & Other	423	613	190	44.9%	2.4%	3.7%	1.3%
13 Net Interchange	849	698	(151)	-17.8%	4.8%	4.2%	-0.6%
14 Total Output	17,536	16,519	(1,017)	-5.8%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,839	1,638	(201)	-10.9%	10.5%	9.9%	-0.6%
16 Native Requirement	15,697	14,881	(816)	-5.2%	89.5%	90.1%	0.6%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.612	2.629	0.017	0.6%			
20 Nuclear	0.650	0.665	0.015	2.3%			
21 Purchases	3.410	3.155	-0.255	-7.5%			
22 Total System Costs	2.434	2.353	-0.081	-3.3%			
23 Intersystem Sales	2.627	2.076	-0.551	-21.0%			
24 Net System Costs	2.411	2.383	-0.028	-1.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,946	14,392	(554)	-3.7%			
28							
29 COST per KWH SALES (\$)	2.532	2.464	-0.068	-2.7%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.050	-0.188	-0.138				
(i) Residential	-0.050	-0.187	-0.137				
(ii) C & I Non-Demand	-0.052	-0.198	-0.146				
(iii) C & I Demand Non-TOD	-0.051	-0.192	-0.141				
(iv) C & I Demand TOD On-Peak	-0.062	-0.247	-0.185				
(v) C & I Demand TOD Off-Peak	-0.042	-0.145	-0.104				
(vi) Outdoor Lighting	-0.039	-0.133	-0.094				
32 REFUND	0.003	-0.003	-0.006				
(i) Residential	0.003	-0.003					
(ii) C & I Non-Demand	0.003	-0.003					
(iii) C & I Demand Non-TOD	0.003	-0.003					
(iv) C & I Demand TOD On-Peak	0.004	-0.003					
(v) C & I Demand TOD Off-Peak	0.003	-0.002					
(vi) Outdoor Lighting	0.002	-0.002					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.485	2.273	-0.211	-8.5%			
(i) Residential	2.477	2.263	-0.214				
(ii) C & I Non-Demand	2.587	2.398					
(iii) C & I Demand Non-TOD	2.526	2.323					
(iv) C & I Demand TOD On-Peak	3.069	2.986					
(v) C & I Demand TOD Off-Peak	2.061	1.756					
(vi) Outdoor Lighting	1.942	1.611					

Residential BILL IMPACT (\$'s)

Calculations:

	Change from Previous Month
[4] = [1]+[2]+[3]	
[6] = [4] - [5]	100 (\$0.21)
[14] = [9]+...+[13]	250 (\$0.53)
[16] = [14] - [15]	500 (\$1.07)
[19] = [1] / [9]	750 (\$1.60)
[20] = [2] / [10]	1,000 (\$2.14)
[21] = [3] / [11]	
[22] = [4] / [14]	
[23] = [5] / [15]	
[24] = [6] / [16]	
[29] = [6] / [27]	
[33] = [29]+[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.

	FCA Application	
	May-09	Jun-09
** GWH OUTPUT **		
Thermal	187,560	360,714
Wind plus disper gen	(92)	(83)
Hydro	235,397	252,597
Hydro and Other	422,865	613,228
Rounded to nearest thousand:	423	613
Sales		
Non Gen Munic Total	483,160,000	467,756,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,838,713,000	1,637,662,000
Rounded to nearest million:	1838.713	1637.662

		System	Intersystem	Retail
April 2009 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 16,310,732.25	\$ 1,805,567.52	\$ 18,116,299.77
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,566,249.22	\$ -	\$ 1,566,249.22
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 2,578.37	\$ -	\$ 2,578.37
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (8,670,541.34)	\$ -	\$ (8,670,541.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,079,744.97	\$ -	\$ 1,079,744.97
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)	\$ (321,715.13)	\$ 890,594.45	\$ 568,879.32
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 12,114.32	\$ -	\$ 12,114.32
14	Real-Time Distribution of Losses Amount	\$ (1,154,046.07)	\$ -	\$ (1,154,046.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 131,695.17	\$ -	\$ 131,695.17
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (539,396.86)	\$ -	\$ (539,396.86)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 100,433.90	\$ -	\$ 100,433.90
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (49,062.78)	\$ -	\$ (49,062.78)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 96.18	\$ -	\$ 96.18
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 841,532.19	\$ -	\$ 841,532.19
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)	\$ 380,445.08	\$ -	\$ 380,445.08
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)	\$ 513,736.37	\$ -	\$ 513,736.37
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (606,193.29)	\$ -	\$ (606,193.29)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (57,009.17)	\$ -	\$ (57,009.17)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ 43,160.85	\$ -	\$ 43,160.85
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 78,700.99	\$ -	\$ 78,700.99
37	Financial Transmission Guarantee Uplift Amount	\$ (81,601.96)	\$ -	\$ (81,601.96)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ (3,129,051.17)	\$ -	\$ (3,129,051.17)
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 103,297.26	\$ -	\$ 103,297.26
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (197,189.61)	\$ -	\$ (197,189.61)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 691,908.52	\$ -	\$ 691,908.52
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (134,701.45)	\$ (51,690.21)	\$ (186,391.66)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (212,135.09)	\$ 49,590.61	\$ (162,544.48)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 637,574.14	\$ (11,377.76)	\$ 626,196.38
19	Real-Time Market Administration Amount	\$ 53,038.96	\$ (8,254.68)	\$ 44,784.28
29	Financial Transmission Rights Market Administration Amount	\$ 68,399.20	\$ -	\$ 68,399.20
33	Day-Ahead Schedule 24 Allocation Amount	\$ 84,328.31	\$ (1,467.15)	\$ 82,861.16
34	Real-Time Schedule 24 Allocation Amount	\$ 7,045.14	\$ (1,087.45)	\$ 5,957.69
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	\$ (146,089.51)	\$ -	\$ (146,089.51)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ 590.96	\$ 590.96
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 1,225,019.78	\$ -	\$ 1,225,019.78
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (1,223,639.77)	\$ -	\$ (1,223,639.77)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (514,765.39)	\$ -	\$ (514,765.39)
TOTAL MISO CHARGES		\$ 6,894,692.58	\$ 2,672,466.29	\$ 9,567,158.87
SCHEDULE 24 (FOR RETAIL)				\$ 88,818.85
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 9,478,340.02

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
April 2009 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (429,209.50)	\$ -	\$ (429,209.50)
2	Day-Ahead Spinning Reserve Amount	\$ (110,151.81)	\$ -	\$ (110,151.81)
3	Day-Ahead Supplemental Reserve	\$ (19,505.85)	\$ -	\$ (19,505.85)
4	Real-Time Regulation Amount	\$ 76,513.55	\$ 109,044.94	\$ 185,558.49
5	Real-Time Spinning Reserve Amount	\$ (21,641.70)	\$ 34,867.73	\$ 13,226.03
6	Real-Time Supplemental Reserve Amount	\$ 534.12	\$ 5,503.08	\$ 6,037.20
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (19,498.77)	\$ -	\$ (19,498.77)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (4,691,833.55)	\$ -	\$ (4,691,833.55)
8b	Real Time Non Excessive Energy Congestion	\$ 1,437,427.86	\$ -	\$ 1,437,427.86
8c	Real Time Non Excessive Energy Loss	\$ 797,260.94	\$ -	\$ 797,260.94
9	Real Time Net Regulation Adjustment Amount	\$ 8,676.92	\$ (4,286.66)	\$ 4,390.26
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 335,271.04	\$ -	\$ 335,271.04
11	Real Time Spinning Reserve Cost Distribution	\$ 202,108.27	\$ -	\$ 202,108.27
12	Real Time Supplemental Reserve Cost Distribution	\$ 14,785.44	\$ -	\$ 14,785.44
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ (15,723.87)	\$ (3,321.31)	\$ (19,045.18)
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ (2,434,986.91)	\$ 141,807.78	\$ (2,293,179.13)

