



414 Nicollet Mall
Minneapolis, Minnesota 55401

RECEIVED

APR 29 2010

—Via Electronic Filing—

PUBLIC SERVICE COMMISSION

April 29, 2010

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

Re: May 2010 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 May 2010.

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 "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The May 2010 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 March 2010 calendar month.

The former system average monthly fuel cost charge 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:

May 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02304
C & I Non-Demand	0.02441
C & I Demand	0.02365
C & I Demand Time of Day On-Peak	0.03040
C & I Demand Time of Day Off-Peak	0.01788
Outdoor Lighting	0.01640

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 PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March FCC 2009 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 May FCC, the net MISO Day 2 costs for March 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this May FCC is \$20,121,844, 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 FCC. The Company is in the process of evaluating this reversal impact and will reflect this adjustment in the subsequent FCC.

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, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the May FCC, the net MISO ASM costs for March 2010 as recorded in Account 555. The MISO ASM cost recovery included in this May FCC is \$-1,583,580 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 March 2010 Asset Based Margin amount of \$57,511 has been included in the May Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2010, the 2009 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 2009 Non-Asset Based Margin credit is \$201,971 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the May FCC is \$17,168, or 0.01¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment is the calculation of the May 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

May-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02424	-\$0.00064	-\$0.00035	\$0.02325
Residential	\$0.02413	-\$0.00064	-\$0.00045	\$0.02304
C & I Non-Demand	\$0.02557	-\$0.00068	-\$0.00048	\$0.02441
C & I Demand Non-TOD	\$0.02477	-\$0.00066	-\$0.00046	\$0.02365
C & I Demand TOD On-Peak	\$0.03184	-\$0.00085	-\$0.00060	\$0.03040
C & I Demand TOD Off-Peak	\$0.01873	-\$0.00050	-\$0.00035	\$0.01788
Outdoor Lighting	\$0.01718	-\$0.00046	-\$0.00032	\$0.01640
Residential				
Residential Service	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
Residential TOD	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
Residential - Underground	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
Residential TOD - Underground	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
Energy Control - (Non-Demand)	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
Limit Off Peak	\$ 0.02413	\$ (0.00064)	\$ (0.00045)	\$ 0.02304
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Limit Off Peak	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Small General Service	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Small General TOD - Metered	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Small General TOD - Unmetered	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Fire and Civil Defense Siren	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
Direct Current (Closed)	\$ 0.02557	\$ (0.00068)	\$ (0.00048)	\$ 0.02441
C & I Demand				
General Service	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
General TOD - On Peak	\$ 0.03184	\$ (0.00085)	\$ (0.00060)	\$ 0.03040
General TOD - Off Peak	\$ 0.01873	\$ (0.00050)	\$ (0.00035)	\$ 0.01788
Peak Controlled (Closed)	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Peak Controlled TOD (Closed) - On Peak	\$ 0.03184	\$ (0.00085)	\$ (0.00060)	\$ 0.03040
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01873	\$ (0.00050)	\$ (0.00035)	\$ 0.01788
Peak Controlled Tiered	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Peak Controlled Tiered TOD - On Peak	\$ 0.03184	\$ (0.00085)	\$ (0.00060)	\$ 0.03040
Peak Controlled Tiered TOD - Off Peak	\$ 0.01873	\$ (0.00050)	\$ (0.00035)	\$ 0.01788
Energy Controlled (Closed)	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Tier 1 Energy Controlled Rider	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Real Time Pricing - Firm - On Peak	\$ 0.03184	\$ (0.00085)	\$ (0.00060)	\$ 0.03040
Real Time Pricing - Firm - Off Peak	\$ 0.01873	\$ (0.00050)	\$ (0.00035)	\$ 0.01788
Real Time Pricing - Controllable - On Peak	\$ 0.03184	\$ (0.00085)	\$ (0.00060)	\$ 0.03040
Real Time Pricing - Controllable - Off Peak	\$ 0.01873	\$ (0.00050)	\$ (0.00035)	\$ 0.01788
Small Municipal Pumping	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Municipal Pumping	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Excess Energy - St. Anthony Falls	\$ 0.02477	\$ (0.00066)	\$ (0.00046)	\$ 0.02365
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640
Street Lighting System	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640
Street Lighting Energy	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640
Street Lighting Energy - Metered	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640
Street Lighting Energy (Closed)	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640
Street Lighting - City of St. Paul	\$ 0.01718	\$ (0.00046)	\$ (0.00032)	\$ 0.01640

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 May-2010

	Column (A) Dec-09	Column (B) Jan-10	Column (C) Feb-10	Column (D) Mar-10	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$38,057,196	\$42,972,111	\$38,278,709	\$27,468,130	\$146,776,146
Account 518 - Nuclear Fuel	\$10,825,157	\$10,021,593	\$8,941,917	\$9,775,774	\$39,564,440
Account 555 - Purchased Power ¹	\$37,855,140	\$41,322,966	\$28,152,883	\$34,011,198	\$141,342,187
Account 555 - MISO Day 2 Charges	\$18,990,451	\$21,515,761	\$14,484,703	\$20,208,392	\$75,199,307
Account 555 MISO Day 2 - Schedule 24	(\$95,539)	(\$95,015)	(\$86,498)	(\$86,548)	(\$363,599)
Account 555 MISO - ASM Charges	\$364,562	(\$2,393,364)	(\$214,099)	(\$1,583,580)	(\$3,826,480)
Total MISO Charges	\$19,259,474	\$19,027,383	\$14,184,106	\$18,538,264	\$71,009,227
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$105,996,967	\$113,344,053	\$89,557,614	\$89,793,366	\$398,691,999
Less Fuel Cost of InterSystem Sales	(\$13,102,962)	(\$18,446,370)	(\$7,919,136)	(\$7,682,321)	(\$47,150,789)
Net System Costs	\$92,894,005	\$94,897,683	\$81,638,478	\$82,111,045	\$351,541,210
System MWH Sales					
Total NSP System Retail	3,532,758	3,750,363	3,303,570	3,553,751	14,140,442
Non-Gen Muni's/Load Pattern	97,380	115,112	80,653	71,253	364,398
Total NSP System MWh Sales	3,630,138	3,865,475	3,384,223	3,625,004	14,504,840
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.559¢	2.455¢	2.412¢	2.265¢	2.424¢
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	2.413¢
(ii) C & I Non-Demand				1.0548	2.557¢
(iii) C & I Demand Non-TOD				1.0219	2.477¢
(iv) C & I Demand TOD On-Peak				1.3135	3.184¢
(v) C & I Demand TOD Off-Peak				0.7726	1.873¢
(vi) Outdoor Lighting				0.7088	1.718¢

¹ Excludes demand-related expenses

North Dakota Retail MWh Sales					
i) Residential	78,441	95,482	80,469	76,676	331,068
ii) C & I Non-Demand	12,512	14,539	12,538	13,603	53,192
iii) C & I Demand Non-TOD	62,568	60,391	58,775	67,572	249,306
iv) C & I Demand TOD On-Peak	16,314	16,696	17,869	22,810	73,689
v) C & I Demand TOD Off-Peak	26,194	28,351	28,482	36,695	119,722
vi) Outdoor Lighting	1,698	2,411	1,654	1,989	7,752
vii) Total	197,727	217,870	199,787	219,345	834,729

May-2010 Recovery Provision (True-up Factor) Calculation

Prior Unrecovered Expenses (Jan-10 Balance of Unrecovered Expenses)	Total
	Jan-10
	(\$107,688)

Prior Expenses Recovered in Mar-2010

	FCF Ratio	True-Up Factor per kWh	Actual ND MWh Sales	Prior Recovered Expenses in
i) Residential				
ii) C & I Non-Demand	0.9956	-0.014¢	76,676	(\$11,026)
iii) C & I Demand Non-TOD	1.0548	-0.015¢	13,603	(\$2,073)
iv) C & I Demand TOD On-Peak	1.0219	-0.015¢	67,572	(\$9,974)
v) C & I Demand TOD Off-Peak	1.3135	-0.019¢	22,810	(\$4,328)
vi) Outdoor Lighting	0.7726	-0.011¢	36,695	(\$4,095)
vii) Total	0.7088	-0.010¢	219,345	(\$31,700)

Actual Cost Should Have Been Recovered in Mar-10

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.265¢	0.000¢	219,345	\$4,968,164

Cost Recovered in Mar-10

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
i) Residential	0.9956	2.463¢	76,676	\$1,888,617
ii) C & I Non-Demand	1.0548	2.610¢	13,603	\$354,980
iii) C & I Demand Non-TOD	1.0219	2.528¢	67,572	\$1,708,342
iv) C & I Demand TOD On-Peak	1.3135	3.250¢	22,810	\$741,234
v) C & I Demand TOD Off-Peak	0.7726	1.911¢	36,695	\$701,393
vi) Outdoor Lighting	0.7088	1.754¢	1,989	\$34,879
vii) Total			219,345	\$5,429,445

Total Balance of Unrecovered Expenses (May-10 Balance of Unrecovered Expenses)

May-2010 Recovery Provision	(\$537,269)
-----------------------------	-------------

Month ND Retail Total MWh Sales	834,729
---------------------------------	---------

May-2010 Recovery Provision per KWH	-0.064¢
-------------------------------------	---------

May-2010 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.064¢	-0.064¢
(ii) C & I Non-Demand	1.0548	-0.064¢	-0.068¢
(iii) C & I Demand Non-TOD	1.0219	-0.064¢	-0.066¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.064¢	-0.085¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.064¢	-0.050¢
(vi) Outdoor Lighting	0.7088	-0.064¢	-0.046¢
May-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$57,511)	(\$17,168)	(\$74,680)
(i) Residential	-0.035¢	-0.010¢	-0.045¢
(ii) C & I Non-Demand	-0.037¢	-0.011¢	-0.048¢
(iii) C & I Demand Non-TOD	-0.036¢	-0.011¢	-0.046¢
(iv) C & I Demand TOD On-Peak	-0.046¢	-0.014¢	-0.060¢
(v) C & I Demand TOD Off-Peak	-0.027¢	-0.008¢	-0.035¢
(vi) Outdoor Lighting	-0.025¢	-0.007¢	-0.032¢
May-2010 Factors			
	Total		
(i) Residential	2.304¢		
(ii) C & I Non-Demand	2.441¢		
(iii) C & I Demand Non-TOD	2.365¢		
(iv) C & I Demand TOD On-Peak	3.040¢		
(v) C & I Demand TOD Off-Peak	1.788¢		
(vi) Outdoor Lighting	1.640¢		

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>		
	Apr-10	May-10	Difference	Percent Change	Apr-10	May-10	Difference
** COSTS (Millions) **							
1 Fossil	\$151.8	\$146.8	(\$5.0)	-3.3%	38.6%	36.8%	-1.8%
2 Nuclear	\$35.6	\$39.6	\$3.9	11.1%	9.1%	9.9%	0.8%
3 Purchases	\$137.7	\$141.3	\$3.7	2.7%	35.0%	35.5%	0.5%
MISO related Purchases	\$67.8	\$71.0	\$3.2	4.7%	17.3%	17.8%	0.5%
4 Total System Costs	392.9	398.7	\$5.8	1.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$45.5	\$47.2	\$1.6	3.5%	11.6%	11.8%	0.2%
6 Net System Costs	\$347.4	\$351.5	\$4.2	1.2%	88.4%	88.2%	-0.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,145	5,808	(337)	-5.5%	20.4%	16.8%	-3.6%
10 Nuclear	4,472	4,834	362	8.1%	14.9%	14.0%	-0.9%
11 Purchases	4,437	4,591	154	3.5%	14.7%	13.3%	-1.4%
12 Hydro & Other	856	851	(5)	-0.6%	2.8%	2.5%	-0.3%
13 Net Interchange	14,180	18,398	4,218	29.7%	47.1%	53.4%	6.3%
14 Total Output	30,090	34,482	4,392	14.6%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,594	1,622	29	1.8%	5.3%	4.7%	-0.6%
16 Native Requirement	28,496	32,860	4,363	15.3%	94.7%	95.3%	0.6%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.470	2.527	0.057	2.3%			
20 Nuclear	0.796	0.818	0.022	2.8%			
21 Purchases	3.103	3.079	-0.024	-0.8%			
22 Total System Costs	1.306	1.156	-0.150	-11.5%			
23 Intersystem Sales	2.858	2.906	0.048	1.7%			
24 Net System Costs	1.219	1.070	-0.149	-12.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,932	14,505	573	4.1%			
28							
29 COST per KWH SALES (\$))	2.493	2.424	-0.069	-2.8%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.039	-0.064	-0.026				
(i) Residential	-0.039	-0.064	-0.026				
(ii) C & I Non-Demand	-0.041	-0.068	-0.027				
(iii) C & I Demand Non-TOD	-0.040	-0.066	-0.026				
(iv) C & I Demand TOD On-Peak	-0.051	-0.085	-0.034				
(v) C & I Demand TOD Off-Peak	-0.030	-0.050	-0.020				
(vi) Outdoor Lighting	-0.027	-0.046	-0.018				
32 REFUND	-0.006	0.000	0.006				
(i) Residential	-0.006	-0.045					
(ii) C & I Non-Demand	-0.006	-0.048					
(iii) C & I Demand Non-TOD	-0.006	-0.046					
(iv) C & I Demand TOD On-Peak	-0.008	-0.060					
(v) C & I Demand TOD Off-Peak	-0.005	-0.035					
(vi) Outdoor Lighting	-0.004	-0.032					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.448	2.360	-0.089	-3.6%			
(i) Residential	2.438	2.304	-0.134				
(ii) C & I Non-Demand	2.583	2.441					
(iii) C & I Demand Non-TOD	2.502	2.365					
(iv) C & I Demand TOD On-Peak	3.216	3.040					
(v) C & I Demand TOD Off-Peak	1.892	1.788					
(vi) Outdoor Lighting	1.736	1.640					

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	(\$0.67)
750	(\$1.00)
1,000	(\$1.34)

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>	
	Apr-10	May-10
** GWH OUTPUT **		
Thermal	707,114	670,538
Wind plus disper gen	(88)	(94)
Hydro	148,608	180,253
Hydro and Other	855,634	850,697
Rounded to nearest thousand:	856	851
Sales		
Non Gen Munic Total	396,936,000	364,398,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,593,526,000	1,622,261,000
Rounded to nearest million:	1593.526	1622.261

		System	Intersystem	Retail
March 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 23,564,265.55	\$ 2,768,468.27	\$ 26,332,733.82
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 1,207,494.09	\$ -	\$ 1,207,494.09
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 6,977.45	\$ -	\$ 6,977.45
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (11,127,404.34)	\$ -	\$ (11,127,404.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,574,395.32	\$ -	\$ 1,574,395.32
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)	\$ 2,074,578.24	\$ 737,821.12	\$ 2,812,399.36
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (86,087.91)	\$ -	\$ (86,087.91)
14	Real-Time Distribution of Losses Amount	\$ (1,132,171.23)	\$ -	\$ (1,132,171.23)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 38,838.87	\$ -	\$ 38,838.87
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 87,276.38	\$ -	\$ 87,276.38
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (2,506.21)	\$ -	\$ (2,506.21)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (49,367.95)	\$ -	\$ (49,367.95)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ (128.47)	\$ -	\$ (128.47)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 437,011.21	\$ -	\$ 437,011.21
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)	\$ (86,565.26)	\$ -	\$ (86,565.26)
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)	\$ (4,360.82)	\$ -	\$ (4,360.82)
Financial Rights Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (333,237.76)	\$ -	\$ (333,237.76)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (75,166.62)	\$ -	\$ (75,166.62)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (227,205.83)	\$ -	\$ (227,205.83)
37	Financial Transmission Rights Guarantee Uplift Amount	\$ 205,308.81	\$ -	\$ 205,308.81
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 244,884.66	\$ -	\$ 244,884.66
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 68,121.44	\$ -	\$ 68,121.44
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (65,028.41)	\$ 8,428.91	\$ (56,599.50)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 228,136.65	\$ -	\$ 228,136.65
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (88,150.74)	\$ 47,843.40	\$ (40,307.34)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (214,991.30)	\$ 7,457.09	\$ (207,534.21)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 766,406.50	\$ (10,799.82)	\$ 755,606.68
19	Real-Time Market Administration Amount	\$ 47,954.89	\$ (5,122.66)	\$ 42,832.23
29	Financial Transmission Rights Market Administration Amount	\$ 77,259.76	\$ -	\$ 77,259.76
33	Day-Ahead Schedule 24 Allocation Amount	\$ 83,114.23	\$ (1,185.70)	\$ 81,928.53
34	Real-Time Schedule 24 Allocation Amount	\$ 5,183.88	\$ (564.83)	\$ 4,619.05
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	\$ (9,284.09)	\$ -	\$ (9,284.09)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 353,569.43	\$ -	\$ 353,569.43
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (299,042.59)	\$ -	\$ (299,042.59)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (614,031.84)	\$ -	\$ (614,031.84)
TOTAL MISO CHARGES		\$ 16,656,045.99	\$ 3,552,345.78	\$ 20,208,391.77
SCHEDULE 24 (FOR RETAIL)				\$ 86,547.58
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 20,121,844.19

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

	System	Intersystem	Retail
March 2010 Actual			
Procurement Charges			
1 Day-Ahead Regulation Amount	\$ (335,569.68)	\$ -	\$ (335,569.68)
2 Day-Ahead Spinning Reserve Amount	\$ (85,877.10)	\$ -	\$ (85,877.10)
3 Day-Ahead Supplemental Reserve	\$ (263,302.05)	\$ -	\$ (263,302.05)
4 Real-Time Regulation Amount	\$ 80,227.18	\$ 105,040.67	\$ 185,267.85
5 Real-Time Spinning Reserve Amount	\$ 11,965.93	\$ 21,577.70	\$ 33,543.63
6 Real-Time Supplemental Reserve Amount	\$ 3,344.68	\$ 108,419.29	\$ 111,763.97
Resource Energy Charges			
7a Real Time Excessive Energy Amount	\$ (6,935.44)		\$ (6,935.44)
7b Real Time Excessive Energy Congestion	\$ -		\$ -
7c Real Time Excessive Energy Loss	\$ -		\$ -
8a Real Time Non Excessive Energy Amount	\$ (2,526,353.31)		\$ (2,526,353.31)
8b Real Time Non Excessive Energy Congestion	\$ 313,512.30		\$ 313,512.30
8c Real Time Non Excessive Energy Loss	\$ 196,374.97		\$ 196,374.97
9 Real Time Net Regulation Adjustment Amount	\$ 1,415.69	\$ (1,304.94)	\$ 110.75
Cost Distribution Charges			
10 Real Time Regulation Reserve Cost Distribution Amount	\$ 298,884.89	\$ -	\$ 298,884.89
11 Real Time Spinning Reserve Cost Distribution	\$ 296,059.14	\$ -	\$ 296,059.14
12 Real Time Supplemental Reserve Cost Distribution	\$ 193,346.53	\$ -	\$ 193,346.53
Penalty Charges			
13 Real Time Excessive/Dificient Energy Deployment	\$ 6,414.20	\$ (1,343.71)	\$ 5,070.49
14 Real Time Contingency Reserve Deployment Failure	\$ 600.45	\$ (77.27)	\$ 523.18
TOTAL MISO ASM CHARGES	\$ (1,815,891.62)	\$ 232,311.74	\$ (1,583,579.88)

