



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

February 28, 2011

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

Re: March 2011 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation operating in North Dakota hereby submits its electric fuel cost charge (FCC) for March 2011.

Pursuant to the Commission authorization of the final compliance tariffs in the Company's 2007 rate proceeding (Case No. PU-07-776) to implement new rates beginning March 1, 2009, a "multi-class" fuel cost mechanism replaced the previous single-factor mechanism. The March 2011 system FCC is based on the average of the most recent four-month actual fuel cost plus a "true-up" factor, reflecting cost recovery deviations during the January 2011 calendar month.

The table below shows the Fuel Cost Charge by customer class category:

March 2011	Fuel Cost Charge (\$/kWh)
Residential	0.02404
C & I Non-Demand	0.02547
C & I Demand	0.02467
C & I Demand Time of Day On-Peak	0.03172
C & I Demand Time of Day Off-Peak	0.01865
Outdoor Lighting	0.01711

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 March 2011 FCC, the net MISO Day 2 costs for January 2011 as recorded in Account 555. The MISO Day 2 cost recovery included in this March FCC is \$12,545,007, 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 Cost Rider, pursuant to the Commission guidance in Docket No. PU-09-016. Consistent

¹ Previously embedded in other FTR charge types.

with the MISO order and the required “net” accounting of ASM costs and revenues, we include in the March FCC, the net MISO ASM costs for January 2011 as recorded in Account 555. The MISO ASM cost recovery included in this March FCC is \$119,964, 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 January 2011 Asset Based Margin amount of \$29,737 has been included in the March Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the 2010 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 2010 Non-Asset Based Margin credit is \$56,225 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the March FCC is -\$7,377, or -0.004¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

OTHER REPORTING ITEM

Attachment is the calculation of the March 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

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 Mar-2011

Mar-2011 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02521	-\$0.00095	-\$0.00011	\$0.02415
Residential	\$0.02510	-\$0.00095	-\$0.00011	\$0.02404
C & I Non-Demand	\$0.02659	-\$0.00101	-\$0.00012	\$0.02547
C & I Demand Non-TOD	\$0.02576	-\$0.00098	-\$0.00011	\$0.02467
C & I Demand TOD On-Peak	\$0.03311	-\$0.00125	-\$0.00014	\$0.03172
C & I Demand TOD Off-Peak	\$0.01948	-\$0.00074	-\$0.00008	\$0.01865
Outdoor Lighting	\$0.01787	-\$0.00068	-\$0.00008	\$0.01711
Residential				
Residential Service	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
Residential TOD	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
Residential - Underground	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
Residential TOD - Underground	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
Energy Control - (Non-Demand)	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
Limit Off Peak	\$ 0.02510	\$ (0.00095)	\$ (0.00011)	\$ 0.02404
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Limit Off Peak	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Small General Service	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Small General TOD - Metered	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Small General TOD - Unmetered	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Fire and Civil Defense Siren	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
Direct Current (Closed)	\$ 0.02659	\$ (0.00101)	\$ (0.00012)	\$ 0.02547
C & I Demand				
General Service	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
General TOD - On Peak	\$ 0.03311	\$ (0.00125)	\$ (0.00014)	\$ 0.03172
General TOD - Off Peak	\$ 0.01948	\$ (0.00074)	\$ (0.00008)	\$ 0.01865
Peak Controlled (Closed)	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Peak Controlled TOD (Closed) - On Peak	\$ 0.03311	\$ (0.00125)	\$ (0.00014)	\$ 0.03172
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01948	\$ (0.00074)	\$ (0.00008)	\$ 0.01865
Peak Controlled Tiered	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Peak Controlled Tiered TOD - On Peak	\$ 0.03311	\$ (0.00125)	\$ (0.00014)	\$ 0.03172
Peak Controlled Tiered TOD - Off Peak	\$ 0.01948	\$ (0.00074)	\$ (0.00008)	\$ 0.01865
Energy Controlled (Closed)	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Tier 1 Energy Controlled Rider	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Real Time Pricing - Firm - On Peak	\$ 0.03311	\$ (0.00125)	\$ (0.00014)	\$ 0.03172
Real Time Pricing - Firm - Off Peak	\$ 0.01948	\$ (0.00074)	\$ (0.00008)	\$ 0.01865
Real Time Pricing - Controllable - On Peak	\$ 0.03311	\$ (0.00125)	\$ (0.00014)	\$ 0.03172
Real Time Pricing - Controllable - Off Peak	\$ 0.01948	\$ (0.00074)	\$ (0.00008)	\$ 0.01865
Small Municipal Pumping	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Municipal Pumping	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Excess Energy - St. Anthony Falls	\$ 0.02576	\$ (0.00098)	\$ (0.00011)	\$ 0.02467
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711
Street Lighting System	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711
Street Lighting Energy	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711
Street Lighting Energy - Metered	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711
Street Lighting Energy (Closed)	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711
Street Lighting - City of St. Paul	\$ 0.01787	\$ (0.00068)	\$ (0.00008)	\$ 0.01711

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 Mar-2011

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Oct-10	Nov-10	Dec-10	Jan-11	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$27,904,463	\$29,250,092	\$42,930,204	\$45,110,406	\$145,195,165
Account 518 - Nuclear Fuel	\$10,528,653	\$8,442,371	\$10,688,880	\$10,741,550	\$40,401,453
Account 555 - Purchased Power ¹	\$35,333,149	\$40,365,101	\$34,161,906	\$41,752,106	\$151,612,262
Account 555 - MISO Day 2 Charges	\$13,229,787	\$17,870,049	\$13,438,358	\$12,635,170	\$57,173,365
Account 555 MISO Day 2 - Schedule 24	(\$91,617)	(\$90,795)	(\$95,443)	(\$90,163)	(\$368,018)
Account 555 MISO - ASM Charges	\$1,826,511	\$1,874,955	\$125,361	\$119,964	\$3,946,791
Total MISO Charges	\$14,964,682	\$19,654,210	\$13,468,276	\$12,664,972	\$60,752,139
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$88,730,947	\$97,711,774	\$101,249,265	\$110,269,033	\$397,961,018
Less Fuel Cost of InterSystem Sales	(\$6,507,051)	(\$11,869,991)	(\$9,477,298)	(\$17,097,148)	(\$44,951,487)
Net System Costs	\$82,223,896	\$85,841,783	\$91,771,967	\$93,171,886	\$353,009,531
System MWh Sales					
Total NSP System Retail	3,133,138	3,097,598	3,539,364	3,962,011	13,732,111
Non-Gen Muni's/Load Pattern	64,086	62,824	66,245	76,589	269,744
Total NSP System MWh Sales	3,197,224	3,160,422	3,605,609	4,038,600	14,001,855
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.572¢	2.716¢	2.545¢	2.307¢	2.521¢
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	2.510¢
(ii) C & I Non-Demand				1.0548	2.659¢
(iii) C & I Demand Non-TOD				1.0219	2.576¢
(iv) C & I Demand TOD On-Peak				1.3135	3.311¢
(v) C & I Demand TOD Off-Peak				0.7726	1.948¢
(vi) Outdoor Lighting				0.7088	1.787¢
North Dakota Retail MWh Sales					
(i) Residential	44,866	51,416	82,934	99,111	278,327
(ii) C & I Non-Demand	8,175	8,696	11,913	14,191	42,975
(iii) C & I Demand Non-TOD	56,339	55,482	62,705	72,443	246,969
(iv) C & I Demand TOD On-Peak	18,625	17,620	18,586	16,560	71,391
(v) C & I Demand TOD Off-Peak	28,988	27,348	30,313	29,313	115,962
(vi) Outdoor Lighting	1,301	1,945	1,951	2,237	7,434
(vii) Total	158,294	162,507	208,402	233,855	763,058
Mar-2011 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Nov-10 Balance of Unrecovered Expenses)					Total
					Nov-10
					(\$152,793)

¹ Excludes demand-related expenses

Prior Expenses Recovered in Jan-2011 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	99,111	(\$28,129)
(ii) C & I Non-Demand	14,191	(\$4,416)
(iii) C & I Demand Non-TOD	72,443	(\$22,326)
(iv) C & I Demand TOD On-Peak	16,560	(\$6,565)
(v) C & I Demand TOD Off-Peak	29,313	(\$6,816)
(vi) Outdoor Lighting	2,237	(\$499)
(vii) Total	233,855	(\$68,751)

Actual Cost Should Have Been Recovered in Jan-11				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.307¢	0.000¢	233,855	\$5,395,035

Cost Recovered in Jan-11 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	99,111	\$2,548,960
(ii) C & I Non-Demand	14,191	\$386,664
(iii) C & I Demand Non-TOD	72,443	\$1,914,140
(iv) C & I Demand TOD On-Peak	16,560	\$562,703
(v) C & I Demand TOD Off-Peak	29,313	\$585,808
(vi) Outdoor Lighting	2,237	\$41,190
(vii) Total	233,855	\$6,039,465

Total Balance of Unrecovered Expenses (Mar-11 Balance of Unrecovered Expenses)	
Mar-2011 Recovery Provision	(\$728,472)
4 Month ND Retail Total MWh Sales	763,058
Mar-2011 Recovery Provision per KWH	-0.095¢

Mar-2011 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9956	-0.095¢	-0.095¢
(ii) C & I Non-Demand	1.0548	-0.095¢	-0.101¢
(iii) C & I Demand Non-TOD	1.0219	-0.095¢	-0.098¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.095¢	-0.125¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.095¢	-0.074¢
(vi) Outdoor Lighting	0.7088	-0.095¢	-0.068¢

Mar-2011 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$29,737)	\$7,377	(\$22,360)
(i) Residential	-0.015¢	0.004¢	-0.011¢
(ii) C & I Non-Demand	-0.015¢	0.004¢	-0.012¢
(iii) C & I Demand Non-TOD	-0.015¢	0.004¢	-0.011¢
(iv) C & I Demand TOD On-Peak	-0.019¢	0.005¢	-0.014¢
(v) C & I Demand TOD Off-Peak	-0.011¢	0.003¢	-0.008¢
(vi) Outdoor Lighting	-0.010¢	0.003¢	-0.008¢

Mar-2011 Factors		Total
(i) Residential		2.404¢
(ii) C & I Non-Demand		2.547¢
(iii) C & I Demand Non-TOD		2.467¢
(iv) C & I Demand TOD On-Peak		3.172¢
(v) C & I Demand TOD Off-Peak		1.865¢
(vi) Outdoor Lighting		1.711¢

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		
	Feb-11	Mar-11	Differ- ence	Percent Change	FCA Application Feb-11	Mar-11	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$132.6	\$145.2	\$12.6	9.5%	34.6%	36.5%	1.9%
2 Nuclear	\$39.8	\$40.4	\$0.6	1.6%	10.4%	10.2%	-0.2%
3 Purchases	\$152.7	\$151.6	(\$1.1)	-0.7%	39.9%	38.1%	-1.8%
MISO related Purchases	\$57.7	\$60.8	\$3.0	5.2%	15.1%	15.3%	0.2%
4 Total System Costs	382.8	398.0	\$15.1	4.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$43.3	\$45.0	\$1.6	3.7%	11.3%	11.3%	0.0%
6 Net System Costs	\$339.5	\$353.0	\$13.5	4.0%	88.7%	88.7%	0.0%
7							
** GWH OUTPUT **							
9 Fossil	4,941	5,354	413	8.4%	30.3%	32.0%	1.7%
10 Nuclear	4,532	4,634	102	2.3%	27.8%	27.7%	-0.1%
11 Purchases	5,046	4,819	(227)	-4.5%	30.9%	28.8%	-2.1%
12 Hydro & Other	963	1,091	128	13.3%	5.9%	6.5%	0.6%
13 Net Interchange	828	847	19	2.3%	5.1%	5.1%	0.0%
14 Total Output	16,310	16,745	435	2.7%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,735	1,621	(115)	-6.6%	10.6%	9.7%	-0.9%
16 Native Requirement	14,575	15,124	550	3.8%	89.4%	90.3%	0.9%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	2.683	2.712	0.029	1.1%			
20 Nuclear	0.878	0.872	-0.006	-0.7%			
21 Purchases	3.027	3.146	0.120	4.0%			
22 Total System Costs	2.347	2.377	0.029	1.3%			
23 Intersystem Sales	2.498	2.774	0.276	11.1%			
24 Net System Costs	2.329	2.334	0.005	0.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,781	14,002	221	1.6%			
28							
29 COST per KWH SALES (\$)	2.463	2.521	0.058	2.4%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.044	-0.095	-0.052				
(i) Residential	-0.043	-0.095	-0.052				
(ii) C & I Non-Demand	-0.046	-0.101	-0.055				
(iii) C & I Demand Non-TOD	-0.045	-0.098	-0.053				
(iv) C & I Demand TOD On-Peak	-0.057	-0.125	-0.068				
(v) C & I Demand TOD Off-Peak	-0.034	-0.074	-0.040				
(vi) Outdoor Lighting	-0.031	-0.068	-0.037				
32 REFUND	-0.024	-0.011	0.013				
(i) Residential	-0.024	-0.011					
(ii) C & I Non-Demand	-0.025	-0.012					
(iii) C & I Demand Non-TOD	-0.025	-0.011					
(iv) C & I Demand TOD On-Peak	-0.032	-0.014					
(v) C & I Demand TOD Off-Peak	-0.019	-0.008					
(vi) Outdoor Lighting	-0.017	-0.008					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.395	2.415	0.019	0.8%			
(i) Residential	2.384	2.404	0.020				
(ii) C & I Non-Demand	2.526	2.547					
(iii) C & I Demand Non-TOD	2.447	2.467					
(iv) C & I Demand TOD On-Peak	3.146	3.172					
(v) C & I Demand TOD Off-Peak	1.850	1.865					
(vi) Outdoor Lighting	1.698	1.711					

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	\$0.02
250	\$0.05
500	\$0.10
750	\$0.15
1,000	\$0.20

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	
	Feb-11	Mar-11
** GWH OUTPUT **		
Thermal	554,312	684,999
Disper gen	(63)	(81)
<u>Hydro plus Wind</u>	409,136	405,934
Hydro and Other	963,385	1,090,852
Rounded to nearest thousand:	963	1,091
<u>Sales</u>		
Non Gen Munic Total	273,415,000	269,744,000
Load Pattern Power	0	0
<u>Resale & Interchange (Intersystem)</u>	1,735,121,000	1,620,605,000
Rounded to nearest million:	1735.121	1620.605

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

Attachment 2

Page 1

		System	Intersystem	Retail
January 2011 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 16,263,828.44	\$ 3,259,264.34	\$ 19,523,092.78
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 4,184,703.95	\$ -	\$ 4,184,703.95
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (13,664,198.88)	\$ -	\$ (13,664,198.88)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,324,696.01	\$ -	\$ 1,324,696.01
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)	\$ 1,317,073.69	\$ 892,863.71	\$ 2,209,937.40
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 11,360.09	\$ -	\$ 11,360.09
14	Real-Time Distribution of Losses Amount	\$ (1,838,707.39)	\$ -	\$ (1,838,707.39)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (107,647.08)	\$ -	\$ (107,647.08)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 10,018.42	\$ -	\$ 10,018.42
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (666.36)	\$ -	\$ (666.36)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ (784,237.77)	\$ -	\$ (784,237.77)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ -	\$ -	\$ -
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,267,633.24	\$ -	\$ 1,267,633.24
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)	\$ 29,870.57	\$ -	\$ 29,870.57
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)	\$ (573.58)	\$ -	\$ (573.58)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (342,857.23)	\$ -	\$ (342,857.23)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (37,793.84)	\$ -	\$ (37,793.84)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (19,693.78)	\$ -	\$ (19,693.78)
37	Financial Transmission Guarantee Uplift Amount	\$ 18,544.17	\$ -	\$ 18,544.17
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 516,157.51	\$ -	\$ 516,157.51
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 242,279.72	\$ -	\$ 242,279.72
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (437,166.59)	\$ 37,881.28	\$ (399,285.31)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 519,451.99	\$ -	\$ 519,451.99
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (185,852.36)	\$ 50,714.25	\$ (135,138.11)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (203,977.03)	\$ 7,390.86	\$ (196,586.17)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 563,581.58	\$ (7,125.60)	\$ 556,455.98
19	Real-Time Market Administration Amount	\$ 31,445.34	\$ (2,557.17)	\$ 28,888.17
29	Financial Transmission Rights Market Administration Amount	\$ 29,611.68	\$ -	\$ 29,611.68
33	Day-Ahead Schedule 24 Allocation Amount	\$ 86,828.51	\$ (1,105.62)	\$ 85,722.89
34	Real-Time Schedule 24 Allocation Amount	\$ 4,844.80	\$ (404.78)	\$ 4,440.02
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	\$ 52,558.60	\$ -	\$ 52,558.60
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 689,179.66	\$ -	\$ 689,179.66
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (731,991.70)	\$ -	\$ (731,991.70)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (468,959.51)	\$ -	\$ (468,959.51)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 58,904.14	\$ -	\$ 58,904.14
TOTAL MISO CHARGES		\$ 8,398,249.01	\$ 4,236,921.27	\$ 12,635,170.28

SCHEDULE 24 (FOR RETAIL) **\$ 90,162.91**

TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL) **\$ 12,545,007.37**

MISO ANCILLARY SERVICES MARKET'S (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
January 2011 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (440,177.97)	\$ -	\$ (440,177.97)
2	Day-Ahead Spinning Reserve Amount	\$ (41,480.85)	\$ -	\$ (41,480.85)
3	Day-Ahead Supplemental Reserve	\$ (92,893.20)	\$ -	\$ (92,893.20)
4	Real-Time Regulation Amount	\$ 88,994.09	\$ 184,315.42	\$ 273,309.51
5	Real-Time Spinning Reserve Amount	\$ (14,932.64)	\$ 15,194.91	\$ 262.27
6	Real-Time Supplemental Reserve Amount	\$ 773.13	\$ 35,137.20	\$ 35,910.33
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (16,828.67)	\$ -	\$ (16,828.67)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 258,309.24	\$ -	\$ 258,309.24
8b	Real Time Non Excessive Energy Congestion	\$ (484,612.38)	\$ -	\$ (484,612.38)
8c	Real Time Non Excessive Energy Loss	\$ 157,969.71	\$ -	\$ 157,969.71
9	Real Time Net Regulation Adjustment Amount	\$ 3,236.13	\$ (343.49)	\$ 2,892.64
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 265,701.49	\$ -	\$ 265,701.49
11	Real Time Spinning Reserve Cost Distribution	\$ 141,714.21	\$ -	\$ 141,714.21
12	Real Time Supplemental Reserve Cost Distribution	\$ 54,003.12	\$ -	\$ 54,003.12
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 6,508.15	\$ (623.44)	\$ 5,884.71
14	Real Time Contingency Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ (113,716.44)	\$ 233,680.60	\$ 119,964.16

