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MAR 01 2010

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PUBLIC SERVICE COMMISSION

February 26, 2010

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

Re: March 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 March 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 new "multi-class" fuel cost mechanism replaced the previously single-factor mechanism. The March 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 January 2010 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:

March 2010	Fuel Cost Charge (\$/kWh)
Residential	0.02358
C & I Non-Demand	0.02498
C & I Demand	0.02420
C & I Demand Time of Day On-Peak	0.03111
C & I Demand Time of Day Off-Peak	0.01830
Outdoor Lighting	0.01679

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 FCC, the net MISO Day 2 costs for January 2010 as recorded in Account 555. The MISO Day 2 cost recovery included in this March FCC is \$21,420,747, 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.

MISO ASM Charges

¹ Previously embedded in other FTR charge types.

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 March FCC, the net MISO ASM costs for January 2010 as recorded in Account 555. The MISO ASM cost recovery included in this March FCC is \$-2,393,364 which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

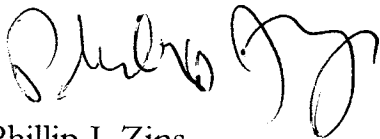
Pursuant to the above referenced Order Adopting Settlement, the January 2010 Asset Based Margin amount of \$160,951 has been included in the March Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2010, the 2009 retail share of the Non-Asset Based Margins 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 March FCC is \$16,831 or 0.009¢ 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,



Phillip J. Zins
Manager, Pricing and Planning

Enclosures (2)

CC: David H. Sederquist

Electric Operations - State of North Dakota

Page 1

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for Mar-2010

Mar-2010 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02474	-\$0.00014	-\$0.00083	\$0.02377
Residential	\$0.02463	-\$0.00014	-\$0.00091	\$0.02358
C & I Non-Demand	\$0.02610	-\$0.00015	-\$0.00096	\$0.02498
C & I Demand Non-TOD	\$0.02528	-\$0.00015	-\$0.00093	\$0.02420
C & I Demand TOD On-Peak	\$0.03250	-\$0.00019	-\$0.00120	\$0.03111
C & I Demand TOD Off-Peak	\$0.01911	-\$0.00011	-\$0.00071	\$0.01830
Outdoor Lighting	\$0.01754	-\$0.00010	-\$0.00065	\$0.01679
Residential				
Residential Service	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
Residential TOD	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
Residential - Underground	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
Residential TOD - Underground	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
Energy Control - (Non-Demand)	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
Limit Off Peak	\$ 0.02463	\$ (0.00014)	\$ (0.00091)	\$ 0.02358
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Limit Off Peak	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Small General Service	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Small General TOD - Metered	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Small General TOD - Unmetered	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Fire and Civil Defense Siren	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
Direct Current (Closed)	\$ 0.02610	\$ (0.00015)	\$ (0.00096)	\$ 0.02498
C & I Demand				
General Service	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
General TOD - On Peak	\$ 0.03250	\$ (0.00019)	\$ (0.00120)	\$ 0.03111
General TOD - Off Peak	\$ 0.01911	\$ (0.00011)	\$ (0.00071)	\$ 0.01830
Peak Controlled (Closed)	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Peak Controlled TOD (Closed) - On Peak	\$ 0.03250	\$ (0.00019)	\$ (0.00120)	\$ 0.03111
Peak Controlled TOD (Closed) - Off Peak	\$ 0.01911	\$ (0.00011)	\$ (0.00071)	\$ 0.01830
Peak Controlled Tiered	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Peak Controlled Tiered TOD - On Peak	\$ 0.03250	\$ (0.00019)	\$ (0.00120)	\$ 0.03111
Peak Controlled Tiered TOD - Off Peak	\$ 0.01911	\$ (0.00011)	\$ (0.00071)	\$ 0.01830
Energy Controlled (Closed)	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Tier 1 Energy Controlled Rider	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Real Time Pricing - Firm - On Peak	\$ 0.03250	\$ (0.00019)	\$ (0.00120)	\$ 0.03111
Real Time Pricing - Firm - Off Peak	\$ 0.01911	\$ (0.00011)	\$ (0.00071)	\$ 0.01830
Real Time Pricing - Controllable - On Peak	\$ 0.03250	\$ (0.00019)	\$ (0.00120)	\$ 0.03111
Real Time Pricing - Controllable - Off Peak	\$ 0.01911	\$ (0.00011)	\$ (0.00071)	\$ 0.01830
Small Municipal Pumping	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Municipal Pumping	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Excess Energy - St. Anthony Falls	\$ 0.02528	\$ (0.00015)	\$ (0.00093)	\$ 0.02420
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679
Street Lighting System	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679
Street Lighting Energy	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679
Street Lighting Energy - Metered	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679
Street Lighting Energy (Closed)	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679
Street Lighting - City of St. Paul	\$ 0.01754	\$ (0.00010)	\$ (0.00065)	\$ 0.01679

	Column (A) Oct-09	Column (B) Nov-09	Column (C) Dec-09	Column (D) Jan-10	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$33,768,296	\$32,464,309	\$38,057,196	\$42,972,111	\$147,261,912
Account 518 - Nuclear Fuel	\$6,097,905	\$5,827,515	\$10,825,157	\$10,021,593	\$32,772,169
Account 555 - Purchased Power ¹	\$33,897,312	\$30,349,302	\$37,855,140	\$41,322,966	\$143,424,720
Account 555 - MISO Day 2 Charges	\$16,893,303	\$15,304,176	\$18,990,451	\$21,515,761	\$72,703,691
Account 555 MISO Day 2 - Schedule 24	(\$93,342)	(\$92,685)	(\$95,539)	(\$95,015)	(\$376,581)
Account 555 MISO - ASM Charges	(\$1,061,115)	\$155,862	\$364,562	(\$2,393,364)	(\$2,934,055)
Total MISO Charges	\$15,738,845	\$15,367,352	\$19,259,474	\$19,027,383	\$69,393,054
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$89,502,358	\$84,008,478	\$105,996,967	\$113,344,053	\$392,851,856
Less Fuel Cost of InterSystem Sales	(\$7,920,494)	(\$6,075,292)	(\$13,102,962)	(\$18,446,370)	(\$45,545,118)
Net System Costs	\$81,581,864	\$77,933,186	\$92,894,005	\$94,897,683	\$347,306,738
System MWH Sales					
Total NSP System Retail	3,392,905	2,948,740	3,532,758	3,750,363	13,624,766
Non-Gen Muni's/Load Pattern	99,178	103,791	97,380	115,112	415,461
Total NSP System MWh Sales	3,492,083	3,052,531	3,630,138	3,865,475	14,040,227
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System	2.336¢	2.553¢	2.559¢	2.455¢	2.474¢
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	2.463¢
(ii) C & I Non-Demand				1.0548	2.610¢
(iii) C & I Demand Non-TOD				1.0219	2.528¢
(iv) C & I Demand TOD On-Peak				1.3135	3.250¢
(v) C & I Demand TOD Off-Peak				0.7726	1.911¢
(vi) Outdoor Lighting				0.7088	1.754¢

¹ Excludes demand-related expenses

Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for Mar-2010

North Dakota Retail MWh Sales

(i) Residential	54,084	51,439	78,441	95,482	279,446
(ii) C & I Non-Demand	9,638	8,994	12,512	14,539	45,683
(iii) C & I Demand Non-TOD	56,461	47,302	62,568	60,391	226,722
(iv) C & I Demand TOD On-Peak	22,100	17,858	16,314	16,696	72,968
(v) C & I Demand TOD Off-Peak	32,420	26,371	26,194	28,351	113,336
(vi) Outdoor Lighting	1,546	1,749	1,698	2,411	7,404
(vii) Total	176,249	153,713	197,727	217,870	745,559

Mar-2010 Recovery Provision (True-up Factor) Calculation**Prior Unrecovered Expenses (Nov-09 Balance of Unrecovered Expenses)**

Total

Nov-09

(\$146,114)

Prior Expenses Recovered in Jan-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	-0.022¢	95,482	(\$21,123)
(iii) C & I Demand Non-TOD	1.0548	-0.023¢	14,539	(\$3,408)
(iv) C & I Demand TOD On-Peak	1.0219	-0.023¢	60,391	(\$13,714)
(v) C & I Demand TOD Off-Peak	1.3135	-0.029¢	16,696	(\$4,873)
(vi) Outdoor Lighting	0.7726	-0.017¢	28,351	(\$4,867)
(vii) Total	0.7088	-0.016¢	2,411	(\$380)
			217,870	(\$48,365)

Actual Cost Should Have Been Recovered in Jan-10

	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.455¢	0.000¢	217,870	\$5,348,709

Cost Recovered in Jan-10

	FCF Ratio	Fuel Cost Recovered	Actual ND MWh Sales	Actual Recovery
(i) Residential	0.9956	2.451¢	95,482	\$2,340,423
(ii) C & I Non-Demand	1.0548	2.597¢	14,539	\$377,566
(iii) C & I Demand Non-TOD	1.0219	2.516¢	60,391	\$1,519,388
(iv) C & I Demand TOD On-Peak	1.3135	3.234¢	16,696	\$539,921
(v) C & I Demand TOD Off-Peak	0.7726	1.902¢	28,351	\$539,276
(vi) Outdoor Lighting	0.7088	1.745¢	2,411	\$42,074
(vii) Total			217,870	\$5,358,648

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

Mar-2010 Recovery Provision	(\$107,688)
4 Month ND Retail Total MWh Sales	745,559
Mar-2010 Recovery Provision per KWH	-0.014¢

Mar-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	-0.014¢	-0.014¢
(ii) C & I Non-Demand	1.0548	-0.014¢	-0.015¢
(iii) C & I Demand Non-TOD	1.0219	-0.014¢	-0.015¢
(iv) C & I Demand TOD On-Peak	1.3135	-0.014¢	-0.019¢
(v) C & I Demand TOD Off-Peak	0.7726	-0.014¢	-0.011¢
(vi) Outdoor Lighting	0.7088	-0.014¢	-0.010¢
Mar-2010 Margin Sharing Refunds			
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	Total
Refund/Special Charge Amount	(\$160,951)	(\$16,831)	(\$177,782)
(i) Residential	-0.082¢	-0.009¢	-0.091¢
(ii) C & I Non-Demand	-0.087¢	-0.009¢	-0.096¢
(iii) C & I Demand Non-TOD	-0.085¢	-0.009¢	-0.093¢
(iv) C & I Demand TOD On-Peak	-0.109¢	-0.011¢	-0.120¢
(v) C & I Demand TOD Off-Peak	-0.064¢	-0.007¢	-0.071¢
(vi) Outdoor Lighting	-0.059¢	-0.006¢	-0.065¢
Mar-2010 Factors			
	Total		
(i) Residential	2.358¢		
(ii) C & I Non-Demand	2.498¢		
(iii) C & I Demand Non-TOD	2.420¢		
(iv) C & I Demand TOD On-Peak	3.111¢		
(v) C & I Demand TOD Off-Peak	1.830¢		
(vi) Outdoor Lighting	1.679¢		

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-10	Mar-10	Differ- ence	Percent Change	FCA Application Feb-10	Mar-10	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$142.2	\$147.3	\$5.0	3.5%	38.3%	37.5%	-0.8%
2 Nuclear	\$29.6	\$32.8	\$3.2	10.8%	8.0%	8.3%	0.3%
3 Purchases	\$136.3	\$143.4	\$7.1	5.2%	36.7%	36.5%	-0.2%
MISO related Purchases	\$63.4	\$69.4	\$6.0	9.4%	17.1%	17.7%	0.6%
4 Total System Costs	371.5	392.9	\$21.4	5.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$32.3	\$45.5	\$13.2	40.8%	8.7%	11.6%	2.9%
6 Net System Costs	\$339.1	\$347.3	\$8.2	2.4%	91.3%	88.4%	-2.9%
7							
8 ** GWH OUTPUT **							
9 Fossil	6,178	6,206	28	0.5%	29.3%	23.7%	-5.6%
10 Nuclear	3,850	4,172	322	8.4%	18.3%	15.9%	-2.4%
11 Purchases	4,880	4,868	(12)	-0.2%	23.2%	18.6%	-4.6%
12 Hydro & Other	778	795	17	2.2%	3.7%	3.0%	-0.7%
13 Net Interchange	5,372	10,130	4,758	88.6%	25.5%	38.7%	13.2%
14 Total Output	21,058	26,171	5,113	24.3%	100.0%	100.0%	0.0%
15 Intersystem Sales	1,561	1,717	156	10.0%	7.4%	6.6%	-0.8%
16 Native Requirement	19,497	24,454	4,957	25.4%	92.6%	93.4%	0.8%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	2.302	2.373	0.071	3.1%			
20 Nuclear	0.768	0.786	0.017	2.2%			
21 Purchases	2.793	2.946	0.154	5.5%			
22 Total System Costs	1.764	1.501	-0.263	-14.9%			
23 Intersystem Sales	2.071	2.652	0.581	28.0%			
24 Net System Costs	1.739	1.420	-0.319	-18.4%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,787	14,040	253	1.8%			
28							
29 COST per KWH SALES (\$) **	2.460	2.474	0.014	0.6%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	-0.040	-0.014	0.025				
(i) Residential	-0.040	-0.014	0.025				
(ii) C & I Non-Demand	-0.042	-0.015	0.027				
(iii) C & I Demand Non-TOD	-0.041	-0.015	0.026				
(iv) C & I Demand TOD On-Peak	-0.052	-0.019	0.033				
(v) C & I Demand TOD Off-Peak	-0.031	-0.011	0.020				
(vi) Outdoor Lighting	-0.028	-0.010	0.018				
32 REFUND	-0.051	-0.092	-0.041				
(i) Residential	-0.051	-0.091					
(ii) C & I Non-Demand	-0.054	-0.096					
(iii) C & I Demand Non-TOD	-0.052	-0.093					
(iv) C & I Demand TOD On-Peak	-0.067	-0.120					
(v) C & I Demand TOD Off-Peak	-0.039	-0.071					
(vi) Outdoor Lighting	-0.036	-0.065					
33 SYSTEM FCC IMPACT (\$ / KWH)	2.369	2.368	-0.002	-0.1%			
(i) Residential	2.360	2.358	-0.002				
(ii) C & I Non-Demand	2.500	2.498					
(iii) C & I Demand Non-TOD	2.422	2.420					
(iv) C & I Demand TOD On-Peak	3.113	3.111					
(v) C & I Demand TOD Off-Peak	1.831	1.830					
(vi) Outdoor Lighting	1.680	1.679					

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	(\$0.00)
250	(\$0.01)
500	(\$0.01)
750	(\$0.02)
1,000	(\$0.02)

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-10	Mar-10
** GWH OUTPUT **		
Thermal	613,159	619,482
Wind plus disper gen	(88)	(90)
Hydro	165,088	175,195
Hydro and Other	778,159	794,587
Rounded to nearest thousand:	778	795
Sales		
Non Gen Munic Total	402,447,000	415,461,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,561,449,000	1,717,467,000
Rounded to nearest million:	1561.449	1717.467

		System	Intersystem	Retail
January 2010 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 20,775,520.54	\$ 4,650,569.74	\$ 25,426,090.28
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 3,190,536.49	\$ -	\$ 3,190,536.49
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 15,094.45	\$ -	\$ 15,094.45
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (12,011,795.92)	\$ -	\$ (12,011,795.92)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 724,208.99	\$ -	\$ 724,208.99
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)	\$ 1,965,451.48	\$ 2,472,099.79	\$ 4,437,551.27
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ 28,326.09	\$ -	\$ 28,326.09
14	Real-Time Distribution of Losses Amount	\$ (1,685,996.35)	\$ -	\$ (1,685,996.35)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 98,336.75	\$ -	\$ 98,336.75
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 109,183.46	\$ -	\$ 109,183.46
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ 1,583.16	\$ -	\$ 1,583.16
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 148,064.32	\$ -	\$ 148,064.32
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 206.87	\$ -	\$ 206.87
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ (129,492.55)	\$ -	\$ (129,492.55)
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)	\$ (95,875.62)	\$ -	\$ (95,875.62)
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)	\$ 1,958.46	\$ -	\$ 1,958.46
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (131,409.02)	\$ -	\$ (131,409.02)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (107,441.27)	\$ -	\$ (107,441.27)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (97,592.40)	\$ -	\$ (97,592.40)
37	Financial Transmission Guarantee Uplift Amount	\$ 172,161.16	\$ -	\$ 172,161.16
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 558,250.63	\$ -	\$ 558,250.63
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 159,419.38	\$ -	\$ 159,419.38
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (98,288.33)	\$ 8,195.90	\$ (90,092.43)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 989,607.08	\$ -	\$ 989,607.08
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	\$ (734,117.41)	\$ 74,033.13	\$ (660,084.28)
42	Real-Time Price Volatility Make Whole Payment Amount	\$ (144,273.28)	\$ 5,081.75	\$ (139,191.53)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 639,493.39	\$ (10,904.78)	\$ 628,588.61
19	Real-Time Market Administration Amount	\$ 50,297.00	\$ (4,730.92)	\$ 45,566.08
29	Financial Transmission Rights Market Administration Amount	\$ 54,707.28	\$ -	\$ 54,707.28
33	Day-Ahead Schedule 24 Allocation Amount	\$ 90,124.72	\$ (1,537.31)	\$ 88,587.41
34	Real-Time Schedule 24 Allocation Amount	\$ 7,090.67	\$ (663.38)	\$ 6,427.29
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	\$ 142.51	\$ -	\$ 142.51
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 180,839.99	\$ -	\$ 180,839.99
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (201,409.27)	\$ -	\$ (201,409.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (199,295.89)	\$ -	\$ (199,295.89)
TOTAL MISO CHARGES		\$ 14,323,617.56	\$ 7,192,143.92	\$ 21,515,761.48
SCHEDULE 24 (FOR RETAIL)				\$ 95,014.70
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 21,420,746.78

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
January 2010 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (471,924.41)	\$ -	\$ (471,924.41)
2	Day-Ahead Spinning Reserve Amount	\$ (73,985.58)	\$ -	\$ (73,985.58)
3	Day-Ahead Supplemental Reserve	\$ (24,999.00)	\$ -	\$ (24,999.00)
4	Real-Time Regulation Amount	\$ 54,584.39	\$ 138,015.37	\$ 192,599.76
5	Real-Time Spinning Reserve Amount	\$ (73,802.25)	\$ 50,621.41	\$ (23,180.84)
6	Real-Time Supplemental Reserve Amount.	\$ 271.31	\$ 5,341.11	\$ 5,612.42
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (48,113.27)	\$ -	\$ (48,113.27)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (3,140,784.87)	\$ -	\$ (3,140,784.87)
8b	Real Time Non Excessive Energy Congestion	\$ 123,801.60	\$ -	\$ 123,801.60
8c	Real Time Non Excessive Energy Loss	\$ 313,088.27	\$ -	\$ 313,088.27
9	Real Time Net Regulation Adjustment Amount	\$ 19,145.78	\$ (3,629.01)	\$ 15,516.77
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 371,992.98	\$ -	\$ 371,992.98
11	Real Time Spinning Reserve Cost Distribution	\$ 306,150.30	\$ -	\$ 306,150.30
12	Real Time Supplemental Reserve Cost Distribution	\$ 20,910.18	\$ -	\$ 20,910.18
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 47,823.38	\$ (13,194.07)	\$ 34,629.31
14	Real Time Contingency Reserve Deployment Failure	\$ 5,322.86	\$ -	\$ 5,322.86
TOTAL MISO ASM CHARGES		\$ (2,570,518.33)	\$ 177,154.81	\$ (2,393,363.52)

