



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

February 28, 2014

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

Re: March 2014 Fuel Cost Charge

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy and operating in North Dakota, hereby submits its electric fuel cost charge (FCC) for March 2014.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2010 rate proceeding (Case No. PU-10-657), the new rates were implemented on May 1, 2012. The new Service Category Ratios listed below also became effective:

Service Category Ratios	Previous	Current
Residential	0.9956	1.0026
C & I Non-Demand	1.0548	1.0281
C & I Demand	1.0219	1.0170
C & I Demand Time of Day On-Peak	1.3135	1.2883
C & I Demand Time of Day Off-Peak	0.7726	0.7889
Outdoor Lighting	0.7088	0.7440

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

March 2014	Fuel Cost Charge (\$/kWh)
Residential	0.03015
C & I Non-Demand	0.03092
C & I Demand	0.03059
C & I Demand Time of Day On-Peak	0.03875
C & I Demand Time of Day Off-Peak	0.02373
Outdoor Lighting	0.02238

MISO CHARGES IMPLEMENTATION

MISO Day 2 Charges

This filing includes our reporting of the Midcontinent Independent System Operator, Inc. (MISO, formerly Midwest Independent Transmission System Operator, Inc.) charges under the Day 2 Market. Pursuant to the Commission's April 6, 2005 Order in Case No. PU-05-147 and the Order in Case No. PU-07-776, Xcel Energy is authorized to recover MISO Day 2 costs. The March 2009 FCC reflected the MISO Day 2 charge types: 3 Auction Revenue Rights (ARR) and 3 Financial Transmission Rights (FTR) charge types¹, to be reflected in the Fuel Cost Rider. Consistent with this Order and the required "net" accounting of Day 2 costs and revenues, we have included in the March 2014 FCC the net MISO Day 2 costs for January 2014 as recorded in Account 555. The MISO Day 2 cost recovery included in this January 2014 FCC is \$29,894,026, 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 ASM charge types are included in the Fuel Cost Rider, pursuant to Commission guidance in Case 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 2014 as recorded in Account

¹ Previously embedded in other FTR charge types.

555. The MISO ASM cost recovery included in this March FCC is \$1,761,368, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

REFUNDS

Asset and Non-Asset Based Margins Sharing Refund

Pursuant to the above referenced Order Adopting Settlement, the March 2014 Asset Based Margin amount of \$306,819 has been included as a credit, or offset, to the March 2014 Fuel Cost Charges. The detailed records are contained in Attachment 3, page 1. Starting from February 2011, the prior year 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 the 2013 Non-Asset Based Margin credit is \$93,142 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the March 2014 FCC is \$2,884, or 0.001¢ per kWh (system basis). Attachment 3, page 2 contains the derivation of this refund amount.

Sales of Renewable Energy Credits

Pursuant to the Commission Order dated September 9, 2010 in Case No. PU-10-19, the Company is authorized to sell excess Renewable Energy Credits (RECs) allocable to our North Dakota jurisdiction and credit 90 percent of the net proceeds back to customers through the Fuel Cost Rider (FCR). (See Attachment 3, page 3).

EXCLUSION

Prairie Rose Wind PPA Exclusion

Pursuant to the Commission's December 21, 2012 Order in the Company's Advanced Determination of Prudence application (Case No. PU-12-59), the energy and costs associated with the January 1, 2013 commencement of the Prairie Rose Wind (PRW) power purchase agreement (PPA) are being excluded from the calculation of the Company's monthly Fuel Cost Rider (FCR). Beginning with the March 2013 FCR filing, the Company has excluded the PRW PPA from any FCR calculations until the Commission has completed a ratemaking proceeding and made a decision regarding the rate treatment for the PRW PPA.

Not reflecting the PRW PPA in our FCR will result in a fuel cost revenue shortfall while the Commission deliberates on this issue in the pending rate case. The Company has filed testimony in its pending electric rate case (Case No. PU-12-813) in support of FCR recovery of PRW PPA costs, and if the Commission ultimately approves FCR recovery, the Company will seek to recover the cumulative shortfall.

OTHER REPORTING ITEM

Attached is the calculation of the March 2014 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 /

PAUL J LEHMAN
MANAGER, REGULATORY COMPLIANCE AND FILINGS

Enclosures (2)
CC: David H. Sederquist

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Current Period Cost of Energy for Mar-2014

Mar-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.03253	\$0.00061	-\$0.00306	\$0.03007
Residential	\$0.03261	\$0.00061	-\$0.00307	\$0.03015
C & I Non-Demand	\$0.03344	\$0.00063	-\$0.00315	\$0.03092
C & I Demand Non-TOD	\$0.03308	\$0.00062	-\$0.00312	\$0.03059
C & I Demand TOD On-Peak	\$0.04191	\$0.00078	-\$0.00395	\$0.03875
C & I Demand TOD Off-Peak	\$0.02566	\$0.00048	-\$0.00242	\$0.02373
Outdoor Lighting	\$0.02420	\$0.00045	-\$0.00228	\$0.02238
Residential				
Residential Service	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
Residential TOD	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
Residential - Underground	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
Residential TOD - Underground	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
Energy Control - (Non-Demand)	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
Limit Off Peak	\$ 0.03261	\$ 0.00061	\$ (0.00307)	\$ 0.03015
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Limit Off Peak	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Small General Service	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Small General TOD - Metered	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Small General TOD - Unmetered	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Fire and Civil Defense Siren	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
Direct Current (Closed)	\$ 0.03344	\$ 0.00063	\$ (0.00315)	\$ 0.03092
C & I Demand				
General Service	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
General TOD - On Peak	\$ 0.04191	\$ 0.00078	\$ (0.00395)	\$ 0.03875
General TOD - Off Peak	\$ 0.02566	\$ 0.00048	\$ (0.00242)	\$ 0.02373
Peak Controlled (Closed)	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Peak Controlled TOD (Closed) - On Peak	\$ 0.04191	\$ 0.00078	\$ (0.00395)	\$ 0.03875
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02566	\$ 0.00048	\$ (0.00242)	\$ 0.02373
Peak Controlled Tiered	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Peak Controlled Tiered TOD - On Peak	\$ 0.04191	\$ 0.00078	\$ (0.00395)	\$ 0.03875
Peak Controlled Tiered TOD - Off Peak	\$ 0.02566	\$ 0.00048	\$ (0.00242)	\$ 0.02373
Energy Controlled (Closed)	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Tier 1 Energy Controlled Rider	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Real Time Pricing - Firm - On Peak	\$ 0.04191	\$ 0.00078	\$ (0.00395)	\$ 0.03875
Real Time Pricing - Firm - Off Peak	\$ 0.02566	\$ 0.00048	\$ (0.00242)	\$ 0.02373
Real Time Pricing - Controllable - On Peak	\$ 0.04191	\$ 0.00078	\$ (0.00395)	\$ 0.03875
Real Time Pricing - Controllable - Off Peak	\$ 0.02566	\$ 0.00048	\$ (0.00242)	\$ 0.02373
Small Municipal Pumping	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Municipal Pumping	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Excess Energy - St. Anthony Falls	\$ 0.03308	\$ 0.00062	\$ (0.00312)	\$ 0.03059
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238
Street Lighting System	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238
Street Lighting Energy	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238
Street Lighting Energy - Metered	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238
Street Lighting Energy (Closed)	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238
Street Lighting - City of St. Paul	\$ 0.02420	\$ 0.00045	\$ (0.00228)	\$ 0.02238

	Column (A) Oct-13	Column (B) Nov-13	Column (C) Dec-13	Column (D) Jan-14	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$31,219,451	\$35,144,174	\$52,485,969	\$53,489,925	\$172,339,519
Account 518 - Nuclear Fuel	\$7,811,889	\$7,744,058	\$7,801,662	\$9,136,018	\$32,493,627
Account 555 - Purchased Power ¹	\$37,388,155	\$47,321,898	\$39,793,736	\$48,385,125	\$172,888,915
Account 555 - Pr. Rose PPA Adjustment	(\$229,062)	(\$204,801)	(\$93,354)	(\$168,834)	(\$696,051)
MISO Day 2 Charges	\$23,751,689	\$19,456,194	\$17,180,234	\$29,980,488	\$90,368,605
MISO Day 2 - Schedule 24	(\$107,178)	(\$106,395)	(\$116,201)	(\$86,462)	(\$416,237)
MISO - ASM Charges	\$2,595,581	\$1,154,328	\$4,994,935	(\$1,761,368)	\$6,983,475
Account 555 - Total MISO Charges	\$26,240,091	\$20,504,127	\$22,058,967	\$28,132,658	\$96,935,844
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$102,430,524	\$110,509,456	\$122,046,981	\$138,974,893	\$473,961,854
Less Fuel Cost of InterSystem Sales	(\$693,295)	(\$4,320,339)	(\$2,366,209)	(\$10,126,119)	(\$17,505,961)
Net System Costs	\$101,737,229	\$106,189,117	\$119,680,772	\$128,848,774	\$456,455,893
System MWh Sales					
Total NSP System Retail	3,454,506	2,994,504	3,509,056	4,065,686	14,023,752
Non-Gen Muni's/Load Pattern	1,544	1,383	1,420	1,687	6,034
Total NSP System MWh Sales	3,456,050	2,995,887	3,510,476	4,067,373	14,029,786
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	2.944¢	3.544¢	3.409¢	3.168¢	3.253¢
Class Ratio/TOD Ratio					
(i) Residential	1.0026	1.0026	1.0026	1.0026	1.0026
(ii) C & I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281
(iii) C & I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170
(iv) C & I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883
(v) C & I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889
(vi) Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440
North Dakota Fuel Cost Factor (FCF)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			3.253¢	1.0026	3.261¢
(ii) C & I Non-Demand			3.253¢	1.0281	3.344¢
(iii) C & I Demand Non-TOD			3.253¢	1.0170	3.308¢
(iv) C & I Demand TOD On-Peak			3.253¢	1.2883	4.191¢
(v) C & I Demand TOD Off-Peak			3.253¢	0.7889	2.566¢
(vi) Outdoor Lighting			3.253¢	0.7440	2.420¢
North Dakota Retail MWh Sales					
(i) Residential	53,649	52,513	86,391	113,485	306,038
(ii) C & I Non-Demand	8,857	8,265	12,206	15,180	44,508
(iii) C & I Demand Non-TOD	65,164	55,698	66,896	77,600	265,358
(iv) C & I Demand TOD On-Peak	17,403	19,158	16,590	19,746	72,897
(v) C & I Demand TOD Off-Peak	25,450	30,526	27,252	35,851	119,079
(vi) Outdoor Lighting	1,429	1,837	2,060	2,075	7,401
(vii) Total	171,952	167,997	211,395	263,937	815,281
Mar-2014 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Nov-13 Balance of Unrecovered Expenses)					Total
					Nov-13
					\$399,377

¹ Excludes demand-related expenses and includeds Prairie Rose Wind PPA expenses

Prior Expenses Recovered in Jan-2014 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	113,485	\$138,224
(ii) C & I Non-Demand	15,180	\$18,689
(iii) C & I Demand Non-TOD	77,600	\$92,538
(iv) C & I Demand TOD On-Peak	19,746	\$30,171
(v) C & I Demand TOD Off-Peak	35,851	\$33,556
(vi) Outdoor Lighting	2,075	\$2,345
(vii) Total	263,937	\$315,523

Actual Cost Should Have Been Recovered in Jan-14				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.168¢	0.000¢	263,937	\$8,361,524

Cost Recovered in Jan-14 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	113,485	\$3,430,235
(ii) C & I Non-Demand	15,180	\$470,734
(iii) C & I Demand Non-TOD	77,600	\$2,381,746
(iv) C & I Demand TOD On-Peak	19,746	\$767,463
(v) C & I Demand TOD Off-Peak	35,851	\$853,208
(vi) Outdoor Lighting	2,075	\$46,194
(vii) Total	263,937	\$7,949,580

Total Balance of Unrecovered Expenses (Mar-14 Balance of Unrecovered Expenses)	
Mar-2014 Recovery Provision	\$495,798
4 Month ND Retail Total MWh Sales	815,281
Mar-2014 Recovery Provision per KWH	0.061¢

Mar-2014 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.061¢	0.061¢
(ii) C & I Non-Demand	1.0281	0.061¢	0.063¢
(iii) C & I Demand Non-TOD	1.0170	0.061¢	0.062¢
(iv) C & I Demand TOD On-Peak	1.2883	0.061¢	0.078¢
(v) C & I Demand TOD Off-Peak	0.7889	0.061¢	0.048¢
(vi) Outdoor Lighting	0.7440	0.061¢	0.045¢

Mar-2014 Refunds/Additional Charges				
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	(\$306,819)	(\$2,884)	(\$315,660)	(\$622,479)
(i) Residential	-0.151¢	-0.001¢	-0.155¢	-0.307¢
(ii) C & I Non-Demand	-0.155¢	-0.001¢	-0.159¢	-0.315¢
(iii) C & I Demand Non-TOD	-0.153¢	-0.001¢	-0.157¢	-0.312¢
(iv) C & I Demand TOD On-Peak	-0.194¢	-0.002¢	-0.199¢	-0.395¢
(v) C & I Demand TOD Off-Peak	-0.119¢	-0.001¢	-0.122¢	-0.242¢
(vi) Outdoor Lighting	-0.112¢	-0.001¢	-0.115¢	-0.228¢

Mar-2014 Factors	
	Total
(i) Residential	3.015¢
(ii) C & I Non-Demand	3.092¢
(iii) C & I Demand Non-TOD	3.059¢
(iv) C & I Demand TOD On-Peak	3.875¢
(v) C & I Demand TOD Off-Peak	2.373¢
(vi) Outdoor Lighting	2.238¢

	FCA Application		Comparison		Generation Type by Percent		
	Feb-14	Mar-14	Differ- ence	Percent Change	FCA Application Feb-14	Mar-14	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$155.4	\$172.3	\$17.0	10.9%	34.9%	36.4%	1.5%
2 Nuclear	\$33.0	\$32.5	(\$0.5)	-1.5%	7.4%	6.9%	-0.5%
3 Purchases	\$163.1	\$172.2	\$9.1	5.6%	36.6%	36.3%	-0.3%
MISO related Purchases	\$94.2	\$96.9	\$2.8	2.9%	21.1%	20.5%	-0.6%
4 Total System Costs	445.6	474.0	\$28.3	6.4%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$11.1	\$17.5	\$6.4	57.9%	2.5%	3.7%	1.2%
6 Net System Costs	\$434.5	\$456.5	\$21.9	5.0%	97.5%	96.3%	-1.2%
7							
** GWH OUTPUT **							
9 Fossil	4,447	5,019	572	12.9%	27.7%	30.4%	2.7%
10 Nuclear	3,460	3,439	(21)	-0.6%	21.6%	20.8%	-0.8%
11 Purchases	5,149	5,051	(98)	-1.9%	32.1%	30.6%	-1.5%
12 Hydro & Other	1,545	1,565	20	1.3%	9.6%	9.5%	-0.1%
13 Net Interchange	1,443	1,442	(1)	-0.1%	9.0%	8.7%	-0.3%
14 Total Output	16,044	16,516	472	2.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	468	563	95	20.2%	2.9%	3.4%	0.5%
16 Native Requirement	15,576	15,953	377	2.4%	97.1%	96.6%	-0.5%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.494	3.434	-0.060	-1.7%			
20 Nuclear	0.954	0.945	-0.009	-0.9%			
21 Purchases	3.168	3.409	0.242	7.6%			
22 Total System Costs	2.778	2.870	0.092	3.3%			
23 Intersystem Sales	2.366	3.108	0.742	31.4%			
24 Net System Costs	2.790	2.861	0.071	2.6%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,758	14,030	272	2.0%			
28							
29 COST per KWH SALES (\$)	3.158	3.253	0.095	3.0%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.259	0.061	-0.198				
(i) Residential	0.260	0.061	-0.199				
(ii) C & I Non-Demand	0.266	0.063	-0.204				
(iii) C & I Demand Non-TOD	0.263	0.062	-0.201				
(iv) C & I Demand TOD On-Peak	0.334	0.078	-0.255				
(v) C & I Demand TOD Off-Peak	0.204	0.048	-0.156				
(vi) Outdoor Lighting	0.193	0.045	-0.147				
32 REFUND	0.152	-0.306	-0.458				
(i) Residential	0.152	-0.307	-0.458				
(ii) C & I Non-Demand	0.156	-0.315	-0.471				
(iii) C & I Demand Non-TOD	0.155	-0.312	-0.467				
(iv) C & I Demand TOD On-Peak	0.196	-0.395	-0.591				
(v) C & I Demand TOD Off-Peak	0.120	-0.242	-0.362				
(vi) Outdoor Lighting	0.113	-0.228	-0.341				
33 SYSTEM FCC IMPACT (\$ / KWH)	3.569	3.008	-0.561	-15.7%			
(i) Residential	3.579	3.015	-0.564				
(ii) C & I Non-Demand	3.670	3.092	-0.578				
(iii) C & I Demand Non-TOD	3.630	3.059	-0.571				
(iv) C & I Demand TOD On-Peak	4.599	3.875	-0.724				
(v) C & I Demand TOD Off-Peak	2.816	2.373	-0.443				
(vi) Outdoor Lighting	2.656	2.238	-0.418				

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	(\$0.56)
250	(\$1.41)
500	(\$2.82)
750	(\$4.23)
1,000	(\$5.64)

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-14	Mar-14
** GWH OUTPUT **		
Thermal	1,092,094	1,054,772
Disper gen	(70)	(77)
Hydro plus Wind	453,100	510,719
Hydro and Other	1,545,124	1,565,414
Rounded to nearest thousand:	1,545	1,585
Sales		
Non Gen Munic Total	5,976,000	6,034,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	468,451,000	563,194,000
Rounded to nearest million:	468.451	563.194

		System	Intersystem	Retail
January 2014 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 26,367,076.23	\$ 8,158,015.60	\$ 34,525,091.83
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 8,700,492.75	\$ -	\$ 8,700,492.75
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 12,230.86	\$ -	\$ 12,230.86
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (20,804,203.80)	\$ -	\$ (20,804,203.80)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 560,199.64	\$ -	\$ 560,199.64
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (12,230.86)	\$ -	\$ (12,230.86)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (1,110,241.87)	\$ 3,169,608.77	\$ 2,059,366.90
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (54,288.41)	\$ -	\$ (54,288.41)
14	Real-Time Distribution of Losses Amount	\$ (3,427,402.67)	\$ -	\$ (3,427,402.67)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ (59,811.90)	\$ -	\$ (59,811.90)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 12,699.74	\$ -	\$ 12,699.74
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (487.53)	\$ -	\$ (487.53)
Congestion-Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 22,422,567.50	\$ -	\$ 22,422,567.50
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 49,304.64	\$ -	\$ 49,304.64
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ (504,986.95)	\$ -	\$ (504,986.95)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (49,304.64)	\$ -	\$ (49,304.64)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 324,656.95	\$ -	\$ 324,656.95
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)	\$ (956.16)	\$ -	\$ (956.16)
FTR-Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (13,431,231.13)	\$ -	\$ (13,431,231.13)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (961,024.74)	\$ -	\$ (961,024.74)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ 142,642.87	\$ -	\$ 142,642.87
37	Financial Transmission Guarantee Uplift Amount	\$ (138,784.45)	\$ -	\$ (138,784.45)
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,280,857.16	\$ -	\$ 1,280,857.16
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 318,348.68	\$ -	\$ 318,348.68
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (174,464.28)	\$ 12,698.75	\$ (161,765.53)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 66,736.63	\$ -	\$ 66,736.63
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (663,570.30)	\$ 190,594.13	\$ (472,976.17)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (401,171.31)	\$ 4,137.75	\$ (397,033.56)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 508,709.57	\$ (11,798.64)	\$ 496,910.93
19	Real-Time Market Administration Amount	\$ 39,631.17	\$ (2,587.18)	\$ 37,043.99
29	Financial Transmission Rights Market Administration Amount	\$ 35,757.76	\$ -	\$ 35,757.76
33	Day-Ahead Schedule 24 Allocation Amount	\$ 83,825.63	\$ (1,946.06)	\$ 81,879.57
34	Real-Time Schedule 24 Allocation Amount	\$ (173,588.63)	\$ 178,170.92	\$ 4,582.29
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	\$ (3,267.93)	\$ -	\$ (3,267.93)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 4,459,226.30	\$ -	\$ 4,459,226.30
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (4,698,431.87)	\$ -	\$ (4,698,431.87)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (582,805.52)	\$ -	\$ (582,805.52)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 150,885.13	\$ -	\$ 150,885.13
TOTAL MISO CHARGES		\$ 18,283,594.26	\$ 11,696,894.04	\$ 29,980,488.30
SCHEDULE 24 (FOR RETAIL)				\$ 86,461.86
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 29,894,026.44

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
January 2014 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (221,890.69)	\$ -	\$ (221,890.69)
2	Day-Ahead Spinning Reserve Amount	\$ (115,509.44)	\$ -	\$ (115,509.44)
3	Day-Ahead Supplemental Reserve	\$ (118,415.44)	\$ -	\$ (118,415.44)
4	Real-Time Regulation Amount	\$ (101,284.06)	\$ 167,231.07	\$ 65,947.01
5	Real-Time Spinning Reserve Amount	\$ (518,542.98)	\$ 516,113.99	\$ (2,428.99)
6	Real-Time Supplemental Reserve Amount	\$ 212,106.83	\$ 3,795.94	\$ 215,902.77
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (51,971.57)	\$ -	\$ (51,971.57)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (1,967,708.67)	\$ -	\$ (1,967,708.67)
8b	Real Time Non Excessive Energy Congestion	\$ (101,182.71)	\$ -	\$ (101,182.71)
8c	Real Time Non Excessive Energy Loss	\$ 145,646.54	\$ -	\$ 145,646.54
9	Real Time Net Regulation Adjustment Amount	\$ 183,912.84	\$ (68,086.55)	\$ 115,826.29
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 91,210.87	\$ -	\$ 91,210.87
11	Real Time Spinning Reserve Cost Distribution	\$ 79,559.72	\$ -	\$ 79,559.72
12	Real Time Supplemental Reserve Cost Distribution	\$ (38,753.04)	\$ -	\$ (38,753.04)
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 162,243.95	\$ (30,580.31)	\$ 131,663.64
14	Real Time Contingency Reserve Deployment Failure	\$ 19,130.65	\$ (8,395.10)	\$ 10,735.55
TOTAL MISO ASM CHARGES		\$ (2,341,447.20)	\$ 580,079.04	\$ (1,761,368.16)

