



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

March 31, 2014

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

Re: April 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 April 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:

April 2014	Fuel Cost Charge (\$/kWh)
Residential	0.03529
C & I Non-Demand	0.03619
C & I Demand	0.03580
C & I Demand Time of Day On-Peak	0.04535
C & I Demand Time of Day Off-Peak	0.02777
Outdoor Lighting	0.02619

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 April 2014 FCC the net MISO Day 2 costs for February 2014 as recorded in Account 555. The MISO Day 2 cost recovery included in this February 2014 FCC is \$18,014,650, 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 April FCC the net MISO ASM costs for February 2014 as recorded in Account

¹ Previously embedded in other FTR charge types.

555. The MISO ASM cost recovery included in this April FCC is \$-914,565, 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 April 2014 Asset Based Margin amount of \$172,630 has been included as a credit, or offset, to the April 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 April 2014 FCC is \$5,868, or 0.003¢ 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 April 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 Apr-2014

Apr-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.03271	\$0.00166	\$0.00083	\$0.03520
Residential	\$0.03280	\$0.00166	\$0.00083	\$0.03529
C & I Non-Demand	\$0.03363	\$0.00171	\$0.00086	\$0.03619
C & I Demand Non-TOD	\$0.03327	\$0.00169	\$0.00085	\$0.03580
C & I Demand TOD On-Peak	\$0.04214	\$0.00214	\$0.00107	\$0.04535
C & I Demand TOD Off-Peak	\$0.02580	\$0.00131	\$0.00066	\$0.02777
Outdoor Lighting	\$0.02434	\$0.00124	\$0.00062	\$0.02619
Residential				
Residential Service	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
Residential TOD	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
Residential - Underground	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
Residential TOD - Underground	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
Energy Control - (Non-Demand)	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
Limit Off Peak	\$ 0.03280	\$ 0.00166	\$ 0.00083	\$ 0.03529
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Limit Off Peak	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Small General Service	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Small General TOD - Metered	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Small General TOD - Unmetered	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Fire and Civil Defense Siren	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
Direct Current (Closed)	\$ 0.03363	\$ 0.00171	\$ 0.00086	\$ 0.03619
C & I Demand				
General Service	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
General TOD - On Peak	\$ 0.04214	\$ 0.00214	\$ 0.00107	\$ 0.04535
General TOD - Off-Peak	\$ 0.02580	\$ 0.00131	\$ 0.00066	\$ 0.02777
Peak Controlled (Closed)	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Peak Controlled TOD (Closed) - On Peak	\$ 0.04214	\$ 0.00214	\$ 0.00107	\$ 0.04535
Peak Controlled TOD (Closed) - Off-Peak	\$ 0.02580	\$ 0.00131	\$ 0.00066	\$ 0.02777
Peak Controlled Tiered	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Peak Controlled Tiered TOD - On Peak	\$ 0.04214	\$ 0.00214	\$ 0.00107	\$ 0.04535
Peak Controlled Tiered TOD - Off Peak	\$ 0.02580	\$ 0.00131	\$ 0.00066	\$ 0.02777
Energy Controlled (Closed)	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Tier 1 Energy Controlled Rider	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Real Time Pricing - Firm - On Peak	\$ 0.04214	\$ 0.00214	\$ 0.00107	\$ 0.04535
Real Time Pricing - Firm - Off Peak	\$ 0.02580	\$ 0.00131	\$ 0.00066	\$ 0.02777
Real Time Pricing - Controllable - On Peak	\$ 0.04214	\$ 0.00214	\$ 0.00107	\$ 0.04535
Real Time Pricing - Controllable - Off-Peak	\$ 0.02580	\$ 0.00131	\$ 0.00066	\$ 0.02777
Small Municipal Pumping	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Municipal Pumping	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Excess Energy - St. Anthony Falls	\$ 0.03327	\$ 0.00169	\$ 0.00085	\$ 0.03580
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619
Street Lighting System	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619
Street Lighting Energy	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619
Street Lighting Energy - Metered	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619
Street Lighting Energy (Closed)	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619
Street Lighting - City of St. Paul	\$ 0.02434	\$ 0.00124	\$ 0.00062	\$ 0.02619

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 Apr-2014

	Column (A) Nov-13	Column (B) Dec-13	Column (C) Jan-14	Column (D) Feb-14	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$35,144,174	\$52,485,969	\$53,489,925	\$40,586,350	\$181,706,418
Account 518 - Nuclear Fuel	\$7,744,058	\$7,801,662	\$9,136,018	\$10,019,374	\$34,701,112
Account 555 - Purchased Power ¹	\$47,321,898	\$39,793,736	\$48,385,125	\$41,849,054	\$177,349,814
Account 555 - Pr. Rose PPA Adjustment	(\$204,801)	(\$93,354)	(\$168,834)	(\$100,484)	(\$567,473)
MISO Day 2 Charges	\$19,456,194	\$17,180,234	\$29,980,488	\$18,096,951	\$84,713,868
MISO Day 2 - Schedule 24	(\$106,395)	(\$116,201)	(\$86,462)	(\$82,302)	(\$391,360)
MISO - ASM Charges	\$1,154,328	\$4,994,935	(\$1,761,368)	(\$914,565)	\$3,473,330
Account 555 - Total MISO Charges	\$20,504,127	\$22,058,967	\$28,132,658	\$17,100,085	\$87,795,838
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$110,509,456	\$122,046,981	\$138,974,893	\$109,454,379	\$480,985,709
Less Fuel Cost of InterSystem Sales	(\$4,320,339)	(\$2,366,209)	(\$10,126,119)	(\$7,375,339)	(\$24,188,005)
Net System Costs	\$106,189,117	\$119,680,772	\$128,848,774	\$102,079,041	\$456,797,704
System MWh Sales					
Total NSP System Retail	2,994,504	3,509,056	4,065,686	3,389,319	13,958,565
Non-Gen Muni's/Load Pattern	1,383	1,420	1,687	-	4,490
Total NSP System MWh Sales	2,995,887	3,510,476	4,067,373	3,389,319	13,963,055
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	3.544¢	3.409¢	3.168¢	3.012¢	3.271¢
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			3.271¢	1.0026	3.280¢
(ii) C & I Non-Demand			3.271¢	1.0281	3.363¢
(iii) C & I Demand Non-TOD			3.271¢	1.0170	3.327¢
(iv) C & I Demand TOD On-Peak			3.271¢	1.2883	4.214¢
(v) C & I Demand TOD Off-Peak			3.271¢	0.7889	2.580¢
(vi) Outdoor Lighting			3.271¢	0.7440	2.434¢
North Dakota Retail MWh Sales					
(i) Residential	52,513	86,391	113,485	87,264	339,653
(ii) C & I Non-Demand	8,265	12,206	15,180	12,455	48,106
(iii) C & I Demand Non-TOD	55,698	66,896	77,600	61,389	261,583
(iv) C & I Demand TOD On-Peak	19,158	16,590	19,746	16,864	72,358
(v) C & I Demand TOD Off-Peak	30,526	27,252	35,851	27,058	120,687
(vi) Outdoor Lighting	1,837	2,060	2,075	2,108	8,080
(vii) Total	167,997	211,395	263,937	207,138	850,467
Apr-2014 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Dec-13 Balance of Unrecovered Expenses)					Total
					Dec-13
					\$1,910,118

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

Prior Expenses Recovered in Feb-2014 [Billing Record]			ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential			87,264	\$129,553
(ii) C & I Non-Demand			12,455	\$18,652
(iii) C & I Demand Non-TOD			61,389	\$89,749
(iv) C & I Demand TOD On-Peak			16,864	\$32,108
(v) C & I Demand TOD Off-Peak			27,058	\$31,572
(vi) Outdoor Lighting			2,108	\$1,555
(vii) Total			207,138	\$303,189

Actual Cost Should Have Been Recovered in Feb-14				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	3.012¢	0.000¢	207,138	\$6,238,997

Cost Recovered in Feb-14 [Billing Record]			ND Billed MWh Sales	Actual Recovery
(i) Residential			87,264	\$2,716,510
(ii) C & I Non-Demand			12,455	\$397,213
(iii) C & I Demand Non-TOD			61,389	\$1,934,986
(iv) C & I Demand TOD On-Peak			16,864	\$674,278
(v) C & I Demand TOD Off-Peak			27,058	\$662,388
(vi) Outdoor Lighting			2,108	\$48,313
(vii) Total			207,138	\$6,433,688

Total Balance of Unrecovered Expenses (Apr-14 Balance of Unrecovered Expenses)	
Apr-2014 Recovery Provision	\$1,412,238
4 Month ND Retail Total MWh Sales	850,467
Apr-2014 Recovery Provision per KWH	0.166¢

Apr-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	0.166¢	0.166¢
(ii) C & I Non-Demand	1.0281	0.166¢	0.171¢
(iii) C & I Demand Non-TOD	1.0170	0.166¢	0.169¢
(iv) C & I Demand TOD On-Peak	1.2883	0.166¢	0.214¢
(v) C & I Demand TOD Off-Peak	0.7889	0.166¢	0.131¢
(vi) Outdoor Lighting	0.7440	0.166¢	0.124¢

Apr-2014 Refunds/Additional Charges				
Refund/Special Charge Amount	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	-REC Refund	Total
	(\$172,630)	(\$5,868)	\$333,838	\$161,208
(i) Residential	-0.093¢	-0.003¢	0.179¢	0.083¢
(ii) C & I Non-Demand	-0.095¢	-0.003¢	0.184¢	0.086¢
(iii) C & I Demand Non-TOD	-0.094¢	-0.003¢	0.182¢	0.085¢
(iv) C & I Demand TOD On-Peak	-0.119¢	-0.004¢	0.230¢	0.107¢
(v) C & I Demand TOD Off-Peak	-0.073¢	-0.002¢	0.141¢	0.066¢
(vi) Outdoor Lighting	-0.069¢	-0.002¢	0.133¢	0.062¢

Apr-2014 Factors		Total
(i) Residential		3.529¢
(ii) C & I Non-Demand		3.619¢
(iii) C & I Demand Non-TOD		3.580¢
(iv) C & I Demand TOD On-Peak		4.535¢
(v) C & I Demand TOD Off-Peak		2.777¢
(vi) Outdoor Lighting		2.619¢

FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -
Prior Month Compared to Current Month FCA

	FCA Application		Comparison		Generation Type by Percent		
	Mar-14	Apr-14	Differ- ence	Percent Change	FCA Application Mar-14	Apr-14	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$172.3	\$181.7	\$9.4	5.4%	36.4%	37.8%	1.4%
2 Nuclear	\$32.5	\$34.7	\$2.2	6.8%	6.9%	7.2%	0.3%
3 Purchases	\$172.2	\$176.8	\$4.6	2.7%	36.3%	36.8%	0.5%
MISO related Purchases	\$95.9	\$87.8	(\$9.1)	-9.4%	20.5%	18.3%	-2.2%
4 Total System Costs	474.0	481.0	\$7.0	1.5%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$17.5	\$24.2	\$6.7	38.2%	3.7%	5.0%	1.3%
6 Net System Costs	\$456.5	\$456.8	\$0.3	0.1%	96.3%	95.0%	-1.3%
7							
** GWH OUTPUT **							
9 Fossil	5,019	5,440	421	8.4%	30.4%	32.3%	1.9%
10 Nuclear	3,439	3,662	223	6.5%	20.8%	21.7%	0.9%
11 Purchases	5,051	4,838	(213)	-4.2%	30.6%	28.7%	-1.9%
12 Hydro & Other	1,565	1,440	(125)	-8.0%	9.5%	8.6%	-0.9%
13 Net Interchange	1,442	1,462	20	1.4%	8.7%	8.7%	0.0%
14 Total Output	16,516	16,842	326	2.0%	100.0%	100.0%	0.0%
15 Intersystem Sales	563	839	276	49.0%	3.4%	5.0%	1.6%
16 Native Requirement	15,953	16,003	50	0.3%	96.6%	95.0%	-1.6%
17							
** COST per KWH OUTPUT (\$) **							
19 Fossil	3.434	3.340	-0.094	-2.7%			
20 Nuclear	0.945	0.948	0.003	0.3%			
21 Purchases	3.409	3.654	0.245	7.2%			
22 Total System Costs	2.870	2.856	-0.014	-0.5%			
23 Intersystem Sales	3.108	2.883	-0.225	-7.2%			
24 Net System Costs	2.861	2.854	-0.007	-0.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,030	13,963	(67)	-0.5%			
28							
29 COST per KWH SALES (\$)	3.253	3.271	0.018	0.6%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS	0.061	0.166	0.105				
(i) Residential	0.061	0.166	0.106				
(ii) C & I Non-Demand	0.063	0.171	0.108				
(iii) C & I Demand Non-TOD	0.062	0.169	0.107				
(iv) C & I Demand TOD On-Peak	0.078	0.214	0.136				
(v) C & I Demand TOD Off-Peak	0.048	0.131	0.083				
(vi) Outdoor Lighting	0.045	0.124	0.078				
32 REFUND	-0.306	0.084	0.390				
(i) Residential	-0.307	0.083	0.390				
(ii) C & I Non-Demand	-0.315	0.086	0.391				
(iii) C & I Demand Non-TOD	-0.311	0.085	0.392				
(iv) C & I Demand TOD On-Peak	-0.394	0.107	0.498				
(v) C & I Demand TOD Off-Peak	-0.241	0.066	0.297				
(vi) Outdoor Lighting	-0.228	0.062	0.290				
33 SYSTEM FCC IMPACT (\$ / KWH)	3.008	3.521	0.513	17.1%			
(i) Residential	3.015	3.529	0.514				
(ii) C & I Non-Demand	3.092	3.619	0.527				
(iii) C & I Demand Non-TOD	3.059	3.580	0.521				
(iv) C & I Demand TOD On-Peak	3.875	4.535	0.660				
(v) C & I Demand TOD Off-Peak	2.373	2.777	0.404				
(vi) Outdoor Lighting	2.238	2.619	0.381				

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	\$0.51
250	\$1.29
500	\$2.57
750	\$3.86
1,000	\$5.14

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	
	Mar-14	Apr-14
** GWH OUTPUT **		
Thermal	1,054,772	946,059
Disper gen	(77)	(101)
Hydro plus Wind	510,719	494,104
Hydro and Other	1,565,414	1,440,062
Rounded to nearest thousand:	1,565	1,440
Sales		
Non Gen Munic Total	6,034,000	4,490,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	563,194,000	838,947,000
Rounded to nearest million:	563.194	838.947

		System	Intersystem	Retail
February 2014 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 25,160,745.90	\$ 5,099,394.12	\$ 30,260,140.02
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 8,274,282.93	\$ -	\$ 8,274,282.93
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 17,076.88	\$ -	\$ 17,076.88
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (20,143,151.17)	\$ -	\$ (20,143,151.17)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 691,667.17	\$ -	\$ 691,667.17
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (17,076.88)	\$ -	\$ (17,076.88)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (664,551.45)	\$ 1,611,989.36	\$ 947,437.91
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (34,048.96)	\$ -	\$ (34,048.96)
14	Real-Time Distribution of Losses Amount	\$ (4,069,923.69)	\$ -	\$ (4,069,923.69)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ -	\$ -	\$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
21	Real-time Net inadvertent Distribution	\$ 40,320.89	\$ -	\$ 40,320.89
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ 15,791.77	\$ -	\$ 15,791.77
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (788.68)	\$ -	\$ (788.68)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 20,765,269.92	\$ -	\$ 20,765,269.92
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 55,117.02	\$ -	\$ 55,117.02
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 1,716,528.49	\$ -	\$ 1,716,528.49
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (55,117.02)	\$ -	\$ (55,117.02)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ 417,300.08	\$ -	\$ 417,300.08
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ -	\$ -	\$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ -	\$ -	\$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (1,189.89)	\$ -	\$ (1,189.89)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (21,210,724.56)	\$ -	\$ (21,210,724.56)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (398,393.14)	\$ -	\$ (398,393.14)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (1,483,535.48)	\$ -	\$ (1,483,535.48)
37	Financial Transmission Guarantee Uplift Amount	\$ 1,483,489.14	\$ -	\$ 1,483,489.14
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 1,644,524.32	\$ -	\$ 1,644,524.32
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 374,463.57	\$ -	\$ 374,463.57
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (322,605.38)	\$ 13,223.06	\$ (309,382.32)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 953,091.87	\$ -	\$ 953,091.87
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (1,390,267.02)	\$ 110,944.13	\$ (1,279,322.89)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (459,924.52)	\$ 52,816.06	\$ (407,108.46)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 382,861.09	\$ (7,497.30)	\$ 375,363.79
19	Real-Time Market Administration Amount	\$ 26,125.64	\$ (2,278.10)	\$ 23,847.54
29	Financial Transmission Rights Market Administration Amount	\$ 39,825.60	\$ -	\$ 39,825.60
33	Day-Ahead Schedule 24 Allocation Amount	\$ 78,460.28	\$ (1,530.49)	\$ 76,929.79
34	Real-Time Schedule 24 Allocation Amount	\$ (153,460.82)	\$ 158,832.58	\$ 5,371.76
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	\$ (0.03)	\$ -	\$ (0.03)
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		\$ 11,061,057.91	\$ 7,035,893.42	\$ 18,096,951.33

SCHEDULE 24 (FOR RETAIL) \$ 82,301.55

TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL) \$ 18,014,649.78

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
February 2014 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (431,525.55)	\$ -	\$ (431,525.55)
2	Day-Ahead Spinning Reserve Amount	\$ (138,810.74)	\$ -	\$ (138,810.74)
3	Day-Ahead Supplemental Reserve	\$ (106,745.38)	\$ -	\$ (106,745.38)
4	Real-Time Regulation Amount	\$ 319,133.05	\$ (4,289.84)	\$ 314,843.21
5	Real-Time Spinning Reserve Amount	\$ (222,423.38)	\$ 134,235.01	\$ (88,188.37)
6	Real-Time Supplemental Reserve Amount	\$ 110,684.47	\$ 5,812.35	\$ 116,496.82
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (56,565.06)	\$ -	\$ (56,565.06)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ (452,686.93)	\$ -	\$ (452,686.93)
8b	Real Time Non Excessive Energy Congestion	\$ (621,339.23)	\$ -	\$ (621,339.23)
8c	Real Time Non Excessive Energy Loss	\$ 85,333.04	\$ -	\$ 85,333.04
9	Real Time Net Regulation Adjustment Amount	\$ (28,101.94)	\$ 1,853.87	\$ (26,248.07)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 170,035.99	\$ -	\$ 170,035.99
11	Real Time Spinning Reserve Cost Distribution	\$ 195,411.56	\$ -	\$ 195,411.56
12	Real Time Supplemental Reserve Cost Distribution	\$ 71,036.27	\$ -	\$ 71,036.27
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 63,852.29	\$ (9,920.29)	\$ 53,932.00
14	Real Time Contignecy Reserve Deployment Failure	\$ 455.63	\$ -	\$ 455.63
TOTAL MISO-ASM-CHARGES		\$ (1,042,255.91)	\$ 127,691.10	\$ (914,564.81)

