



414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

November 26, 2014

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

Re: December 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 December 2014.

Pursuant to Commission authorization of the final compliance tariffs in the Company's 2012 rate proceeding (Case No. PU-12-813), the new rates were implemented on May 1, 2014. The new Service Category Ratios listed below also become effective:

Service Category Ratios	Current	Effective May 2014
Residential	1.0026	0.9969
C & I Non-Demand	1.0281	1.0318
C & I Demand	1.0170	1.0184
C & I Demand Time of Day On-Peak	1.2883	1.2798
C & I Demand Time of Day Off-Peak	0.7889	0.7954
Outdoor Lighting	0.7440	0.7341

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

December 2014	Fuel Cost Charge (\$/kWh)
Residential	0.02764
C & I Non-Demand	0.02861
C & I Demand	0.02824
C & I Demand Time of Day On-Peak	0.03548
C & I Demand Time of Day Off-Peak	0.02205
Outdoor Lighting	0.02035

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 December 2014 FCC the net MISO Day 2 costs for October 2014 as recorded in Account 555. The MISO Day 2 cost recovery included in this October 2014 FCC is \$7,724,508, 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 December FCC the net MISO ASM costs for October 2014 as recorded in

¹ Previously embedded in other FTR charge types.

Account 555. The MISO ASM cost recovery included in this December FCC is \$2,501,452, which is the net of many items. The detailed records are contained in Attachment 2, page 2.

SPENT NUCLEAR FUEL DISPOSAL FEE

The Company received notification from the DOE on May 12, 2014 that the Spent Nuclear Fuel Disposal Fee, which was 1.0 mill per kilowatt hour of electricity generated and sold, would be discontinued effective May 16, 2014.² The Disposal Fee is an authorized component of FERC account 518. The charge had been collected from customers via a line item in our monthly Fuel Cost Charge filings. We no longer collect the Disposal Fee from North Dakota customers and will not do so unless, of course, the DOE reinstates a fee.

REFUNDS

Asset and Non-Asset Based Margins Sharing Refund

Under the terms of the Revised Second Amended Settlement adopted by the Commission³ on February 26, 2014, retroactive to January 1, 2014, the Company began passing through 100 percent of wholesale asset based margins to North Dakota customers. The December 2014 Asset Based Margin amount of -\$65,420 has been included as a credit, or offset, to the December 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 has been 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 December 2014 FCC is \$9,871, or 0.005¢ 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). Under the February 26, 2014 Settlement, instead of 90 percent, 100 percent of the North Dakota state jurisdictional share of revenue generated by the sale of Renewable Energy Credits was credited to customers. (See Attachment 3, page 3).

² Company submitted an informational filing to the commission on May 21, 2014 regarding this charge under Case No. PU-14-012

³ Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195

Net Credit for Transmission Interchange Reconciliation

Included in the December 2014 Fuel Cost Charge (FCC) computation is a net credit resulting from a transmission interchange reconciliation between the Company, Alliant Energy (IPL) and Western Area Power Administration (WAPA), the load balancing authority for East River Electric Power Cooperative (EREPC), pertaining to inadvertent power flow and emergency service at certain interconnection points. The Company received a net settlement payment of \$5,650,409 which the Company will refund to NSP retail customers according to the respective jurisdictional MWh sales weighting. The refund amount to North Dakota customers is \$308,512. The Company has also included an interest payment of \$8,458 based on the prime lending interest rate (3.25%) for the 10 months the Company has held the funding. The overall one-time refund to North Dakota customers included in the December 2014 FCC is \$316,970. (See Attachment 1, page 3).

PRAIRIE ROSE WIND PPA

Pursuant to the Commission's December 21, 2012 Order in the Company's Advance 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.

As a result of the Revised Second Amended Settlement adopted by the Commission on February 26, 2014, the Prairie Rose Wind energy costs incurred on and after February 26, 2014 would be included in the FCR calculation, and the Company would forego any unrecovered portion the Prairie Rose PPA had incurred prior to that time. As such, starting with the May 2014 FCC, the Company has included the Prairie Rose PPA costs in the computation.

PURCHASED POWER AGREEMENT (PPA) COST RECOVERY REVIEW

Pursuant to the Commission's February 26, 2014 Order Adopting Settlement (Case No. PU-12-813) the following procedural changes reflected in Revised Second Amended Settlement were intended to provide additional transparency regarding cost recovery of renewable energy projects or purchases:

- The Company will notify the Commission in its monthly FCR filings of any new renewable projects, qualifying in part or whole for FCR cost recovery, whose costs are included in the calculation of the Fuel Cost Charges. In addition, the

Company will file an annual summary listing the new resources that have been included in the FCR during the previous calendar year.

- Future renewable energy resources or purchases with FCR-qualifying costs that are 50 MW or larger in size (nameplate capacity) will require approval of an Advance Determination of Prudence before included for recovery in the FCR; and
- MISO market energy purchases are not subject to the above requirements.

For the October 2014 FCR reporting month there are no new renewable projects or purchases that require the above referenced reporting obligation. The Company will monitor and comply with these obligations under the Settlement going forward.

Other Reporting Item

Attached is the calculation of the December 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

Dec-2014 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	\$0.02664	\$0.00069	\$0.00040	\$0.02773
Residential	\$0.02656	\$0.00069	\$0.00040	\$0.02764
C & I Non-Demand	\$0.02749	\$0.00071	\$0.00041	\$0.02861
C & I Demand Non-TOD	\$0.02713	\$0.00070	\$0.00041	\$0.02824
C & I Demand TOD On-Peak	\$0.03409	\$0.00088	\$0.00051	\$0.03548
C & I Demand TOD Off-Peak	\$0.02119	\$0.00055	\$0.00032	\$0.02205
Outdoor Lighting	\$0.01956	\$0.00050	\$0.00029	\$0.02035
Residential				
Residential Service	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
Residential TOD	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
Residential - Underground	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
Residential TOD - Underground	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
Energy Control - (Non-Demand)	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
Limit Off Peak	\$ 0.02656	\$ 0.00069	\$ 0.00040	\$ 0.02764
C & I Non-Demand				
Energy Controlled - (Non-Demand)	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Limit Off Peak	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Small General Service	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Small General TOD - Metered	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Small General TOD - Unmetered	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Fire and Civil Defense Siren	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
Direct Current (Closed)	\$ 0.02749	\$ 0.00071	\$ 0.00041	\$ 0.02861
C & I Demand				
General Service	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
General TOD - On Peak	\$ 0.03409	\$ 0.00088	\$ 0.00051	\$ 0.03548
General TOD - Off Peak	\$ 0.02119	\$ 0.00055	\$ 0.00032	\$ 0.02205
Peak Controlled (Closed)	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Peak Controlled TOD (Closed) - On Peak	\$ 0.03409	\$ 0.00088	\$ 0.00051	\$ 0.03548
Peak Controlled TOD (Closed) - Off Peak	\$ 0.02119	\$ 0.00055	\$ 0.00032	\$ 0.02205
Peak Controlled Tiered	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Peak Controlled Tiered TOD - On Peak	\$ 0.03409	\$ 0.00088	\$ 0.00051	\$ 0.03548
Peak Controlled Tiered TOD - Off Peak	\$ 0.02119	\$ 0.00055	\$ 0.00032	\$ 0.02205
Energy Controlled (Closed)	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Tier 1 Energy Controlled Rider	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Real Time Pricing - Firm - On Peak	\$ 0.03409	\$ 0.00088	\$ 0.00051	\$ 0.03548
Real Time Pricing - Firm - Off Peak	\$ 0.02119	\$ 0.00055	\$ 0.00032	\$ 0.02205
Real Time Pricing - Controllable - On Peak	\$ 0.03409	\$ 0.00088	\$ 0.00051	\$ 0.03548
Real Time Pricing - Controllable - Off Peak	\$ 0.02119	\$ 0.00055	\$ 0.00032	\$ 0.02205
Small Municipal Pumping	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Municipal Pumping	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Excess Energy - St. Anthony Falls	\$ 0.02713	\$ 0.00070	\$ 0.00041	\$ 0.02824
Outdoor Lighting				
Automatic Protective Lighting	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035
Street Lighting System	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035
Street Lighting Energy	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035
Street Lighting Energy - Metered	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035
Street Lighting Energy (Closed)	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035
Street Lighting - City of St. Paul	\$ 0.01956	\$ 0.00050	\$ 0.00029	\$ 0.02035

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Jul-14	Aug-14	Sep-14	Oct-14	4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	\$40,296,537	\$50,710,522	\$36,722,573	\$47,290,204	\$175,019,836
Account 518 - Nuclear Fuel	\$10,690,492	\$10,714,115	\$9,669,747	\$5,755,755	\$36,830,109
Account 555 - Purchased Power ¹	\$40,196,299	\$32,258,409	\$36,666,368	\$40,492,666	\$149,613,741
MISO Day 2 Charges	\$16,196,936	\$12,907,701	\$5,662,960	\$7,791,951	\$42,559,549
MISO Day 2 - Schedule 24	(\$63,569)	(\$73,480)	(\$75,206)	(\$67,443)	(\$279,698)
MISO - ASM Charges	\$1,119,467	\$1,790,087	\$1,512,102	\$2,501,452	\$6,923,109
Account 555 - Total MISO Charges	\$17,252,834	\$14,624,308	\$7,099,857	\$10,225,960	\$49,202,960
Financial Instruments	\$0	\$0	\$0	\$0	\$0
Total System Costs	\$108,436,162	\$108,307,354	\$90,158,545	\$103,764,585	\$410,666,646
Less Fuel Cost of InterSystem Sales	(\$4,263,576)	(\$5,849,212)	(\$4,531,926)	(\$10,015,322)	(\$24,660,037)
Net System Costs	\$104,172,586	\$102,458,142	\$85,626,618	\$93,749,263	\$386,006,609
System MWh Sales					
Total NSP System Retail	3,756,198	3,677,230	3,732,293	3,325,315	14,491,036
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	3,756,198	3,677,230	3,732,293	3,325,315	14,491,036
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	2.773¢	2.786¢	2.294¢	2.819¢	2.664¢
Class Ratio/TOD Ratio					
(i) Residential	0.9969	0.9969	0.9969	0.9969	0.9969
(ii) C & I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318
(iii) C & I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184
(iv) C & I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798
(v) C & I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954
(vi) Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341
North Dakota Fuel Cost Factor (FCF)					
			Avg Unit Cost	FCF Ratio	4 Month Average
(i) Residential			2.664¢	0.9969	2.656¢
(ii) C & I Non-Demand			2.664¢	1.0318	2.749¢
(iii) C & I Demand Non-TOD			2.664¢	1.0184	2.713¢
(iv) C & I Demand TOD On-Peak			2.664¢	1.2798	3.409¢
(v) C & I Demand TOD Off-Peak			2.664¢	0.7954	2.119¢
(vi) Outdoor Lighting			2.664¢	0.7341	1.956¢
North Dakota Retail MWh Sales					
(i) Residential	57,840	58,736	54,548	52,181	223,305
(ii) C & I Non-Demand	8,642	8,513	8,423	8,558	34,136
(iii) C & I Demand Non-TOD	68,584	64,783	65,780	65,501	264,648
(iv) C & I Demand TOD On-Peak	19,467	18,035	17,918	20,499	75,919
(v) C & I Demand TOD Off-Peak	31,376	27,309	28,467	32,253	119,405
(vi) Outdoor Lighting	1,148	1,185	1,362	1,563	5,258
(vii) Total	187,057	178,561	176,498	180,555	722,671
Dec-2014 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (Aug-14 Balance of Unrecovered Expenses)					Total
					Aug-14
					\$325,929

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

Prior Expenses Recovered in Oct-2014 [Billing Record]		
	ND Billed MWh Sales	Prior Recovered Expenses
(i) Residential	52,181	(\$51,838)
(ii) C & I Non-Demand	8,558	(\$9,537)
(iii) C & I Demand Non-TOD	65,501	(\$71,395)
(iv) C & I Demand TOD On-Peak	20,499	(\$30,212)
(v) C & I Demand TOD Off-Peak	32,253	(\$29,575)
(vi) Outdoor Lighting	1,563	(\$1,795)
(vii) Total	180,555	(\$194,352)

Actual Cost Should Have Been Recovered in Oct-14				
	Actual	Base	Actual ND MWh Sales	Expected Recovery
	2.819¢	0.000¢	180,555	\$5,089,845

Cost Recovered in Oct-14 [Billing Record]		
	ND Billed MWh Sales	Actual Recovery
(i) Residential	52,181	\$1,472,839
(ii) C & I Non-Demand	8,558	\$250,035
(iii) C & I Demand Non-TOD	65,501	\$1,888,588
(iv) C & I Demand TOD On-Peak	20,499	\$742,860
(v) C & I Demand TOD Off-Peak	32,253	\$726,671
(vi) Outdoor Lighting	1,563	\$32,503
(vii) Total	180,555	\$5,113,496

Total Balance of Unrecovered Expenses (Dec-14 Balance of Unrecovered Expenses)	
Dec-2014 Recovery Provision	\$496,630
4 Month ND Retail Total MWh Sales	722,671
Dec-2014 Recovery Provision per KWH	0.069¢

Dec-2014 Recovery Provision (True-up Factor) per kWh by Customer Category			
	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	0.069¢	0.069¢
(ii) C & I Non-Demand	1.0318	0.069¢	0.071¢
(iii) C & I Demand Non-TOD	1.0184	0.069¢	0.070¢
(iv) C & I Demand TOD On-Peak	1.2798	0.069¢	0.088¢
(v) C & I Demand TOD Off-Peak	0.7954	0.069¢	0.055¢
(vi) Outdoor Lighting	0.7341	0.069¢	0.050¢

Dec-2014 Refunds/Additional Charges					
	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	WAPA/Alliant Refund	Total
Refund/Special Charge Amount	\$65,420	(\$9,871)	\$347,795	(\$316,970)	\$413,215
(i) Residential	0.030¢	-0.005¢	0.160¢	-0.146¢	0.040¢
(ii) C & I Non-Demand	0.031¢	-0.005¢	0.166¢	-0.151¢	0.041¢
(iii) C & I Demand Non-TOD	0.031¢	-0.005¢	0.164¢	-0.149¢	0.041¢
(iv) C & I Demand TOD On-Peak	0.039¢	-0.006¢	0.206¢	-0.187¢	0.051¢
(v) C & I Demand TOD Off-Peak	0.024¢	-0.004¢	0.128¢	-0.117¢	0.032¢
(vi) Outdoor Lighting	0.022¢	-0.003¢	0.118¢	-0.108¢	0.029¢

Dec-2014 Factors	
	Total
(i) Residential	2.764¢
(ii) C & I Non-Demand	2.861¢
(iii) C & I Demand Non-TOD	2.824¢
(iv) C & I Demand TOD On-Peak	3.548¢
(v) C & I Demand TOD Off-Peak	2.205¢
(vi) Outdoor Lighting	2.035¢

	<u>FCA Application</u>		<u>Comparison</u>		<u>Generation Type by Percent</u>		
	Nov-14	Dec-14	Differ- ence	Percent Change	FCA Application Nov-14	Dec-14	Differ- ence
** COSTS (Millions) **							
1 Fossil	\$169.5	\$175.0	\$5.5	3.3%	41.0%	42.6%	1.6%
2 Nuclear	\$41.5	\$36.8	(\$4.7)	-11.3%	10.1%	9.0%	-1.1%
3 Purchases	\$145.8	\$149.6	\$3.8	2.6%	35.3%	36.4%	1.1%
MISO related Purchases	\$56.1	\$49.2	(\$6.9)	-12.3%	13.6%	12.0%	-1.6%
4 Total System Costs	413.0	410.7	(\$2.3)	-0.6%	100.0%	100.0%	0.0%
5 Intersystem Sales	\$21.4	\$24.7	\$3.2	15.0%	5.2%	6.0%	0.8%
6 Net System Costs	\$391.5	\$386.0	(\$5.5)	-1.4%	94.8%	94.0%	-0.8%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,224	5,441	217	4.2%	31.7%	33.6%	1.9%
10 Nuclear	4,601	4,090	(511)	-11.1%	27.9%	25.2%	-2.7%
11 Purchases	4,571	4,451	(120)	-2.6%	27.8%	27.5%	-0.3%
12 Hydro & Other	1,360	1,509	149	11.0%	8.3%	9.3%	1.0%
13 Net Interchange	710	711	1	0.1%	4.3%	4.4%	0.1%
14 Total Output	16,466	16,202	(264)	-1.6%	100.0%	100.0%	0.0%
15 Intersystem Sales	839	988	150	17.9%	5.1%	6.1%	1.0%
16 Native Requirement	15,627	15,214	(414)	-2.6%	94.9%	93.9%	-1.0%
17							
18 ** COST per KWH OUTPUT (\$) **							
19 Fossil	3.245	3.217	-0.028	-0.9%			
20 Nuclear	0.903	0.900	-0.002	-0.2%			
21 Purchases	3.191	3.361	0.171	5.3%			
22 Total System Costs	2.508	2.535	0.027	1.1%			
23 Intersystem Sales	2.557	2.495	-0.061	-2.4%			
24 Net System Costs	2.505	2.537	0.032	1.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	14,577	14,491	(86)	-0.6%			
28							
29 COST per KWH SALES (\$)	2.686	2.664	-0.022	-0.8%			
30							
31 RECOVERY PROV (\$ / KWH) - SYS							
(i) Residential	-0.357	0.069	0.426				
(ii) C & I Non-Demand	-0.356	0.069	0.424				
(iii) C & I Demand Non-TOD	-0.368	0.071	0.439				
(iv) C & I Demand TOD On-Peak	-0.363	0.070	0.433				
(v) C & I Demand TOD Off-Peak	-0.457	0.088	0.545				
(vi) Outdoor Lighting	-0.284	0.055	0.339				
(vi) Outdoor Lighting	-0.262	0.050	0.312				
32 REFUND	-0.359	0.040	0.399				
(i) Residential	-0.360	0.040	0.424				
(ii) C & I Non-Demand	-0.369	0.041	0.439				
(iii) C & I Demand Non-TOD	-0.365	0.041	0.433				
(iv) C & I Demand TOD On-Peak	-0.462	0.051	0.545				
(v) C & I Demand TOD Off-Peak	-0.283	0.032	0.339				
(vi) Outdoor Lighting	-0.267	0.029	0.312				
33 SYSTEM FCC IMPACT (\$ / KWH)	1.970	2.773	0.803	40.7%			
(i) Residential	1.964	2.764	0.800				
(ii) C & I Non-Demand	2.033	2.861	0.828				
(iii) C & I Demand Non-TOD	2.006	2.824	0.818				
(iv) C & I Demand TOD On-Peak	2.521	3.548	1.027				
(v) C & I Demand TOD Off-Peak	1.567	2.205	0.638				
(vi) Outdoor Lighting	1.446	2.035	0.589				

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	\$0.80
250	\$2.00
500	\$4.00
750	\$6.00
1,000	\$8.00

Some miscellaneous totals refer to so many terms that their formula would be too long. So intermediate totals are developed here, then an overall total is taken and is rounded, and finally it's simply referred to above.

	<u>FCA Application</u>	
	Nov-14	Dec-14
** GWH OUTPUT **		
Thermal	769,805	937,409
Disper gen	(82)	(81)
Hydro plus Wind	590,091	571,788
Hydro and Other	1,359,814	1,509,116
Rounded to nearest thousand:	1,360	1,509
Sales		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	838,505,000	988,185,000
Rounded to nearest million:	838.505	988.185

		System	Intersystem	Retail
October 2014 Actual				
Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	\$ 8,053,479.74	\$ 7,809,079.49	\$ 15,862,559.23
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	\$ 2,626,282.04	\$ -	\$ 2,626,282.04
3	Day-Ahead Financial Bilateral Transaction Loss Amount	\$ 1,944.46	\$ -	\$ 1,944.46
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	\$ (15,067,199.80)	\$ -	\$ (15,067,199.80)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	\$ 1,442,653.08	\$ -	\$ 1,442,653.08
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	\$ (1,944.46)	\$ -	\$ (1,944.46)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	\$ (267,718.41)	\$ 1,138,611.97	\$ 870,893.56
13 c	Real-Time Asset Energy Amount - Loss Component (1)	\$ (17,101.55)	\$ -	\$ (17,101.55)
14	Real-Time Distribution of Losses Amount	\$ (1,236,679.64)	\$ -	\$ (1,236,679.64)
16	Real-Time Financial Bilateral Transaction Loss Amount	\$ (48.58)	\$ -	\$ (48.58)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	\$ 48.58	\$ -	\$ 48.58
21	Real-time Net inadvertent Distribution	\$ 71,496.69	\$ -	\$ 71,496.69
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	\$ (21,419.55)	\$ -	\$ (21,419.55)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	\$ (16,365.63)	\$ -	\$ (16,365.63)
Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	\$ 4,127,571.69	\$ -	\$ 4,127,571.69
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	\$ 1,508.75	\$ -	\$ 1,508.75
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	\$ 5,075,832.85	\$ -	\$ 5,075,832.85
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (1,508.75)	\$ -	\$ (1,508.75)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	\$ -	\$ -	\$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	\$ (562.00)	\$ -	\$ (562.00)
15	Real-Time Financial Bilateral Transaction Congestion Amount	\$ 440.25	\$ -	\$ 440.25
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	\$ (440.25)	\$ -	\$ (440.25)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	\$ (9,207.90)	\$ -	\$ (9,207.90)
FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	\$ (6,623,772.88)	\$ -	\$ (6,623,772.88)
30	Financial Transmission Rights Monthly Allocation Amount	\$ (140,934.26)	\$ -	\$ (140,934.26)
31	Financial Transmission Rights Transaction Amount	\$ -	\$ -	\$ -
32	Financial Transmission Rights Yearly Allocation Amount	\$ -	\$ -	\$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	\$ (739,710.56)	\$ -	\$ (739,710.56)
37	Financial Transmission Guarantee Uplift Amount	\$ 755,421.53	\$ -	\$ 755,421.53
38	Financial Transmission Rights Monthly Transaction Amount	\$ -	\$ -	\$ -
Uplift Charges				
23	Real-Time Revenue Neutrality Uplift Amount	\$ 868,925.28	\$ -	\$ 868,925.28
Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	\$ 152,832.02	\$ -	\$ 152,832.02
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (200,330.96)	\$ 121,267.09	\$ (79,063.87)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 178,912.09	\$ -	\$ 178,912.09
25	Real-Time Revenue Sufficiency Guarantee Make Whole Payment Amount	\$ (47,021.92)	\$ 19,273.51	\$ (27,748.41)
43	Real-Time Price Volatility Make Whole Payment Amount	\$ (224,857.01)	\$ 9,544.06	\$ (215,312.95)
Market Administration Charges				
4	Day-Ahead Market Administration Amount	\$ 481,762.21	\$ (16,154.42)	\$ 465,607.79
19	Real-Time Market Administration Amount	\$ 34,090.50	\$ (2,780.16)	\$ 31,310.34
29	Financial Transmission Rights Market Administration Amount	\$ 23,626.96	\$ -	\$ 23,626.96
33	Day-Ahead Schedule 24 Allocation Amount	\$ 66,695.92	\$ (2,239.02)	\$ 64,456.90
34	Real-Time Schedule 24 Allocation Amount	\$ (29,650.06)	\$ 32,636.22	\$ 2,986.16
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	\$ (54,710.46)	\$ 29,213.68	\$ (25,496.78)
26	Real-Time Uninstructed Deviation Amount	\$ -	\$ -	\$ -
Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	\$ 6,044,899.06	\$ -	\$ 6,044,899.06
40	Auction Revenue Rights - Monthly ARR Revenue	\$ (6,528,060.99)	\$ -	\$ (6,528,060.99)
41	Auction Revenue Rights - ARR Stage 2 Distribution	\$ (290,711.50)	\$ -	\$ (290,711.50)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	\$ 165,031.72	\$ -	\$ 165,031.72
TOTAL MISO CHARGES		\$ (1,346,501.70)	\$ 9,138,452.42	\$ 7,791,950.72
SCHEDULE 24 (FOR RETAIL)				\$ 67,443.06
TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)				\$ 7,724,507.66

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
October 2014 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	\$ (310,873.59)	\$ -	\$ (310,873.59)
2	Day-Ahead Spinning Reserve Amount	\$ (46,681.76)	\$ -	\$ (46,681.76)
3	Day-Ahead Supplemental Reserve	\$ (56,362.80)	\$ -	\$ (56,362.80)
4	Real-Time Regulation Amount	\$ (49,330.84)	\$ 212,780.80	\$ 163,449.96
5	Real-Time Spinning Reserve Amount	\$ (37,255.54)	\$ 36,972.34	\$ (283.20)
6	Real-Time Supplemental Reserve Amount	\$ (45.14)	\$ (883.11)	\$ (928.25)
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	\$ (18,516.86)	\$ -	\$ (18,516.86)
7b	Real Time Excessive Energy Congestion	\$ -	\$ -	\$ -
7c	Real Time Excessive Energy Loss	\$ -	\$ -	\$ -
8a	Real Time Non Excessive Energy Amount	\$ 2,449,010.34	\$ -	\$ 2,449,010.34
8b	Real Time Non Excessive Energy Congestion	\$ (142,933.57)	\$ -	\$ (142,933.57)
8c	Real Time Non Excessive Energy Loss	\$ 40,194.66	\$ -	\$ 40,194.66
9	Real Time Net Regulation Adjustment Amount	\$ (962.51)	\$ (2,115.62)	\$ (3,078.13)
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	\$ 119,361.97	\$ -	\$ 119,361.97
11	Real Time Spinning Reserve Cost Distribution	\$ 126,349.39	\$ -	\$ 126,349.39
12	Real Time Supplemental Reserve Cost Distribution	\$ 80,725.44	\$ -	\$ 80,725.44
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	\$ 132,236.87	\$ (30,218.04)	\$ 102,018.83
14	Real Time Contignecy Reserve Deployment Failure	\$ -	\$ -	\$ -
TOTAL MISO ASM CHARGES		\$ 2,284,916.06	\$ 216,536.37	\$ 2,501,452.43

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Asset Based Margin Sharing

1 Forecast Month	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15
2 True-up Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
3												
4 Monthly Refund	(280,361)	(232,398)	(191,441)	(106,644)	(91,428)	(52,496)	(53,939)	(35,487)	(38,675)	(84,564)		
5												
6 Forecast North Dakota Sales	204,151	186,753	165,759	167,300	190,371	186,036	182,561	177,719	158,767	216,391	237,301	203,682
7												
8 Current Month Refund Factor	(0.137)	(0.124)	(0.115)	(0.064)	(0.048)	(0.028)	(0.030)	(0.020)	(0.024)	(0.039)	-	-
9												
14 Expected Refund	(68,557)	50,152	(306,819)	(172,630)	(373,518)	(51,493)	(219,413)	136,839	(132,082)	155,128	(189,676)	65,420
15 Actual Refunded	(42,099)	(9,616)	(124,742)	(227,780)	(245,533)	(240,829)	(141,270)	(53,775)	18,919	5,144		
16 Deviation	(26,458)	59,768	(182,077)	55,150	(127,985)	189,336	(78,143)	190,614	(151,001)	149,984	(189,676)	65,420
17												
18 True-up Factor	(0.013)	0.032	(0.110)	0.033	(0.067)	0.102	(0.043)	0.107	(0.095)	0.069	-	-
19												
20 Realized Margin	(0.150)	(0.092)	(0.225)	(0.031)	(0.115)	0.074	(0.072)	0.087	(0.119)	0.030	-	-
21												
22 Class Ratios												
23 Residential	1.0026	1.0026	1.0012	0.9998	0.9983	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0281	1.0281	1.0290	1.0300	1.0309	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0170	1.0170	1.0174	1.0177	1.0181	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2883	1.2883	1.2862	1.2841	1.2819	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7889	0.7889	0.7905	0.7922	0.7938	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7440	0.7440	0.7415	0.7391	0.7366	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.151)	(0.093)	(0.226)	(0.031)	(0.115)	0.073	(0.072)	0.087	(0.119)	0.030	-	-
32 C&I Non-Demand	(0.155)	(0.095)	(0.232)	(0.032)	(0.119)	0.076	(0.075)	0.090	(0.123)	0.031	-	-
33 C&I Demand Non-TOD	(0.153)	(0.094)	(0.229)	(0.031)	(0.117)	0.075	(0.074)	0.089	(0.122)	0.031	-	-
34 C&I Demand TOD On-Peak	(0.194)	(0.119)	(0.290)	(0.040)	(0.148)	0.094	(0.093)	0.112	(0.153)	0.039	-	-
35 C&I Demand TOD Off-Peak	(0.119)	(0.073)	(0.178)	(0.024)	(0.091)	0.059	(0.058)	0.069	(0.095)	0.024	-	-
36 Outdoor Lighting	(0.112)	(0.069)	(0.167)	(0.023)	(0.085)	0.054	(0.053)	0.064	(0.088)	0.022	-	-

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Non-Asset Based Margin Sharing

1 Forecast Month	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15
2 True-up Month	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14
3												
4 Monthly Refund	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)	(7,762)
5												
6 Forecast North Dakota Sales	198,863	204,151	186,753	165,759	167,300	190,371	186,036	182,561	177,719	158,767	216,391	-
7												
8 Current Month Refund Factor	(0.004)	(0.004)	(0.004)	(0.005)	(0.005)	(0.004)	(0.004)	(0.004)	(0.004)	(0.005)	(0.004)	-
9												
14 Expected Refund	(15,511)	(12,506)	(7,639)	(2,884)	(5,868)	(4,580)	(10,029)	(7,647)	(10,541)	(6,116)	(9,734)	-
15 Actual Refund	(15,634)	(17,384)	(9,533)	(6,066)	(3,601)	(4,694)	(7,250)	(9,293)	(8,568)	(8,223)	(7,625)	-
16 Deviation	123	4,878	1,894	3,182	(2,267)	114	(2,779)	1,646	(1,973)	2,107	(2,109)	-
17												
18 True-up Factor	0.000	0.002	0.001	0.002	(0.001)	0.000	(0.001)	0.001	(0.001)	0.001	(0.001)	-
19												
20 Realized Margin	(0.004)	(0.001)	(0.003)	(0.003)	(0.006)	(0.004)	(0.006)	(0.003)	(0.005)	(0.004)	(0.005)	-
21												
22 Class Ratios												
23 Residential	1.0026	1.0026	1.0026	1.0012	0.9998	0.9983	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0281	1.0281	1.0281	1.0290	1.0300	1.0309	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0174	1.0177	1.0181	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2862	1.2841	1.2819	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7905	0.7922	0.7938	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7440	0.7440	0.7440	0.7415	0.7391	0.7366	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29												
30 Realized Margin Adj for Class Ratios												
31 Residential	(0.004)	(0.001)	(0.003)	(0.003)	(0.006)	(0.004)	(0.006)	(0.003)	(0.005)	(0.004)	(0.005)	-
32 C&I Non-Demand	(0.004)	(0.001)	(0.003)	(0.003)	(0.006)	(0.004)	(0.006)	(0.003)	(0.006)	(0.004)	(0.005)	-
33 C&I Demand Non-TOD	(0.004)	(0.001)	(0.003)	(0.003)	(0.006)	(0.004)	(0.006)	(0.003)	(0.006)	(0.004)	(0.005)	-
34 C&I Demand TOD On-Peak	(0.005)	(0.002)	(0.004)	(0.004)	(0.008)	(0.005)	(0.007)	(0.004)	(0.007)	(0.005)	(0.006)	-
35 C&I Demand TOD Off-Peak	(0.003)	(0.001)	(0.002)	(0.002)	(0.005)	(0.003)	(0.005)	(0.003)	(0.004)	(0.003)	(0.004)	-
36 Outdoor Lighting	(0.003)	(0.001)	(0.002)	(0.002)	(0.004)	(0.003)	(0.004)	(0.002)	(0.004)	(0.003)	(0.003)	-

Northern States Power Company, A Minnesota Corporation
 Electric Operations - State of North Dakota
 Derivation of Adjustment for Fuel Clause Rider
 Sales of Renewable Energy Credits

1 Forecast Month	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15
2 True-up Month	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
3													
4 Monthly Refund	-	-	(39,728)	-	(72,037)	(23,952)	-	-	(21,192)	-	-	-	-
5													
6 Forecast North Dakota Sales	198,863	204,151	186,753	165,759	167,300	190,371	186,036	182,561	177,719	158,767	216,391	-	-
7													
8 Current Month Refund Factor	-	-	(0.021)	-	(0.043)	(0.013)	-	-	(0.012)	-	-	-	-
9													
14 Expected Refund	98,806	(496,354)	260,871	(315,660)	333,838	(300,330)	269,885	(350,362)	318,815	(335,974)	333,685	-	-
15 Actual Refund	(162,065)	(180,694)	(112,695)	(15,330)	(8,084)	26,080	(48,930)	(14,388)	(36,062)	38,635	(14,110)	-	-
16 Deviation	260,871	(315,660)	373,566	(300,330)	341,922	(326,410)	318,815	(335,974)	354,877	(374,609)	347,795	-	-
17													
18 True-up Factor	0.131	(0.155)	0.200	(0.181)	0.204	(0.171)	0.171	(0.184)	0.200	(0.236)	0.161	-	-
19													
20 Realized Refund	0.131	(0.155)	0.179	(0.181)	0.161	(0.184)	0.171	(0.184)	0.188	(0.236)	0.161	-	-
21													
22 Class Ratios													
23 Residential	1.0026	1.0026	1.0026	1.0012	0.9998	0.9983	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24 C&I Non-Demand	1.0281	1.0281	1.0281	1.0290	1.0300	1.0309	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25 C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0174	1.0177	1.0181	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26 C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2862	1.2841	1.2819	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27 C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7905	0.7922	0.7938	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28 Outdoor Lighting	0.7440	0.7440	0.7440	0.7415	0.7391	0.7366	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30 Realized Margin Adj for Class Ratios													
31 Residential	0.132	(0.155)	0.179	(0.181)	0.161	(0.184)	0.171	(0.183)	0.187	(0.235)	0.160	-	-
32 C&I Non-Demand	0.135	(0.159)	0.184	(0.186)	0.166	(0.190)	0.177	(0.190)	0.194	(0.243)	0.166	-	-
33 C&I Demand Non-TOD	0.133	(0.157)	0.182	(0.184)	0.164	(0.187)	0.175	(0.187)	0.191	(0.240)	0.164	-	-
34 C&I Demand TOD On-Peak	0.169	(0.199)	0.230	(0.233)	0.207	(0.236)	0.219	(0.236)	0.240	(0.302)	0.206	-	-
35 C&I Demand TOD Off-Peak	0.103	(0.122)	0.141	(0.143)	0.128	(0.146)	0.136	(0.146)	0.149	(0.188)	0.128	-	-
36 Outdoor Lighting	0.098	(0.115)	0.133	(0.134)	0.119	(0.136)	0.126	(0.135)	0.138	(0.173)	0.118	-	-