414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

March 31, 2015

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

Re: April 2015 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 2015.

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 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:

April 2015	Fuel Cost Charge ($/kWh)
Residential	0.03272
C & I Non-Demand	0.03386
C & I Demand	0.03342
C & I Demand Time of Day On-Peak	0.04200
C & I Demand Time of Day Off-Peak	0.02610
Outdoor Lighting	0.02409

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 types[1], 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 2015 FCC the net MISO Day 2 costs for February 2015 as recorded in Account 555. The MISO Day 2 cost recovery included in this April 2015 FCC is $8,545,974, 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

[1] Previously embedded in other FTR charge types.

MISO Order and the required "net" accounting of ASM costs and revenues, we include in the April 2015 FCC the net MISO ASM costs for February 2015 as recorded in Account 555. The MISO ASM cost recovery included in this April 2015 FCC is $-693,218, 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 Commission[3] 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 Asset Based Margin amount of $-104,518 has been included as a credit, or offset, to the April 2015 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 2014 Non-Asset Based Margin credit is $194,148 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the April 2015 FCC is $22,770, or 0.012¢ 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

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[2] The Company submitted an informational filing to the Commission on May 21, 2014 regarding this charge in 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

generated by the sale of Renewable Energy Credits was credited to customers. (See Attachment 3, 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 April 2015 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 April 2015 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
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider

Current Period Cost of Energy for Apr-2015

Apr-2015 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.02904**	**$0.00169**	**$0.00208**	**$0.03282**
Residential	**$0.02895**	**$0.00169**	**$0.00208**	**$0.03272**
C & I Non-Demand	**$0.02996**	**$0.00175**	**$0.00215**	**$0.03386**
C & I Demand Non-TOD	**$0.02957**	**$0.00173**	**$0.00212**	**$0.03342**
C & I Demand TOD On-Peak	**$0.03717**	**$0.00217**	**$0.00267**	**$0.04200**
C & I Demand TOD Off-Peak	**$0.02310**	**$0.00135**	**$0.00166**	**$0.02610**
Outdoor Lighting	**$0.02132**	**$0.00124**	**$0.00153**	**$0.02409**
Residential				
Residential Service	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
Residential TOD	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
Residential - Underground	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
Residential TOD - Underground	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
Energy Control - (Non-Demand)	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
Limit Off Peak	$ 0.02895	$ 0.00169	$ 0.00208	$ 0.03272
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Limit Off Peak	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Small General Service	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Small General TOD - Metered	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Small General TOD - Unmetered	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Fire and Civil Defense Siren	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
Direct Current (Closed)	$ 0.02996	$ 0.00175	$ 0.00215	$ 0.03386
C & I Demand				
General Service	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
General TOD - On Peak	$ 0.03717	$ 0.00217	$ 0.00267	$ 0.04200
General TOD - Off Peak	$ 0.02310	$ 0.00135	$ 0.00166	$ 0.02610
Peak Controlled (Closed)	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Peak Controlled TOD (Closed) - On Peak	$ 0.03717	$ 0.00217	$ 0.00267	$ 0.04200
Peak Controlled TOD (Closed) - Off Peak	$ 0.02310	$ 0.00135	$ 0.00166	$ 0.02610
Peak Controlled Tiered	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Peak Controlled Tiered TOD - On Peak	$ 0.03717	$ 0.00217	$ 0.00267	$ 0.04200
Peak Controlled Tiered TOD - Off Peak	$ 0.02310	$ 0.00135	$ 0.00166	$ 0.02610
Energy Controlled (Closed)	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Tier 1 Energy Controlled Rider	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Real Time Pricing - Firm - On Peak	$ 0.03717	$ 0.00217	$ 0.00267	$ 0.04200
Real Time Pricing - Firm - Off Peak	$ 0.02310	$ 0.00135	$ 0.00166	$ 0.02610
Real Time Pricing - Controllable - On Peak	$ 0.03717	$ 0.00217	$ 0.00267	$ 0.04200
Real Time Pricing - Controllable - Off Peak	$ 0.02310	$ 0.00135	$ 0.00166	$ 0.02610
Small Municipal Pumping	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Municipal Pumping	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Excess Energy - St. Anthony Falls	$ 0.02957	$ 0.00173	$ 0.00212	$ 0.03342
Outdoor Lighting				
Automatic Protective Lighting	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409
Street Lighting System	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409
Street Lighting Energy	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409
Street Lighting Energy - Metered	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409
Street Lighting Energy (Closed)	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409
Street Lighting - City of St. Paul	$ 0.02132	$ 0.00124	$ 0.00153	$ 0.02409

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Current Period Cost of Energy for Apr-2015

	Column (A)	Column (B)	Column (C)	Column (D)	Column (E)
	Nov-14	Dec-14	Jan-15	Feb-15	**4 Month Total**
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$42,328,130	$51,460,555	$44,941,924	$47,850,869	$186,581,478
Account 518 - Nuclear Fuel	$7,073,944	$8,700,192	$10,473,127	$8,777,256	$35,024,519
Account 555 - Purchased Power[1]	$48,502,403	$39,600,500	$41,184,349	$43,866,224	$173,153,477
MISO Day 2 Charges	$9,407,951	$4,418,667	$5,629,384	$8,617,678	$28,073,680
MISO Day 2 - Schedule 24	($73,700)	($64,885)	($68,054)	($71,704)	($278,343)
MISO - ASM Charges	$3,944,007	$5,059,791	$3,294,871	($693,218)	$11,605,451
Account 555 - Total MISO Charges	$13,278,258	$9,413,573	$8,856,201	$7,852,757	$39,400,788
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$111,182,735	$109,174,820	$105,455,601	$108,347,106	$434,160,261
Less Fuel Cost of InterSystem Sales	($8,724,508)	($12,051,483)	($9,742,335)	($9,436,666)	($39,954,992)
Net System Costs	$102,458,227	$97,123,336	$95,713,266	$98,910,440	$394,205,269
System MWH Sales					
Total NSP System Retail	2,859,179	3,698,615	3,798,198	3,218,358	13,574,350
Non-Gen Muni's/Load Pattern	-	-	-	-	-
Total NSP System MWh Sales	2,859,179	3,698,615	3,798,198	3,218,358	13,574,350
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	**3.583¢**	**2.626¢**	**2.520¢**	**3.073¢**	**2.904¢**
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			2.904¢	0.9969	**2.895¢**
(ii) C & I Non-Demand			2.904¢	1.0318	**2.996¢**
(iii) C & I Demand Non-TOD			2.904¢	1.0184	**2.957¢**
(iv) C & I Demand TOD On-Peak			2.904¢	1.2798	**3.717¢**
(v) C & I Demand TOD Off-Peak			2.904¢	0.7954	**2.310¢**
(vi) Outdoor Lighting			2.904¢	0.7341	**2.132¢**
North Dakota Retail MWh Sales					
(i) Residential	48,241	88,017	97,052	78,124	311,434
(ii) C & I Non-Demand	7,710	12,414	13,474	10,948	44,546
(iii) C & I Demand Non-TOD	52,553	74,067	71,260	60,357	258,237
(iv) C & I Demand TOD On-Peak	16,235	18,800	17,107	16,203	68,345
(v) C & I Demand TOD Off-Peak	25,082	28,581	32,599	25,768	112,030
(vi) Outdoor Lighting	1,695	1,970	2,074	1,891	7,630
(vii) Total	151,516	223,849	233,566	193,291	802,222

Apr-2015 Recovery Provision (True-up Factor) Calculation

	Total
Prior Unrecovered Expenses (Dec-14 Balance of Unrecovered Expenses)	**Dec-14**
	$746,863

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

Northern States Power Company
Electric Operations - State of North Dakota
Derivation of Adjustment for Fuel Clause Rider
Current Period Cost of Energy for Apr-2015

Prior Expenses Recovered in Feb-2015 [Billing Record]

	ND Billed MWh Sales	Prior Receovered Expenses
(i) Residential	78,124	($36,434)
(ii) C & I Non-Demand	10,948	($6,081)
(iii) C & I Demand Non-TOD	60,357	($32,361)
(iv) C & I Demand TOD On-Peak	16,203	($8,810)
(v) C & I Demand TOD Off-Peak	25,768	($9,176)
(vi) Outdoor Lighting	1,891	($1,347)
(vii) Total	193,291	($94,209)

Actual Cost Should Have Been Recovered in Feb-15

Actual	Base	Actual ND MWh Sales	Expected Recovery
3.073¢	0.000¢	193,291	$5,939,832

Cost Recovered in Feb-15 [Billing Record]

	ND Billed MWh Sales	Actual Recovery
(i) Residential	78,124	$2,186,324
(ii) C & I Non-Demand	10,948	$317,015
(iii) C & I Demand Non-TOD	60,357	$1,722,928
(iv) C & I Demand TOD On-Peak	16,203	$581,313
(v) C & I Demand TOD Off-Peak	25,768	$574,622
(vi) Outdoor Lighting	1,891	$39,050
(vii) Total	193,291	$5,421,252

Total Balance of Unrecovered Expenses (Apr-15 Balance of Unrecovered Expenses)

Apr-2015 Recovery Provision	$1,359,652
4 Month ND Retail Total MWh Sales	802,222
Apr-2015 Recovery Provision per KWH	**0.169¢**

Apr-2015 Recovery Provision (True-up Factor) per kWh by Customer Category

	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	0.9969	0.169¢	**0.169¢**
(ii) C & I Non-Demand	1.0318	0.169¢	**0.175¢**
(iii) C & I Demand Non-TOD	1.0184	0.169¢	**0.173¢**
(iv) C & I Demand TOD On-Peak	1.2798	0.169¢	**0.217¢**
(v) C & I Demand TOD Off-Peak	0.7954	0.169¢	**0.135¢**
(vi) Outdoor Lighting	0.7341	0.169¢	**0.124¢**

Refunds/Additional Charges

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	Total
Refund/Special Charge Amount	$104,158	($22,770)	$314,753	**$418,911**
(i) Residential	0.055¢	-0.012¢	0.165¢	**0.208¢**
(ii) C & I Non-Demand	0.057¢	-0.012¢	0.171¢	**0.215¢**
(iii) C & I Demand Non-TOD	0.056¢	-0.012¢	0.169¢	**0.212¢**
(iv) C & I Demand TOD On-Peak	0.070¢	-0.015¢	0.212¢	**0.267¢**
(v) C & I Demand TOD Off-Peak	0.044¢	-0.010¢	0.132¢	**0.166¢**
(vi) Outdoor Lighting	0.040¢	-0.009¢	0.122¢	**0.153¢**

Apr-2015 Factors

	Total
(i) Residential	**3.272¢**
(ii) C & I Non-Demand	**3.386¢**
(iii) C & I Demand Non-TOD	**3.342¢**
(iv) C & I Demand TOD On-Peak	**4.200¢**
(v) C & I Demand TOD Off-Peak	**2.610¢**
(vi) Outdoor Lighting	**2.409¢**

Northern States Power Company
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		
			Differ-	Percent	FCA Application		Differ-
	Mar-15	Apr-15	ence	Change	Mar-15	Apr-15	ence
** COSTS (Millions) **							
1 Fossil	$186.0	$186.6	$0.6	0.3%	43.3%	43.0%	-0.3%
2 Nuclear	$32.0	$35.0	$3.0	9.4%	7.4%	8.1%	0.7%
3 Purchases	$169.8	$173.2	$3.4	2.0%	39.5%	39.9%	0.4%
MISO related Purchases	$41.8	$39.4	($2.4)	-5.7%	9.7%	9.1%	-0.6%
4 Total System Costs 5	429.6	434.2	$4.6	1.1%	100.0%	100.0%	0.0%
Intersystem Sales	$40.5	$40.0	($0.6)	-1.4%	9.4%	9.2%	-0.2%
6 Net System Costs	$389.0	$394.2	$5.2	1.3%	90.6%	90.8%	0.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	5,924	5,859	(65)	-1.1%	36.3%	35.6%	-0.7%
10 Nuclear	3,675	4,049	374	10.2%	22.5%	24.6%	2.1%
11 Purchases	4,099	3,979	(120)	-2.9%	25.1%	24.2%	-0.9%
12 Hydro & Other	1,836	1,792	(44)	-2.4%	11.2%	10.9%	-0.3%
13 Net Interchange	803	761	(42)	-5.2%	4.9%	4.6%	-0.3%
14 Total Output	16,337	16,440	103	0.6%	100.0%	100.0%	0.0%
15 Intersystem Sales 16	1,531	1,481	(50)	-3.3%	9.4%	9.0%	-0.4%
Native Requirement	14,806	14,959	153	1.0%	90.6%	91.0%	0.4%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.140	3.185	0.044	1.4%			
20 Nuclear	0.871	0.865	-0.006	-0.7%			
21 Purchases	4.142	4.352	0.210	5.1%			
22 Total System Costs	2.629	2.641	0.011	0.4%			
23 Intersystem Sales	2.647	2.698	0.051	1.9%			
24 Net System Costs	2.628	2.635	0.008	0.3%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,681	13,574	(107)	-0.8%			
28							
29 COST per KWH SALES (¢)	2.844	2.904	0.060	2.1%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	-0.189	0.169	0.359				
(i) Residential	-0.189	0.169	0.358				
(ii) C & I Non-Demand	-0.195	0.175	0.370				
(iii) C & I Demand Non-TOD	-0.193	0.173	0.365				
(iv) C & I Demand TOD On-Peak	-0.242	0.217	0.459				
(v) C & I Demand TOD Off-Peak	-0.151	0.135	0.285				
(vi) Outdoor Lighting	-0.139	0.124	0.263				
32 REFUND	-0.298	0.209	0.507				
(i) Residential	-0.299	0.208					
(ii) C & I Non-Demand	-0.306	0.215					
(iii) C & I Demand Non-TOD	-0.303	0.212					
(iv) C & I Demand TOD On-Peak	-0.384	0.267					
(v) C & I Demand TOD Off-Peak	-0.235	0.166					
(vi) Outdoor Lighting	-0.222	0.153					
33 SYSTEM FCC IMPACT (¢ / KWH)	2.357	3.282	0.926	39.3%			
(i) Residential	2.349	3.272	0.923				
(ii) C & I Non-Demand	2.432	3.386					
(iii) C & I Demand Non-TOD	2.400	3.342					
(iv) C & I Demand TOD On-Peak	3.016	4.200					
(v) C & I Demand TOD Off-Peak	1.874	2.610					
(vi) Outdoor Lighting	1.730	2.409					

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]

Residential BILL IMPACT ($'s)

kWh	Change from Previous Month
100	$0.92
250	$2.31
500	$4.61
750	$6.92
1,000	$9.23

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-15	Apr-15
** GWH OUTPUT **		
Thermal	1,205,145	1,214,834
Disper gen	(84)	(78)
Hydro plus Wind	630,879	577,059
Hydro and Other	1,835,940	1,791,815
Rounded to nearest thousand:	1,836	1,792
Sales		
Non Gen Munic Total	0	0
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	1,531,319,000	1,481,053,000
Rounded to nearest million:	1531.319	1481.053

Northern States Power Company | Attachment 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

February 2015 Actual

			System		Intersystem		Retail
Energy and Loss Charges							
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$	8,091,355.95	$	4,195,308.89	$	12,286,664.84
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$	3,746,588.94	$	-	$	3,746,588.94
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	6,378.65	$	-	$	6,378.65
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$	(11,731,613.87)	$	-	$	(11,731,613.87)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$	1,059,024.79	$	-	$	1,059,024.79
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(6,378.65)	$	-	$	(6,378.65)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component (1)	$	789,094.69	$	1,743,666.38	$	2,532,761.07
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$	72,520.67	$	-	$	72,520.67
14	Real-Time Distribution of Losses Amount	$	(1,785,962.00)	$	-	$	(1,785,962.00)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(59,939.70)	$	-	$	(59,939.70)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$	(5,530.01)	$	-	$	(5,530.01)
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$	840.85	$	-	$	840.85
Congestion Related Charges							
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$	2,495,521.83	$	-	$	2,495,521.83
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	4,571.24	$	-	$	4,571.24
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$	1,447,300.89	$	-	$	1,447,300.89
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(4,571.24)	$	-	$	(4,571.24)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	$	298,360.38	$	-	$	298,360.38
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)	$	12,085.15	$	-	$	12,085.15
FTR Related Charges							
28	Financial Transmission Rights Hourly Allocation Amount	$	(2,638,215.63)	$	-	$	(2,638,215.63)
30	Financial Transmission Rights Monthly Allocation Amount	$	(113,847.87)	$	-	$	(113,847.87)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(71,077.02)	$	-	$	(71,077.02)
37	Financial Transmission Guarantee Uplift Amount	$	67,927.21	$	-	$	67,927.21
38	Financial Transmission Rights Monthly Transacton Amount	$	-	$	-	$	-
Uplift Charges							
23	Real-Time Revenue Neutrality Uplift Amount	$	716,461.93	$	-	$	716,461.93
Revenue Sufficiency Guarantee (RSG) Charges							
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	206,399.66	$	-	$	206,399.66
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(100,928.64)	$	33,732.18	$	(67,196.46)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	154,958.46	$	-	$	154,958.46
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(68,367.77)	$	5,944.00	$	(62,423.77)
43	Real-Time Price Volatility Make Whole Payment Amount	$	(327,724.31)	$	21,241.80	$	(306,482.51)
Market Adminstration Charges							
4	Day-Ahead Market Administration Amount	$	623,735.83	$	(11,477.47)	$	612,258.36
19	Real-Time Market Administration Amount	$	40,413.21	$	(5,980.02)	$	34,433.19
29	Financial Transmission Rights Market Administration Amount	$	35,475.84	$	-	$	35,475.84
33	Day-Ahead Schedule 24 Allocation Amount	$	67,939.47	$	(1,239.19)	$	66,700.28
34	Real -Time Schedule 24 Allocation Amount	$	(31,611.17)	$	36,614.75	$	5,003.58
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	$	(378,713.36)	$	70,005.00	$	(308,708.36)
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-
Auction Revenue Rights (ARR)							
39	Auction Revenue Rights - FTR Auction Transactions	$	7,250,896.00	$	-	$	7,250,896.00
40	Auction Revenue Rights - Monthly ARR Revenue	$	(7,412,271.29)	$	28,268.10	$	(7,384,003.19)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(165,295.02)	$	-	$	(165,295.02)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	215,789.60	$	-	$	215,789.60
	TOTAL MISO CHARGES	**$**	**2,501,593.69**	**$**	**6,116,084.42**	**$**	**8,617,678.11**
	SCHEDULE 24 (FOR RETAIL)					**$**	**71,703.86**
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)					**$**	**8,545,974.25**

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
February 2015 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	$ (114,510.61)	$ -	$ (114,510.61)
2	Day-Ahead Spinning Reserve Amount	$ (97,635.22)	$ -	$ (97,635.22)
3	Day-Ahead Supplemental Reserve	$ (45,228.22)	$ -	$ (45,228.22)
4	Real-Time Regulation Amount	$ 367.07	$ 27,363.07	$ 27,730.14
5	Real-Time Spinning Reserve Amount	$ 7,438.18	$ 39,877.66	$ 47,315.84
6	Real-Time Supplemental Reserve Amount.	$ 310.18	$ 6,029.61	$ 6,339.79
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ (24,390.77)		$ (24,390.77)
7b	Real Time Excessive Energy Congestion	$ -		$ -
7c	Real Time Excessive Energy Loss	$ -		$ -
8a	Real Time Non Excessive Energy Amount	$ (549,938.30)		$ (549,938.30)
8b	Real Time Non Excessive Energy Congestion	$ (173,397.46)		$ (173,397.46)
8c	Real Time Non Excessive Energy Loss	$ (9,957.34)		$ (9,957.34)
9	Real Time Net Regulation Adjustment Amount	$ 3,679.08	$ (597.60)	$ 3,081.48
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 95,425.93	$ -	$ 95,425.93
11	Real Time Spinnng Reserve Cost Distribution	$ 72,504.33	$ -	$ 72,504.33
12	Real Time Supplemental Reserve Cost Distribution	$ 35,309.03	$ -	$ 35,309.03
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	$ 40,938.82	$ (7,218.58)	$ 33,720.24
14	Real Time Contignecy Reserve Deployment Failure	$ 413.49	$ -	$ 413.49
	TOTAL MISO ASM CHARGES	**$ (758,671.81)**	**$ 65,454.16**	**$ (693,217.65)**

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

#													
1	**Forecast Month**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**
2	**True-up Month**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
3													
4	Monthly Refund	(58,150)	(58,410)										
5													
6	Forecast North Dakota Sales	214,698	190,045	163,417	175,362	-	-	-	-	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.027)	(0.031)	-	-	-	-	-	-	-	-	-	-
9													
14	Expected Refund	(240,764)	87,087	(225,701)	104,158	-	-	-	-	-	-	-	-
15	Actual Refunded	(73,213)	(75,480)										
16	Deviation	(167,551)	162,567	(225,701)	104,158	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.078)	0.086	-	-	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	(0.105)	**0.055**	-	-	-	-	-	-	-	-	-	-
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.105)	0.055	-	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.108)	0.057	-	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.107)	0.056	-	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.135)	0.070	-	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.084)	0.044	-	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.077)	0.040	-	-	-	-	-	-	-	-	-	-

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

1	**Forecast Month**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**
2	**True-up Month**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**
3													
4	Monthly Refund	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)	(16,179)
5													
6	Forecast North Dakota Sales	203,682	214,698	190,045	-	-	-	-	-	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.008)	(0.008)	(0.009)	-	-	-	-	-	-	-	-	-
13													
14	Expected Refund	(9,871)	(6,219)	(16,187)	-	-	-	-	-	-	-	-	-
15	Actual Refund	(9,863)	(9,298)	(9,596)									
16	Deviation	(8)	3,079	(6,591)	-	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.000)	0.001	(0.003)	-	-	-	-	-	-	-	-	-
19													
20	**Realized Margin**	(0.008)	(0.006)	**(0.012)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.008)	(0.006)	(0.012)	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.008)	(0.006)	(0.012)	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.008)	(0.006)	(0.012)	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.010)	(0.008)	(0.015)	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.006)	(0.005)	(0.010)	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.006)	(0.004)	(0.009)	-	-	-	-	-	-	-	-	-

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

1	**Forecast Month**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**
2	**True-up Month**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
3													
4	Monthly Refund	-	-										
5													
6	Forecast North Dakota Sales	214,698	190,045										
7													
8	**Current Month Refund Factor**	-	-	-	-	-	-	-	-	-	-	-	-
13													
14	Expected Refund	(378,673)	240,848	-	-	-	-	-	-	-	-	-	-
15	Actual Refund	22,566	(73,905)										
16	Deviation	(401,239)	314,753	-	-	-	-	-	-	-	-	-	-
17													
18	**True-up Factor**	(0.187)	0.166	-	-	-	-	-	-	-	-	-	-
19													
20	**Realized Refund**	(0.187)	**0.166**	-	-	-	-	-	-	-	-	-	-
21													
22	**Class Ratios**												
23	Residential	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969	0.9969
24	C&I Non-Demand	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318	1.0318
25	C&I Demand Non-TOD	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184	1.0184
26	C&I Demand TOD On-Peak	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798	1.2798
27	C&I Demand TOD Off-Peak	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954	0.7954
28	Outdoor Lighting	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341	0.7341
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.186)	0.165	-	-	-	-	-	-	-	-	-	-
32	C&I Non-Demand	(0.193)	0.171	-	-	-	-	-	-	-	-	-	-
33	C&I Demand Non-TOD	(0.190)	0.169	-	-	-	-	-	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.239)	0.212	-	-	-	-	-	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.149)	0.132	-	-	-	-	-	-	-	-	-	-
36	Outdoor Lighting	(0.137)	0.122	-	-	-	-	-	-	-	-	-	-