414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

August 29, 2013

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

Re: September 2013 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 September 2013.

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

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September 2013 fuel cost adjustment
Northern States Power Company

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

September 2013	Fuel Cost Charge ($/kWh)
Residential	0.03153
C & I Non-Demand	0.03233
C & I Demand	0.03198
C & I Demand Time of Day On-Peak	0.04052
C & I Demand Time of Day Off-Peak	0.02481
Outdoor Lighting	0.02340

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 September 2013 FCC the net MISO Day 2 costs for July 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this September 2013 FCC is $32,020,076, 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 September FCC the net MISO ASM costs for July 2013 as recorded in Account 555. The MISO ASM cost recovery included in this September FCC is $2,176,112,

[1] Previously embedded in other FTR charge types.

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 September 2013 Asset Based Margin amount of $11,541 has been included as a credit, or offset, to the September 2013 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 2012 Non-Asset Based Margin credit is $163,647 and this credit amount will be distributed equally each month over the following 12-month period. The refund reflected in the September 2013 FCC is $11,255, or 0.006¢ 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 September 2013 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 Sep-2013

Sep-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.03156**	**$0.00149**	**-$0.00160**	**$0.03145**
Residential	**$0.03164**	**$0.00150**	**-$0.00161**	**$0.03153**
C & I Non-Demand	**$0.03245**	**$0.00153**	**-$0.00165**	**$0.03233**
C & I Demand Non-TOD	**$0.03210**	**$0.00152**	**-$0.00163**	**$0.03198**
C & I Demand TOD On-Peak	**$0.04066**	**$0.00192**	**-$0.00206**	**$0.04052**
C & I Demand TOD Off-Peak	**$0.02490**	**$0.00118**	**-$0.00126**	**$0.02481**
Outdoor Lighting	**$0.02348**	**$0.00111**	**-$0.00119**	**$0.02340**
Residential				
Residential Service	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
Residential TOD	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
Residential - Underground	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
Residential TOD - Underground	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
Energy Control - (Non-Demand)	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
Limit Off Peak	$ 0.03164	$ 0.00150	$ (0.00161)	$ 0.03153
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Limit Off Peak	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Small General Service	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Small General TOD - Metered	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Small General TOD - Unmetered	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Fire and Civil Defense Siren	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
Direct Current (Closed)	$ 0.03245	$ 0.00153	$ (0.00165)	$ 0.03233
C & I Demand				
General Service	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
General TOD - On Peak	$ 0.04066	$ 0.00192	$ (0.00206)	$ 0.04052
General TOD - Off Peak	$ 0.02490	$ 0.00118	$ (0.00126)	$ 0.02481
Peak Controlled (Closed)	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Peak Controlled TOD (Closed) - On Peak	$ 0.04066	$ 0.00192	$ (0.00206)	$ 0.04052
Peak Controlled TOD (Closed) - Off Peak	$ 0.02490	$ 0.00118	$ (0.00126)	$ 0.02481
Peak Controlled Tiered	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Peak Controlled Tiered TOD - On Peak	$ 0.04066	$ 0.00192	$ (0.00206)	$ 0.04052
Peak Controlled Tiered TOD - Off Peak	$ 0.02490	$ 0.00118	$ (0.00126)	$ 0.02481
Energy Controlled (Closed)	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Tier 1 Energy Controlled Rider	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Real Time Pricing - Firm - On Peak	$ 0.04066	$ 0.00192	$ (0.00206)	$ 0.04052
Real Time Pricing - Firm - Off Peak	$ 0.02490	$ 0.00118	$ (0.00126)	$ 0.02481
Real Time Pricing - Controllable - On Peak	$ 0.04066	$ 0.00192	$ (0.00206)	$ 0.04052
Real Time Pricing - Controllable - Off Peak	$ 0.02490	$ 0.00118	$ (0.00126)	$ 0.02481
Small Municipal Pumping	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Municipal Pumping	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Excess Energy - St. Anthony Falls	$ 0.03210	$ 0.00152	$ (0.00163)	$ 0.03198
Outdoor Lighting				
Automatic Protective Lighting	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340
Street Lighting System	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340
Street Lighting Energy	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340
Street Lighting Energy - Metered	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340
Street Lighting Energy (Closed)	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340
Street Lighting - City of St. Paul	$ 0.02348	$ 0.00111	$ (0.00119)	$ 0.02340

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 Sep-2013

	Column (A) Apr-13	Column (B) May-13	Column (C) Jun-13	Column (D) Jul-13	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$35,714,843	$29,187,911	$30,055,242	$45,631,501	$140,589,497
Account 518 - Nuclear Fuel	$7,928,444	$7,881,823	$7,625,738	$8,175,496	$31,611,501
Account 555 - Purchased Power[1]	$36,915,144	$40,825,865	$39,781,933	$37,842,727	$155,365,668
Account 555 - Pr. Rose PPA Adjustment	($245,881)	($179,008)	($79,357)	($58,918)	($563,164)
MISO Day 2 Charges	$20,200,320	$20,346,311	$32,197,013	$32,118,523	$104,862,166
MISO Day 2 - Schedule 24	($105,670)	($95,649)	($93,541)	($98,447)	($393,306)
MISO - ASM Charges	$2,993,845	$4,308,216	$2,731,861	$2,176,112	$12,210,034
Account 555 - Total MISO Charges	$23,088,494	$24,558,878	$34,835,333	$34,196,188	$116,678,894
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$103,401,044	$102,275,469	$112,218,889	$125,786,994	$443,682,396
Less Fuel Cost of InterSystem Sales	($3,073,114)	($2,707,087)	($4,232,490)	($2,040,932)	($12,053,623)
Net System Costs	$100,327,930	$99,568,382	$107,986,398	$123,746,062	$431,628,773
System MWH Sales					
Total NSP System Retail	3,378,291	3,209,691	3,072,176	4,009,193	13,669,351
Non-Gen Muni's/Load Pattern	1,583	1,435	1,478	1,518	6,014
Total NSP System MWh Sales	3,379,874	3,211,126	3,073,654	4,010,711	13,675,365
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	**2.968¢**	**3.101¢**	**3.513¢**	**3.085¢**	**3.156¢**
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			3.156¢	1.0026	**3.164¢**
(ii) C & I Non-Demand			3.156¢	1.0281	**3.245¢**
(iii) C & I Demand Non-TOD			3.156¢	1.0170	**3.210¢**
(iv) C & I Demand TOD On-Peak			3.156¢	1.2883	**4.066¢**
(v) C & I Demand TOD Off-Peak			3.156¢	0.7889	**2.490¢**
(vi) Outdoor Lighting			3.156¢	0.7440	**2.348¢**
North Dakota Retail MWh Sales					
(i) Residential	77,422	56,984	47,215	66,645	248,266
(ii) C & I Non-Demand	11,358	9,208	7,654	9,393	37,613
(iii) C & I Demand Non-TOD	61,841	59,676	54,586	72,433	248,536
(iv) C & I Demand TOD On-Peak	17,131	18,879	17,781	20,609	74,400
(v) C & I Demand TOD Off-Peak	28,505	29,459	28,184	32,946	119,094
(vi) Outdoor Lighting	1,682	1,365	1,200	1,168	5,415
(vii) Total	197,939	175,571	156,620	203,194	733,324
Sep-2013 Recovery Provision (True-up Factor) Calculation					
Prior Unrecovered Expenses (May-13 Balance of Unrecovered Expenses)					Total **May-13**
					$962,652

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

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 Sep-2013

Prior Expenses Recovered in Jul-2013 [Billing Record]

	ND Billed MWh Sales	Prior Receovered Expenses
(i) Residential	66,645	$105,131
(ii) C & I Non-Demand	9,393	$15,181
(iii) C & I Demand Non-TOD	72,433	$113,956
(iv) C & I Demand TOD On-Peak	20,609	$41,471
(v) C & I Demand TOD Off-Peak	32,946	$40,351
(vi) Outdoor Lighting	1,168	$1,488
(vii) Total	203,194	$317,578

Actual Cost Should Have Been Recovered in Jul-13

Actual	Base	Actual ND MWh Sales	Expected Recovery
3.085¢	0.000¢	203,194	$6,268,535

Cost Recovered in Jul-13 [Billing Record]

	ND Billed MWh Sales	Actual Recovery
(i) Residential	66,645	$1,912,735
(ii) C & I Non-Demand	9,393	$275,811
(iii) C & I Demand Non-TOD	72,433	$2,103,425
(iv) C & I Demand TOD On-Peak	20,609	$759,261
(v) C & I Demand TOD Off-Peak	32,946	$743,669
(vi) Outdoor Lighting	1,168	$24,572
(vii) Total	203,194	$5,819,473

Total Balance of Unrecovered Expenses (Sep-13 Balance of Unrecovered Expenses)

Sep-2013 Recovery Provision	$1,094,136
4 Month ND Retail Total MWh Sales	733,324
Sep-2013 Recovery Provision per KWH	**0.149¢**

Sep-2013 Recovery Provision (True-up Factor) per kWh by Customer Category

	FAF Ratio	Recovery Provision Adjustment	Recovery Provision Adj by Class
(i) Residential	1.0026	0.149¢	**0.150¢**
(ii) C & I Non-Demand	1.0281	0.149¢	**0.153¢**
(iii) C & I Demand Non-TOD	1.0170	0.149¢	**0.152¢**
(iv) C & I Demand TOD On-Peak	1.2883	0.149¢	**0.192¢**
(v) C & I Demand TOD Off-Peak	0.7889	0.149¢	**0.118¢**
(vi) Outdoor Lighting	0.7440	0.149¢	**0.111¢**

Sep-2013 Refunds/Additional Charges

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund	June FCC Error Refund	Total
Refund/Special Charge Amount	($11,541)	($11,255)	($258,005)		**($269,546)**
(i) Residential	-0.007¢	-0.006¢	-0.148¢		**-0.161¢**
(ii) C & I Non-Demand	-0.007¢	-0.007¢	-0.151¢		**-0.165¢**
(iii) C & I Demand Non-TOD	-0.007¢	-0.007¢	-0.150¢		**-0.163¢**
(iv) C & I Demand TOD On-Peak	-0.008¢	-0.008¢	-0.190¢		**-0.206¢**
(v) C & I Demand TOD Off-Peak	-0.005¢	-0.005¢	-0.116¢		**-0.126¢**
(vi) Outdoor Lighting	-0.005¢	-0.005¢	-0.109¢		**-0.119¢**

Sep-2013 Factors

	Total
(i) Residential	**3.153¢**
(ii) C & I Non-Demand	**3.233¢**
(iii) C & I Demand Non-TOD	**3.198¢**
(iv) C & I Demand TOD On-Peak	**4.052¢**
(v) C & I Demand TOD Off-Peak	**2.481¢**
(vi) Outdoor Lighting	**2.340¢**

Northern States Power Company, A Minnesota Corporation
Electric Operations - State of North Dakota
FUEL CLAUSE ADJUSTMENT (FCA) COMPARISON -
Prior Month Compared to Current Month FCA

	FCA Application		Comparison		Generation Type by Percent		
			Differ-ence	Percent Change	FCA Application		Differ-ence
	Aug-13	Sep-13			Aug-13	Sep-13	
** COSTS (Millions) **							
1 Fossil	$134.6	$140.6	$6.0	4.4%	31.8%	31.7%	-0.1%
2 Nuclear	$31.6	$31.6	$0.0	0.1%	7.5%	7.1%	-0.4%
3 Purchases	$149.3	$154.8	$5.5	3.7%	35.3%	34.9%	-0.4%
MISO related Purchases	$107.2	$116.7	$9.5	8.9%	25.4%	26.3%	0.9%
4 Total System Costs	422.7	443.7	$21.0	5.0%	100.0%	100.0%	0.0%
5 Intersystem Sales	$12.4	$12.1	($0.4)	-2.8%	2.9%	2.7%	-0.2%
6 Net System Costs	$410.3	$431.6	$21.3	5.2%	97.1%	97.3%	0.2%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,336	3,646	310	9.3%	22.5%	23.4%	0.9%
10 Nuclear	3,052	2,998	(54)	-1.8%	20.6%	19.3%	-1.3%
11 Purchases	5,829	6,362	533	9.1%	39.3%	40.9%	1.6%
12 Hydro & Other	2,040	1,961	(79)	-3.9%	13.8%	12.6%	-1.2%
13 Net Interchange	565	583	18	3.2%	3.8%	3.7%	-0.1%
14 Total Output	14,822	15,550	728	4.9%	100.0%	100.0%	0.0%
15 Intersystem Sales	525	484	(42)	-8.0%	3.5%	3.1%	-0.4%
16 Native Requirement	14,297	15,066	770	5.4%	96.5%	96.9%	0.4%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	4.035	3.856	-0.179	-4.4%			
20 Nuclear	1.034	1.054	0.020	1.9%			
21 Purchases	2.562	2.433	-0.129	-5.0%			
22 Total System Costs	2.852	2.853	0.001	0.0%			
23 Intersystem Sales	2.361	2.493	0.131	5.6%			
24 Net System Costs	2.870	2.865	-0.005	-0.2%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,024	13,675	651	5.0%			
28							
29 COST per KWH SALES (¢)	3.150	3.156	0.006	0.2%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.343	0.149	-0.194				
(i) Residential	0.344	0.150	-0.195				
(ii) C & I Non-Demand	0.353	0.153	-0.200				
(iii) C & I Demand Non-TOD	0.349	0.152	-0.197				
(iv) C & I Demand TOD On-Peak	0.442	0.192	-0.250				
(v) C & I Demand TOD Off-Peak	0.271	0.118	-0.153				
(vi) Outdoor Lighting	0.255	0.111	-0.144				
32 REFUND	0.073	-0.160	-0.233				
(i) Residential	0.073	-0.161					
(ii) C & I Non-Demand	0.075	-0.165					
(iii) C & I Demand Non-TOD	0.074	-0.163					
(iv) C & I Demand TOD On-Peak	0.094	-0.206					
(v) C & I Demand TOD Off-Peak	0.058	-0.126					
(vi) Outdoor Lighting	0.054	-0.119					
33 SYSTEM FCC IMPACT (¢ / KWH)	3.566	3.145	-0.421	-11.8%			
(i) Residential	3.575	3.153	-0.422				
(ii) C & I Non-Demand	3.666	3.233					
(iii) C & I Demand Non-TOD	3.626	3.198					
(iv) C & I Demand TOD On-Peak	4.594	4.052					
(v) C & I Demand TOD Off-Peak	2.813	2.481					
(vi) Outdoor Lighting	2.653	2.340					

Residential BILL IMPACT ($'s)

kWh	Change from Previous Month
100	($0.42)
250	($1.05)
500	($2.11)
750	($3.16)
1,000	($4.22)

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]

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	
	Aug-13	Sep-13
** GWH OUTPUT **		
Thermal	1,335,655	1,251,339
Disper gen	(72)	102,415
Hydro plus Wind	704,698	606,903
Hydro and Other	2,040,281	1,960,657
Rounded to nearest thousand:	2,040	1,961
Sales		
Non Gen Munic Total	5,966,000	6,014,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	525,363,000	483,566,000
Rounded to nearest million:	525.363	483.566

Northern States Power Company, A Minnesota Corporation

Attachment 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Page 1

			System		Intersystem		Retail
July 2013 Actual							
Energy and Loss Charges							
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$	44,099,902.05	$	1,019,186.38	$	45,119,088.43
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$	2,933,154.78	$	-	$	2,933,154.78
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	601.22	$	-	$	601.22
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$	(20,122,645.49)	$	-	$	(20,122,645.49)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$	2,075,250.68	$	-	$	2,075,250.68
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(601.22)	$	-	$	(601.22)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component (1)	$	1,407,615.63	$	722,097.75	$	2,129,713.38
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$	69,809.40	$	-	$	69,809.40
14	Real-Time Distribution of Losses Amount	$	(2,711,960.90)	$	-	$	(2,711,960.90)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	743.64	$	-	$	743.64
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	(743.64)	$	-	$	(743.64)
21	Real-time Net inadvertent Distribution	$	(36,340.08)	$	-	$	(36,340.08)
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$	33,376.32	$	-	$	33,376.32
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$	(11,911.70)	$	-	$	(11,911.70)
Congestion Related Charges							
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$	373,027.03	$	-	$	373,027.03
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	724.98	$	-	$	724.98
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$	1,462,679.75	$	-	$	1,462,679.75
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(724.98)	$	-	$	(724.98)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	$	106,059.20	$	-	$	106,059.20
15	Real-Time Financial Bilateral Transaction Congestion Amount	$	1,717.96	$	-	$	1,717.96
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$	(1,717.96)	$	-	$	(1,717.96)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	$	(1,123.71)	$	-	$	(1,123.71)
FTR Related Charges							
28	Financial Transmission Rights Hourly Allocation Amount	$	(824,018.73)	$	-	$	(824,018.73)
30	Financial Transmission Rights Monthly Allocation Amount	$	(14,006.72)	$	-	$	(14,006.72)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(15,953.83)	$	-	$	(15,953.83)
37	Financial Transmission Guarantee Uplift Amount	$	22,251.71	$	-	$	22,251.71
38	Financial Transmission Rights Monthly Transacton Amount	$	-	$	-	$	-
Uplift Charges							
23	Real-Time Revenue Neutrality Uplift Amount	$	868,806.37	$	-	$	868,806.37
Revenue Sufficiency Guarantee (RSG) Charges							
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	94,775.50	$	-	$	94,775.50
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(49,648.45)	$	1,331.04	$	(48,317.41)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	1,007,971.39	$	-	$	1,007,971.39
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(848,813.78)	$	188,548.98	$	(660,264.80)
43	Real-Time Price Volatility Make Whole Payment Amount	$	(204,633.95)	$	4,364.92	$	(200,269.03)
Market Adminstration Charges							
4	Day-Ahead Market Administration Amount	$	652,744.34	$	(2,262.62)	$	650,481.72
19	Real-Time Market Administration Amount	$	47,233.47	$	(1,500.28)	$	45,733.19
29	Financial Transmission Rights Market Administration Amount	$	39,879.92	$	-	$	39,879.92
33	Day-Ahead Schedule 24 Allocation Amount	$	92,456.66	$	(421.87)	$	92,034.79
34	Real -Time Schedule 24 Allocation Amount	$	6,691.72	$	(280.01)	$	6,411.71
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	$	60,489.38	$	-	$	60,489.38
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-
Auction Revenue Rights (ARR)							
39	Auction Revenue Rights - FTR Auction Transactions	$	4,791,800.92	$	-	$	4,791,800.92
40	Auction Revenue Rights - Monthly ARR Revenue	$	(4,926,872.47)	$	-	$	(4,926,872.47)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(488,456.26)	$	-	$	(488,456.26)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	197,868.53	$	-	$	197,868.53
	TOTAL MISO CHARGES	$	30,187,458.68	$	1,931,064.29	$	32,118,522.97
	SCHEDULE 24 (FOR RETAIL)					$	98,446.50
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)					$	32,020,076.47

Northern States Power Company, A Minnesota Corporation

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
	July 2013 Actual			
Procurement Charges				
1	Day-Ahead Regulation Amount	$ (89,711.20)	$ -	$ (89,711.20)
2	Day-Ahead Spinning Reserve Amount	$ (273,578.60)	$ -	$ (273,578.60)
3	Day-Ahead Supplemental Reserve	$ (115,494.23)	$ -	$ (115,494.23)
4	Real-Time Regulation Amount	$ (170,756.47)	$ 155,582.46	$ (15,174.01)
5	Real-Time Spinning Reserve Amount	$ 131,193.61	$ 27,103.51	$ 158,297.12
6	Real-Time Supplemental Reserve Amount.	$ 40,426.99	$ 292.85	$ 40,719.84
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ 51,376.29		$ 51,376.29
7b	Real Time Excessive Energy Congestion	$ -		$ -
7c	Real Time Excessive Energy Loss	$ -		$ -
8a	Real Time Non Excessive Energy Amount	$ 2,046,222.94		$ 2,046,222.94
8b	Real Time Non Excessive Energy Congestion	$ (297,858.97)		$ (297,858.97)
8c	Real Time Non Excessive Energy Loss	$ (39,945.04)		$ (39,945.04)
9	Real Time Net Regulation Adjustment Amount	$ 63,754.24	$ (4,181.18)	$ 59,573.06
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 131,110.94	$ -	$ 131,110.94
11	Real Time Spinnng Reserve Cost Distribution	$ 251,968.13	$ -	$ 251,968.13
12	Real Time Supplemental Reserve Cost Distribution	$ 155,426.38	$ -	$ 155,426.38
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	$ 121,360.72	$ (8,181.68)	$ 113,179.04
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	$ 2,005,495.73	$ 170,615.96	$ 2,176,111.69

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-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**
2	**True-up Month**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
3													
4	Monthly Refund	(111,891)	(56,628)	(48,164)	(91,255)	(46,210)	(38,419)	(19,892)					
5													
6	Forecast North Dakota Sales	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072	160,760	-	-	-
7													
8	**Current Month Refund Factor**	(0.059)	(0.029)	(0.028)	(0.056)	(0.024)	(0.020)	(0.011)	-	-	-	-	-
9													
14	Expected Refund	(44,630)	(52,527)	(121,803)	(65,176)	(85,565)	(56,127)	(58,687)	(27,522)	(11,541)	-	-	-
15	Actual Refunded	(34,718)	(43,979)	(84,402)	(100,304)	(73,088)	(67,024)	(67,038)					
16	Deviation	(9,912)	(8,548)	(37,401)	35,128	(12,477)	10,897	8,351	(27,522)	(11,541)	-	-	-
17													
18	**True-up Factor**	(0.005)	(0.004)	(0.022)	0.022	(0.007)	0.006	0.005	-	-	-	-	-
19													
20	**Realized Margin**	(0.064)	(0.034)	(0.050)	(0.034)	(0.031)	(0.014)	(0.007)	-	-	-	-	-
21													
22	**Class Ratios**												
23	Residential	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24	C&I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25	C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26	C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27	C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28	Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.064)	(0.034)	(0.050)	(0.035)	(0.031)	(0.014)	(0.007)	-	-	-	-	-
32	C&I Non-Demand	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)	(0.015)	(0.007)	-	-	-	-	-
33	C&I Demand Non-TOD	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)	(0.015)	(0.007)	-	-	-	-	-
34	C&I Demand TOD On-Peak	(0.082)	(0.043)	(0.064)	(0.044)	(0.040)	(0.019)	(0.008)	-	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.050)	(0.027)	(0.039)	(0.027)	(0.024)	(0.011)	(0.005)	-	-	-	-	-
36	Outdoor Lighting	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)	(0.011)	(0.005)	-	-	-	-	-

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-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**
2	**True-up Month**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**
3													
4	Monthly Refund	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)	(13,637)
5													
6	Forecast North Dakota Sales	204,198	190,659	193,918	172,034	162,994	190,995	190,839	175,314	-	-	-	-
7													
8	**Current Month Refund Factor**	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.007)	(0.008)	-	-	-	-
13													
14	Expected Refund	(11,060)	(13,140)	(12,137)	(13,173)	(14,257)	(14,119)	(14,164)	(14,651)	-	-	-	-
15	Actual Refund	(12,560)	(13,605)	(11,517)	(12,691)	(13,731)	(13,105)	(13,036)	(17,033)				
16	Deviation	1,500	465	(620)	(482)	(526)	(1,014)	(1,128)	2,382	-	-	-	-
17													
18	**True-up Factor**	0.001	0.000	(0.000)	(0.000)	(0.000)	(0.001)	(0.001)	0.001	-	-	-	-
19													
20	**Realized Margin**	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	**(0.006)**	-	-	-	-
21													
22	**Class Ratios**												
23	Residential	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24	C&I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25	C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26	C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27	C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28	Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	-	-	-	-
32	C&I Non-Demand	(0.006)	(0.007)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	-	-	-	-
33	C&I Demand Non-TOD	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	-	-	-	-
34	C&I Demand TOD On-Peak	(0.008)	(0.009)	(0.009)	(0.011)	(0.011)	(0.010)	(0.010)	(0.008)	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.005)	(0.005)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	-	-	-	-
36	Outdoor Lighting	(0.004)	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.006)	(0.005)	-	-	-	-

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**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**
2	**True-up Month**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**
3													
4	Monthly Refund	(280,039)	-	-	(590,344)	(8,187)	-	-	(2,054)	-	(129,308)		
5													
6	Forecast North Dakota Sales	193,427	241,910	204,198	190,659	193,918	172,034	162,994	190,995	190,839	175,314		
7													
8	**Current Month Refund Factor**	(0.145)	-	-	(0.310)	(0.004)	-	-	(0.001)	-	(0.074)	-	-
13													
14	Expected Refund	-	-	(280,039)	-	(161,476)	(406,613)	(94,613)	(137,192)	187,000	(22,405)	-	-
15	Actual Refund			(118,563)	(183,731)	(75,050)	(269,421)	(281,613)	(116,841)	6,612	106,292		
16	Deviation	-	-	(161,476)	183,731	(86,426)	(137,192)	187,000	(20,351)	180,388	(128,697)	-	-
17													
18	**True-up Factor**	-	-	(0.079)	0.096	(0.045)	(0.080)	0.115	(0.011)	0.095	(0.073)	-	-
19													
20	**Realized Refund**	(0.145)	-	(0.079)	(0.213)	(0.049)	(0.080)	0.115	(0.012)	0.095	(0.147)	-	-
21													
22	**Class Ratios**												
23	Residential	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026	1.0026
24	C&I Non-Demand	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281	1.0281
25	C&I Demand Non-TOD	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170	1.0170
26	C&I Demand TOD On-Peak	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883	1.2883
27	C&I Demand TOD Off-Peak	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889	0.7889
28	Outdoor Lighting	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440	0.7440
29													
30	**Realized Margin Adj for Class Ratios**												
31	Residential	(0.145)	-	(0.079)	(0.214)	(0.049)	(0.080)	0.115	(0.012)	0.095	(0.148)	-	-
32	C&I Non-Demand	(0.149)	-	(0.081)	(0.219)	(0.050)	(0.082)	0.118	(0.012)	0.097	(0.151)	-	-
33	C&I Demand Non-TOD	(0.147)	-	(0.080)	(0.217)	(0.050)	(0.081)	0.117	(0.012)	0.096	(0.150)	-	-
34	C&I Demand TOD On-Peak	(0.187)	-	(0.102)	(0.275)	(0.063)	(0.103)	0.148	(0.015)	0.122	(0.190)	-	-
35	C&I Demand TOD Off-Peak	(0.114)	-	(0.062)	(0.168)	(0.038)	(0.063)	0.091	(0.009)	0.075	(0.116)	-	-
36	Outdoor Lighting	(0.108)	-	(0.059)	(0.159)	(0.036)	(0.059)	0.085	(0.009)	0.070	(0.109)	-	-