Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401

—Via Electronic Filing—

September 30, 2013

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

Re: October 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 October 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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October 2013 fuel cost adjustment
Northern States Power Company

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

October 2013	Fuel Cost Charge ($/kWh)
Residential	0.03442
C & I Non-Demand	0.03529
C & I Demand	0.03491
C & I Demand Time of Day On-Peak	0.04422
C & I Demand Time of Day Off-Peak	0.02708
Outdoor Lighting	0.02554

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 October 2013 FCC the net MISO Day 2 costs for August 2013 as recorded in Account 555. The MISO Day 2 cost recovery included in this October 2013 FCC is $24,207,242, 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 October FCC the net MISO ASM costs for August 2013 as recorded in Account

[1] Previously embedded in other FTR charge types.

555. The MISO ASM cost recovery included in this October FCC is $1,760,793, 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 October 2013 Asset Based Margin amount of $59,787 has been included as a credit, or offset, to the October 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 October 2013 FCC is $14,171, or 0.008¢ 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 October 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 Oct-2013

Oct-2013 Fuel Cost Charges	Fuel Cost Factor	Energy True-Up Factor	Others or Refunds	Base & FCA Factor
System	**$0.03170**	**$0.00293**	**-$0.00031**	**$0.03433**
Residential	**$0.03178**	**$0.00294**	**-$0.00031**	**$0.03442**
C & I Non-Demand	**$0.03259**	**$0.00302**	**-$0.00031**	**$0.03529**
C & I Demand Non-TOD	**$0.03224**	**$0.00298**	**-$0.00031**	**$0.03491**
C & I Demand TOD On-Peak	**$0.04084**	**$0.00378**	**-$0.00039**	**$0.04422**
C & I Demand TOD Off-Peak	**$0.02501**	**$0.00231**	**-$0.00024**	**$0.02708**
Outdoor Lighting	**$0.02358**	**$0.00218**	**-$0.00023**	**$0.02554**
Residential				
Residential Service	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
Residential TOD	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
Residential - Underground	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
Residential TOD - Underground	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
Energy Control - (Non-Demand)	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
Limit Off Peak	$ 0.03178	$ 0.00294	$ (0.00031)	$ 0.03442
C & I Non-Demand				
Energy Controlled - (Non-Demand)	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Limit Off Peak	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Small General Service	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Small General TOD - Metered	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Small General TOD - Unmetered	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Fire and Civil Defense Siren	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
Direct Current (Closed)	$ 0.03259	$ 0.00302	$ (0.00031)	$ 0.03529
C & I Demand				
General Service	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
General TOD - On Peak	$ 0.04084	$ 0.00378	$ (0.00039)	$ 0.04422
General TOD - Off Peak	$ 0.02501	$ 0.00231	$ (0.00024)	$ 0.02708
Peak Controlled (Closed)	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Peak Controlled TOD (Closed) - On Peak	$ 0.04084	$ 0.00378	$ (0.00039)	$ 0.04422
Peak Controlled TOD (Closed) - Off Peak	$ 0.02501	$ 0.00231	$ (0.00024)	$ 0.02708
Peak Controlled Tiered	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Peak Controlled Tiered TOD - On Peak	$ 0.04084	$ 0.00378	$ (0.00039)	$ 0.04422
Peak Controlled Tiered TOD - Off Peak	$ 0.02501	$ 0.00231	$ (0.00024)	$ 0.02708
Energy Controlled (Closed)	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Tier 1 Energy Controlled Rider	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Real Time Pricing - Firm - On Peak	$ 0.04084	$ 0.00378	$ (0.00039)	$ 0.04422
Real Time Pricing - Firm - Off Peak	$ 0.02501	$ 0.00231	$ (0.00024)	$ 0.02708
Real Time Pricing - Controllable - On Peak	$ 0.04084	$ 0.00378	$ (0.00039)	$ 0.04422
Real Time Pricing - Controllable - Off Peak	$ 0.02501	$ 0.00231	$ (0.00024)	$ 0.02708
Small Municipal Pumping	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Municipal Pumping	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Excess Energy - St. Anthony Falls	$ 0.03224	$ 0.00298	$ (0.00031)	$ 0.03491
Outdoor Lighting				
Automatic Protective Lighting	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554
Street Lighting System	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554
Street Lighting Energy	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554
Street Lighting Energy - Metered	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554
Street Lighting Energy (Closed)	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554
Street Lighting - City of St. Paul	$ 0.02358	$ 0.00218	$ (0.00023)	$ 0.02554

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 Oct-2013

	Column (A) May-13	Column (B) Jun-13	Column (C) Jul-13	Column (D) Aug-13	Column (E) 4 Month Total
Fuel and Purchased Power Costs					
Account 151 - Fossil Fuel	$29,187,911	$30,055,242	$45,631,501	$45,410,138	$150,284,792
Account 518 - Nuclear Fuel	$7,881,823	$7,625,738	$8,175,496	$11,242,069	$34,925,126
Account 555 - Purchased Power[1]	$40,825,865	$39,781,933	$37,842,727	$37,604,844	$156,055,369
Account 555 - Pr. Rose PPA Adjustment	($179,008)	($79,357)	($58,918)	($44,921)	($362,204)
MISO Day 2 Charges	$20,346,311	$32,197,013	$32,118,523	$24,320,465	$108,982,311
MISO Day 2 - Schedule 24	($95,649)	($93,541)	($98,447)	($113,223)	($400,858)
MISO - ASM Charges	$4,308,216	$2,731,861	$2,176,112	$1,760,793	$10,976,982
Account 555 - Total MISO Charges	$24,558,878	$34,835,333	$34,196,188	$25,968,036	$119,558,435
Financial Instruments	$0	$0	$0	$0	$0
Total System Costs	$102,275,469	$112,218,889	$125,786,994	$120,180,166	$460,461,518
Less Fuel Cost of InterSystem Sales	($2,707,087)	($4,232,490)	($2,040,932)	($5,022,275)	($14,002,784)
Net System Costs	$99,568,382	$107,986,398	$123,746,062	$115,157,891	$446,458,734
System MWH Sales					
Total NSP System Retail	3,209,691	3,072,176	4,009,193	3,788,747	14,079,807
Non-Gen Muni's/Load Pattern	1,435	1,478	1,518	1,699	6,130
Total NSP System MWh Sales	3,211,126	3,073,654	4,010,711	3,790,446	14,085,937
Average Unit Cost of Fuel and Purchased Power					
Fuel Cost per kWh for NSP System					
Adjusted System Cost without Pr. Rose PPA	**3.101¢**	**3.513¢**	**3.085¢**	**3.038¢**	**3.170¢**
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	3.170¢	1.0026	**3.178¢**
(ii) C & I Non-Demand	3.170¢	1.0281	**3.259¢**
(iii) C & I Demand Non-TOD	3.170¢	1.0170	**3.224¢**
(iv) C & I Demand TOD On-Peak	3.170¢	1.2883	**4.084¢**
(v) C & I Demand TOD Off-Peak	3.170¢	0.7889	**2.501¢**
(vi) Outdoor Lighting	3.170¢	0.7440	**2.358¢**

North Dakota Retail MWh Sales

	May-13	Jun-13	Jul-13	Aug-13	4 Month Total
(i) Residential	56,984	47,215	66,645	61,039	231,883
(ii) C & I Non-Demand	9,208	7,654	9,393	8,922	35,177
(iii) C & I Demand Non-TOD	59,676	54,586	72,433	61,754	248,449
(iv) C & I Demand TOD On-Peak	18,879	17,781	20,609	18,670	75,939
(v) C & I Demand TOD Off-Peak	29,459	28,184	32,946	28,678	119,267
(vi) Outdoor Lighting	1,365	1,200	1,168	1,236	4,969
(vii) Total	175,571	156,620	203,194	180,299	715,684

Oct-2013 Recovery Provision (True-up Factor) Calculation

Prior Unrecovered Expenses (Jun-13 Balance of Unrecovered Expenses)	Total Jun-13
	$2,505,707

[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 Oct-2013

Prior Expenses Recovered in Aug-2013 [Billing Record]

	ND Billed MWh Sales	Prior Receovered Expenses
(i) Residential	61,039	$142,109
(ii) C & I Non-Demand	8,922	$20,295
(iii) C & I Demand Non-TOD	61,754	$137,859
(iv) C & I Demand TOD On-Peak	18,670	$52,983
(v) C & I Demand TOD Off-Peak	28,678	$49,268
(vi) Outdoor Lighting	1,236	$1,650
(vii) Total	180,299	$404,164

Actual Cost Should Have Been Recovered in Aug-13

Actual	Base	Actual ND MWh Sales	Expected Recovery
3.038¢	0.000¢	180,299	$5,477,484

Cost Recovered in Aug-13 [Billing Record]

	ND Billed MWh Sales	Actual Recovery
(i) Residential	61,039	$1,862,333
(ii) C & I Non-Demand	8,922	$277,853
(iii) C & I Demand Non-TOD	61,754	$1,899,838
(iv) C & I Demand TOD On-Peak	18,670	$728,038
(v) C & I Demand TOD Off-Peak	28,678	$684,123
(vi) Outdoor Lighting	1,236	$27,492
(vii) Total	180,299	$5,479,677

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

Oct-2013 Recovery Provision	$2,099,350
4 Month ND Retail Total MWh Sales	715,684
Oct-2013 Recovery Provision per KWH	**0.293¢**

Oct-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	0.293¢	**0.294¢**
(ii) C & I Non-Demand	1.0281	0.293¢	**0.302¢**
(iii) C & I Demand Non-TOD	1.0170	0.293¢	**0.298¢**
(iv) C & I Demand TOD On-Peak	1.2883	0.293¢	**0.378¢**
(v) C & I Demand TOD Off-Peak	0.7889	0.293¢	**0.231¢**
(vi) Outdoor Lighting	0.7440	0.293¢	**0.218¢**

Oct-2013 Refunds/Additional Charges

	Asset Based Margin Sharing Refund	Non-Asset Based Margin Sharing Refund	REC Refund		Total
Refund/Special Charge Amount	($59,787)	($14,171)	$19,743		**($40,044)**
(i) Residential	-0.034¢	-0.008¢	0.011¢		**-0.031¢**
(ii) C & I Non-Demand	-0.035¢	-0.008¢	0.011¢		**-0.031¢**
(iii) C & I Demand Non-TOD	-0.034¢	-0.008¢	0.011¢		**-0.031¢**
(iv) C & I Demand TOD On-Peak	-0.043¢	-0.010¢	0.014¢		**-0.039¢**
(v) C & I Demand TOD Off-Peak	-0.027¢	-0.006¢	0.009¢		**-0.024¢**
(vi) Outdoor Lighting	-0.025¢	-0.006¢	0.008¢		**-0.023¢**

Oct-2013 Factors

	Total
(i) Residential	**3.442¢**
(ii) C & I Non-Demand	**3.529¢**
(iii) C & I Demand Non-TOD	**3.491¢**
(iv) C & I Demand TOD On-Peak	**4.422¢**
(v) C & I Demand TOD Off-Peak	**2.708¢**
(vi) Outdoor Lighting	**2.554¢**

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-	Percent	FCA Application		Differ-
	Sep-13	Oct-13	ence	Change	Sep-13	Oct-13	ence
** COSTS (Millions) **							
1 Fossil	$140.6	$150.3	$9.7	6.9%	31.7%	32.6%	0.9%
2 Nuclear	$31.6	$34.9	$3.3	10.5%	7.1%	7.6%	0.5%
3 Purchases	$154.8	$155.7	$0.9	0.6%	34.9%	33.8%	-1.1%
MISO related Purchases	$116.7	$119.6	$2.9	2.5%	26.3%	26.0%	-0.3%
4 Total System Costs	443.7	460.5	$16.8	3.8%	100.0%	100.0%	0.0%
5 Intersystem Sales	$12.1	$14.0	$1.9	16.2%	2.7%	3.0%	0.3%
6 Net System Costs	$431.6	$446.5	$14.8	3.4%	97.3%	97.0%	-0.3%
7							
8 ** GWH OUTPUT **							
9 Fossil	3,646	4,160	514	14.1%	23.4%	25.1%	1.7%
10 Nuclear	2,998	3,341	343	11.4%	19.3%	20.2%	0.9%
11 Purchases	6,362	6,711	349	5.5%	40.9%	40.5%	-0.4%
12 Hydro & Other	1,961	1,793	(168)	-8.6%	12.6%	10.8%	-1.8%
13 Net Interchange	583	554	(29)	-5.0%	3.7%	3.3%	-0.4%
14 Total Output	15,550	16,559	1,009	6.5%	100.0%	100.0%	0.0%
15 Intersystem Sales	484	503	19	4.0%	3.1%	3.0%	-0.1%
16 Native Requirement	15,066	16,056	990	6.6%	96.9%	97.0%	0.1%
17							
18 ** COST per KWH OUTPUT (¢) **							
19 Fossil	3.856	3.613	-0.243	-6.3%			
20 Nuclear	1.054	1.045	-0.009	-0.9%			
21 Purchases	2.433	2.320	-0.113	-4.7%			
22 Total System Costs	2.853	2.781	-0.073	-2.5%			
23 Intersystem Sales	2.493	2.784	0.292	11.7%			
24 Net System Costs	2.865	2.781	-0.084	-2.9%			
25							
26							
27 TOTAL SYSTEM GWH SALES	13,675	14,086	411	3.0%			
28							
29 COST per KWH SALES (¢)	3.156	3.170	0.014	0.4%			
30							
31 RECOVERY PROV (¢ / KWH) - SYS	0.149	0.293	0.144				
(i) Residential	0.150	0.294	0.145				
(ii) C & I Non-Demand	0.153	0.302	0.148				
(iii) C & I Demand Non-TOD	0.152	0.298	0.147				
(iv) C & I Demand TOD On-Peak	0.192	0.378	0.186				
(v) C & I Demand TOD Off-Peak	0.118	0.231	0.114				
(vi) Outdoor Lighting	0.111	0.218	0.107				
32 REFUND	-0.160	-0.065	0.095				
(i) Residential	-0.160	-0.031					
(ii) C & I Non-Demand	-0.164	-0.031					
(iii) C & I Demand Non-TOD	-0.163	-0.031					
(iv) C & I Demand TOD On-Peak	-0.206	-0.039					
(v) C & I Demand TOD Off-Peak	-0.126	-0.024					
(vi) Outdoor Lighting	-0.119	-0.023					
33 SYSTEM FCC IMPACT (¢ / KWH)	3.145	3.398	0.253	8.0%			
(i) Residential	3.153	3.442	0.289				
(ii) C & I Non-Demand	3.233	3.529					
(iii) C & I Demand Non-TOD	3.198	3.491					
(iv) C & I Demand TOD On-Peak	4.052	4.422					
(v) C & I Demand TOD Off-Peak	2.481	2.708					
(vi) Outdoor Lighting	2.340	2.554					

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	$0.29
250	$0.72
500	$1.44
750	$2.16
1,000	$2.89

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	
	Sep-13	Oct-13
** GWH OUTPUT **		
Thermal	1,251,339	1,208,332
Disper gen	102,415	173,434
Hydro plus Wind	606,903	411,665
Hydro and Other	1,960,657	1,793,431
Rounded to nearest thousand:	1,961	1,793
Sales		
Non Gen Munic Total	6,014,000	6,130,000
Load Pattern Power	0	0
Resale & Interchange (Intersystem)	483,566,000	502,927,000
Rounded to nearest million:	483.566	502.927

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail
	August 2013 Actual			
	Energy and Loss Charges			
1 a	Day-Ahead Asset Energy Amount - Energy Component (1)	$ 32,276,671.38	$ 3,810,312.44	$ 36,086,983.82
1 c	Day-Ahead Asset Energy Amount - Loss Component (1)	$ 3,032,797.69	$ -	$ 3,032,797.69
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,324.76	$ -	$ 1,324.76
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component (1)	$ (18,435,445.13)	$ -	$ (18,435,445.13)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component (1)	$ 1,965,031.52	$ -	$ 1,965,031.52
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,324.76)	$ -	$ (1,324.76)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component (1)	$ 1,328,252.17	$ 1,299,074.71	$ 2,627,326.88
13 c	Real-Time Asset Energy Amount - Loss Component (1)	$ (16,273.61)	$ -	$ (16,273.61)
14	Real-Time Distribution of Losses Amount	$ (1,507,357.00)	$ -	$ (1,507,357.00)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 677.03	$ -	$ 677.03
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (677.03)	$ -	$ (677.03)
21	Real-time Net inadvertent Distribution	$ 119,797.08	$ -	$ 119,797.08
22 a	Real-Time Non-Asset Energy Amount - Energy Component (1)	$ 86,524.35	$ -	$ 86,524.35
22 c	Real-Time Non-Asset Energy Amount - Loss Component (1)	$ (594.34)	$ -	$ (594.34)
	Congestion Related Charges			
1 b	Day-Ahead Asset Energy Amount - Congestion Component (1)	$ 1,989,081.66	$ -	$ 1,989,081.66
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 3,800.06	$ -	$ 3,800.06
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component (1)	$ 825,173.23	$ -	$ 825,173.23
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (3,800.06)	$ -	$ (3,800.06)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component (1)	$ (143,015.10)	$ -	$ (143,015.10)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 399.99	$ -	$ 399.99
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (399.99)	$ -	$ (399.99)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component (1)	$ 2,684.17	$ -	$ 2,684.17
	FTR Related Charges			
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,716,631.05)	$ -	$ (2,716,631.05)
30	Financial Transmission Rights Monthly Allocation Amount	$ 4,804.57	$ -	$ 4,804.57
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (147,235.30)	$ -	$ (147,235.30)
37	Financial Transmission Guarantee Uplift Amount	$ 146,985.47	$ -	$ 146,985.47
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
	Uplift Charges			
23	Real-Time Revenue Neutrality Uplift Amount	$ 264,314.94	$ -	$ 264,314.94
	Revenue Sufficiency Guarantee (RSG) Charges			
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 93,914.39	$ -	$ 93,914.39
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (90,652.04)	$ 24,133.17	$ (66,518.87)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 207,994.07	$ -	$ 207,994.07
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (423,174.32)	$ 70,596.63	$ (352,577.69)
43	Real-Time Price Volatility Make Whole Payment Amount	$ (136,192.66)	$ (379.06)	$ (136,571.72)
	Market Adminstration Charges			
4	Day-Ahead Market Administration Amount	$ 648,104.05	$ (9,168.24)	$ 638,935.81
19	Real-Time Market Administration Amount	$ 34,124.15	$ (3,862.62)	$ 30,261.53
29	Financial Transmission Rights Market Administration Amount	$ 41,347.79	$ -	$ 41,347.79
33	Day-Ahead Schedule 24 Allocation Amount	$ 109,504.84	$ (1,475.29)	$ 108,029.55
34	Real -Time Schedule 24 Allocation Amount	$ 5,788.65	$ (595.70)	$ 5,192.95
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	$ (4,965.72)	$ -	$ (4,965.72)
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	$ (492,328.17)	$ -	$ (492,328.17)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 197,868.53	$ -	$ 197,868.53
	TOTAL MISO CHARGES	**$ 19,131,828.71**	**$ 5,188,636.04**	**$ 24,320,464.75**
	SCHEDULE 24 (FOR RETAIL)			**$ 113,222.50**
	TOTAL MISO CHARGES LESS SCHEDULES 24 (FOR RETAIL)			**$ 24,207,242.25**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail
August 2013 Actual				
Procurement Charges				
1	Day-Ahead Regulation Amount	$ (86,105.52)	$ -	$ (86,105.52)
2	Day-Ahead Spinning Reserve Amount	$ (101,823.02)	$ -	$ (101,823.02)
3	Day-Ahead Supplemental Reserve	$ (64,370.74)	$ -	$ (64,370.74)
4	Real-Time Regulation Amount	$ (147,111.51)	$ 53,888.55	$ (93,222.96)
5	Real-Time Spinning Reserve Amount	$ 15,195.01	$ 14,571.25	$ 29,766.26
6	Real-Time Supplemental Reserve Amount.	$ 77,491.93	$ 352.52	$ 77,844.45
Resource Energy Charges				
7a	Real Time Excessive Energy Amount	$ 65,765.12		$ 65,765.12
7b	Real Time Excessive Energy Congestion	$ -		$ -
7c	Real Time Excessive Energy Loss	$ -		$ -
8a	Real Time Non Excessive Energy Amount	$ 363,016.84		$ 363,016.84
8b	Real Time Non Excessive Energy Congestion	$ 847,364.59		$ 847,364.59
8c	Real Time Non Excessive Energy Loss	$ 211,215.94		$ 211,215.94
9	Real Time Net Regulation Adjustment Amount	$ 28,934.57	$ (5,549.90)	$ 23,384.67
Cost Distribution Charges				
10	Real Time Regulation Reserve Cost Distribution Amount	$ 132,504.81	$ -	$ 132,504.81
11	Real Time Spinnng Reserve Cost Distribution	$ 202,030.48	$ -	$ 202,030.48
12	Real Time Supplemental Reserve Cost Distribution	$ 100,689.38	$ -	$ 100,689.38
Penalty Charges				
13	Real Time Excessive/Dificient Energy Deployment	$ 57,266.41	$ (8,960.62)	$ 48,305.79
14	Real Time Contignecy Reserve Deployment Failure	$ 26,451.63	$ (22,024.35)	$ 4,427.28
	TOTAL MISO ASM CHARGES	**$ 1,728,515.92**	**$ 32,277.45**	**$ 1,760,793.37**

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)	(74,848)				
5													
6	Forecast North Dakota Sales	190,659	193,918	172,034	162,994	190,995	190,839	175,314	177,072	160,760	205,971	-	-
7													
8	**Current Month Refund Factor**	(0.059)	(0.029)	(0.028)	(0.056)	(0.024)	(0.020)	(0.011)	(0.042)	-	-	-	-
9													
14	Expected Refund	(44,630)	(52,527)	(121,803)	(65,176)	(85,565)	(56,127)	(58,687)	(27,522)	(11,541)	(59,787)	-	-
15	Actual Refunded	(34,718)	(43,979)	(84,402)	(100,304)	(73,088)	(67,024)	(67,038)	(42,583)				
16	Deviation	(9,912)	(8,548)	(37,401)	35,128	(12,477)	10,897	8,351	15,061	(11,541)	(59,787)	-	-
17													
18	**True-up Factor**	(0.005)	(0.004)	(0.022)	0.022	(0.007)	0.006	0.005	0.009	-	-	-	-
19													
20	**Realized Margin**	(0.064)	(0.034)	(0.050)	(0.034)	(0.031)	(0.014)	(0.007)	**(0.034)**	-	-	-	-
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)	(0.034)	-	-	-	-
32	C&I Non-Demand	(0.066)	(0.035)	(0.051)	(0.035)	(0.032)	(0.015)	(0.007)	(0.035)	-	-	-	-
33	C&I Demand Non-TOD	(0.065)	(0.034)	(0.051)	(0.035)	(0.031)	(0.015)	(0.007)	(0.034)	-	-	-	-
34	C&I Demand TOD On-Peak	(0.082)	(0.043)	(0.064)	(0.044)	(0.040)	(0.019)	(0.008)	(0.043)	-	-	-	-
35	C&I Demand TOD Off-Peak	(0.050)	(0.027)	(0.039)	(0.027)	(0.024)	(0.011)	(0.005)	(0.027)	-	-	-	-
36	Outdoor Lighting	(0.048)	(0.025)	(0.037)	(0.026)	(0.023)	(0.011)	(0.005)	(0.025)	-	-	-	-

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	177,072	-	-	-
7													
8	**Current Month Refund Factor**	(0.007)	(0.007)	(0.007)	(0.008)	(0.008)	(0.007)	(0.007)	(0.008)	(0.008)	-	-	-
13													
14	Expected Refund	(11,060)	(13,140)	(12,137)	(13,173)	(14,257)	(14,119)	(14,164)	(14,651)	(14,765)	-	-	-
15	Actual Refund	(12,560)	(13,605)	(11,517)	(12,691)	(13,731)	(13,105)	(13,036)	(17,033)	(14,231)			
16	Deviation	1,500	465	(620)	(482)	(526)	(1,014)	(1,128)	2,382	(534)	-	-	-
17													
18	**True-up Factor**	0.001	0.000	(0.000)	(0.000)	(0.000)	(0.001)	(0.001)	0.001	(0.000)	-	-	-
19													
20	**Realized Margin**	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.006)	**(0.008)**	-	-	-
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)	(0.008)	-	-	-
32	C&I Non-Demand	(0.006)	(0.007)	(0.008)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	(0.008)	-	-	-
33	C&I Demand Non-TOD	(0.006)	(0.007)	(0.007)	(0.008)	(0.009)	(0.008)	(0.008)	(0.007)	(0.008)	-	-	-
34	C&I Demand TOD On-Peak	(0.008)	(0.009)	(0.009)	(0.011)	(0.011)	(0.010)	(0.010)	(0.008)	(0.010)	-	-	-
35	C&I Demand TOD Off-Peak	(0.005)	(0.005)	(0.006)	(0.006)	(0.007)	(0.006)	(0.006)	(0.005)	(0.006)	-	-	-
36	Outdoor Lighting	(0.004)	(0.005)	(0.005)	(0.006)	(0.006)	(0.006)	(0.006)	(0.005)	(0.006)	-	-	-

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

		Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
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)	(91,465)	
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	177,072	
7													
8	**Current Month Refund Factor**	(0.145)	-	-	(0.310)	(0.004)	-	-	(0.001)	-	(0.074)	(0.052)	-
13													
14	Expected Refund	-	-	(280,039)	-	(161,476)	(406,613)	(94,613)	(137,192)	187,000	(22,405)	180,388	-
15	Actual Refund			(118,563)	(183,731)	(75,050)	(269,421)	(281,613)	(116,841)	6,612	106,292	69,180	
16	Deviation	-	-	(161,476)	183,731	(86,426)	(137,192)	187,000	(20,351)	180,388	(128,697)	111,208	-
17													
18	**True-up Factor**	-	-	(0.079)	0.096	(0.045)	(0.080)	0.115	(0.011)	0.095	(0.073)	0.063	-
19													
20	**Realized Refund**	(0.145)	-	(0.079)	(0.213)	(0.049)	(0.080)	0.115	(0.012)	0.095	(0.147)	0.011	-
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)	0.011	-
32	C&I Non-Demand	(0.149)	-	(0.081)	(0.219)	(0.050)	(0.082)	0.118	(0.012)	0.097	(0.151)	0.011	-
33	C&I Demand Non-TOD	(0.147)	-	(0.080)	(0.217)	(0.050)	(0.081)	0.117	(0.012)	0.096	(0.150)	0.011	-
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)	0.014	-
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)	0.009	-
36	Outdoor Lighting	(0.108)	-	(0.059)	(0.159)	(0.036)	(0.059)	0.085	(0.009)	0.070	(0.109)	0.008	-