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July 10, 2008

Illona Jeffcoat-Sacco
North Dakota Public Service Commission
State Capitol
600 East Boulevard
Bismarck, ND 58505-0480

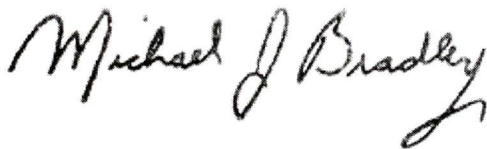
Re: In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in North Dakota Case No. PU-07-776

Dear Ms. Jeffcoat-Sacco:

Enclosed please find the original and eleven copies of the late filed Exhibits 25-32 which Northern States Power Company, a Minnesota Corporation operating in North Dakota, agreed to provide during the evidentiary hearings in the above-entitled Docket.

Please contact me if further information is required.

Very truly yours,



Michael J. Bradley
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MJB/jjh
Enclosures
cc: Doug Bahr
1185992v1

83 **PU-07-776** Filed: 7/10/2008 Pages: 18
Late Filed Exhibits 25-32

Northern States Power Company
Moss&Barnett, Michael J. Bradley

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 25, providing the top ten liquid natural gas exporting countries.

Response:

Attached is a chart with the requested information.

Country	Maximum Exporting Capacity Capabilities (million mt/yr)
Qatar	29.3
Indonesia	29.0
Malaysia	22.7
Algeria	20.7
Nigeria	18.0
Australia	15.4
Trinidad & Tobago	15.0
Egypt	12.7
Oman	9.9
Brunei	6.7
UAE	6.0
Norway	4.2
Equatorial Guinea	3.4
Libya	0.7

Source: Platts LNG Daily's Terminal Tracker

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 26 comparing the historical and forecasted retail sales growth rates for the Company's North Dakota and Minnesota electric operations.

Response:

The attached schedule shows the annual weather-normalized retail sales in megawatt-hours (MWh) for both the North Dakota and Minnesota jurisdictions for the years 1998 through 2006. Also shown are the forecasted annual retail sales for each jurisdiction for the years 2007 and 2008.

The schedule also presents the annual percentage change in MWh sales for each year from 1999 through 2008. Shown separately is the simple average of the annual percentage changes in actual sales for those years.

For the North Dakota jurisdiction, the historical average annual percentage change in actual retail sales for 1999 to 2006 was 1.5 percent. The 2008 test year forecast growth rate of 1.4 percent is slightly lower than the historical average.

For the Minnesota jurisdiction, the historical average annual percentage change in actual retail sales is 1.6 percent, which was also the forecasted growth rate in 2008.

Both the 1999 – 2006 average growth rate and the 2008 test year forecast growth rate are lower for the North Dakota jurisdiction than for the Minnesota jurisdiction.

Xcel Energy
Electric Utility - State of North Dakota
Comparison of ND and MN Jurisdictional Retail Sales Growth

North Dakota Jurisdiction Weather-Normalized Electric Sales (MWh)		
		<u>RETAIL</u>
Actual	1998	1,928,987
	1999	1,938,691
	2000	2,000,104
	2001	2,022,371
	2002	2,128,065
	2003	2,062,851
	2004	2,105,478
	2005	2,085,956
Forecast	2006	2,164,206
	2007	2,187,031
	2008	2,217,924
ND Annual % Change		
		<u>RETAIL</u>
Actual	1999	0.5%
	2000	3.2%
	2001	1.1%
	2002	5.2%
	2003	-3.1%
	2004	2.1%
	2005	-0.9%
	2006	3.8%
Forecast	2007	1.1%
	2008TY	1.4%
1999-2006 Annual Average		1.5%

Minnesota Jurisdiction Weather-Normalized Electric Sales (MWh)		
		<u>RETAIL</u>
Actual	1998	27,906,945
	1999	28,371,159
	2000	29,350,325
	2001	29,570,657
	2002	29,903,237
	2003	30,369,619
	2004	30,832,384
	2005	31,407,453
Forecast	2006	31,700,279
	2007	32,245,610
	2008	32,772,720
MN Annual % Change		
		<u>RETAIL</u>
Actual	1999	1.7%
	2000	3.5%
	2001	0.8%
	2002	1.1%
	2003	1.6%
	2004	1.5%
	2005	1.9%
	2006	0.9%
Forecast	2007	1.7%
	2008TY	1.6%
1999-2006 Annual Average		1.6%

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 27 showing the impact on the test year revenue deficiency of reflecting the historical sales growth trend (using data from 1998 to 2006) in the development of 2008 test year sales.

Response:

To determine the historical growth trend, a linear regression analysis was performed on sales data from 1998 to 2006. Using the resulting sales growth trend to develop the 2008 sales forecast would result in a 6,011 MWh reduction of total retail sales for the test year.

By applying the proposed rates to the lower sales forecast, we calculate a \$486,000 reduction in test year non-fuel revenues and a corresponding *increase* in the filed revenue deficiency. Please see the attached schedules for the related calculations.

Xcel Energy
 Electric Utility - State of North Dakota

Impact on Revenue Deficiency of Using Historical Sales Growth Rate

2008 MWh Sales Forecast			
	Reflected in Test Year	Using Historic Growth Trend (1)	Change
Res	780,386	767,054	-13,332
C&I	1,410,913	1,424,605	13,692
Other	26,625	20,254	-6,371
Retail	2,217,924	2,211,913	-6,011

Proposed Revenue \$/kWh			
	Excl. Fuel (2)	Fuel	Incl. Fuel
Res	0.0476	0.0255	0.0731
C&I	0.0432	0.0255	0.0687
Other	0.0695	0.0255	0.0950

Impact on 2008 TY Revenue of Using Historic Growth Rate Trend (000's)			
	Excl. Fuel (2)	Fuel	Incl. Fuel
Res	-\$635	-\$340	-\$975
C&I	\$591	\$349	\$940
Other	-\$443	-\$162	-\$605
Retail	-\$486	-\$153	-\$640

Notes:

-
- (1) The historic growth trend forecast is based on a linear regression analysis of historical 'weather-normalized sales data from 1998 to 2006.
- (2) Using the historic growth rate trend to forecast 2008 TY sales would result in a reduction of sales and a consequent increase in the revenue deficiency of \$486,000 (the forecasted non-fuel revenue decrease).

Source: RevModTY08PrintCustPctRegress.xls

Xcel Energy
 Electric Utility - State of North Dakota

Impact on Revenue Deficiency of Using Historical Sales Growth Rate

		North Dakota Weather Normalized Calendar Month Electric Sales (MWh)			
		Total Res	Total C&I	Total Other	Total RETAIL
H I S T O R Y	1998	693,403	1,199,754	35,830	1,928,987
	1999	693,973	1,209,602	35,116	1,938,691
	2000	709,397	1,262,394	28,313	2,000,104
	2001	698,428	1,299,108	24,835	2,022,371
	2002	737,358	1,365,912	24,795	2,128,065
	2003	741,471	1,297,029	24,352	2,062,851
	2004	736,202	1,344,652	24,624	2,105,478
R E G I S T R E D	2005	741,637	1,319,045	25,274	2,085,956
	2006	746,129	1,391,603	26,474	2,164,206
	1998	691,963	1,214,911	32,722	1,939,597
	1999	699,472	1,235,881	31,475	1,966,828
	2000	706,982	1,256,850	30,228	1,994,060
	2001	714,491	1,277,819	28,982	2,021,292
	2002	722,000	1,298,789	27,735	2,048,523
T E S T I N G	2003	729,509	1,319,758	26,488	2,075,755
	2004	737,018	1,340,728	25,241	2,102,986
	2005	744,527	1,361,697	23,994	2,130,218
	2006	752,036	1,382,666	22,747	2,157,450
	2007	759,545	1,403,636	21,501	2,184,681
	2008	767,054	1,424,605	20,254	2,211,913
	T Y	2007	771,311	1,388,636	27,085
2008		780,386	1,410,913	26,625	2,217,924

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 28 showing the largest amount of incentive compensation made to one employee and the allocation to the North Dakota electric jurisdiction.

Response:

The largest amount of incentive compensation made to one employee is for Richard C. Kelly, who is Chairman, President, and CEO of Xcel Energy. As shown on the attached schedule, the amount allocated to North Dakota electric operations is \$5,522.

Northern States Power Company, a Minnesota Corporation
Electric Utility -- State of North Dakota
Test Year Impact of Annual Incentive paid to Xcel Energy CEO
(2007 award paid in 2008)

	<u>Amount</u>	<u>Alloc %</u>
Annual Incentive Award - Target Level:	\$ 1,100,000	
Recoverable Portion (25% cap):	\$ 275,000	
Allocation to NSPM Operating Company:	\$ 103,675	37.70%
Allocation to NSPM Electric Utility Operations:	92,877	89.59%
Allocation to North Dakota Jurisdiction:	<u><u>\$ 5,522</u></u>	5.95%

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 29 showing the electric loads of Southwest Public Service Company (“SPS”) and Northern States Power Company (MN) (“NSPM”) as well as the state jurisdictional contributions to each company’s load.

Response:

See the attached schedule which shows the retail energy sales and peak demands for each system, and the associated state jurisdiction contributions and ratios.

Xcel Energy
Electric Utility -- State of North Dakota
Comparison of NSPM and SPS Electric Loads

NSP (MN)

<u>State Juris.</u>	<u>Retail</u> <u>MWh Sales</u>	<u>% of Total</u>	<u>Peak</u> <u>MW Demand</u>	<u>% of Total</u>
MN	32,660,016	88.75%	6,613	89.70%
ND	2,208,999	6.00%	351	4.76%
SD	<u>1,929,281</u>	<u>5.24%</u>	<u>408</u>	<u>5.53%</u>
Total	36,798,296	100.00%	7,372	100.00%

SPS

<u>State Juris.</u>	<u>Retail</u> <u>MWh Sales</u>	<u>% of Total</u>	<u>Peak</u> <u>MW Demand</u>	<u>% of Total</u>
TX	13,653,730	76.17%	2,515	76.17%
NM	<u>4,271,834</u>	<u>23.83%</u>	<u>787</u>	<u>23.83%</u>
Total	17,925,564	100.00%	3,302	100.00%

Notes:

1. Data reflects most recent 2008 forecast
2. NSPM jurisdictional peak demands reflect coincident contribution to NSPM system peak
3. SPS jurisdictional contributions to system peak demand are not available within SPS; an estimate is shown here based on ratio of retail sales.

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 30, providing the cost allocation for the Faribault Energy Park Interconnection Project and the High Bridge Generating Station interconnections.

Response:

The Interconnection agreements for both the Faribault Energy Park Interconnection Project and the High Bridge Generating Station Combined Cycle Plan Project were signed prior to MISO implementing its new cost allocation. Therefore, the cost of the interconnection network facilities was assigned to NSP transmission.

Correction on the Mankato Energy Center Interconnection Project

During the evidentiary hearing, Mr. Walter Grivna testified that the Mankato Energy Center Interconnection project had been shared between Xcel Energy and the generator. That statement was incorrect. In actuality, the interconnection agreement was signed prior to MISO implementing its new cost allocation. Therefore, the cost for the interconnection network facilities was assigned to NSP transmission. However, the three short transmission lines were determined to be Direct Interconnection Facilities, not Network (shared system) facilities, and were therefore paid 100 % by the generator.

During the evidentiary hearings, Xcel Energy was requested to provide a late filed Exhibit 32, providing the estimated cost of the CAPX Fargo-Twin Cities 345 kV line.

Response:

The present cost estimate for the CAPX Fargo- Twin Cities 345 kV line is \$390-\$560 million. This estimate is a range because the line has not yet been routed and the estimate represents a potential range in routing of between 210 and 270 Miles.

It should be noted that this estimate is only for a 345 kV line from Fargo to the Twin Cities and, as such, does not include the transmission costs associated with increasing wind energy deliveries from the state of North Dakota. For example, additional costs will include the costs for developing wind collector substations, transmission to deliver the wind generation to the bulk (230 or 345 kV) electric system, and any upgrades to that system that may be necessary to reliably deliver the energy over that system to the Fargo area.

During the evidentiary hearings, Xcel Energy was requested to provide as late filed Exhibit 32 Mr. Phillip Zins' workpapers that show the development of the E8760 class allocation factors.

Response:

Attached are the requested workpapers.

During the evidentiary hearings, Xcel Energy was requested to provide as late filed Exhibit 32 Mr. Phillip Zins' workpapers that show the development of the E8760 class allocation factors.

Response:

Attached are the requested workpapers.

Fuel Cost Rider - Service Category Ratios

		SERVICE CATEGORY					TOTAL
		Residential	C&I Non-Dmd	C&I Demand	Outdoor Lighting		
STEP 1: DEVELOP CLASS RATIOS							
1.	Assigned Test-Year Marginal Energy Cost *	\$42,239,366	\$7,771,796	\$68,911,803	\$716,727	\$119,639,692	
2.	Test-Year Energy (at Generator) (MWh)	849,131	147,459	1,377,611	20,238	2,394,439	
3.	Average Load-Weighted Marginal Energy Cost Per kWh (1)/(2)	\$49.7442	\$52.7050	\$50.0227	\$35.4153	\$49.9657	
4.	Class Ratio (Class Unit Cost / System Unit Cost)	0.9956	1.0548	1.0011	0.7088		
STEP 2: DE-AVERAGE C&I DEMAND CLASS RATIOS							
5.	Ratio of On- to Off-Peak Energy Charges				TOD On-Peak 1.70	TOD Off-Peak	
6.	C&I Demand Class On/Off Peak Percentage				0.4224	0.5776	
7.	C&I Demand TOD On-Peak Ratio = 1 / (0.4224 + (0.5776 / 1.700)) **				1.3121		
8.	C&I Demand TOD Off-Peak Ratio = 1 / ((1.7000 x 0.4224) + 0.5776) **					0.7718	
9.	C&I Non-TOD On-Peak Weighting				Non-TOD 0.4608		
10.	C&I Non-TOD Off-Peak Weighting				0.5392		
11.	C&I Demand Non-TOD Ratio = (0.46080 x 1.3121) + (0.53920 x 0.7718)				1.0208		
STEP 3: DEVELOP SERVICE CATEGORY RATIOS							
12.	SERVICE CATEGORY RATIOS Residential, C&I Non-Demand & Lighting = Class Ratio (Step1) C&I Demand = Class Ratio (Step 1) x TOD Ratio (Step 2)	0.9956	1.0548	1.0219	1.3135	0.7726	0.7088

* E8760 Allocator = Sum of Hourly System Marginal Costs times Class Hourly Loads

** TOD Ratio Equations is derived from the following:
 Weighted Average Energy Charge = (0.4224 x On Peak Energy Charge) + (0.5776 x Off Peak Energy Charge)
 Where 0.4224 and 0.5776 are C&I Demand class on- and off-peak % respectively

Corrections

Sales	782,202	135,756	690,293	223,122	367,833	18,717	2,217,924
Sales x Ratios	778,761	143,196	705,406	293,081	284,205	13,267	2,217,915
C&I Demand Non-TOD			318,077	372,216	690,293	46.08%	53.92%
C&I Demand TOD			223,122	367,833	590,955	37.76%	62.24%
C&I Demand TOTAL			541,199	740,049	1,281,248	42.24%	57.76%
Step 1 Source: TY08E8760.xls					1,281,248		
					0		

Source: RevModTY08, CI

Fuel Cost Rider - Service Category Ratios

	SERVICE CATEGORY					TOTAL
	Residential	C&I Non-Dmd	C&I Demand	Outdoor Lighting		
STEP 1: DEVELOP CLASS RATIOS						
1. Assigned Test-Year Marginal Energy Cost *	\$42,239,366	\$7,771,796	\$68,911,803	\$716,727		\$119,639,692
2. Test-Year Energy (at Generator) (MWh)	849,131	147,459	1,377,611	20,238		2,394,439
3. Average Load-Weighted Marginal Energy Cost Per kWh (1)/(2)	\$49.7442	\$52.7050	\$50.0227	\$35.4153		\$49.9657
4. Class Ratio (Class Unit Cost / System Unit Cost)	0.9956	1.0548	1.0011	0.7088		
STEP 2: DE-AVERAGE C&I DEMAND CLASS RATIOS						
5. Ratio of On- to Off-Peak Energy Charges				TOD On-Peak	TOD Off-Peak	
6. C&I Demand Class On/Off Peak Percentage				0.4224	0.5776	
7. C&I Demand TOD On-Peak Ratio = $1 / (0.4224 + (0.5776 / 1.700))$ **				1.3121		
8. C&I Demand TOD Off-Peak Ratio = $1 / ((1.7000 \times 0.4224) + 0.5776)$ **					0.7718	
				Non-TOD		
9. C&I Non-TOD On-Peak Weighting				0.4421		
10. C&I Non-TOD Off-Peak Weighting				0.5579		
11. C&I Demand Non-TOD Ratio = $(0.4421 \times 1.3121) + (0.5579 \times 0.7718)$				1.0107		
STEP 3: DEVELOP SERVICE CATEGORY RATIOS						
12. SERVICE CATEGORY RATIOS Residential, C&I Non-Demand & Lighting = Class Ratio (Step1) C&I Demand = Class Ratio (Step 1) x TOD Ratio (Step 2)	0.9956	1.0548	1.0118	1.3135	0.7726	0.7088

* E8760 Allocator = Sum of Hourly System Marginal Costs times Class Hourly Loads

** TOD Ratio Equations is derived from the following:

Weighted Average Energy Charge = $(0.4224 \times \text{On Peak Energy Charge}) + (0.5776 \times \text{Off Peak Energy Charge})$
 Where 0.4224 and 0.5776 are C&I Demand class on- and off-peak % respectively

Sales	782,202	135,756	927,774	131,018	222,456	18,717	2,217,924
Sales x Ratios	778,761	143,196	938,702	172,098	171,880	13,267	2,217,903

C&I Demand Non-TOD			410,181	517,593	927,774	44.21%	55.79%
C&I Demand TOD			131,018	222,456	353,474	37.07%	62.93%
C&I Demand TOTAL			541,199	740,049	1,281,248	42.24%	57.76%

Step 1 Source: TY08E8760.xls

Source: RevModTY08, CI

1,281,248

0