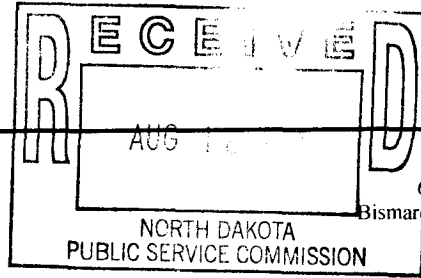




Public Service Commission  
State of North Dakota



COMMISSIONERS

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Executive Secretary  
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August 18, 2011

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
600 E Boulevard Ave Dept 408  
Bismarck ND 58505

**RE: PU-10-657  
Northern States Power Company  
2011 Electric Rate Increase  
Application**

**PU-11-55  
Northern States Power Company  
2012 Electric Rate Increase  
Application**

Dear Mr. Nitschke:

Enclosed are original copies of staff's revenue requirements and ratemaking proposals and cost of capital and cost and equity Direct Testimony and Exhibits in the above captioned proceedings.

Thank you.

Sincerely,

Mark Gruman  
Legal Counsel

Enclosure

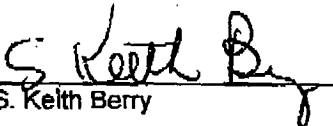
STATE OF NORTH DAKOTA  
BEFORE THE  
PUBLIC SERVICE COMMISSION

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

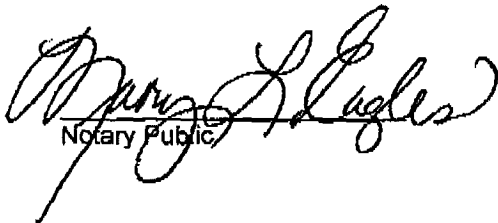
)  
)  
) Case No. PU - 10-857  
) Case No. PU - 11-55

**AFFIDAVIT OF  
S. Keith Berry**

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

  
S. Keith Berry

Subscribed and sworn to before me, this 15<sup>th</sup> day of August, 2011

  
Notary Public

OFFICIAL SEAL  
MARY L. EAGLES  
NOTARY PUBLIC - ARKANSAS  
PULASKI COUNTY  
MY COMMISSION EXPIRES 07-13-2012

Before the North Dakota Public Service Commission

In the Matter of the Application of Northern States Power Company,  
a Minnesota corporation  
For Authority to Increase Rates for Electric Utility Service in North Dakota

Case Nos. PU-10-657 and PU-11-55  
Exhibit\_\_(SKB-1)

TESTIMONY OF DR. S. KEITH BERRY  
ON BEHALF OF  
THE ADVOCACY STAFF

August 18, 2011

1 **I. INTRODUCTION AND QUALIFICATIONS**

2

3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is S. Keith Berry and my business address is 1600 Washington Avenue,  
5 Hendrix College, Conway, AR 72032.

6

7 Q. WHERE ARE YOU EMPLOYED?

8 A. My academic affiliation is Professor of Economics and Business at Hendrix College in  
9 Conway, Arkansas. I am also a principal in the firm of Economic and Financial  
10 Consulting Group, Inc.

11

12 Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

13 A. I received my B.A. in mathematics from Hendrix College, and my Ph.D. in economics  
14 from Vanderbilt University. I was an instructor in statistics at Vanderbilt in 1976-77 and  
15 was an instructor/assistant professor at Hendrix College from 1977-79. In July 1979, I  
16 joined the Staff of the Arkansas Public Service Commission as Manager of the Finance  
17 Section. The primary responsibility of that Section was the preparation and presentation  
18 of testimony concerning the cost of capital in utility rate cases. I assumed the duties of  
19 Manager of both the Finance and Rate Sections in July 1980. I was promoted to Director  
20 of Research and Policy Development in September 1986. Beginning in September 1989,  
21 I returned to teaching at Hendrix College.

22

1 I have submitted testimony in more than seventy different proceedings before public  
2 service commissions or other regulatory agencies, including testimony in the area of cost  
3 of capital. My publications include articles in the *American Economic Review*, *Journal*  
4 *of Regulatory Economics*, *Land Economics*, the *Energy Journal* (coauthor), the *Journal*  
5 *of Economics and Business*, *The Quarterly Review of Economics and Business*, *The*  
6 *Financial Review*, the *Eastern Economic Journal*, *Managerial and Decision Economics*,  
7 *Public Choice*, and the *Review of Industrial Organization*. I have made presentations  
8 concerning utility regulation and the cost of capital at the National Association of  
9 Regulatory Utility Commissioners ("NARUC") Advanced Studies Program, the Eastern  
10 NARUC Utility Rate Seminar, the Western NARUC Utility Rate Seminar, the National  
11 Conference of Regulatory Utility Commission Engineers, and the Annual Conference of  
12 the Institute of Public Utilities. While on the Staff of the Arkansas Public Service  
13 Commission, I served on the NARUC Subcommittee on Electricity and the Research  
14 Advisory Committee of the National Regulatory Research Institute (Deputy Chairman,  
15 1988-89). I am currently a member of the American Economic Association and the  
16 Southern Economic Association. A copy of my *Curriculum Vita* is provided in Exhibit\_\_  
17 (SKB-2).

18  
19 Q. ON WHOSE BEHALF ARE YOU APPEARING?

20 A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service  
21 Commission.

22  
23 **II. SUMMARY OF TESTIMONY**

1

2 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS  
3 PROCEEDING?

4 A. I will make recommendations concerning the cost of capital, including cost of equity, of  
5 Northern States Power-Minnesota (“NSPM”) operating in North Dakota. I will also rebut  
6 the Direct Testimony of NSPM cost of capital witness Ann E. Bulkley.

7

8 Q. WHAT HAVE YOU REVIEWED IN THE PREPARATION OF YOUR DIRECT  
9 TESTIMONY?

10 A. I have reviewed the Company’s filing in this Docket, including testimony, exhibits, and  
11 workpapers, responses to data requests, relevant issues of *Value Line Investment Survey*,  
12 NSP’s recent SEC Form 10-Qs and 10-K, and other documents and data.

13

14 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

15 A. I recommend a capital structure with 52.564 percent common equity, 46.293 per cent  
16 long-term debt, and 1.143 per cent short-term debt. This is the same capital structure  
17 proportions that the Company is proposing, which I find to be reasonable. The Company  
18 is requesting a cost of equity of 11.25% and a weighted cost of capital of 8.74%. My  
19 analysis indicates that reasonable estimate of the cost of equity is in the range of 9.3% -  
20 10.3%. Based on my point recommendation of 9.55%, which reflects an adjustment for  
21 lower risk, my recommended weighted average cost of capital is 7.85%. This is shown in  
22 my Exhibit\_\_(SKB-3).

23

1 **III. CAPITAL STRUCTURE FOR NSPM**

2

3 Q. HOW DID YOU CALCULATE THE OVERALL RATE OF RETURN, OR  
4 WEIGHTED AVERAGE COST OF CAPITAL?

5 A. I utilized the weighted average cost of capital approach wherein the various components'  
6 capital costs are weighted by their proportions in the capital structure and then summed.

7

8 Q. WHAT CAPITAL COMPONENTS DID YOU EMPLOY?

9 A. Common equity, long-term debt, and short-term debt, as shown in Exhibit \_\_ (SKB-3).

10

11 Q. PLEASE EXPLAIN THE DETERMINATION OF THE RELATIVE PROPORTIONS  
12 OF THESE CAPITAL COMPONENTS.

13 A. I used the same capital structure as the Company proposed, which I found to be  
14 reasonable.

15

16 **IV. COST OF DEBT FOR NSPM**

17

18 Q. HOW DID YOU DETERMINE THE COST OF LONG-TERM DEBT FOR NSPM?

19 A. I used a 6.07% cost rate, which is the same as the Company's.

20

21 Q. HOW DID YOU DETERMINE THE COST OF SHORT-TERM DEBT FOR NSPM?

22 A. I used a 2.06% cost rate, which is the same as the Company's.

23

1

2 **V. COST OF EQUITY FOR NSPM**

3

4 Q. PLEASE DISCUSS THE FINANCIAL AND ECONOMIC TENETS THAT GUIDED  
5 YOU IN ESTIMATING NSPM'S COST OF EQUITY.

6 A. The cost of, or required return on, equity is a valid cost just as other more explicit  
7 expenses incurred by the utility in the provision of utility service to ratepayers. The  
8 difficulty with estimating the cost of equity is that it is nowhere explicitly stated in a  
9 utility's accounts, and must be inferred from market data.

10

11 If the return allowed by the regulatory authority is set higher than the required return on  
12 equity, then monopoly profits will inure to the benefit of the shareholders, at the expense  
13 of customers. If the return is set too low, then the financial position of the shareholders  
14 will be eroded and the utility will be unable to adequately attract necessary capital. When  
15 the allowed return on equity is set equal to the cost of equity, stockholders will be given  
16 the opportunity to earn a fair return on equity, which will also afford the utility the  
17 opportunity to viably attract capital. Thus, from the perspective of balancing the interests  
18 of ratepayers and shareholders, and simulating the competitive market model, a cost-  
19 based allowed return on equity is a desirable goal. Note that in the case of the cost of  
20 equity that is estimated with current data, the cost of equity is also the marginal cost of  
21 equity. The decisions that consumers make will be based on those price signals, which  
22 reflect the economic costs, including the marginal cost of equity, to society of providing

1 utility service. In that sense, an allowed return based on the cost of equity is  
2 economically efficient.

3  
4 In my analysis of the cost of equity for NSPM, I relied solely upon the Discounted Cash  
5 Flow Method, since other methods for estimating the cost of equity are unreliable as I  
6 discuss in my Rebuttal of Ms. Bulkley.

7  
8 Q. PLEASE DISCUSS YOUR RISK-COMPARABLE SAMPLE.

9 A. In order to develop a market-based cost of equity and have sufficient data in the analysis  
10 it is appropriate to use a sample of companies comparable in risk to NSPM. As a  
11 starting point I utilized the same Risk Comparable sample as did Ms. Bulkley except that  
12 I: (1) Included Xcel Energy (“Xcel”), the parent company of NSPM, in the sample (2)  
13 Excluded DPL and Progress Energy from the Risk Comparable sample since both of  
14 those companies are parties to merger transactions; and (3) Excluded Hawaiian Electric  
15 because of its significant holdings of American Savings Bank.

16  
17 For cost of capital purposes it is reasonable to include NSPM’s parent company as a part  
18 of the risk-comparable sample. There is no circularity involved because Xcel’s common  
19 equity is used to supply NSPM’s common equity. That is the only source of common  
20 stock for NSPM. Surely an analysis of NSPM’s cost of equity should include an analysis  
21 of the cost of equity of the sole supplier of NSPM’s common equity. Further, note that  
22 NSPM accounted for approximately 42% of Xcel’s revenues in calendar year 2010. This

1 indicates that NSPM accounts for a significant part of Xcel's operations, and implicitly,  
2 Xcel's cost of equity.

3  
4  
5 **VI. DISCOUNTED CASH FLOW METHODOLOGY**

6  
7 Q. PLEASE DISCUSS YOUR APPLICATION OF THE DISCOUNTED CASH FLOW  
8 METHOD ("DCF") TO ESTIMATE NSPM'S COST OF EQUITY.

9 A, The concept of a return to capital is closely associated with time: a reward to the  
10 suppliers of capital for deferring consumption. Calculations of the embedded costs of  
11 debt are relatively straightforward since those costs are fixed and contractual in nature.  
12 The cost of equity, in contrast, is not spelled out in a contractual manner and is more  
13 difficult to calculate. However, it can be inferred through an appropriate examination of  
14 current stock market data and widely disseminated financial information.

15  
16 Rational investors in common stock are primarily concerned with the cash flows that they  
17 expect to receive from ownership of the stock. For the individual investor those cash  
18 flows consist of expected future dividends as well as capital gains or losses expected  
19 from selling the stock at some future point in time. However, for investors in aggregate  
20 (across ownership changes) expected cash flows are comprised of future dividends only.  
21 There is no conceptual difference between these two interpretations of cash flow.

22

1 The market price of the common stock embodies investors' expectations about that  
2 stream of future dividends. However, a dividend expected to be received in the future is  
3 not valued as highly by investors as that same dividend received today. The investor  
4 implicitly imputes a discount to future dividends. Also, the further in the future the  
5 dividend is expected to be received, the greater is the discount.

6  
7 This value, or market price, that investors impute to that share of common stock is the  
8 present value of the stream of dividends expected to be received by them. These future  
9 dividends are discounted by an amount determined by the discount rate, or cost of equity.  
10 This relationship is characterized in Equation (1) below where  $P_0$  represents the current  
11 share price,  $D_i$  represents the dividend expected to be received at the end of period "i",  
12 and "k" is the discount rate, or cost of equity:

13  
14 (1) 
$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + D_3/(1+k)^3 + \dots$$

15  
16 In this form, without further simplifying and reasonable assumptions, Equation (1) is  
17 mathematically intractable. However, if we assume that investors expect future  
18 dividends to increase at a constant rate of growth, g, then Equation (1) can be expressed  
19 as:

20 (2) 
$$P_0 = D_1/(1+k) + D_1(1+g)/(1+k)^2 + D_1(1+g)^2/(1+k)^3 + \dots$$

21  
22 Equation (2) can then be solved for  $P_0$  as:  
23

1                   (3)  $P_0 = D_1/(k-g)$ , for  $k > g$ .

2  
3                   Equation (3) demonstrates that this constant growth DCF method is a market-based  
4                   approach. Any changes in investors' discount rate, expected growth rate in dividends, or  
5                   dividends expected one period hence are actually captured by changes in the market price  
6                   of the stock. For example, other things being equal, if the cost of equity decreases, then  
7                   investors will bid the market price up.

8  
9                   The constant growth DCF model shown in Equation (3) can be re-expressed as:

10  
11                   (4)  $k = D_1/P_0 + g$ ,

12  
13                   which implies that the cost of equity is simply the sum of the expected dividend yield and  
14                   the anticipated growth rate. Because of the quarterly nature of dividend payments, I have  
15                   defined  $D_1 = D_0(1 + g/4)$ , where  $D_0$  is the current annualized dividend. Thus, the final  
16                   form of the DCF equation is:

17  
18                   (5)  $K = D_0(1 + g/4)/P_0 + g$ .

19  
20                   Q.    HOW DID YOU DETERMINE THE GROWTH RATE IN YOUR DCF MODEL?

21                   A.    It is important for the analyst to ascertain investors' expectations about future sustainable  
22                   long-term growth in dividends per share in order to properly implement the DCF method.  
23                   Keep in mind that it is not what the analyst believes future growth will be, but what

1 investors believe about future long-term sustainable growth. It is those expectations that  
2 influence the stock price. Further, if sustainable, growth in book value per share  
3 (“BVPS”), earnings per share (“EPS”), and dividends per share (“DPS”) will be  
4 equivalent.

5  
6 I utilized recent editions of *Value Line Investment Survey*, a well-respected and widely  
7 disseminated source of information about companies, to develop my array of data for  
8 inferring investors’ growth expectations. I also used the growth estimates of Ms.  
9 Bulkley, shown in Exhibit\_\_(AEB-1), Schedule 3, page 3 of 3.

10  
11 I used seven different estimates of investor-expected growth:

12 (1) g1 – Expected 10 year EPS annual growth for the years 2005 to 2015 as reported in  
13 *Value Line*;<sup>1</sup>

14 (2) g2 – Expected 10 year BVPS annual growth for the years 2005 to 2015 as reported in  
15 *Value Line*;<sup>2</sup>

16 (3) g3 – Expected annual EPS growth for the years 2007-09 to 2014-16 as reported in  
17 *Value Line*;

18 (4) g4 – Zack’s projected EPS annual growth as shown in Bulkley Exhibit\_(AEB-1),  
19 Schedule 3, page 1 of 3;

20 (5) g5 – First Call’s projected EPS annual growth as shown in Bulkley Exhibit\_(AEB-1),  
21 Schedule 3, page 1 of 3;<sup>3</sup>

---

<sup>1</sup> For some Companies the ten year period was 2004-2014 given the data presented by *Value Line*. Portland General’s was calculated over a nine-year period because of data limitations.

<sup>2</sup> For some Companies the ten year period was 2004-2014 given the data presented by *Value Line*. Portland General’s was calculated over a nine-year period because of data limitations.

1 (6)  $g_6$  – “br + vs” using data reported in *Value Line* for the years 2014-16;<sup>4</sup> and

2 (7)  $g_7$  – “br + vs” using data reported in *Value Line* for the years 2010-11.

3  
4 It is my opinion that taken together these seven growth rates provide a reasonable basis  
5 upon which to infer the investor-expected growth rate in the DCF method.

6  
7 Note that the expression “br + vs” is a measure of long-term sustainable expected growth  
8 in BVPS, based on two fundamental sources of BVPS growth: earnings retention (“br”)  
9 and accretion (or dilution) of BVPS due to the issuance of new common stock (“vs”).  
10 Since the DCF formula relies on investor-expected growth in DPS, and since long-term  
11 growth is ultimately derived from, and equal to, long-term growth in BVPS, this  
12 approach is useful in gauging investors’ dividend growth expectations.

13  
14 The “br” component implicitly considers factors that cause sustainable growth in DPS,  
15 EPS, and BVPS due to earnings retention, where “b”, the expected retention ratio, is  
16 multiplied times “r”, the expected return on equity. A simple example, assuming no  
17 stock issuance, should clarify the working of this component. Assume that a company  
18 has an initial BVPS of \$20, “r” is equal to 10%, and “b” is equal to 40%. Investors  
19 expect this hypothetical utility to earn  $10\% \times \$20 = \$2.00$  per share. Of this amount  
20 40%, or \$.80 per share is retained, and 60%, or \$1.20 per share, will be paid out in  
21 dividends. The BVPS will grow to \$20.80 in the next period because of earnings  
22 retention. This represents a growth in BVPS of  $(\$20.80 - \$20) / \$20 = 4\%$ . EPS in the next

---

<sup>3</sup> For Xcel,  $g_4$  and  $g_5$  were not used since they were not presented in Ms. Bulkley’s Testimony.

<sup>4</sup> For some Companies the period was 2013-2015 because of the data presented in *Value Line*.

1 period will be  $10\% \times \$20.80$ , which represents growth in EPS of 4%. DPS in the next  
2 period are  $60\% \times \$2.08 = \$1.248$ , which also represents growth of 4%. DPS, EPS, and  
3 BVPS all grow at the long-term sustainable growth rate of 4%.

4  
5 At this juncture, it is important to point out that “r”, the *expected* return on equity is not  
6 necessarily equal to “k”, the *required* return on equity. That investor-expected return on  
7 equity, “r” may be greater or less than “k”, the investor-expected required return on  
8 equity. In particular, if “r” is greater (less) than “k”, then the stock-market price-to-book  
9 value ratio is greater (less) than one. It is only when  $r = k$  that the price-to-book ratio is  
10 equal to one.

11  
12 Another fundamental factor that determines sustainable growth in BVPS, EPS, and DPS  
13 is represented by the “vs” term. This second determinant of growth in BVPS is caused  
14 by the issuance of new common stock. If new stock is issued at a price below BVPS,  
15 dilution decreases the BVPS, and the investor-expected growth rate is thereby decreased.  
16 Conversely, if new stock is issued at a price above BVPS, accretion occurs and the  
17 growth rate is correspondingly increased. This factor is significant to investor  
18 expectations if the price-to-book value is significantly greater than one and if the firm is  
19 expected to issue common stock in the future (as reflected in *Value Line*). In this case  
20 those two conditions are met with regard to the Risk Comparable sample. This factor is  
21 discussed extensively in *Cost of Capital to a Public Utility* by Myron Gordon, who  
22 provided a major impetus for the use of the DCF method in utility rate proceedings.

23

1 For each firm, “vs” was calculated as  $n^*(P/B - 1)$  where  $n^*$  is the expected annual rate of  
2 growth in common shares outstanding, P is the arithmetic average of the monthly high  
3 and low stock prices for the period December 2010 – May, 2011 (obtained from  
4 corresponding editions of *Standard and Poor’s Stock Guide*), and B is the BVPS at the  
5 end of calendar year 2010 (as reported in *Value Line*).

6  
7 These different growth rate estimates are shown in Exhibit\_\_(SKB-4).

8  
9 Q. PLEASE DISCUSS YOUR CALCULATIONS OF THE OTHER COMPONENTS IN  
10 THE DCF METHOD.

11 A. In the DCF procedure, it is important to utilize a price term that is fairly current since a  
12 current price embodies all of the information currently available to investors, and will  
13 implicitly embody a current estimate of investors’ required return on equity. However,  
14 that price should be averaged in an appropriate manner so as to eliminate the influence of  
15 random fluctuations in price. In order to minimize the possibility of an aberrant price I  
16 utilized an average price over a recent time period, December, 2010 - May, 2011. This  
17 method employed the high and low stock prices for each month. Those results are shown  
18 in Exhibit\_\_(SKB-5).

19  
20 The appropriate dividend yield for each firm was calculated using the annualized  
21 dividend as reported in *Standard’s and Poor’s Stock Guide, June, 2011*, and the  
22 arithmetic average of the high and low stock prices for the months of December, 2010 -

1 May, 2011 , as reported in *Standard's and Poor's Stock Guide*. Those results are shown  
2 in Exhibit\_\_(SKB-5).

3  
4 Q. WHAT ARE YOUR COST OF EQUITY DCF RESULTS USING THESE SEVEN  
5 DIFFERENT GROWTH RATE ESTIMATES AND THE ADJUSTED DIVIDEND  
6 YIELDS FOR EACH COMPANY IN THE RISK COMPARABLE SAMPLE?

7 A. Those results are shown in Exhibit\_\_(SKB-6) for k1 through k7, which correspond to  
8 growth rates g1 through g7, respectively. As shown there the average DCF cost of equity  
9 is approximately 9.8%

10  
11 Q. DID YOU MAKE A FLOTATION COST ADJUSTMENT?

12 A. No, I did not. In response to a data request, the Company stated that Ms. Bulkley's  
13 testimony was not intended to indicate that there are specific projected stock issuances by  
14 Xcel during that period. Further, the Company stated that it was changing the testimony  
15 of Ms. Bulkley on p. 21, lines 26-28 to state: "The Company may need to access the  
16 equity market in the next several years on a more regular basis than in the past in order to  
17 finance its capital investment plan." (Response to Data Request No. AS-COC-9 attached  
18 as Exhibit\_\_(SKB-7)). Note that Xcel is the parent company of NSPM.

19  
20 Because of the uncertainty associated with projected common stock issuances, and the  
21 corresponding uncertainty of incurrence of flotation expenses, in this case, it is  
22 inappropriate to include a flotation cost adjustment for purposes of NSPM's allowed  
23 return on equity.

1

2 Q. WHAT IS YOUR DCF-BASED RECOMMENDATION FOR THE ALLOWED  
3 RETURN ON EQUITY IN THIS CASE?

4 A. Based on the prior analysis discussed above my recommendation is a cost of equity range  
5 of 9.3% - 10.3%, with a point recommendation of 9.8%, unadjusted for lower risk.

6

7 Q. DID YOU PLACE ANY RELIANCE OR WEIGHT ON OTHER COST OF EQUITY  
8 METHODS SUCH AS THE CAPITAL ASSET PRICING MODEL OR THE RISK  
9 PREMIUM METHODS?

10 A. No, I did not. Those methods are generally unreliable for reasons that I will discuss later  
11 in my Direct Testimony.

12

13 Q. DID YOU MAKE ANY ADJUSTMENTS TO YOUR COST OF EQUITY  
14 ESTIMATES?

15 A. Yes, I did. It is my understanding that NSPM is proposing a Projected Test Year. If,  
16 indeed, a Projected Test Year is used for purposes of calculating NSPM-North Dakota's  
17 revenue requirement in this case, then much, if not all of the Company's risk of  
18 regulatory lag will be eliminated.

19

20 Q. WHAT IS REGULATORY LAG?

21

22 A. Regulatory lag is the lag between the time a utility incurs higher and prudent expenses  
23 and the time that it recovers those higher expenses from ratepayers. That lag tends to

1 increase a utility's risk and cost of equity. Of course, that increased risk is implicitly  
2 reflected in a market-based cost of equity method such as the DCF method. In particular,  
3 the price is lower and the estimated cost of equity is correspondingly higher. In this case,  
4 the use of a Projected Test Year diminishes that risk associated with regulatory lag.

5  
6 Also, it is my understanding that North Dakota Law 49-05-16 provides that advance  
7 determination of prudence potentially gives investors protection from investment failure.  
8 That law provides a more favorable regulatory atmosphere in North Dakota, which  
9 reduces the risk of NSPM's operations in North Dakota.

10  
11 Consequently, for consistency it is appropriate to adjust downward the cost of equity and  
12 allowed return on equity to reflect that lower risk. In this case I adjusted the point  
13 estimate of 9.8% downward by 25 basis points to 9.55% to reflect that diminishing of  
14 regulatory risk.

15  
16 Q. WHAT IS YOUR OVERALL COST OF CAPITAL RECOMMENDATION FOR NSPM  
17 IN THIS CASE?

18 A. My overall recommendation is 7.85% as shown in Table 1 below.

19  
20  
21  
22  
23

TABLE 1

Capital Component	Proportion	Cost	Weighted Cost
Long-Term Debt	46.293%	6.07%	2.81%
Short-Term Debt	1.143%	2.06%	0.02%
Common Equity	52.564%	9.55%	5.02%

OVERALL WEIGHTED COST OF CAPITAL = 7.85%

**VII. REBUTTAL OF NSPM WITNESS BULKLEY**

Q. DR. BERRY, HAVE YOU READ AND ANALYZED THE COST OF CAPITAL TESTIMONY, EXHIBITS AND WORKPAPERS OF NSPM WITNESS MS. ANN E. BULKLEY?

A. Yes, I have.

Q. DO YOU DISAGREE WITH PARTS OF HER ANALYSIS AND CONCLUSIONS?

A. Yes, I do.

Q. WHICH PARTS OF HER ANALYSIS DO YOU DISAGREE WITH?

A. I disagree with her analysis and conclusions in the following areas:

- (1) The Risk Comparable sample;
- (2) The dividend yield Ms. Bulkley uses in her DCF analysis;
- (3) The growth rate estimates she used in her DCF analysis;

1 (4) The growth adjustment made to the dividend yield in her DCF analysis;

2 (5) The weight given the risk premium method and her calculation of the risk  
3 premium estimate of the cost of equity;

4 (6) The flotation adjustment applied to her recommended allowed return on equity;  
5 and

6 (7) Her evaluation of the Company's risk compared with the risk-comparable sample  
7 using the ratio of capital expenditures to net plant.

8  
9 Q. PLEASE DISCUSS YOUR MODIFICATIONS TO MS. BULKLEY'S RISK-  
10 COMPARABLE SAMPLE.

11 A. As I discussed earlier, I deleted DPL and Progress Energy from the Risk Comparable  
12 sample because they are each engaged in merger discussions, which can have a skewed  
13 impact on stock prices. I included Xcel in the in the Risk Comparable Sample since Xcel  
14 is the parent company of NSPM, and NSPM constitutes a significant portion of Xcel's  
15 earnings per share (approximately 37% in 2010). I excluded Hawaiian Electric because  
16 of its significant holdings of American Savings Bank.

17  
18 Q. PLEASE DISCUSS YOUR DIFFERENCES WITH MS. BULKLEY'S DIVIDEND  
19 YIELD.

20 A. I utilized more recent prices than did Ms. Bulkley, which were higher. This resulted in  
21 lower dividend yields for DCF purposes than Ms. Bulkley's. This does not reflect an  
22 error on the part of Ms. Bulkley, but simply reflects the fact that since Ms. Bulkley filed  
23 testimony in December, 2010, her DCF prices were based on prices from 2010, which

1 were lower than the prices I used. Nevertheless, it is appropriate to use my price terms  
2 since they are more recent.

3  
4 Q. PLEASE DISCUSS THE GROWTH RATE ESTIMATES USED BY MS. BULKLEY  
5 IN HER DCF ANALYSIS.

6 A. As discussed in her Direct Testimony (p. 17, line 8 through p. 18, line 13) she solely  
7 relied on EPS growth rate projections to estimate the investor-expected sustainable long-  
8 run growth rate in DPS. There are three general problems with relying exclusively on her  
9 approach.

10  
11 First, in the DCF method it is important to estimate sustainable long-run growth rates in  
12 DPS. No doubt, earnings growth rates are a factor in dividend growth rates, but they are  
13 not the sole factor that investors would look to in formulating their dividend growth rate  
14 expectations. As I discussed earlier, investors also look to expected dividend growth  
15 rates, expected book value growth rates, and expected earnings retention. Ms. Bulkley  
16 places entirely too much weight on short-term earnings growth rate expectations.

17  
18 Second, the earnings growth rates that she exclusively utilizes are simply not sustainable.  
19 As shown in Exhibit AEB-1, Schedule 3, page 3 of 3, the average growth rate in earning  
20 per share she uses is 6.37%. However, as I discussed earlier, a key long-term component  
21 of dividend growth is derived from growth in book value per share. Most of that growth  
22 is derived from earnings retention, or the “br” factor that I discussed earlier. As shown in  
23 my Exhibit\_\_(SKB-8), the “b” factor for the risk-comparable group is approximately

1 40%. Given that  $g$  is approximately equal to “ $br$ ”, this implies that, in the context of  
2 Ms. Bulkley’s analysis,  $6.37\% = 40\% \times r$ , or that  $r$ , the investor-expected return on  
3 equity, is  $r = 6.37\%/40\% = 15.925\%$ , or approximately 16%. There is absolutely no  
4 evidence that investors expect the utilities in the Risk Comparable sample to earn  
5 approximately 16% on a long-term sustainable basis. For example, as shown in my  
6 Exhibit\_\_(SKB-8), both historical and expected returns on equity are in the range of 9-  
7 10%, significantly less than 16%. Consequently, Ms. Bulkley’s 6.37% growth rate  
8 factor, relying exclusively on short-term EPD growth rate, is simply not sustainable, and  
9 is inappropriate for usage in the DCF method.

10  
11 Third, while Ms. Bulkley characterizes her earnings growth estimates as long-term, they  
12 are not. The *Value Line* earnings growth rate estimates are for approximately seven  
13 years, and the Zach’s and First Call estimates are for approximately five years. Utility  
14 EPS are more volatile than DPS and BVPS. Consequently, EPS *growth* rates are a lot  
15 more volatile than DPS and BVPS growth rates. As I have pointed out earlier, the growth  
16 rates appropriate for usage in the DCF method are long-term in nature. In the  
17 determination of the price in the DCF method, only about 20% to 30% of the market  
18 price is determined by the dividends in the first 5 to 7 years. Ms. Bulkley neglects the  
19 remaining 70% to 80% of future dividends that determine the market price and fails to  
20 consider investor’s long-term growth rate expectations. To base long-term investor  
21 growth rate expectations exclusively on short term growth rates, as Ms. Bulkley did, is  
22 inappropriate.

1 Q. PLEASE DISCUSS YOUR DISAGREEMENT WITH MS. BULKLEY'S GROWTH  
2 RATE ADJUSTMENT TO THE DIVIDEND YIELD.

3 A. Ms. Bulkley adjusted the dividend yield by a factor of " $1 + g/2$ ". To better reflect the fact  
4 that dividends are paid quarterly, I prefer that an adjustment factor of " $1 + g/4$ " be  
5 applied. In my opinion, Ms. Bulkley's adjustment leads to a small over-estimate of the  
6 DCF cost of equity.

7

8 Q. PLEASE DISCUSS MS. BULKLEY'S RISK PREMIUM ANALYSIS.

9 A. I have two problems with her risk premium analysis. First, the level of the risk premium  
10 is not only dependent upon the level of interest rates, but other factors as well. As I show  
11 in my article in *Managerial and Decision Economics*, attached as Exhibit—(SKB-9),  
12 interest rate variability correlates negatively with risk premia, and there is a general  
13 trending down in risk premia over time. Consequently, it is my opinion that the risk  
14 premium method is at best difficult to properly apply, and is just not reliable because of  
15 the instability of risk premia. Ms. Bulkley's risk premium conclusions should be  
16 accorded no weight by this Commission.

17

18 Second, even if the Commission were to accord some weight to the risk premium  
19 method, Ms. Bulkley has utilized speculative interest rate inputs into her risk premium  
20 analysis. Part of her analysis uses 2012-2021 projections of 30-year Treasury bond yields  
21 of 5.80 per cent. That interest rate assumption is entirely speculative, and does not reflect  
22 current market conditions. For example, the average of the 30-year Treasury bond yields  
23 for the period January, 2011 through June, 2011 is 4.45%. If we apply that Treasury

1 Bond yield to my risk premium equation in the article mentioned, the resultant risk-  
2 premium based cost of equity is approximately 10.25%. If we apply that Treasury Bond  
3 yield to her revised risk premium equation, the risk-premium based cost of equity is  
4 approximately 10.6%. Both of these are toward the top end on my cost of equity range.  
5 Note that I make these calculations for the benefit of the Commission, if it accords some  
6 weight to the risk premium method.

7  
8 Q. PLEASE DISCUSS MS. BULKLEY'S ANALYSIS OF THE RATIO OF PROJECTED  
9 CAPITAL EXPENDITURES TO NET PLANT?

10 A. On pp. 28-32 of her Direct Testimony she makes the claim that NSPM's ratio of  
11 projected capital expenditures to net plant is significantly greater than the corresponding  
12 ratios for the Risk Comparable sample, and that because of that an allowed return on  
13 equity toward the upper end of the range of results is appropriate.

14  
15 However, she is focusing on just one risk factor that investors are aware of in evaluating  
16 their risk expectations of NSPM. In fact, there is a myriad of risk factors that investors  
17 will consider. For example, investors consider:

- 18 (1) Macroeconomic conditions, both national and regional such as inflation rates,  
19 unemployment rates, Gross Domestic Product growth rates, and interest rates;  
20 (2) Financial or regulatory accounting principles or policies imposed by the  
21 Financial Accounting Standards Board, the SEC, the Federal Energy  
22 Regulatory Commission, and similar entities with regulatory oversight;  
23 (3) Changes in tax laws;

- 1 (4) Unusual, severe, or catastrophic weather conditions, which may simply be
- 2 weather-induced decreases in usage, or storm-induced repairs to utility
- 3 infrastructure;
- 4 (5) Unscheduled generation or transmission outages, maintenance, or repair;
- 5 (6) Unanticipated changes to fossil fuel, nuclear fuel, or natural gas supply costs,
- 6 or unavailability due to higher demand, shortages, transportation problems or
- 7 other developments;
- 8 (7) Nuclear or environmental incidents;
- 9 (8) Costs associated with the storage of spent nuclear fuel;
- 10 (9) Adequate funding of nuclear decommissioning trust funds;
- 11 (10) Electric transmission or natural gas pipeline constraints;
- 12 (11) Employee workforce factors, such as collective bargaining agreements
- 13 with unions;
- 14 (12) Changes in environmental laws and regulations, including regulations
- 15 related to carbon charges;
- 16 (13) Customer business conditions, including the percentage of load accounted
- 17 for by business cycle sensitive industrial load;
- 18 (14) Conservation by customers;
- 19 (15) Nuclear regulatory policies and procedures;
- 20 (16) Credit risk associated with customers that do not pay their bills and
- 21 counterparties that owe money or product and breach their obligations;
- 22 (17) Risks associated with funding of defined benefit pensions and post-
- 23 retirement plans for employees;

1 (18) Increasing costs associated with health care plans; and

2 (19) Regulatory risk and regulatory lag.

3

4 Q. DOES THIS ARRAY OF RISK FACTORS IMPLY THAT ADJUSTMENTS SHOULD  
5 BE MADE TO YOUR DCF BASED COST OF EQUITY?

6 A. No, it does not. The common stock market price terms in the Risk Comparable sample  
7 implicitly reflect investor-evaluations of these risk factors. To the extent investors are  
8 concerned with these risk factors, the stock market price terms will be correspondingly  
9 lower and reflected in a greater dividend yield.

10

11 Consequently, Ms. Bulkley's implicit argument that investors focus disproportionately on  
12 the ratio of capital expenditures to net plant is fallacious, and should be accorded no  
13 weight by this Commission.

14

15 However, I should point out that regulatory lag looms large for investors and has an  
16 indirect bearing on most of the factors listed above. For example, if health care costs  
17 increase, regulatory lag associated with recovering those increases in health care costs  
18 will, other things being equal, increase a Company's risk and cost of equity.  
19 Consequently, any diminishing of regulatory lag will, other things being equal, decrease a  
20 Company's risk and cost of equity.

21

22 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

23 A. Yes, it does.

## **S. KEITH BERRY**

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### **CURRENT POSITIONS**

---

*Professor, Department of Economics and Business  
Hendrix College, 2002-Present*

*Vice President  
Economic & Financial Consulting Group, Inc., 1990-Present  
Conway, AR 72032*

### **EDUCATION**

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*Ph.D., Economics  
Vanderbilt University, 1979*

*B.A., Mathematics  
Hendrix College, 1973*

### **PREVIOUS POSITIONS**

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*Director, Center for Entrepreneurial Studies  
Hendrix College, 2001-2007*

*Chair, Department of Economics and Business –Supervisor of five faculty  
Hendrix College, 2003-05*

*Associate Professor of Economics and Business  
Hendrix College, 1994-2002*

*Assistant Professor of Economics and Business  
Hendrix College, 1989-1994*

*Director of Research and Policy Development-Supervisor of six policy analysts  
Arkansas Public Service Commission, Little Rock, AR, 1986-1989*

*Manager of Rates and Finance Sections*-Supervisor of six rate and financial analysts  
Arkansas Public Service Commission, Little Rock, AR, 1979-1986

*Instructor/Assistant Professor of Economics and Business*  
Hendrix College, Conway, AR, 1977-1979

*Instructor*  
Vanderbilt University, 1976-77

## **COURSES TAUGHT**

Principles of Micro  
Principles of Macro  
Industrial Organization  
Environmental Economics  
Money, Banking and Credit  
Intermediate Micro  
Intermediate Macro  
International Economics  
Principles of Statistics  
Intermediate Statistics  
Western Intellectual Traditions

## **CURRENT AND PAST CONSULTING ACTIVITIES WITH THE ARKANSAS PUBLIC SERVICE COMMISSION**

I have been retained as a consultant and expert witness by the Arkansas Public Service Commission continuously since 1990. In that capacity, I have advised the Arkansas Commission, and filed testimony on behalf of the Arkansas Commission, on the following subjects:

- (1) Regional Transmission Organizations;
- (2) Independent Coordinator of Transmission;
- (3) Locational marginal pricing;
- (4) Resource Planning;
- (5) Mergers;
- (6) National Interest Electric Transmission Corridors;
- (7) Transmission Planning
- (8) Standard Market Design;
- (9) Demand Side Resources;
- (10) System Pooling Agreements;
- (11) Stranded Costs;
- (11) FERC Rulemaking on Transmission Issues;

- (13) Fuel Adjustment Clauses;
- (14) Interruptible Rates;
- (15) Avoided Cost Pricing;
- (16) Nuclear decommissioning rates;
- (17) Retail electric utility rate cases;
- (18) Gas Distribution utility rate cases.

## **TESTIMONY OR REPORTS PRESENTED TO COMMISSIONS OR AGENCIES**

*Federal Energy Regulatory Commission, Docket No. ER10-2001.* Testimony concerning depreciation expense used in bandwidth calculations. April, 2011.

*Federal Energy Regulatory Commission, Docket No. ER10-1350.* Testimony concerning bandwidth calculations. December, 2010-January, 2011.

*Federal Energy Regulatory Commission, Docket No. EL10-55-000.* Testimony concerning depreciation expense used in bandwidth calculations. October, 2010.

*Federal Energy Regulatory Commission, Docket No. EL09-1224-000.* Testimony concerning 2009 bandwidth calculations for Entergy Operating Companies. January and February, 2010.

*Connecticut Department of Public Utility Control.* Participation in task force that performed a Management Audit of the Connecticut Light & Power Company, May, 2009.

*Federal Energy Regulatory Commission, Docket No. ER09-636-000.* Affidavit concerning Entergy Arkansas notice of intent to withdraw from the Entergy System Agreement, April, 2009.

*Federal Energy Regulatory Commission, Docket No. EL08-51-000.* Testimony concerning recovery of Spindletop regulatory asset in 2008 bandwidth remedy. February, 2009.

*Federal Energy Regulatory Commission, Docket No. ER08-1056-000.* Testimony concerning inclusion of certain Evangeline gas costs in 2008 bandwidth calculations for Entergy, January, 2009.

*Federal Energy Regulatory Commission, Docket No. ER08-1056-000.* Affidavit on 2008 bandwidth remedy on Entergy System. July 2008.

*Federal Energy Regulatory Commission, Docket No. ER07-956-000.* Testimony concerning Entergy System Agreement 2007 bandwidth effects of imprudence and depreciation, February-March, 2008.

*Federal Energy Regulatory Commission, Docket No. EC07-70-000.* Affidavit concerning Entergy acquisition of Calcasieu Power, LLC.

*Maryland Public Service Commission, Case No. 9062.* Testimony concerning the cost of capital of Chesapeake Utilities Corporation, August, 2006.

*Federal Energy Regulatory Commission, Docket No. EL06-76-000.* Affidavit in Complaint by APSC concerning production costs on the Entergy System, April, 2006.

*Federal Energy Regulatory Commission, Docket No. ER03-583-000, et al.* Testimony concerning purchased power agreements on Entergy System, November, 2003.

*Federal Energy Regulatory Commission, Docket No. ER03-753-000.* Testimony concerning unit power rate schedule on Entergy System, November, 2003.

*Federal Energy Regulatory Commission, Docket No. EL01-88-000.*  
Testimony opposing production cost equalization on the Entergy System, March, 2003, April, 2003, and July, 2003.

*Securities and Exchange Commission, File No. 70-9785,* Affidavit concerning issues associated with exempt wholesale generators for American Electric Power, September, 2002.

*Federal Energy Regulatory Commission, Docket No. EL01-88-000.*  
Affidavit opposing production cost equalization on the Entergy System, July, 2001.

*Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.*  
Affidavit concerning production cost equalization on the Entergy System, May, 2001.

*State of Arkansas General Assembly,* Testimony concerning HB 1411 regarding funding of the White River Navigation Project, January, 2001.

*Federal Energy Regulatory Commission, Docket Nos. EL00-66-000 et al.*  
Testimony concerning modification of Entergy System Agreement to accommodate deregulation and interruptible rates, December, 2000, January, 2001, and February, 2001.

*Federal Energy Regulatory Commission, Docket Nos. EL98-40-000 et al.*  
Testimony concerning the merger of American Electric Power and Central and South West, May, 1999 and June, 1999.

*Federal Energy Regulatory Commission, Docket No. EC99-18-000*  
Affidavit concerning the proposed acquisition of Pilgrim Nuclear Unit by Entergy Corporation, January, 1999.

- Securities and Exchange Commission, File No. 70-9049*  
Affidavit concerning financial risk of diversification of Entergy Corporation, October, 1998.
- Arkansas Public Service Commission, Docket No. 98-081-TF*  
Testimony concerning off-peak rates, March, 1998.
- "Report on the Cost of Equity of New York Power Authority,"* December, 1997.
- State of Arkansas General Assembly*  
Economic Policy Analysis of Telecommunications Reform Act of 1997, January, 1997.
- Securities and Exchange Commission, File No. 70-8725*  
Affidavit concerning financial risk of diversification of Southern Company, October, 1996 and January, 1997.
- Federal Energy Regulatory Commission, Docket No. ER95-53-000*  
Testimony concerning the equalization of nuclear decommissioning costs of Entergy, October, 1996.
- Securities and Exchange Commission, File No. 70-8809*  
Affidavit concerning financial risk of diversification of Central and Southwest. May, 1996.
- "Report on the Cost of Equity of New York Power Authority,"* January, 1996.
- Federal Energy Regulatory Commission, Docket No. ER95-1042-000*  
Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources, October, 1995.
- Federal Energy Regulatory Commission, Docket No. ER95-53-000*  
Affidavit concerning nuclear decommissioning cost equalization on the Entergy System. June, 1995.
- "Report on the Development of Electric Utility and Railroad Comparable Samples for the Tax Division of the Arkansas Public Service Commission,"* February, 1995.
- Federal Energy Regulatory Commission, Docket No. EL94-13-000*  
Testimony concerning the merger of Entergy and Gulf States Utilities. October, 1994.
- Arkansas Public Service Commission, Docket No. 94-355-U*  
Testimony concerning the cost of capital of Louisiana-Nevada Transit. October, 1994.
- Oklahoma Corporation Commission, PUD 940000354*  
Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. July, 1994.

*Arkansas Public Service Commission, Docket No. 94-175-U*

Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. June, 1994.

*Securities and Exchange Commission, File No. 70-8339*

Affidavit concerning the merger of Central and Southwest and El Paso Electric. April, 1994.

*Federal Energy Regulatory Commission, Docket Nos. EC94-7-000 and ER94-898-000*

Testimony concerning the merger of Central and Southwest and El Paso Electric. February, 1994.

*Arkansas Public Service Commission, Docket No. 93-081-U*

Testimony concerning the cost of debt of Arkansas Louisiana Gas Co. October, 1993.

*Federal Energy Regulatory Commission, Docket Nos. EC92-21-000 and ER92-806-00*

Testimony concerning the merger of Entergy and Gulf States Utilities. March, 1993.

*Federal Energy Regulatory Commission, Docket Nos. ER92-341-000, EL92-35-000, and EL92-36-000*

Testimony concerning the cost of capital of System Energy Resources. December, 1992.

*Securities and Exchange Commission, File No. 70-8059*

Affidavit concerning the merger of Entergy and Gulf States Utilities. November, 1992.

*Oklahoma Corporation Commission, PUD 0001317*

Testimony concerning the cost of capital and a weather normalization adjustment clause for Arkansas Louisiana Gas Co. May, 1992.

*Kansas Corporation Commission, Docket No. 181,200-U*

Testimony concerning the cost of capital and a weather normalization adjustment clause for Arkansas Louisiana Gas Co. May, 1992.

*Arkansas Public Service Commission, Docket No. 92-032-U*

Testimony concerning a weather normalization adjustment clause for Arkansas Louisiana Gas Co. February, 1992.

*Arkansas Public Service Commission, Docket No. 89-143-C*

Testimony concerning franchise fee or tax on AT&T in the City of Little Rock. January, 1992.

*Federal Energy Regulatory Commission, Docket No. EL90-48-000*

Testimony concerning the spin-off of a coal unit on the Entergy System. January, 1992.

*Arkansas State Banking Commission*

Economic and Financial Report on the Feasibility of the Proposed First Community Bank,

Conway, Arkansas (prepared by Economic & Financial Consulting Group, Inc.), May, 1991

*Arkansas Public Service Commission, Docket No. 90-133-U*

Testimony concerning non-traffic sensitive costs on telephone systems. November, 1990.

*Federal Energy Regulatory Commission, Docket Nos. ER89-678-000 and EL90-16-000*

Testimony concerning the cost of capital and nuclear decommissioning of System Energy Resources. November, 1990

*Arkansas Public Service Commission, Docket No. 90-004-U*

Testimony concerning the capital structure of Arkansas Western Gas Co. October, 1990.

*Arkansas Public Service Commission, Docket No. 88-115-TF*

Testimony concerning phase-in plan for Arkansas Power and Light Co. September, 1988.

*Arkansas Public Service Commission, Docket No. 87-201-U*

Testimony concerning the cost of capital of GTE Southwest, Inc. August, 1988.

*Arkansas Public Service Commission, Docket No. 87-166-TF*

Testimony concerning nuclear decommissioning trust fund of Arkansas Power and Light Co. January, 1988.

*Arkansas Public Service Commission, Docket No. 87-070-U*

Testimony concerning the cost of capital of Arkansas Louisiana Gas Co. September, 1987.

*Arkansas Public Service Commission, Docket No. 87-071-U*

Testimony concerning the cost of capital of Arkansas Energy Resources. August, 1987.

*Federal Energy Regulatory Commission, Docket Nos. EL86-58-000 and EL86-59-000*

Testimony concerning the cost of capital of System Energy Resources, Inc. and Middle South Services. March, 1987

*Arkansas Public Service Commission, Docket No. 87-028-U*

Testimony concerning a preferred stock issuance by Arkla. March, 1987.

*Arkansas Public Service Commission, Docket No. 84-165-U*

Testimony concerning the cost of capital of Southwestern Bell. February, 1987.

*Arkansas Public Service Commission, Docket No. 86-243-TF*

Testimony concerning incentive rates for Arkansas Power and Light Co. January, 1987.

*Securities and Exchange Commission, File No. 70-7299*

Affidavit concerning a preferred stock issuance by System Energy Resources. December,

1986.

*Arkansas Public Service Commission, Docket No. 86-175-TF*

Testimony concerning incentive rates for Arkansas Power and Light Co. September, 1986.

*Arkansas Public Service Commission, Docket No. 86-147-TF*

Testimony concerning a tax adjustment rider for Arkansas Power and Light Co. August, 1986.

*Arkansas Public Service Commission, Docket No. 86-112-TF*

Testimony concerning seasonally differentiated rates of Arkansas Power and Light Co. June, 1986.

*Arkansas Public Service Commission, Docket No. 86-090-U*

Testimony concerning gas transportation policy. June, 1986.

*Arkansas Public Service Commission, Docket No. 85-299-U*

Testimony concerning cost allocations between customer classes on Arkansas Power and Light Co. February, 1986.

*Arkansas Public Service Commission, Docket No. 84-249-U*

Testimony concerning the cost of capital, incentive rates, and phase-in plan for Arkansas Power and Light Co. May, 1985.

*Arkansas Public Service Commission, Docket No. 85-104-TF*

Testimony concerning interruptible incentive rates for Arkansas Power and Light Co. May, 1985.

*Arkansas Public Service Commission, Docket No. 85-043-U*

Testimony concerning a rate freeze for Arkansas Louisiana Gas Co. February, 1985.

*Arkansas Public Service Commission, Docket No. 84-084-U*

Testimony concerning cost allocations and phase-in plan for Arkansas Electric Cooperative Corporation. September, 1984.

*Arkansas Public Service Commission, Docket No. 84-199-U*

Testimony concerning the cost of capital, rate design, and class cost allocations for Arkansas Power and Light Co. September, 1984.

*Arkansas Public Service Commission, Docket No. F-007*

Testimony concerning fuel and gas adjustment clauses. May, 1984.

*Arkansas Public Service Commission, Docket No. 83-161-U*

Testimony concerning the cost of capital and replacement cost pricing for Arkansas

Louisiana Gas Co. March 1984.  
*Arkansas Public Service Commission, Docket No. 83-253-U*  
Testimony concerning the cost of capital of AT&T. January, 1984.

*Arkansas Public Service Commission, Docket No. 83-153-U*  
Testimony concerning the cost of capital of Allied Telephone Co. December, 1983.

*Arkansas Public Service Commission, Docket No. 83-206-U*  
Testimony concerning a rate reduction for Arkansas Power and Light. December, 1983

*Arkansas Public Service Commission, Docket No. 83-045-U*  
Testimony concerning the cost of capital and customer stock purchase plan on Southwestern Bell. September, 1983.

*Arkansas Public Service Commission, Docket No. 81-104-AP-2*  
Testimony concerning nuclear fuel negative salvage costs of Arkansas Power and Light Co. July, 1983.

*Arkansas Public Service Commission, Docket No. 82-314-U*  
Testimony concerning the cost of capital and customer stock purchase plan on Arkansas Power and Light Co. April, 1983.

*Federal Energy Regulatory Commission, RM-80-36-000*  
Comments concerning a generic rate of return. December, 1982.

*Illinois Commerce Commission, Docket No. 82-0152*  
Testimony concerning the cost of capital of Illinois Power Co. July, 1982.

*Arkansas Public Service Commission, Docket No. 81-260-U*  
Testimony concerning the rate of return of Arkansas Electric Cooperative Corporation. June, 1982.

*Arkansas Public Service Commission, Docket No. 82-037-U*  
Testimony concerning the cost of capital for Southwestern Bell. May, 1982.

*Arkansas Public Service Commission, Docket No. 81-349-U*  
Testimony concerning the cost of capital of Associated Natural Gas Co. April, 1982.

*Arkansas Public Service Commission, Docket No. TD-80-06*  
Testimony concerning overall capitalization rate. November, 1981.

*Arkansas Public Service Commission, Docket No. 81-161-U*  
Testimony concerning the cost of capital of Oklahoma Gas and Electric. October, 1981.

*Arkansas Public Service Commission, Docket No. 81-144-U*

Testimony concerning the cost of capital and nuclear decommissioning trust funds for Arkansas Power and Light Co. September, 1981.

*Arkansas Public Service Commission, Docket No. U-3136*

Testimony concerning the cost of capital of Southwestern Electric Power Co. April, 1981.

*Arkansas Public Service Commission, Docket No. U-3117*

Testimony concerning an econometric model for directory assistance for Southwestern Bell Co. April, 1981.

*Arkansas Public Service Commission, Docket No. U-3071*

Testimony concerning the rate of return and an econometric model of demand for Arkansas Electric Cooperative Corp. July, 1980.

*Arkansas Public Service Commission, Docket No. U-3089*

Testimony concerning the rate of return of North Arkansas Telephone Cooperative. July, 1980.

*Arkansas Public Service Commission, Docket No. U-3096*

Testimony concerning the cost of capital of United Telephone Co. March, 1980.

*Arkansas Public Service Commission, Docket No. U-3052*

Testimony concerning the cost of capital of Associated Natural Gas Co. March, 1980.

*Arkansas Public Service Commission, Docket No. U-3036*

Testimony concerning the cost of capital of United Telephone Co. November, 1979.

## **HONORS AND AWARDS**

---

*Wincott Visiting Research Fellowship*

University of Buckingham, United Kingdom, Fall, 1997

*Earhart Fellowship (with Nicholas Georgescu-Roegen)*

Vanderbilt University, 1975-1976

*Graduate School Assistantship*

Vanderbilt University, 1973-1976

*Mosley Economics Award*

Hendrix College, 1973

*Hogan Math Award*  
Hendrix College, 1972

*Alpha Chi (scholastic),*  
Hendrix College

*Rensselaer Math and Science Award, 1968*

## **PUBLICATIONS**

---

"Sub-Optimal Generation Portfolio Variance with Rate of Return Regulation," *Technology and Investment*, 1, 2010, pp. 114-17.

"Firm Incentives for Invention Prizes With Multiple Winners," *Eastern Economic Journal*, 32, 2006, pp. 83-95.

"Generation Search Costs and Ramsey Pricing in a Partially Deregulated Electric Utility Industry," *Journal of Economics and Business*, 54, 2002, pp. 331-343.

"Substitution Between Bundled and Unbundled Products After Deregulation in Electricity Generation," *Eastern Economic Journal*, 26, 2000, pp. 455-68.

"Stranded Costs, Access Charges, and Ramsey Pricing in the U.S. Electric Utility Industry," *The Quarterly Review of Economics and Finance*, 40, 2000, pp. 503-17.

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"Interest Rate Risk and Utility Risk Premia During 1982-93," *Managerial and Decision Economics*, 19, 1998, pp. 127-35.

"Asymmetric Demand Information in Regulation," *Studies in Economics and Finance*, 18, 1998, pp. 129-41.

"Utility Mergers and the Cost of Capital," *Journal of Financial and Strategic Decisions*, 11, 1998, pp. 73-82.

"Interest Rate Risk and Utility Bond and Dividend Yields," *Advances in Investment Analysis and Portfolio Management*, Volume III, 1995, pp. 183-191.

"Rent-Seeking With Multiple Winners," *Public Choice*, 8, 1993, pp. 437-43.

"A Risk-Adjusted Approach for Assessing Factors that Determine Utilities' Allowed Returns on Equity," (with Timothy Mason), *The Review of Industrial Organization*, 8, 1993, pp. 113-23.

"Ramsey Pricing in the Presence of Risk," *Managerial and Decision Economics*, March-April, 1992, pp. 111-17.

"The Impact of Consumers on the Dissipation of Rents," *Eastern Economic Journal*, July-September, 1991, pp. 345-49.

"Expected Rate Minimization and Excess Capacity in Regulated Utilities," *The Quarterly Review of Economics and Business*, Volume 30, Number 3, Fall 1990, pp. 85-95.

"Flotation Cost Allowance Methodologies: A Synthesis Using Present Value Analysis," *The Financial Review*, Volume 25, Number 3, August, 1990, pp.487-500.

"The Allocation of Risk Between Stockholders and Ratepayers in Regulated Utilities," *Land Economics*, Volume 64, Number 2, May, 1988, pp. 114-24.

"Rate-of-Return Regulation and Demand Uncertainty with a Symmetric Regulatory Constraint," *The American Economist*, Fall, 1987, pp. 8-12.

"The Relevance of Quasi Rationality in Competitive Markets: Comment," *American Economic Review*, Volume 77, Number 3, June, 1987, pp. 496-8.

"The Ratepayer and Stockholder under Alternative Regulatory Policies: Comment," *Land Economics*, Volume 63, Number 2, May, 1987, pp. 201-5.

"The Impact of Nuclear Power Plant Construction Activity on the Electric Utility Industry's Cost of Capital," (with Samuel Loudenslager), *The Energy Journal*, Volume 8, Number 2, April, 1987, pp. 63-75.

"When is Excess Capacity Desirable?" *New Regulatory and Management Strategies in a Changing Market Environment*, Institute of Public Utilities, 1987, pp. 358-371.

"Random Pseudo-Disturbance Generators in a Stochastic Simulation of an Econometric Model,"(with Cliff Huang), *Journal of Statistical Computation and Simulation*, Vol.22, Nos. 3 and 4, pp. 285-302.

"The Quarterly Cost of Equity: Implications for Setting the Annual Return on Equity," *Electric Ratemaking*, Volume 2, Number 2, April/May, 1983, pp.8-10.

Book Review of *Issues in Public-Utility Pricing and Regulation*, edited by Michael A. Crew, Lexington, Mass.: D.C. Heath & Co., 1980, in *Southern Economic Journal*, Volume 48, Number 4, April, 1982, pp. 1112-3.

"The Discounted Cash Flow Formula: Validation and Estimation," *Proceedings of the Second NARUC Biennial Regulatory Information Conference*, pp.397-400.

## **WORKING PAPERS**

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"A Comparison of Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions"

"Pay-as-Bid and Market-Clearing-Price Bidding Processes in Electric Utility Auctions with Merchants' Risk Preference"

"Sub-Optimal Generation Portfolio Variance with Rate of Return Regulation"

"Collusion in Rent-Seeking With Decreasing Returns to Scale"

## **PRESENTATIONS**

---

"Offer Curve Behavior for Merchant Plants in Electric Utility Regional Transmission Organizations", 2005 Southern Economics Association Meetings, Washington, D.C.

"Deans, Teams, and Faculty Dreams: Cooperation in Hard Work," Speaker, Session at 57<sup>th</sup> Annual Meeting of the American Conference of Academic Deans, New Orleans, January, 2001.

"Changes in Risk in Electric Utility Mergers During Transition to Competition", 1999 Southern Economic Association Convention.

"Stranded Cost in the U.S. Electric Utility Industry: Last Gasp of Ramsey Pricing?" Discussion Paper, Wincott Series, University of Buckingham, United Kingdom, December, 1997.

"Interest Rate Risk and Utility Risk Premia During 1982-93," 1994 Southern Economic Association Convention.

"Interest Rate Risk and Utility Bond and Dividend Yields," 1992 Western Economic Association Convention.

"Scaling Up Nuclear Decommissioning Costs," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1992.

"Assessing Factors That Determine Utilities' Allowed Returns on Equity: A Risk-Adjusted

Institutional Approach," (with Timothy Mason), 1989 Southern Economic Association Convention.

"The Grand Gulf Experience," Sixty-Fifth National Conference of Regulatory Utility Commission Engineers, Hot Springs, AR, 1987.

"Some Fundamental Principles in the Determination of a Utility's Cost of Capital," Seventh Annual Western Utility Rate Seminar, Salt Lake City, Utah, 1987.

"A Critique of Various Phase-in Plans," NARUC Advanced Regulatory Studies Program, Williamsburg, VA, 1986.

"Principles in the Determination of a Utility's Cost of Capital," Thirteenth Annual Eastern NARUC Utility Rate Seminar, Ft. Lauderdale, Florida, 1985.

"Nuclear Unit Construction and Electric Utilities' Cost of Capital," Western Economic Association Convention, 1984.

"Current Issues in Utility Regulation," Fifth Annual Seminar Series, Hendrix College, 1984.

"The Economics of Two-Part Rate Structures for Regulated Utilities," Midwest Economics Association Convention, 1981.

## **COLLEGIATE SERVICE**

Chair, Department of Economics and Business. While Chair I led the Department in the development of an International Business Minor. This will be a precursor to an International Business Major.

Director, Center for Entrepreneurial Studies, Hendrix College, 2001-Present. I obtained \$200,000 in external funding for the Center's start-up. The Center brought Secretary of Commerce Don Evans, former Secretary of HUD Jack Kemp, and former Council of Economic Advisors Chair Dr. Glenn Hubbard to speak to the Hendrix campus. Additionally, the Center sponsored a number of Business Roundtables where local businesspeople spoke to Hendrix students. In 2004, the Center provided supervision for a Hendrix Team that was a semi-finalist in the Arkansas Governor's Business Plan Competition.

Faculty Advisor, Phi Beta Lambda, the Collegiate Division of Future Business Leaders of America, 2002-Present

Chair, Committee on Curriculum, Hendrix College, 1998-2002. Responsible for development of new General Education Requirements as Hendrix moved from a trimester calendar to a semester calendar

Member of Search Committee for Provost for Hendrix College, 2002

Member of Faculty Committee that assisted in the writing of a \$3.9 million grant to Hendrix College from the Robert & Ruby Priddy Charitable Trust, 2002

Hendrix College Alumni Association Board of Governors Awards Committee, 1999-2000

Chair, Committee on Student Life, Hendrix College, 1995-96

## **OTHER EXPERIENCE**

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Presentation on China Odyssey III at Conway Rotary Club, November, 2007

“Symposium on Business and the Liberal Arts: Integrating Professional and Liberal Education,” Sponsored by the Council of Independent Colleges, Chicago, IL, May, 2007.

Member, eSTEM Public Charter Schools, Inc. Board of Directors, Little Rock, AR, 2007-Present

Discussant at 2005 American Economics Association/TPUG Session.

Chair, Finance Committee, Trinity United Methodist Church, 2005-06, Little Rock, AR.

Reviewer for *Quarterly Review of Economics and Finance*, *Eastern Economic Journal*, *Journal of Economic Surveys*, *Contemporary Economic Policy*, *Economics and Politics*, *Land Economics*, *The American Economist*, *Managerial and Decision Economics*, *International Journal of Energy Systems*, *Journal of Economics and Business*, and *IEEE PES Transactions on Power Systems*

Blue Ribbon Panel, advice to Frueauff Foundation concerning modification of its investment objectives, 2003

Discussant at 2001 Southern Economics Association Convention

“Report on the Economic Feasibility of the White River Navigation Project,” February, 2000

Member, Board of the Arkansas Policy Foundation, 1999-Present

“The Democratization of Capitalism on Wall Street,” *Log Cabin Democrat*, Conway, Arkansas, June 7, 1999

Panelist on Governor's Economic Summit, Roundtable on Tax and Regulatory Policy, June 9-10, 1998, Little Rock, AR

"Taxes and Savings in Arkansas," Murphy Commission Report, May, 1998

"Feasibility Analysis of the Formation of a Local Electric Utility in Batesville and Independence County," with Mike Hughes and W.W. Elrod, II, April, 1998

Discussant at 1999 Southern Economics Association Convention

Discussant at 1996 Western Economics Association Convention

Discussant at 1994 Southern Economics Association Convention

Discussant at 1993 Southern Economics Association Convention

Participant on judges' panel for selection of outstanding Arkansas businesses and executives in 1988  
*for Arkansas Business*

Lecturer, Business Leaders Day, 1988, University of Arkansas, Fayetteville, Arkansas

Research Advisory Committee, National Regulatory Research Institute, 1986-1989, Deputy Chairman (1988-1989)

Subcommittee on Electricity, National Association of Regulatory Utility Commissioners, 1987-1989

Subcommittee on Economics, National Association of Regulatory Utility Commissioners, 1979-1987

## **PROFESSIONAL ORGANIZATIONS**

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American Economics Association  
Southern Economics Association

CAPITAL PROPORTIONS AND OVERALL COST OF CAPITAL

Capital Component	Amount (\$000's)	Proportion	Cost	Weighted Cost
Long-Term Debt	\$3,399,494	46.293%	6.07%	2.81%
Short-Term Debt	\$83,926	1.143%	2.06%	0.02%
Common Equity	\$3,859,990	52.564%	9.55%	5.02%
Total	\$7,343,410	100.000%		<b>7.85%</b>

DCF GROWTH RATES

Company	g1	g2	g3	g4	g5	g6	g7
AEP	3.57%	4.55%	3.50%	4.00%	3.90%	4.79%	3.96%
CLECO	6.83%	7.61%	8.00%	7.00%	3.00%	4.04%	6.04%
Great Plains Energy	-2.17%	3.68%	6.00%	13.00%	13.00%	2.17%	2.56%
IDACORP	5.02%	4.33%	5.50%	4.00%	4.00%	5.01%	5.83%
NextEra Energy	8.51%	8.47%	5.00%	6.40%	6.83%	6.40%	7.96%
Pinnacle West	3.10%	1.76%	6.00%	6.80%	5.50%	3.85%	3.73%
Portland General	7.77%	2.42%	3.00%	9.60%	5.75%	3.85%	3.67%
Southern Co.	4.32%	5.76%	5.00%	5.10%	5.32%	6.23%	5.18%
Westar Energy	4.47%	3.94%	8.50%	8.00%	10.00%	4.49%	2.93%
Xcel Energy	4.65%	4.41%	5.50%	NA	NA	4.52%	4.08%

STOCK PRICES AND DIVIDEND YIELDS

Company	Dec. 2010 Hi Price	Dec. 2010 Lo Price	Jan. 2011 Hi Price	Jan. 2011 Lo Price	Feb. 2011 Hi Price	Feb. 2011 Lo Price	Mar. 2011 Hi Price	Mar. 2011 Lo Price	Apr. 2011 Hi Price	Apr. 2011 Lo Price	May. 2011 Hi Price	May. 2011 Lo Price	Average Price	Quart. Dividend	Dividend Yield
AEP	\$36.47	\$34.92	\$36.92	\$35.19	\$36.07	\$34.96	\$36.37	\$33.47	\$36.56	\$34.37	\$38.99	\$36.07	\$35.86	\$0.46	5.13%
CLECO	\$31.22	\$30.05	\$31.83	\$30.56	\$32.65	\$31.05	\$34.51	\$31.93	\$35.64	\$33.91	\$35.66	\$33.73	\$32.73	\$0.28	3.42%
Great Plains Energy	\$19.73	\$18.79	\$20.14	\$19.10	\$21.14	\$18.97	\$20.19	\$18.90	\$20.74	\$19.58	\$21.21	\$20.04	\$19.88	\$0.21	4.18%
IDACORP	\$37.76	\$36.57	\$38.72	\$36.53	\$38.37	\$37.12	\$38.30	\$36.14	\$39.39	\$37.65	\$40.38	\$37.97	\$37.91	\$0.30	3.17%
NextEra Energy	\$52.49	\$50.25	\$54.73	\$51.54	\$55.55	\$53.70	\$55.86	\$52.04	\$57.00	\$54.28	\$58.98	\$56.34	\$54.40	\$0.55	4.04%
Pinnacle West	\$41.99	\$40.15	\$42.26	\$40.71	\$42.42	\$40.70	\$44.07	\$41.23	\$43.47	\$41.93	\$45.64	\$43.54	\$42.34	\$0.53	4.96%
Portland General	\$22.65	\$21.34	\$22.63	\$21.64	\$23.45	\$22.42	\$24.00	\$23.00	\$25.00	\$23.30	\$26.00	\$24.73	\$23.35	\$0.27	4.54%
Southern Co.	\$38.49	\$37.43	\$38.79	\$37.55	\$38.19	\$37.05	\$38.62	\$36.51	\$39.05	\$37.43	\$40.87	\$38.85	\$38.24	\$0.47	4.94%
Westar Energy	\$25.52	\$24.50	\$26.07	\$25.04	\$26.35	\$25.32	\$26.60	\$25.12	\$27.23	\$25.58	\$27.98	\$26.66	\$26.00	\$0.32	4.92%
Xcel Energy	\$23.89	\$23.19	\$24.14	\$23.26	\$24.00	\$23.40	\$24.67	\$23.17	\$24.37	\$23.28	\$25.39	\$24.10	\$23.91	\$0.26	4.35%

DCF COST OF EQUITY ESTIMATES

Company	k1	k2	k3	k4	k5	k6	k7
AEP	8.75%	9.73%	8.68%	9.18%	9.08%	9.98%	9.14%
CLECO	10.31%	11.10%	11.49%	10.48%	6.45%	7.49%	9.51%
Great Plains Energy	1.98%	7.90%	10.24%	17.31%	17.31%	6.36%	6.76%
IDACORP	8.22%	7.53%	8.71%	7.20%	7.20%	8.22%	9.04%
NextEra Energy	12.64%	12.60%	9.09%	10.51%	10.94%	10.51%	12.08%
Pinnacle West	8.09%	6.74%	11.03%	11.84%	10.53%	8.86%	8.73%
Portland General	12.40%	6.99%	7.57%	14.25%	10.36%	8.44%	8.25%
Southern Co.	9.31%	10.78%	10.00%	10.11%	10.33%	11.25%	10.19%
Westar Energy	9.45%	8.91%	13.53%	13.02%	15.05%	9.47%	7.89%
Xcel Energy	9.05%	8.81%	9.91%	NA	NA	8.92%	8.47%
<b>Average</b>	9.02%	9.11%	10.03%	11.54%	10.80%	8.95%	9.01%
<b>Overall Average</b>	<b>9.78%</b>						

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-COC-9

Date Received: April 28, 2011

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Question:

Provide projected information for XEI's projected common stock issuances for the years 2011-2015, as referred to on lines 26-28, p. 21 of Exhibit AEB-1. This information should include number of shares issued, total dollar value of issuance, and issuance costs.

Response:

Ms. Bulkley's testimony does not reference specific projected stock issuances for 2011-2015 and was not intended to indicate that there are specific projected stock issuances during that period. As a point of clarification, the referenced sentence on lines 26-28, p. 21 of Ms. Bulkley's testimony should state:

“The Company ~~will~~ may need to access the equity market in the next several years on a more regular basis than in the past in order to finance its capital investment plan.”

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Preparer: Ann E. Bulkley

Title: Vice President, Concentric Energy Advisors, Inc.

Telephone: 508-263-6200

Date: May 16, 2011

EARNED RETURNS ON EQUITY AND RETENTION RATIOS

Company	r 2010	r 2011	r 14-16	b 2010	b 2011	b 14-16
AEP	9.32%	10.70%	10.42%	34.23%	40.65%	44.00%
CLECO	11.39%	10.40%	9.65%	57.21%	53.62%	41.82%
Great Plains Energy	7.31%	6.05%	7.45%	45.75%	36.15%	31.43%
IDACORP	9.54%	9.24%	8.49%	57.89%	58.62%	54.84%
NextEra Energy	14.43%	12.10%	10.82%	57.81%	51.16%	52.38%
Pinnacle West	9.28%	9.10%	9.15%	32.26%	33.33%	34.29%
Portland General	8.17%	8.21%	8.42%	38.82%	38.86%	40.00%
Southern Co.	12.72%	12.76%	12.87%	24.05%	24.80%	32.31%
Westar Energy	8.60%	8.23%	10.00%	31.11%	26.86%	40.00%
Xcel Energy	9.55%	10.22%	10.00%	35.90%	41.14%	42.50%
Average	10.03%	9.70%	9.73%	41.50%	40.52%	41.36%

# Interest Rate Risk and Utility Risk Premia During 1982-93

S. Keith Berry\*

*Department of Economics and Business, Hendrix College, Conway, USA*

## INTRODUCTION

The risk premium method of calculating a fair return on equity for a regulated utility is frequently used in regulatory proceedings. That method considers the relationship between a utility's bond yield and its required return on equity, and is especially useful when other methods, such as the capital asset pricing model and the discounted cash flow (DCF) model exhibit less reliability.<sup>1</sup> Although the discounted cash flow method is the favored method for estimating a utility's cost of equity in rate proceedings, the risk premium method provides a useful check on the DCF results. This is even more important in today's financial environment because of the difficulty of measuring investor-expected growth rates in the DCF method.

If bond yields and required returns on equity move up and down in lockstep, it is straightforward to calculate the appropriate cost of equity using the risk premium method. However, if they do not, estimation of the cost of equity is much more difficult. One explanation of this variability in risk premia is differences in 'interest rate risk'. In particular, arguments have been made in rate cases that utility bonds are riskier in the 1980s than they were earlier because of the significant increase in interest rate variability that occurred in the early 1980s (primarily caused by increased inflation rate variability).<sup>2</sup> In particular, when capital costs, and interest rates, increase, utility bondholders, who earlier 'locked-in' at lower interest rates, miss out on those higher interest rates. Bondholders who experience this will then

prospectively require an 'interest rate risk' premium, and utility bond interest rates will be correspondingly greater. Furthermore, utility bonds of differing overall risk may exhibit differing sensitivities to that 'interest rate risk'.

In contrast, the argument goes, utility common stock returns have some protection from that risk. If capital costs increase, utilities can request a rate increase to increase the allowed return. Consequently, utility common shareholders can earn the higher capital costs, and do not necessarily require an 'interest rate risk' premium.<sup>3</sup> Thus, over time we would not necessarily expect to see utility bond yields and required equity returns move in one-to-one lockstep. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.

Berry (1995) performed an analysis of the impact of interest rate (and capital cost) risk on interest rates and dividend yields. Those results indicate that interest rates are positively related to interest rate variability, but dividend yields are not affected by dividend yield variability. However, that study focused on *dividend yields*, which are easy to measure, and did not consider required equity returns which are much more difficult to measure. Furthermore, that study did not focus on risk premia, and the relationship between bond yields and required returns on equity, as does this paper. This paper utilizes required returns, as measured by Commission-allowed returns, in the risk premium analysis.

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Other studies have shown that there is an inverse relationship between interest rates and risk premia in recent years, but not in earlier years. Carleton *et al.* (1983) found that there was no relationship between electric utility risk premia and interest rates during the 1970s. Brigham *et al.* (1985) estimated a positive relationship between risk premia and interest rates for the 1966–79 period and a negative relationship between the variables during the 1980–84 period. They attributed this to increased inflation risk and its effect on interest rates. Similarly, Harris (1986) showed that there was a negative relationship between utility risk premia and interest rates during the 1982–84 period. Harris and Marston (1992) concluded that there was a negative relationship between the S&P 500 risk premia and interest rates for the 1982–91 period. However, none of these studies used Commission-allowed returns in the calculations of risk premia.

This paper considers two factors not previously considered in the literature. First, allowed returns are used as a proxy for required returns on equity, with appropriate consideration for partial adjustment. Second, explicit usage is made of measures of interest rate risk to gauge their impact on risk premia. Regression analyses is employed to estimate the effects of utility bond yields, interest rate variability, and time trends on required returns on equity and risk premia over the period 1982–93. In the second section, we present a simple regression model, which tests for an inverse relationship between required returns on equity and interest rates. This model, while not very sophisticated, has the inherent advantage that it can be easily used to estimate risk premia. In the third section, we consider a more complex model which explicitly considers various measures of interest rate variability, as well as interest rate levels.

#### REGRESSION RESULTS WITH INTEREST RATES

A common formulation of the risk premium is:

$$K = YD + RP \quad (1)$$

where  $K$  is the required return on common equity,  $YD$  is the utility's current cost of long-term debt (yield) and  $RP$  is the risk premium. Since  $YD$  is directly measurable, and if  $RP$  can be properly measured,  $K$  can then be directly estimated.<sup>4</sup>

However, there are two general problems with the implementation of a risk premium methodology:

1. The estimation of  $RP$  is often based on historical earned returns, which may or may not be indicative of required returns; and
2. The level of  $RP$  may not be constant through time. In particular, there may be an inverse relationship between interest rates and risk premia.<sup>5</sup>

To address the first problem we use Commission-allowed returns as a reasonable surrogate for required returns, with a partial adjustment feature, as will be discussed later. Commissions and their staff spend a significant amount of time in rate cases considering the determination of a utility's appropriate return on equity. As discussed earlier, the primary method employed is the DCF method, which, when performed properly, estimates the required return on equity.<sup>6</sup> Furthermore, Commission-allowed returns may represent better estimates of equity costs, than DCF methods using analysts' forecasts, since Commissions comprehend a wide variety of cost of capital methods.

For illustration we have arrayed risk premia by year in Table 1. For comparative purposes we also show the estimated risk premia using the long-term US Treasury bond yield. Note that there is a general upward trend in risk premia associated with Moody's utility bond yields, which occurs during a period of generally decreasing interest rates. Furthermore, the estimated risk premia are less than those reported in Harris and Marston (1992). This can be attributed to two factors. First, utilities are generally less risky than the S&P 500 which were used in the Harris and Marston study, with corresponding lower required returns. Second, Commission-allowed returns may incorporate lower DCF growth rates than the analysts' forecasts used by Harris and Marston.

Finally, risk premia for Treasury bonds, shown in Table 1, appear to be fairly stable, albeit with a slight upward drift over the 1982–93 period. Moody's yields fell by much more (777 basis points) over that period, than did Treasury yields (578 points). An explanation for this is provided in Berry (1995). As shown there, although there is a close one-to-one relationship between Moody's utility bond yields and Treasury yields, interest rate risk had a significant impact on Moody's

INTEREST RATE RISK AND UTILITY RISK PREMIA

Table 1. Equity Risk Premia

Year (1)	US Treasury Bond Yields (2) (%)	Allowed Return on Equity (3) (%)	Equity Risk Premia [(3)-(2)] (4) (%)	Moody's Utility Bond Yields (5) (%)	Equity Risk Premia [(3)-(5)] (6) (%)
1982	12.23	15.46	3.23	15.33	0.13
1983	10.84	15.18	4.34	13.31	1.87
1984	11.99	15.25	3.26	14.03	1.22
1985	10.75	14.38	3.63	12.29	2.09
1986	8.14	13.2	5.06	9.46	3.74
1987	8.64	12.86	4.22	9.98	2.88
1988	8.98	12.82	3.84	10.45	2.37
1989	8.58	12.92	4.34	9.66	3.26
1990	8.74	12.63	3.89	9.76	2.87
1991	8.16	12.41	4.25	9.21	3.20
1992	7.52	11.84	4.32	8.57	3.27
1993	6.45	11.54	5.09	7.56	3.98
Change 1982-93	-5.78	-3.92	+1.86	-7.77	+3.85

Note: 1993 data are partial year.

yields. The decrease in interest rate risk during the 1980s, consequently, caused an incremental decrease in Moody's yields, in excess of that corresponding to the decrease in Treasury yields.<sup>7</sup> As will be discussed later, although the risk premia associated with Treasury bonds appear to be fairly stable during the 1982-93 period, there are specific reasons for that, which will not necessarily be repeated in the future.

In our regression analysis we use allowed returns and the corresponding bond yields for that utility's Moody's bond rating from 6 months earlier than the date of the Commission rate order.<sup>8</sup> This provides a better matching since the evidentiary record on the required return on equity is usually developed some months before the date of the rate order. The data on allowed returns was obtained from various editions of *Public Utilities Fortnightly* (1983-93).<sup>9</sup> The data on Moody's bond yields was obtained from various editions of *Moody's Public Utility Manual* (1982-93). This yielded a total of 1226 rate case observations over the period 1982-93. For each month we averaged the cross-sectional data to obtain 130 usable time series observations.<sup>10</sup>

Consistent with Equation (1), let  $K_t^*$  represent the required return on equity at time  $t$  such that

$$K_t^* = RP_t + YD_t \quad (2)$$

where  $RP_t$  and  $YD_t$  are the risk premium and current cost of debt at time  $t$ , respectively. To allow for a varying risk premium set

$$RP_t = \alpha + \beta YD_t \quad (2a)$$

Postulate a regulator adjustment function of the form:

$$K_t - K_{t-1} = \gamma(K_t^* - K_{t-1}), \quad 0 < \gamma < 1 \quad (3)$$

where  $K_t$  is the allowed return at time  $t$  and  $\gamma$  is the adjustment factor. This equation implies an inertia on the part of regulators such that with a change in the required return on equity from the prior period's allowed return on equity,  $K_t^* - K_{t-1}$ , the regulator only moves part way to a new allowed return. The greater the value of  $\gamma$ , the greater the degree of regulator adjustment.<sup>11</sup>

Substitution of Equation (2) into Equation (3) yields

$$K_t = \gamma RP_t + \gamma YD_t + (1 - \gamma)K_{t-1} \quad (4)$$

or

$$K_t = \alpha\gamma + (1 + \beta)\gamma YD_t + (1 - \gamma)K_{t-1} \quad (4a)$$

For purposes here, we used the allowed return from 1 month earlier. Regulators are aware of recent allowed returns and will likely partially base their current allowed return awards on those recent historical allowed returns, consistent with Equation (3).<sup>12</sup> We then performed an ordinary least squares regression of the allowed returns on the corresponding bond yields and lagged allowed returns. This resulted in the following regression equation:

$$K_t = 0.03337 + 0.22301 YD_t + 0.56788 K_{t-1},$$

(6.11) (8.58)

(Durbin-Watson = 2.41,  $R^2 = 0.905$ ). (5)

The  $t$ -statistics are shown in parentheses, and indicate significance for both independent variables at the 1% level. The implied value of  $\gamma$ , the adjustment factor, is  $1 - 0.56788 = 0.43212$ .

The implied risk premium equation, corresponding to Equation (2a), is

$$RP_t = 0.07722 - 0.48392 YD_t. \quad (6)$$

Equation (6) indicates the presence of an inverse relationship between risk premia and interest rates. For every 100 basis point drop in interest rates, the risk premium *increases* by approximately 48 basis points and the cost of equity decreases by approximately 52 basis points. Conversely, for every 100 basis point increase in interest rates, the risk premium *decreases* by approximately 48 basis points and the cost of equity increases by approximately 52 basis points.

To the extent interest rate variability is a major factor in the level of capital costs, we would expect to empirically observe this inverse relationship between risk premia and interest rates.<sup>13</sup> That is, as interest rate variability increases, interest rate risk increases, interest rates increase, and risk premia fall since utility equity costs change very little, or decrease, for the reasons mentioned in the introduction. The converse would be true in the case of a decrease in interest rate variability.<sup>14</sup>

An alternative formulation of Equation (1) is

$$K_t^* = RP_t + GOV_t, \quad (7)$$

where  $GOV_t$  is the yield on long-term US Treasury bonds and  $RP_t$  is the corresponding risk premium. Performing a similar regression analysis with  $GOV$  instead of  $YD$  produces:

$$K_t = 0.1981 + 0.16016 GOV_t + 0.73703 K_{t-1},$$

(3.74) (12.09)

(Durbin-Watson = 2.56,  $R^2 = 0.889$ ). (8)

The  $R^2$  is statistically significant at the 1% level with both independent variables statistically significant.

The implied risk premium equation, corresponding to Equation (2a), is

$$K_t^* = 0.07533 - 0.39096 GOV_t. \quad (9)$$

This formulation, too, indicates an inverse relationship between risk premia, measured relative to Treasury bonds, and Treasury bond yields. In

particular, note that for a given 100 basis point increase in interest rates the risk premium decreases by 39 basis points. The relative change in risk premia is not as great, which is attributable to less interest rate variability and interest rate risk associated with Treasury bonds.<sup>15</sup> Over the 1982-93 period, while Treasury yields fell by 578 basis points, Moody's utility bond yields fell by 777 basis points.

### REGRESSION RESULTS WITH BOND YIELD VARIABILITY

A factor that could directly and significantly affect risk premia is investor-perceived variability in utility bond yields. It is likely that historical variability in those bond yields would impact investor perceptions of interest rate risk and increase utility bond yields. Furthermore, to the extent that there is some substitutability between utility common stocks and utility bonds, as interest rate risk associated with bonds increases, investors may increase their preferences for utility stocks. This should tend to decrease required returns on utility common stock.<sup>16</sup> Both of these effects will tend to reduce the risk premium when utility bond interest rate risk increases.

While some of that interest rate variability may be picked up in the data on interest rate levels, those interest rate levels also reflect other factors, such as general tightness (or laxity) in capital market conditions, prevalence of call provisions, and differential tax wedges.<sup>17</sup> Thus, we performed a regression analysis that explicitly included a measure for interest rate variability. An obvious measure is the standard deviation (S.D.) in interest rates in the immediate past. If our hypothesis is correct, an increase in the S.D. should decrease  $RP$ .

We considered two different historical timeframes for estimating the S.D.: 3 years and 5 years ( $SD3$  and  $SD5$ , respectively). For example, with the 3 year time frame, the S.D. at month  $n$  is calculated using the 36 months prior to month  $n$ . With the 5-year time frame, the prior 60 months were used. Each of these measures was calculated separately for bond yields for Moody's *Aaa*, *Aa*, *A* and *Baa* utility bonds and then averaged across bond ratings to obtain the average  $SD3$  and  $SD5$  for each month.

**Table 2. Regression Results With  $YD$ , Dependent Variable =  $K$**

Variable				
Constant	0.1077	0.0981	0.0790	0.1001
$t$	-0.0002** (-7.25)	-0.0002** (-6.16)	-0.0001** (-4.47)	-0.0002** (-6.09)
$YD$	0.2584** (7.55)	0.2032** (6.12)	0.1947** (5.57)	0.1950** (5.89)
$SD3$	-0.5087** (-5.31)			
$RMSD3$		-0.1695** (-3.91)		
$SD5$			-0.1282 (-1.43)	
$RMSD5$				-0.1307** (-3.83)
$K_{t-1}$	0.1302 (1.59)	0.2131* (2.60)	0.3312** (4.18)	0.2099* (2.53)
$R^2$	0.9332**	0.9270**	0.9194**	0.9267**
Durbin-Watson	2.06	2.08	2.15	2.07
$N$	130	130	130	130

Note:  $t$ -statistics in parentheses. \* and \*\* indicate significance at the 5% and 1% levels, respectively.

These are reasonable historical time frames for purposes of estimating forward-looking investor expectations of interest rate risk. Of course, if there has been little change in these S.D.s during the sample period, then none of this matters. However, as discussed in Berry (1995) there has been significant volatility in bond yields. This has led to sharp increases in S.D.s in the early 1980s (almost triple the level in the 1970s), with some decrease in the latter 1980s.

Another way of gauging this variability is to consider the deviation of the immediately preceding month's yield from the relevant prior months' yields. As in the case of S.D.s, 3- and 5-year lags were considered. For example, in the case of 3 years, the formula used to calculate the root mean square deviation ( $RMSD$ ) in month  $n$  is

$$RMSD3(n) = \left( \left[ \sum_{i=n-36}^{n-1} (YD_{n-1} - YD_i)^2 \right] / 36 \right)^{1/2} \quad (10)$$

where  $YD_{n-1}$  is the yield in the immediately preceding month and  $YD_i, i = 1, \dots, n-1$ , corresponds to the yields in the prior months. An analogous formula for  $RMSD$  ( $RMSD5$ ) was used for the case of 5 years. As in the cases for  $SD3$  and  $SD5$ , different data series were calculated for the four Moody's bond ratings and then averaged across bond ratings.

The  $RMSD$  may be an appropriate measure of the risk perceived by an investor since it measures the potential interest rate swings (based on prior months' interest rates) relative to the immediately preceding month's yield. In contrast, the variable S.D. measures interest variability over a prior time frame relative to the mean over that same time frame. That mean does not necessarily equal

a current yield, and hence may underestimate investor perceptions with regard to potential interest rate variability. Thus, usage of the  $RMSD$  assumes that, in month  $n$ , investors may look at month  $n-1$ 's yield relative to prior months' interest rates to gauge the full impact of any potential interest rate swing. Note that, as discussed in Berry (1995) the trends in  $RMSD$  are similar to those of S.D. To comprehend for the possibility of a time trend in risk premia we included a monthly trend variable,  $t$ . This type of variable was discussed in Morin (1994), pp. 291-292) and was statistically significant there.

Our more complete formulation using  $SD3$  is then:

$$K_t^* = RP_t + YD_t \quad (11)$$

where

$$RP_t = \alpha + \beta t + \delta YD_t + \theta SD3_t \quad (11a)$$

Assuming a regulator adjustment function as shown in Equation (3) and substituting Equations (11) and (11a) into Equation (3) produces our regression equation:

$$K_t = \alpha\gamma + \beta\gamma t + (\delta + 1)\gamma YD_t + \theta\gamma SD3_t + (1 - \gamma)K_{t-1} \quad (12)$$

Similar regression equations were used for  $SD5$ ,  $RMSD3$  and  $RMSD5$ , where each of those variables were used in place of  $SD3$ . Our hypotheses are that the coefficient associated with  $t$  will be negative (consistent with Morin), the coefficient associated with  $YD$  will be positive, and that the coefficient associated with  $SD3$  ( $SD5$ ,  $RMSD3$ ,  $RMSD5$ ) will be negative, as investors shift their relative preference to utility stock as interest rate risk on utility bonds increase.

**Table 3. Implied Risk Premium Results, Dependent Variable = *RP***

Variable				
Constant	0.1238	0.1247	0.1181	0.1267
<i>t</i>	-0.0002	-0.0003	-0.0002	-0.0003
<i>YD</i>	-0.7029	-0.7418	-0.7089	-0.7532
<i>SD3</i>	-0.5849			
<i>RMSD3</i>		-0.2154		
<i>SD5</i>			-0.1917	
<i>RMSD5</i>				-0.1654

**Table 5. Implied Risk Premium Results, Dependent Variable = *RP***

Variable				
Constant	0.1366	0.1390	0.1208	0.1408
<i>t</i>	-0.0004	-0.0003	-0.0002	-0.0003
<i>GOV</i>	-0.7906	-0.8169	-0.7399	-0.8215
<i>SD3</i>	-0.3357			
<i>RMSD3</i>		-0.1848		
<i>SD5</i>			0.1045	
<i>RMSD5</i>				-0.1655

The dependent variable, *K*, was then regressed on the three independent variables: time, yield and measures of variability in yields. Those four regression results are shown in Table 2.

Note that the regression slope coefficients are generally significant, although the coefficient for *SD5* was not. There is a statistically significant downward time trend, which is consistent with the result in Morin. The effects of *YD* on *K* are positive and significant. Three of the four coefficients associated with interest rate risk, *SD3*, *RMSD3* and *RMSD5* are significant and negative as was hypothesized. Finally, note that all of the slope coefficients associated with *YD* are significantly less than one, which supports the hypothesis that as interest rates decrease risk premia increase.

As can be seen in Table 2, the adjustment coefficients are in the range 67–87%, which are higher than the adjustment coefficient of 43% from Equation (5). This can be explained by noting that Equation (5) does not include the other factors shown in Table 2 (in particular, interest rate variability). Consequently, the adjustment coefficient measurement in Equation (5) is

clouded by the effects of the other factors. It appears that regulators are not adjusting *K* to *K\** very much (only 43%), simply because *K* is also reacting to other factors not captured in Equation (5). Table 2 properly captures those additional effects and isolates the larger adjustment coefficient effect.

The implied risk premium results, corresponding to Equation (11a), are shown in Table 3. As can be seen there, the coefficient associated with *YD* is between approximately -0.70 and -0.75. This indicates that each increase in utility bond yields of 100 basis points produces a decrease in the risk premium of 70 to 75 basis points. Increases in interest rates result in decreases in risk premia. Furthermore, the negative slope coefficients associated with interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 3 has a negative slope, which is consistent with results reported in Morin (1994).<sup>18</sup>

To some extent the variable *YD* may include both the effects of general tightness or laxity in financial markets and interest rate risk. In order to better focus on the two separate factors, it would be appropriate to replace *YD* with *GOV* in

**Table 4. Regression Results With *GOV*, Dependent Variable = *K***

Variable				
Constant	0.0781	0.0818	0.0639	0.0874
<i>t</i>	-0.0002** (-4.85)	-0.0002** (-5.10)	-0.0001** (-3.21)	-0.0002** (-5.44)
<i>GOV</i>	0.1197** (2.99)	0.1078** (2.66)	0.1376** (3.18)	0.1108** (2.80)
<i>SD3</i>	-0.1919 (-1.85)			
<i>RMSD3</i>		-0.1088* (-2.21)		
<i>SD5</i>			0.0553 (0.54)	
<i>RMSD5</i>				-0.1027** (-2.71)
<i>K<sub>t-1</sub></i>	0.4283** (5.30)	0.4113** (5.04)	0.4709** (6.01)	0.3794** (4.55)
<i>R</i> <sup>2</sup>	0.9092**	0.9102**	0.9069**	0.9119**
Durbin-Watson	2.18	2.17	2.24	2.13
<i>N</i>	130	130	130	130

Note: *t*-statistics are in parentheses. \* and \*\* indicate significance at the 5% and 1% levels, respectively.

Equations (11) and (11a), since  $GOV$  will more directly reflect changes in the supply and demand for loan funds, without the effect of utility bonds' interest rate risk. The corresponding equations with  $SD3$  are:

$$K^* = RP_t + GOV_t \quad (13)$$

$$RP_t = \alpha + \beta t + \delta GOV_t + \theta SD3_t \quad (13a)$$

These Equations focus on the relationship between utility stocks and government bonds. Assuming an adjustment mechanism as shown in Equation (3) a regression equation analogous to Equation (12) can be developed. Those regression results are shown in Table 4 and are similar to those from Table 2. However, note that the slope coefficients associated with  $GOV$  are smaller than those associated with  $YD$  in Table 2. This is consistent with the results in Berry (1995) wherein it was shown that  $GOV$  had a larger effect on utility bond yields than on utility common stock dividend yields. Given an imperfect, although positive, relationship between Treasury bonds and utility bonds, and an imperfect relationship between utility bonds and utility stocks, it naturally follows that there would be an even more imperfect relationship between Treasury bonds and utility stocks. This means that there is more substitutability between utility common stocks and utility bonds than between utility stocks and US Treasury bonds. A further point to note from Table 4 is that the slope coefficients associated with  $S.D.$  are statistically insignificant, while those associated with  $RMSD$  are significant.

The implied risk premium results, corresponding to Equation (13a) are shown in Table 5. As can be seen there, the coefficient associated with  $GOV$  is between approximately  $-0.74$  and  $-0.82$  less than those associated with  $YD$  in Table 3. This is consistent with the point raised above concerning relative substitutability between stocks and bonds. An increase in Treasury yields of 100 basis points produces an increase of 18–26 basis points in the cost of equity, and a corresponding decrease in the risk premium of 74–82 basis points. In sharp contrast to the reported results in Table 1, controlling for other factors, risk premia relative to Treasury yields are not necessarily stable, but change as Treasury yields change. Increases in Treasury yields result in decreases in risk premia, and those decreases are greater than those associated with similar in-

creases in utility bond yields. Furthermore, the negative slope coefficients associated with utility bond interest rate risk, imply smaller risk premia as hypothesized. The trend variable in Table 5 has a negative slope, which is consistent with results reported in Morin (1994), as well as in Table 3.

## CONCLUSIONS

This paper examined, through regression analysis, the possibility that there is an inverse relationship between risk premia and both interest rates and interest rate risk in the utility industry. We demonstrated that that is the case over the 1982–93 time period. Furthermore, it was shown that there is a statistically significant basis for asserting that risk premia increase as interest rates decrease. Our analysis also indicated that there was a downward time trend in risk premia in that period. All of these phenomena occurred with either utility bond yields or long-term US Treasury bond yields. However, for an equivalent increase in either utility bond yields or Treasury yields, required equity returns increase by a slightly greater amount with regard to utility bond yields.

It was also shown that regulators may exhibit an inertia in their setting of allowed returns, such that they move partially to the new required return, in the event capital conditions warrant a change. The degree of movement is in the range of 50–80% relative to the prior month's allowed return.

There are several policy implications from the above analysis. First, when regulators use the risk premium method for setting the allowed return on equity, they should consider the degree of recent interest rate variability and consequent interest rate risk, in comparing utility common stocks and utility bonds. The appropriate risk premium will be narrower the greater the interest rate risk. As demonstrated here, the better measure of interest rate risk is  $RMSD$ , not  $S.D.$  Second, objective regulators who attempt to utilize the risk premium method should implicitly compensate for the indicated regulator inertia. For example, calculate the risk premium using  $K^*$ , rather than  $K$ . Third, while Table 1 implies that risk premia relative to Treasury bonds are more stable, that is not the case when consideration is made for other factors, as shown in Tables 4 and 5. There is not necessarily any gain in precision in using a risk premium method based on Treasury bonds.

Fourth, if the US enters a period of relative stability in interest rates, we are likely to see utility risk premia increase, a phenomenon utility executives nor regulators have any degree of control over. This widening will not occur because of increases in required equity returns, but because of relatively lower interest rates and less interest rate risk.

### NOTES

1. See Bonbright *et al.*, 1988 (pp. 317–28) for a discussion of these methods.
2. Gordon and Halpern (1976) show that an increase in variable and uncertain inflation will theoretically decrease the spread between bond and share yields. This acts through the Fisher effect and the resultant increase in interest rate uncertainty. Examples of rate cases where this argument has been made are Arkansas Public Service Commission (1987), Docket No. 87-070-U, Federal Energy Regulatory Commission (1986), Docket Nos. EL86-58-000 and EL86-59-000, Hawaii Public Utility Commission, Docket No. 4156, Kentucky Public Service Commission, Case No. 8045, and Pennsylvania Public Utility Commission, Docket R-811510.
3. These points are noted in Brigham *et al.* (1985) and Taylor and Peake (1982).
4. See Ibbotson Associates (1993), Carleton *et al.* (1983), Brigham *et al.* (1985) and Harris (1986) for a discussion of risk premia.
5. See Brennan (1982), Brigham *et al.* (1985) and Harris (1986). Other sources are Harris and Marston (1992), Gordon and Halpern (1976) and Federal Energy Regulatory Commission Staff (1992).
6. This approach was also taken in the Federal Energy Regulatory Commission (1992) Staff study.
7. During the same period, any interest rate risk associated with Treasury bonds was not as large, nor did it exhibit as large a decrease.
8. Given the rate case process (testimony, hearing, order writing) a 6 month lag is reasonable. However, if the 6 month period is either too long or short, the analysis here would only result in a mis-estimate of the intercept term, not the slope coefficients. For example, in a period of increasing interest rates (non-accelerating), if the appropriate lag should have been only 3 months, the 6 month lag will result in an over-estimate of the intercept term, but no mis-estimate of the slope terms. With a non-decelerating decrease in interest rates, the intercept term will be under-estimated, with no mis-estimated slope terms. The focus of this paper is on the slope terms. Furthermore, regression analyses was also performed using (a) bond yields contemporaneous with the date of the allowed return and (b) bond yields from 12 months earlier. In both those cases, the Durbin-Watson statistics were worse and the corresponding  $R^2$  were less than with the 6 month lag. Additionally, the slope coefficients for the  $YD$  and  $GOV$  variables were not as large, nor as significant as in the 6 month lag case. Consequently, the 6 month lag scenario was utilized here.
9. For the electric and gas rate cases the data was from *Public Utilities Fortnightly's* 'Annual Surveys', while the telecommunications data was from *Public Utilities Fortnightly's* 'Selected Utility Rate Filings'.
10. The data was aggregated into monthly data for three reasons. First, Durbin-Watson statistics can then be sensibly calculated. Second, this approach is consistent with prior studies. Third, this aggregation facilitates the partial adjustment feature. There were months when there were no reported allowed returns, which decreased our total sample size.
11. See Johnston, 1972 (pp. 300–301), for discussion of this technique.
12. This approach implicitly assumes that regulators focus on allowed returns in other jurisdictions in the prior month. This is reasonable for two reasons. First, there is a certain amount of 'peer pressure' amongst regulators wherein they generally do not want their own jurisdiction's allowed returns to be out of line with other jurisdictions, unless justified by general financial and economic circumstances (such as changes in interest rates). Second, the last allowed rate of return for a particular utility may be anywhere from 6 months to 3 years earlier. Modelling those differing periods adds unnecessary complexity to the analysis, in light of the first point raised.
13. See Berry (1995) for an empirical investigation of the impact of interest rate variability on the level of interest rates.
14. Other explanations for an inverse relationship between interest rates and risk premia have to do with call provisions and tax rates. In a high interest rate environment firms will include more call provisions in new bond issues, for which bond investors require even higher interest rate compensation. Additionally, with increasing interest rates, the tax wedge applied to interest on bonds grows relative to that on common stock due to the favorable tax treatment on the capital gains component of stock returns.
15. It could also be attributable to increased utility credit risk during that period.
16. This effect can be readily observed in the DCF method where  $K$  is calculated as  $D/P + g$ .  $D$  is the expected dividend,  $P$  is the stock's market price, and  $g$  is the investor-expected long-term growth rate in dividends. As  $P$  increases because of investors' relative preference for utility stocks,  $K$  will decrease.
17. As shown in Berry (1995), the impact of the tightness of capital markets has differential effects on interest rates and common stock dividend yields.
18. This negative slope coefficient associated with the time variable also provides an explanation as to why the positive interest rate slope coefficients are

INTEREST RATE RISK AND UTILITY RISK PREMIA

135

smaller in Table 3 than that reflected in Equation (2). Throughout the 1982-93 period, interest rates were generally decreasing, which according to the results in Table 3, will lead to decreases in required equity returns. However, during that same period the trend variable  $t$  was increasing. This increasing trend variable implies an additional source for decreases in required equity returns over that time period. Since Equation (2) does not explicitly separate out the trend variable, the overall effect in Equation (2) includes both of these effects, which will make the Equation (2) slope coefficient larger.

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STATE OF NORTH DAKOTA  
BEFORE THE  
PUBLIC SERVICE COMMISSION

In the matter of the Application of Northern )  
States Power Company, a Minnesota Corporation )  
For Authority to Increase Rates for Electric Service ) Case No. PU - 10-657  
In North Dakota ) Case No. PU - 11-55

**AFFIDAVIT OF  
Michael J. McGarry**

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

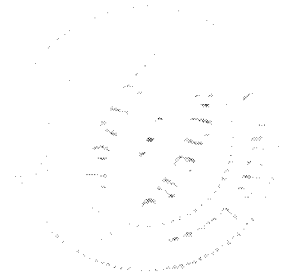
  
Michael J. McGarry

Subscribed and sworn to before me, this 16th day of August, 2011



Notary Public

Sandra K Gladden  
Notary Public, State of South Carolina  
My Commission Expires May 12th, 2021



**BEFORE THE NORTH DAKOTA PUBLIC SERVICE  
COMMISSION  
STATE OF NORTH DAKOTA**

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 Nos. PU-10-657 and PU-11-55  
Exhibit \_\_\_\_ (MJM-1)

**DIRECT TESTIMONY AND EXHIBITS OF  
MICHAEL J. MCGARRY, SR.**

**August 18, 2011**

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

**Table of Contents**

I.	INTRODUCTION AND QUALIFICATIONS .....	1
II.	SUMMARY OF COMPANY’S FILING .....	7
III.	UNCONTESTED ADJUSTMENTS .....	10
IV.	STAFF RECOMMENDED ADJUSTMENTS.....	11
	Adjustment 1- Mercury Emission.....	12
	Adjustment 2-Pleasant Valley-Byron Transmission Line .....	13
	Adjustment 3-Sale of Lakefield Junction-Fox Lake Transmission Line .....	14
	Adjustment 4-Remove Wind2Battery Project and ITC (Co. Adj. A5).....	15
	Adjustment 5-Customer Deposits .....	20
	Adjustment 6-Bargaining Unit Wage Adjustment.....	21
	Adjustment 7-Employee Benefits .....	23
	Adjustment 8-Employee Retirement Programs .....	24
	Adjustment 9-Mercury Sorbent Reduction.....	26
	Adjustment 10-Qwest Pole Attachments .....	28
	Adjustment 11-Bad Debt Expense.....	30
	Adjustment 12-Economic Development Costs .....	33
	Adjustment 13-Charitable Contributions .....	35
	Adjustments 14 & 15-Incentive Compensation .....	37
	Adjustment 16-Aviation Expense .....	40
	Adjustment 17-Nuclear Waste Disposal Litigation Costs .....	42
	Adjustment 18-Directors’ and Officers’ Insurance.....	43
	Adjustments 19, 20 & 21-Amortization Adjustments .....	44
	Adjustment 22-Cash Working Capital.....	46
	Adjustment 23-Interest Synchronization .....	47
V.	STAFF’S RECOMMENDATIONS FOR 2012 STEP .....	47
VI.	RELIABILITY .....	48
VII.	PRAIRIE ISLAND DECOMMISSIONING TRUST FUND.....	57
	Appendix A - Qualification of Michael J. McGarry, Sr. ....	A-1

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **I.     INTRODUCTION AND QUALIFICATIONS**

2   **Q.     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3   A.     My name is Michael J. McGarry, Sr. My business address is 2131 Woodruff  
4         Road, Suite 2100, PMB 309 Greenville, SC 29607.

5   **Q.     BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?**

6   A.     I am employed by Blue Ridge Consulting Services, Inc., located in Greenville,  
7         South Carolina, as President and Chief Executive Officer.

8   **Q.     PLEASE STATE YOUR EXPERIENCE AND EDUCATIONAL  
9         BACKGROUND.**

10  A.     I have been President of Blue Ridge Consulting Services, Inc. since 2004. I have  
11         overseen numerous rate case audits, prudence reviews, and management and  
12         operational audits. I have worked with clients to manage various aspects of the  
13         regulatory and rate case process; prepared supporting analyses and testimony for  
14         submission to regulatory bodies and interveners; prepared revenue requirement  
15         and cost of service analyses; and developed complex revenue requirement models  
16         to present alternative positions to a utility's proposed rate request. Prior to  
17         assuming my present position, I was Vice President of East Coast Operations  
18         from July 2003 to June 2004 with Hawks, Giffels & Pullin (HGP), Inc. In that  
19         position, I was responsible for developing and overseeing client engagements in  
20         utility regulatory affairs, management audits, and rate case management. From  
21         August 2001 to July 2003, I was an independent consultant working on a number

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 of different projects, including a renewal/update of delivery service tariffs for  
2 Illinois Power and several utility street lighting cost benefit assessment projects.  
3 From June 2000 until August 2001, I was a senior consultant with Denali  
4 Consulting, Inc., a utility supply chain and e-procurement strategy and  
5 implementation firm. From October 1997 through June 2000, I was employed by  
6 Navigant Consulting, Inc. and several of its predecessors or acquired firms  
7 working on a number of different projects, including a management audit of  
8 Southern Connecticut Gas Company and the original delivery service tariff filing  
9 for Illinois Power. From July 1985 through October 1997, I was employed by the  
10 New York State Department of Public Service (NYSDPS) in its Utility  
11 Operational Audit Section in which the staff conducted focused operational audits  
12 in many facets of utility operations for all sectors of the utility industry, including  
13 gas, electric, telecommunications, and water. Prior to my employment with the  
14 NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983)  
15 and then Seminole Electric Cooperative (1983 to 1985). I received my Masters of  
16 Business Administration from the State University of New York at Buffalo in  
17 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in  
18 1981.

19 **Q. HAVE YOU TESTIFIED BEFORE?**

20 A. Yes. I have presented or supported testimony in Colorado, Delaware, Illinois,  
21 Maine, Michigan, Maryland, New York, Nova Scotia, Pennsylvania, and Utah.  
22 These proceedings included testimony involving management decisions and

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           prudence impacts, operations and maintenance expenses, capital investments,  
2           revenue requirements, project management, and other areas.

3           I have also presented topics before staff groups from regulatory commissions,  
4           NARUC sub-committee groups, and as a program faculty member (2010) for the  
5           Institute of Public Utilities at Michigan State University. Topics presented include  
6           management auditing and prudence reviews, service company costs and  
7           allocations, forecasting methodology and modeling, revenue requirements, rate  
8           base, and price regulation theory.

9   **Q.   HAVE YOU INCLUDED A MORE DETAILED DESCRIPTION OF YOUR**  
10 **QUALIFICATIONS?**

11  A.   Yes. A description of my qualifications is included as Appendix A.

12 **Q.   ON WHOSE BEHALF ARE YOU TESTIFYING?**

13  A.   I am appearing on behalf of the Advocacy Staff of the North Dakota Public  
14       Service Commission.

15 **Q.   ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH**  
16 **YOUR TESTIMONY?**

17  A.   Yes. I am sponsoring the following exhibits:

- 18       • Exhibit\_\_\_(MJM-2), Schedule 1 Comparison of Company's 2011 Revenue
- 19        Requirements and Staff's Proposal
- 20       • Exhibit\_\_\_(MJM-2), Schedule 2 Rate of Return Calculation
- 21       • Exhibit\_\_\_(MJM-2), Schedule 2.1 Impact of Staff's Rate of Return on Company's
- 22        Proposed Revenue Requirements
- 23       • Exhibit\_\_\_(MJM-2), Schedule 3.1-Summary of Adjustments to Company's
- 24        Proposed Rate Base
- 25       • Exhibit\_\_\_(MJM-2), Schedule 3.2-Summary of Staff's Adjustments to Company's
- 26        Proposed Operating Income

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

- 1 • Exhibit \_\_\_ (MJM-2), Schedule 4.1-Adjustment 1 Mercury Emissions (Co. Adj.  
2 A38)
- 3 • Exhibit \_\_\_ (MJM-2), Schedule 4.2-Adjustment 2 Remove Transmission-Pleasant  
4 Valley/Bryon Not in Service
- 5 • Exhibit \_\_\_ (MJM-2), Schedule 4.3-Adjustment 3 Sale of Lakefield Junction/Fox  
6 Lake Transmission Line
- 7 • Exhibit \_\_\_ (MJM-2), Schedule 4.4-Adjustment 4 Remove Wind2Battery Project
- 8 • Exhibit \_\_\_ (MJM-2), Schedule 4.5-Adjustment 5 Customer Deposits (Co. Adj. A19)
- 9 • Exhibit \_\_\_ (MJM-2), Schedule 4.6-Adjustment 6 Bargaining Unit Wage Adjustment
- 10 • Exhibit \_\_\_ (MJM-2), Schedule 4.7-Adjustment 7 Employee Benefits
- 11 • Exhibit \_\_\_ (MJM-2), Schedule 4.8-Adjustment 8 Employee Retirement Programs  
12 (Co. Adj. O2)
- 13 • Exhibit \_\_\_ (MJM-2), Schedule 4.9-Adjustment 9 Mercury Sorbent Reduction (Co.  
14 Adj. A14)
- 15 • Exhibit \_\_\_ (MJM-2), Schedule 4.10-Adjustment 10 Qwest Pole Replacements (Co.  
16 Adj. A11)
- 17 • Exhibit \_\_\_ (MJM-2), Schedule 4.11-Adjustment 11 Bad Debt (Co. Adj. A10)
- 18 • Exhibit \_\_\_ (MJM-2), Schedule 4.12-Adjustment 12 Economic Development Costs  
19 (Co. Adj. A15)
- 20 • Exhibit \_\_\_ (MJM-2), Schedule 4.13-Adjustment 13 Charitable Contributions (Co.  
21 Adj. A18)
- 22 • Exhibit \_\_\_ (MJM-2), Schedule 4.14-Adjustment 14 Payroll Taxes-Excluded  
23 Incentive Comp (Co. Adj. A26)
- 24 • Exhibit \_\_\_ (MJM-2), Schedule 4.15-Adjustment 15 Incentive Compensation (Co.  
25 Adj. A26)
- 26 • Exhibit \_\_\_ (MJM-2), Schedule 4.16-Adjustment 16 Aviation Expense (Co. Adj.  
27 A28)
- 28 • Exhibit \_\_\_ (MJM-2), Schedule 4.17-Adjustment 17 Nuclear Waste Disposal  
29 Litigation Costs
- 30 • Exhibit \_\_\_ (MJM-2), Schedule 4.18-Adjustment 18 Directors' and Officers'  
31 Insurance
- 32 • Exhibit \_\_\_ (MJM-2), Schedule 4.19-Adjustment 19 2011 Rate Case Expenses (Co.  
33 Adj. A31)
- 34 • Exhibit \_\_\_ (MJM-2), Schedule 4.20-Adjustment 20 ND EPA Emission Credit  
35 Auction Proceeds (Co. Adj. A32)
- 36 • Exhibit \_\_\_ (MJM-2), Schedule 4.21-Adjustment 21 2011 Demand Side  
37 Management (Co. Adj. A33)
- 38 • Exhibit \_\_\_ (MJM-2), Schedule 4.22-Adjustment 22 Cash Working Capital
- 39 • Exhibit \_\_\_ (MJM-2), Schedule 4.23-Adjustment 23 Interest Synchronization
- 40 • Exhibit \_\_\_ (MJM-2), Schedule 5 Comparison of Company's 2012 Step Up Revenue  
41 Requirements and Staff's Proposal
- 42 • Exhibit \_\_\_ (MJM-3) through Exhibit \_\_\_ (MJM-47) are various documents that  
43 support my testimony

44 **Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR**  
45 **DIRECTION?**

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. Yes.

2 **Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?**

3 A. The purpose of my testimony is to offer adjustments for the North Dakota Public  
4 Service Commission (Commission) to consider as it determines the revenue  
5 requirements and ratemaking proposals in the application of Northern States  
6 Power (NSP or Company) for authority to increase its electric base rates in this  
7 proceeding.<sup>1</sup>

8 **Q. ARE YOU ADDRESSING ANY ISSUES RELATED TO THE**  
9 **COMPANY'S COSTS OF CAPITAL OR DEBT STRUCTURE?**

10 A. No. Dr. S. Keith Berry is addressing cost of capital and debt structure on behalf  
11 of the North Dakota Public Service Commission. I have used Dr. Berry's  
12 proposed adjustment to the weighted cost of capital to determine the overall effect  
13 of the proposed adjustments on the Company's revenue requirements.

14 **Q. ARE YOU ADDRESSING ANY ISSUES RELATED TO THE**  
15 **COMPANY'S JURISDICTIONAL AND CLASS COSTS OF SERVICE OR**  
16 **RATE DESIGN?**

17 A. No. Mr. Howard Solganick will provide testimony on behalf of the Staff of the  
18 North Dakota Public Service Commission regarding cost of service allocation and  
19 rate design.

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<sup>1</sup> In most cases, where I refer to NSP, I am referring to NSP's operations and costs associated with NSP's North Dakota jurisdiction. However, where necessary and appropriate, I will refer to NSPM (NSP's Minnesota overall corporate function). NSP's North Dakota operation is a jurisdictional operation within NSPM. In addition and where appropriate, I will designate NSP's other companies or jurisdictions, including NSP-W (Wisconsin). Finally, NSPM is a subsidiary of Xcel Energy, Inc.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    WHAT HAVE YOU REVIEWED IN THE PREPARATION OF YOUR**  
2       **TESTIMONY?**

3    A.    I have reviewed the application and testimony of the NSP, associated supporting  
4        exhibits and workpapers, responses to data requests in this case, and previous  
5        orders of the Commission.

6   **Q.    WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR**  
7       **DIRECT SUPERVISION?**

8    A.    Yes.

9   **Q.    PLEASE SUMMARIZE YOUR FINDINGS, CONCLUSIONS, AND**  
10       **RECOMMENDATIONS.**

11   A.    Based on my analysis of the information provided to date, I have concluded that  
12        the Company's 2011 revised proposed rate increase of \$17,990,000<sup>2</sup> should be  
13        reduced by \$6,545,000 resulting in a rate increase of \$11,446,000.<sup>3</sup> The  
14        Company's 2012 Step revised proposed rate increase of \$20,365,000<sup>4</sup> should be  
15        adjusted by (\$6,691,000) resulting in a revenue requirement for 2012 of  
16        \$13,674,000.<sup>5</sup> These adjustments include my adjustments and the impact of the  
17        Cost of Capital adjustment supported by Dr. Berry. My recommended revenue  
18        requirement and proposed adjustments can be found in Exhibit MJM-2.

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<sup>2</sup> Exhibit \_\_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission.

<sup>3</sup> Exhibit \_\_\_\_ (MJM-2) Schedule 1, Comparison of Company's 2011 Revenue Requirements and Staff's Proposal.

<sup>4</sup> Exhibit \_\_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission, Revised Schedule 7.

<sup>5</sup> Exhibit \_\_\_\_ (MJM-2) Schedule 5, Comparison of Company's 2012 Revenue Requirements and Staff's Proposal.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1    **II.    SUMMARY OF COMPANY’S FILING**

2    **Q.    PLEASE SUMMARIZE THE COMPANY’S APPLICATION FOR AN**  
3    **INCREASE IN BASE RATES?**

4    A.    In its application to the Commission, NSP indicated:

5                    “The rate and tariff changes proposed in this Notice would result in  
6                    an annual increase of electric revenues of \$19.773 million or 12.02  
7                    percent, effective for electric service on and after January 19,  
8                    2011, or upon final approval if the rates are suspended and interim  
9                    rates approved. The test year for the proposed increase is 2011.  
10                   The Company is also requesting a step increase of \$4.226 million  
11                   or 2.57 percent for a total of \$23.999 million or 14.59 percent  
12                   effective January 1, 2012.” (NSP Application Dated December 20,  
13                   2010).

14   **Q.    DID THE COMPANY REVISE ITS FILING DURING THE COURSE OF**  
15   **YOUR REVIEW OF THE APPLICATION?**

16   A.    Yes.  On April 8, 2011, NSP Minnesota (NSPM) formally notified the North  
17   Dakota Public Service Commission that it was terminating the Merricourt Wind  
18   Project (Merricourt Project).  In that letter, the Company indicated that it would  
19   provide an update by May 20, 2011, of the impact of the termination of the  
20   project on NSP’s pending electric rate case before the Commission.  On May 10,  
21   2011, NSP submitted that update which revised the Company’s application.  The  
22   Company provided a series of updated schedules for Mr. Felling’s testimony to  
23   reflect the cancellation of the Merricourt project.  As a result of the cancellation  
24   of the Merricourt Project, NSP’s North Dakota adjusted base (i.e., nonfuel) rate  
25   increase was reduced to \$17.990 million or 10.94 percent.  This represents about a  
26   \$1.783 million decrease from the Company’s original request for 2011 of \$19.773

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 million (12.02 percent). For the 2012 step increase, the termination modified the  
2 requested increase to \$2.374 million or 1.44 percent. This is a \$1.852 million  
3 reduction from the original request of \$4.226 million (2.57 percent). In total, for  
4 both 2011 and the 2012 step increase, the adjusted overall increase in base rates  
5 sought is \$20.364 million or 12.38 percent, effective January 1, 2012. In total, the  
6 effect of terminating the Merricourt Project is a \$3.635 million reduction.<sup>6</sup>

7 **Q. WHAT IS THE COMPANY PROPOSING FOR A TEST YEAR?**

8 A. The Company is proposing that rates be set based on a budgeted test year for  
9 2011.<sup>7</sup> NSP then made adjustments for traditional regulatory adjustments such as  
10 advertising expenses, economic development, etc. along with other ratemaking  
11 adjustments and budget corrections NSP believes appropriate.<sup>8</sup>

12 **Q. DO YOU HAVE AN OPINION CONCERNING THE COMPANY'S USE**  
13 **OF THIS TEST YEAR?**

14 A. I have testified in several jurisdictions to the appropriateness of a historical test  
15 year with known and measurable changes that adjust the rate year to be more  
16 reflective of rates during the rate effective period. Using a historical test year with  
17 known and measurable adjustments is a more widely accepted approach to  
18 determining revenue requirements and operating revenues and reduces concerns  
19 about inaccuracies and overstatements of budgets. However, per North Dakota

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<sup>6</sup> Exhibit \_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission.

<sup>7</sup> Direct Testimony of John M. Felling page 1, lines 16-17.

<sup>8</sup> Direct Testimony of John M. Felling page 3, lines 4-12.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           Century Code (NDCC) § 49-05-04.1, subd. 2, the Company has the option of  
2           providing a future test year based on budgeted data.

3   **Q.    WHAT IS THE COMPANY PROPOSING FOR ITS TEST YEAR RATE**  
4   **BASE?**

5   A.    The Company's revised proposed an adjusted rate base of \$317,494,000,<sup>9</sup> which  
6        was derived from the actual average balances on the Company's book and records  
7        as of April 30, 2010. The Company then applied the 2010 budget projections for  
8        May through December 2010 to arrive at the beginning balances for 2011. NSP  
9        further included the 2011 capital budget, which was adjusted for plant additions,  
10       retirements, depreciation, and salvage and removal costs projected to occur during  
11       the test year.<sup>10</sup> For the 2012 step, the Company's revised proposed an average  
12       rate base of \$327,429,000.<sup>11</sup>

13 **Q.    WHAT REVENUE DEFICIENCY HAS THE COMPANY PROPOSED IN**  
14 **THIS PROCEEDING FOR ITS JURISDICTIONAL ELECTRIC**  
15 **OPERATIONS?**

16 A.    NSP's proposed 2011 test period operating income requirement is \$27,749,000<sup>12</sup>  
17        which is based on the revised adjusted rate base of \$317,494,000<sup>13</sup> and a proposed  
18        rate of return of 8.74%.<sup>14</sup> The Company calculated an adjusted pro forma income

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<sup>9</sup> Exhibit \_\_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission, Revised Schedule 7.

<sup>10</sup> Direct Testimony of John M. Felling, page 34, lines 7-18.

<sup>11</sup> Exhibit \_\_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission, Revised Schedule 7.

<sup>12</sup> Ibid., Revised Schedule 7.

<sup>13</sup> Ibid., Revised Schedule 7.

<sup>14</sup> Ibid., Revised Schedule 7.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           deficiency of \$10,934,000.<sup>15</sup> When considering income taxes, the resulting  
2           revenue requirement requested by the Company is \$17,991,000.<sup>16</sup> For the 2012  
3           step, the Company is requesting a revenue requirement of \$20,365,000<sup>17</sup> or an  
4           additional \$2,374,000.

5   **III.   UNCONTESTED ADJUSTMENTS**

6   **Q.    WHAT ARE THE UNCONTESTED ADJUSTMENTS THAT YOU**  
7   **PROPOSE THE COMMISSION ACCEPT?**

8   A.    After reviewing the Company's updated filing and evaluating the supporting  
9         assumptions and calculations, I am recommending the following adjustments to  
10        be accepted by the Commission:

11       Plant Related Budget Adjustments:

- 12                Bonus Tax Depreciation
- 13                Monticello Projects
- 14                Prairie Island MUR Projects
- 15                Transmission Interconnect

16       Non-Plant Related Budget Adjustments:

- 17                LiDAR Tree Trimming
- 18                Joint Pricing Zone Update

19       Traditional Adjustments:

- 20                Professional & Association Dues

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<sup>15</sup> Ibid., Revised Schedule 7.

<sup>16</sup> Ibid., Revised Schedule 7.

<sup>17</sup> Ibid., Revised Schedule 7.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           Rate Case Adjustments – Plant Related

2                   Black Dog Units 3&4 Life Extension

3                   Prairie Island Life Extension

4                   Steam Net Salvage

5                   Other Production Net Salvage

6           Rate Case Adjustments – Non-Plant Related

7                   Leases on Vacant Buildings

8                   Employee Expense

9                   2008 Rate Case PF Storage

10          Rate Case Adjustments – Known & Measurable 2012 Step

11                   Merricourt Wind Annualization – Accept Company’s updated filing

12                   Nuclear Production Monticello – EPU

13                   2011 Transmission Plant Amortization

14                   Nuclear Outage Amortization

15   **IV.   STAFF RECOMMENDED ADJUSTMENTS**

16   **Q.   PLEASE DESCRIBE HOW THE REMAINDER OF YOUR TESTIMONY**  
17   **IS PRESENTED.**

18   A.   In the following sections, I will present adjustments to the Company’s proposed  
19   revenue requirement that I recommend that the Commission adopt to reflect a  
20   reasonable revenue requirement that will allow NSP the opportunity to earn its  
21   allowed rate of return.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           **Adjustment 1- Mercury Emission**

2       **Q.     PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY’S**  
3           **POSITION CONCERNING THE MERCURY EMISSIONS**  
4           **ADJUSTMENT.**

5       A.     NSPM spent monitoring and engineering dollars in regard to compliance with  
6           Minnesota’s mercury emission regulations. The Company is including the North  
7           Dakota allocation of these control costs in the test period.<sup>18</sup>

8       **Q.     IS INCLUSION OF THE MERCURY EMISSION CONTROL COSTS IN**  
9           **THE TEST YEAR FOR 2012 AND BEYOND EQUITABLE?**

10      A.     No. Mercury emissions control is entirely associated with maintaining compliance  
11           with Minnesota regulations. North Dakota has no such regulations. Furthermore,  
12           no current federal regulations exist for the limitation of mercury emissions by  
13           power plants.

14      **Q.     HAS THE EPA INITIATED FEDERAL REGULATION CONCERNING**  
15           **MERCURY EMISSION FROM POWER PLANTS?**

16      A.     Yes. The Clean Air Mercury Rule (CAMR) was finalized in May 2005. However,  
17           on February 8, 2008, the U.S. Court of Appeals for the DC Circuit vacated the  
18           CAMR. The EPA drafted and published new mercury rules in the Federal  
19           Register on May 3, 2011.<sup>19</sup> However, these are proposed regulations that are only  
20           being considered by the EPA and for which comments are being received.

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<sup>18</sup> Direct Testimony of John M. Felling, page 27, lines 23-24.

<sup>19</sup> Exhibit \_\_\_ (MJM-4) Data Request and Response AS-RR-302.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           Considering the speculative nature of the proposed rules and the fact that the U.S.  
2           Court of Appeals has already vacated a previous set of EPA regulations in this  
3           regard, not only do no known and measureable regulations mandated by the  
4           federal government currently exist, but no assurances exist as to future regulations  
5           or regulatory levels for power plant mercury emissions.

6   **Q.   WHAT PORTION OF THE MERCURY EMISSION CONTROL COSTS**  
7   **SHOULD THE NORTH DAKOTA JURISDICTION BEAR?**

8   A.   Since neither North Dakota nor the federal government have any known and  
9        measureable regulations regarding mercury emissions, none of the mercury  
10       emission control costs should be borne by the North Dakota ratepayers. All  
11       mercury emission control costs, including the amounts associated with rate base,  
12       depreciation, amortization, and tax, should be removed from the test year for 2012  
13       and beyond. Therefore, I have reduced rate base by \$252,479 and operating  
14       income has increased by \$8,421 as shown on Exhibit \_\_\_\_ (MJM-2) Schedule  
15       4.1, Adjustment 1 Mercury Emissions (Co. Adj. A38).

16       **Adjustment 2-Pleasant Valley-Byron Transmission Line**

17   **Q.   PLEASE EXPLAIN THE COMPANY’S PROPOSED POST FILING**  
18   **ADJUSTMENT TO THE 2011 TEST YEAR FOR THE PLEASANT**  
19   **VALLEY – BYRON TRANSMISSION LINE CAPITAL PROJECT.**

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The Company included this project in the 2011 test year even though the  
2 scheduled in-service date was 2012.<sup>20</sup> As a result, the Company indicated that  
3 they intend to adjust the 2011 revenue requirement on rebuttal by approximately  
4 \$28,000 to reflect that the above capital project will not be in-service until 2012.<sup>21</sup>

5 **Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT?**

6 A. Yes. I agree that the Pleasant Valley – Byron project should be removed from rate  
7 base since the project will not be in service in 2011. I have included the  
8 Company's adjustment in my revenue requirement calculations which reduces  
9 rate base by \$115,000 and increases net operating income by \$96,632 as shown  
10 on Exhibit \_\_\_ (MJM-2) Schedule 4.2, Adjustment 2 Remove Transmission-  
11 Pleasant Valley/Bryon Not in Service.

12 **Adjustment 3-Sale of Lakefield Junction-Fox Lake Transmission Line**

13 **Q. DID THE COMPANY PROPOSE ANY OTHER POST FILING**  
14 **ADJUSTMENTS TO THE REVENUE REQUIREMENT FOR THE 2011**  
15 **TEST YEAR?**

16 A. Yes. The Company sold the Lakefield Junction-Fox Lake 161KV Transmission  
17 line in 2011.<sup>22</sup>

18 **Q. WAS THE SALE INCLUDED IN THE 2011 TEST YEAR?**

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<sup>20</sup> Exhibit \_\_\_ (MJM-5) IRB-1, Schedule 4, page 1 of 3.

<sup>21</sup> Exhibit \_\_\_ (MJM-6) Data Request and Response AS-2-RR-22.

<sup>22</sup> Exhibit \_\_\_ (MJM-7) Data Request and Response AS-2-RR-13.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. An estimate was included in the 2011 test year because the sale had not been  
2 completed at the time the rate case was filed.<sup>23</sup> However, when asked to provide  
3 a list of all properties sold or transferred, the Company provided an analysis of the  
4 rate base and revenue requirement effect of the sale of the transmission line.

5 **Q. WHAT IS THE IMPACT OF THE SALE ON THE 2011 TEST YEAR?**

6 A. The Company calculates a reduction in the revenue requirement of \$122,242.<sup>24</sup>

7 **Q. DO YOU AGREE WITH THE COMPANY CALCULATION?**

8 A. Yes. I have included the impact of the sale in my revenue requirement  
9 calculation. I have reduced rate base by \$708,828 and increased operating income  
10 by \$26,706 as shown on Exhibit \_\_\_ (MJM-2) Schedule 4.3, Adjustment 3 Sale of  
11 Lakefield Junction/Fox Lake Transmission Line.

12 **Adjustment 4-Remove Wind2Battery Project and ITC (Co. Adj. A5)**

13 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S**  
14 **WIND2BATTERY PROJECT.**

15 A. In April 2009, NSPM sought approval of the Wind2Battery project from the  
16 Minnesota Public Service Commission (MNPS) in MNPS Docket No. E-  
17 002/AI-09-379. The Wind2Battery project is a 1 MW sodium sulfur battery  
18 storage facility that is operating in conjunction with the 11 MW Minwind project  
19 in Luveme, Minnesota. By storing energy for Minwind, the Company would be  
20 able to manage some of the variable production associated with wind power from

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<sup>23</sup> Exhibit \_\_\_ (MJM-7) Data Request and Response AS-2-RR-13.

<sup>24</sup> Exhibit \_\_\_ (MJM-7) Data Request and Response AS-2-RR-13, Attachment A, page 1 of 1.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           this project. In addition, the Wind2Battery project is intended to give the  
2           Company experience and information that allow it us to assess and improve the  
3           viability of scaling up battery storage on its system as additional wind power is  
4           added to meet the renewable policies. The Company stated in its filing that even  
5           though the battery is proven technology, the application of the battery as support  
6           for wind energy has not been tested on a large scale. The integration equipment  
7           and the study of the use of the battery for this purpose will be funded through a  
8           Renewable Development Fund (RDF) grant. In addition to the Company, the  
9           University of Minnesota, Great Plains Institute and the National Renewable  
10          Energy Laboratories are assisting in the research and receiving a portion of the  
11          RDF grant.<sup>25</sup>

12   **Q.   HOW WOULD THE USE OF THIS UNPROVEN APPLICATION BE**  
13   **BENEFICIAL TO COMPANY AND RATEPAYERS?**

14   **A.   In the application before the MNPSC, the Company states that the following:**

15                                 “This project and future additional applications will also allow us  
16                                 to better leverage transmission in the future, as we will be able to  
17                                 store wind energy when the grid is at full capacity and move the  
18                                 energy onto the transmission grid when the bottlenecks have been  
19                                 removed. In summary, batteries will add to the value of wind  
20                                 projects now and in the future because of their ability to charge  
21                                 off-peak and discharge on-peak as well as during times of  
22                                 transmission constraints. We currently plan to complete our studies  
23                                 by the end of 2009, with associated findings and recommendations  
24                                 developed during the first half of 2010.<sup>26</sup>  
25

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<sup>25</sup> Exhibit\_\_\_ (MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission.

<sup>26</sup> Exhibit\_\_\_ (MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission, page 4.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 **Q. WHAT WAS THE COMPANY’S ESTIMATED PROJECT COSTS FOR**  
2 **THE 1 MW BATTERY APPLICATION?**

3 A. At the time, NSPM indicated that the project would cost approximately \$5  
4 million. However, the RDF grant would lower the total to \$3.5million. NSPM  
5 sought approval from the MNPSC for \$3.5 million.<sup>27</sup>

6 **Q. IS THE COMPANY SEEKING COST RECOVERY OF THIS PROJECT**  
7 **FROM NORTH DAKOTA RATEPAYERS IN THIS RATE CASE?**

8 A. Yes. Included in NSPM’s April 2009 application to MNPSC is a detailed revenue  
9 requirements calculation. In that calculation, which was necessary because NSPM  
10 was seeking recovery under Minnesota’s Renewable Energy Standard Rider cost  
11 mechanism, Schedule 3 shows the detailed revenue requirements associated with  
12 the project for 2009 through 2013. The schedule clearly shows that the revenue  
13 requirement would be allocated to Minnesota jurisdictional customers. For  
14 example in 2011, the schedule shows that Minnesota customers would be  
15 responsible for \$620,087 of a total \$846,477. From this, I conclude that the  
16 remaining costs are imbedded with the jurisdictional allocations to NSPM’s other  
17 jurisdictional entities including North Dakota.

18 **Q. WAS THIS PROJECT APPROVED BY THE MINNESOTA PSC?**

19 A. Yes. On September 14, 2009 the MNPSC issued its approval of the company’s  
20 application at the cost levels listed in the NSPM application.<sup>28</sup>

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<sup>27</sup> Exhibit \_\_\_ (MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission, page 8.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    TO YOUR KNOWLEDGE, DID THE COMPANY SEEK APPROVAL OF**  
2       **THE PROJECT FROM THE NORTH DAKOTA COMMISSION?**

3    A.    No. I have conferred with Advocacy Staff and reviewed the Commission’s web-  
4       site and found no such similar filing. It was not until Advocacy Staff and I were  
5       reviewing the list of uncontested adjustments, that either of us realized that it was  
6       very likely that the cost for this project were embedded in the Company’s filing.

7   **Q.    WHAT CONCERNS DO YOU HAVE WITH THIS PROJECT AND THE**  
8       **WAY THE COMPANY HAS HANDLED THE REQUEST FOR**  
9       **APPROVAL?**

10   A.    From a non-engineering perspective, the project costs appear exorbitant for a  
11       1MW installation. From publically available information and my general industry  
12       knowledge, 1 MW of installed capacity for a combine cycle natural gas turbine  
13       costs approximately \$1,000 per kW or \$1,000,000 per MW. It seems to me to  
14       spend \$3,500,000 million for 1 MW is excessive. Since I am not an engineer, I  
15       cannot pass judgment on the total merits of the project. However, the North  
16       Dakota Commission and its Staff do have that capability or can certainly hire an  
17       expert engineer to evaluate the technical merits of the project. They were never  
18       given that opportunity and presumably were allocated a portion of the cost of the  
19       project. As a result, North Dakota ratepayers are expected to pay for an expensive  
20       experimental project without a showing of need.

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<sup>28</sup> Exhibit \_\_\_ (MJM-9) September 14, 2009 Order approving OES recommendation on Wind2battery.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    YOU STATE “PRESUMABLY WERE ALLOCATED A PORTION OF**  
2       **THE COSTS.” HOW DID YOU ARRIVE AT THIS PRESUMPTION?**

3    A.    The Company included an investment tax credit (ITC) adjustment for the project  
4        in their application in this docket. The Company determined that the  
5        Wind2battery project was eligible for the ITC and that this credit would reduce  
6        rate base by about \$8,000.<sup>29</sup> Therefore, I concluded that the costs for the  
7        Wind2Battery project are included in the NSP North Dakota rate case.

8   **Q.    WHAT DO YOU RECOMMEND?**

9    A.    I believe that NSPM should have provided the North Dakota Commission with  
10        the same opportunity to review the project and determine whether it would be  
11        beneficial to the Company’s North Dakota customer. To presume that approval  
12        by one jurisdiction is appropriate in all jurisdictions is wrong particularly when  
13        the other jurisdictions will be unknowingly expected to pay a portion of the costs.  
14        Further, I recommend that the cost of this project be removed from the  
15        Company’s North Dakota filing until such time that NSPM seeks and obtains  
16        approval of the project from the North Dakota Commission. As such and based  
17        on the information contained in Schedule 3 of NSPM’s April 2009 filing in  
18        Minnesota, I have removed the costs of the project. In addition, I have removed  
19        the Company’s adjustment for the Investment Tax Credit (Company adjustment  
20        A5). My calculations are shown in Exhibit \_\_\_ (MJM-2) Schedule 4.4 and result  
21        in a reduction of \$229,550 to rate base and \$30,244 increase to operating income.

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<sup>29</sup> Direct Testimony of John M. Felling, pages 43-44, lines 26-27 and 1-10.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1            **Adjustment 5-Customer Deposits**

2            **Q.    PLEASE EXPLAIN THE COMPANY’S ADJUSTMENT TO CUSTOMER**  
3            **DEPOSITS.**

4            A.    Customer deposits are funds the Company collects as security for providing  
5            service. Much in the same way a landlord collects 1 or 2 month’s rent as a  
6            security deposit, a utility collects funds from customers as security. These funds  
7            belong to customers and are returned or credited to customer bills when service is  
8            discontinued. Witness Felling indicated that customer deposits are treated as  
9            customer supplied capital and thus it is appropriate to pay ratepayers a return on  
10           that investment while also recovering the interest paid on those deposits. As a  
11           result, there is an adjustment to rate base (a decrease) and to interest expense (an  
12           increase). Witness Felling’s adjustment resulted in a decrease to North Dakota’s  
13           jurisdictional rate base of \$131,000<sup>30</sup> and increased interest expense by \$1,000.<sup>31</sup>

14          **Q.    DO YOU AGREE WITH THE COMPANY’S ADJUSTMENT?**

15          A.    No.

16          **Q.    PLEASE EXPLAIN.**

17          A.    As part of my analysis, I reviewed the information provided in response to a data  
18           request<sup>32</sup> and determined that the 13-month average balance used to calculate the  
19           adjustment was based on actual balances for the twelve months ended June 30,  
20           2010. When updated to the 13-month average ended December 2010, the

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<sup>30</sup> Exhibit \_\_\_ (JMF-1) Schedule 5a, Page 3 of 3, line 29, Column 13.

<sup>31</sup> Exhibit \_\_\_ (JMF-1) Schedule 5b, Page 2 of 5, line 14, Column 20.

<sup>32</sup> Exhibit \_\_\_ (MJM-10) Data Request and Response AS-RR-231.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 customer balance on a total NSPM company basis would increase by \$727,365.  
2 After allocation, this increase in the customer deposits would result in an increase  
3 of the fund balance by \$34,182 on a ND-Electric jurisdictional basis. As a result,  
4 rate base would be reduced by this same \$34,182 (keeping in mind that these  
5 funds are ratepayer funds). A similar calculation for the interest expense  
6 adjustment for O&M only slightly changes the Company's adjustment from \$768  
7 to \$968, and, because of rounding, adjustment to interest expense will remain  
8 unchanged.

9 **Q. WHAT DO YOU RECOMMEND?**

10 A. I recommend that the Company's rate base be reduced by \$34,182 to reflect the  
11 actual 13 month average ending December 2010 customer deposit balances as  
12 shown on Exhibit \_\_\_\_ (MJM-2) Schedule 4.4, Adjustment 4 Customer Deposits  
13 (Co. Adj. A19). The impact of the interest expense on operating income was less  
14 than a thousand dollars and is immaterial.

15 **Adjustment 6-Bargaining Unit Wage Adjustment**

16 **Q. WHAT ASSUMPTIONS DID THE COMPANY USE TO DEVELOP THE**  
17 **2011 BUDGET TEST YEAR FOR BARGAINING UNIT EMPLOYEES'**  
18 **WAGES AND SALARIES?**

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The Company used a salary level increase of 3.0% for bargaining employees in its  
2 2011 test year. The salary level used for bargaining unit employees was based  
3 upon an agreement that was effective until December 31, 2010.<sup>33</sup>

4 **Q. IS THERE A NEW AGREEMENT THAT REPLACES THE UNION**  
5 **AGREEMENT THAT ENDED DECEMBER 31, 2010?**

6 A. Yes, the Company stated that since the time the rate case application was filed,  
7 binding interest-based arbitration occurred that resulted in a new labor  
8 agreement.<sup>34</sup>

9 **Q. ARE THE PROVISIONS WITHIN THE NEW LABOR AGREEMENT**  
10 **DIFFERENT THAN THE ASSUMPTIONS USED BY THE COMPANY IN**  
11 **ITS INITIAL RATE CASE FILING?**

12 A. Yes, there are several provisions in the new labor agreement that will impact the  
13 2011 test year costs. The first is a reduction in the base salary increase for  
14 bargaining employees from the assumed 3.0% to 2.5%. The Company stated it  
15 would make a downward adjustment in its Rebuttal Testimony to reflect the  
16 reduction to a 2.5% increase in base salary in 2011 for bargaining employees.<sup>35</sup>

17 **Q. HAVE YOU INCLUDED THIS DOWNWARD ADJUSTMENT IN WAGE**  
18 **REDUCTIONS IN YOUR REVENUE REQUIREMENTS**  
19 **CALCULATIONS?**

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<sup>33</sup> Exhibit \_\_\_ (MJM-11) Data Request and Response AS-RR-130.

<sup>34</sup> Exhibit \_\_\_ (MJM-11) Data Request and Response AS-RR-130.

<sup>35</sup> Exhibit \_\_\_ (MJM-11) Data Request and Response AS-RR-130.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. Yes. I have also included the resultant impact to payroll taxes in my revenue  
2 requirements calculations. Operating income should increase by \$23,582 and rate  
3 base should be reduced by \$8,197 to reflect the wages and payroll taxes that have  
4 been capitalized. My calculations are shown on Exhibit \_\_\_ (MJM-2) Schedule  
5 4.6, Adjustment 6 Bargaining Unit Wage Adjustment.

6 **Adjustment 7-Employee Benefits**

7 **Q. WHAT OTHER PROVISIONS IN THE NEW LABOR AGREEMENT ARE**  
8 **DIFFERENT FROM WHAT THE COMPANY USED IN ITS ESTIMATED**  
9 **2011 TEST YEAR?**

10 A. The new labor agreement reduced the High Deductible Health Plan (HDHP) for  
11 certain bargaining employees.<sup>36</sup> Changes were also made for non-bargaining  
12 employees. The savings associated with the reductions in the HDHP plan were  
13 not reflected in the 2011 test year due to the timing of finalizing the plans and the  
14 bargaining unit negotiations.<sup>37</sup>

15 **Q. WHAT IS THE IMPACT OF THESE SAVINGS ON THE COMPANY'S**  
16 **RATE INCREASE REQUEST?**

17 A. The Company stated that the impact of the reduction in the HDHP to the 2011 test  
18 year for the North Dakota electric jurisdiction is approximately \$174,000.  
19 Offsetting this HDHP decrease is a cost increase of approximately \$8,000  
20 resulting from the NSPM bargaining dental cost share change of 60 percent

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<sup>36</sup> Direct Testimony of Jill H. Reed, p. 15, lines 20-21.

<sup>37</sup> Exhibit \_\_\_ (MJM-12) Data Request and Response AS-RR-148.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           employer and 40 percent employee to a cost share of 75 percent employer and 25  
2           percent employee.<sup>38</sup>

3   **Q.    ARE THERE ANY ADDITIONAL CHANGES THAT SHOULD BE MADE**  
4   **AS A RESULT OF THE NEW LABOR AGREEMENT?**

5   A.    Yes, two mandatory drug programs were not reflected in the 2011 test year due to  
6           the timing of finalizing the program changes and the labor negotiations with the  
7           NSP union. These prescription drug plan changes have since been implemented  
8           for all non-bargaining and bargaining NSP employees. The Company stated that  
9           the 2011 test year for the North Dakota electric jurisdiction from these changes is  
10          a savings of \$12,000.<sup>39</sup>

11 **Q.    WHAT DO YOU RECOMMEND?**

12 A.    I recommend accepting the Company's adjustment for changes to employee  
13          benefits as a result of the new bargaining agreement and have included an  
14          adjustment within my revenue requirements calculations for the changes.  
15          Operating income should increase by \$108,029 as shown in Exhibit \_\_\_\_ (MJM-2)  
16          Schedule 4.7, Adjustment 7 Employee Benefits.

17           **Adjustment 8-Employee Retirement Programs**

18 **Q.    WHAT IS THE COMPANY'S ADJUSTMENT FOR EMPLOYEE**  
19 **RETIREMENT PROGRAMS?**

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<sup>38</sup> Exhibit \_\_\_\_ (MJM-12) Data Request and Response AS-RR-148.

<sup>39</sup> Exhibit \_\_\_\_ (MJM-13) Data Request and Response AS-RR-149.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The Company made an adjustment of \$68,833 for the ND electric jurisdiction to  
2 represent the net difference between the original 2011 budget amount and the  
3 2011 estimated amount from a Towers Watson actuarial study dated October 1,  
4 2010.<sup>40</sup>

5 **Q. WERE THE ESTIMATED 2011 EMPLOYEE RETIREMENT PROGRAM**  
6 **COSTS UPDATED FOR ACTUAL COSTS?**

7 A. Yes, the final updated information that establishes the actual 2011 pension costs  
8 was provided to the Company by Towers Watson in a report dated May 10,  
9 2011.<sup>41</sup>

10 **Q. DID THE COMPANY CALCULATE THE IMPACT OF USING THIS**  
11 **NEW TOWERS WATSON STUDY ON ITS REVENUE REQUEST?**

12 A. Yes, using the revised actual costs provided in the recent Towers Watson study  
13 dated May 10, 2011, the Company calculated that the 2011 budget should have  
14 been reduced by \$80,838.<sup>42</sup>

15 **Q. WHAT DO YOU RECOMMEND?**

16 A. During periods with significant variability, multi-year averages are frequently  
17 used to smooth out any extremes. However, when changes are made that will  
18 have a continual future impact resulting in a trend (either up or down) a multi-  
19 year average is not a good indicator of expected costs during the rate effective  
20 period.

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<sup>40</sup> Exhibit \_\_\_ (MJM-14) Data Request and Response AS-RR-151.

<sup>41</sup> Exhibit \_\_\_ (MJM-15) Data Request and Response AS-RR-196.

<sup>42</sup> Exhibit \_\_\_ (MJM-16) Data Request and Response AS-RR-328.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           The Company made changes to its 401(k) Savings Plan by raising the  
2           level of contributions required for bargaining and non-bargaining employees to  
3           receive the full employer match.<sup>43</sup> The Company also eliminated a post  
4           retirement medical benefit<sup>44</sup> that will result in declining costs each year with the  
5           reduction in post retirement benefits available to retiring employees. Thus these  
6           changes will have continual future impact and the use of a multi-year average  
7           would not be reflective of the costs to be incurred during the rate effective period.

8           I recommend that the employee retirement programs reflect the most  
9           recent actuarial study that takes into consideration modifications of retirement  
10          benefits and their impact over time. I recommend that the Commission adopt the  
11          Company's calculated reduction to retirement benefits expenses of \$80,838  
12          reflective of the most recent actuarial study. Operating income would increase by  
13          \$49,129 as shown on Exhibit \_\_\_ (MJM-2) Schedule 4.8, Adjustment 8 Employee  
14          Retirement Programs (Co. Adj. O2).

15          **Adjustment 9-Mercury Sorbent Reduction**

16          **Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S**  
17          **POSITION CONCERNING THE SHERCO 3 MERCURY SORBENT**  
18          **ADJUSTMENT.**

19          **A.** Mercury sorbent is used in Sherco Unit 3 to reduce mercury emissions during  
20          plant operation. The Company reevaluated the budget requirements of Sherco

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<sup>43</sup> Direct testimony of Jill H. Reed, page 19, lines 3-6.

<sup>44</sup> Direct testimony of Jill H. Reed, page 19, lines 13-14.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           Unit 3, resulting in a North Dakota jurisdictional downward adjustment to  
2           mercury sorbent costs of \$52,061.<sup>45</sup>

3   **Q.    IS THE COMPANY-PROPOSED ADJUSTMENT EQUITABLE?**

4   A.    No. Mercury sorbent is used in Sherco 3 to remain within Minnesota power plant  
5           mercury emission regulations. However, North Dakota has no such regulations.  
6           Furthermore, no current federal regulations exist for the limitation of mercury  
7           emissions by power plants.

8   **Q.    HAS THE EPA INITIATED FEDERAL REGULATION CONCERNING**  
9           **MERCURY EMISSION FROM POWER PLANTS?**

10 A.    Yes. The Clean Air Mercury Rule (CAMR) was finalized in May 2005. However,  
11           on February 8, 2008, the U.S. Court of Appeals for the DC Circuit vacated the  
12           CAMR. The EPA drafted and published new mercury rules in the Federal  
13           Register on May 3, 2011.<sup>46</sup> However, these are proposed regulations that are  
14           being considered and for which comments are being received. Considering the  
15           speculative nature of the proposed rules and the fact that the U.S. Court of  
16           Appeals has already vacated a previous set of EPA regulations in this regard, not  
17           only do no known and measureable regulations mandated by the federal  
18           government currently exist, but no assurances exist as to future regulations or  
19           regulatory levels for power plant mercury emissions.

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<sup>45</sup> Exhibit \_\_\_ (MJM-17) Company Workpaper A14-2.

<sup>46</sup> Exhibit \_\_\_ (MJM-4) Data Request and Response AS-RR-302.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    WHAT PORTION OF THE MERCURY SORBENT EXPENSE SHOULD**  
2   **NORTH DAKOTA JURISDICTION CUSTOMERS BEAR?**

3   A.    Since neither North Dakota nor the federal government have any known and  
4        measureable regulations regarding mercury emissions, none of the mercury  
5        sorbent expense should be borne by the North Dakota ratepayers. Therefore, the  
6        revenue requirement should be modified to remove all of Sherco 3's allocated  
7        mercury sorbent expense.

8   **Q.    DOES THE TEST YEAR BUDGET INCLUDE ANY OTHER MERCURY**  
9   **SORBENT EXPENSE?**

10  A.    Yes. According to the Company, an allocated amount of the mercury sorbent  
11        expense for the King plant is also in the test year budget.<sup>47</sup> For the same reasons  
12        cited for removing the Sherco mercury sorbent expense, the allocated King plant  
13        mercury sorbent expense should be removed from the test year. The result would  
14        be an increase to operating income of \$153,559 as shown on Exhibit \_\_\_\_ (MJM-  
15        2) Schedule 4.9, Adjustment 9 Mercury Sorbent Reduction (Co. Adj. 14).

16        **Adjustment 10-Qwest Pole Attachments**

17  **Q.    PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S**  
18  **POSITION CONCERNING THE QWEST POLE ATTACHMENTS**  
19  **ADJUSTMENT.**

20  A.    Qwest, the phone company that owns poles on which NSPM's distribution wires  
21        are attached in the North Dakota jurisdiction, is expanding their pole replacement

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<sup>47</sup> Exhibit \_\_\_\_ (MJM-18) Data Request and Response AS-RR-342 Revised.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           program. Poles are replaced for deficiencies due to deterioration. When a pole is  
2           replaced, Company crews must remove the NSPM wires and reattach them to the  
3           replacement poles. NSPM had an original 2011 budget of \$109,000 for  
4           approximately 104 pole replacements at a cost of about \$1,049 per pole.<sup>48</sup> Qwest  
5           has increased their program significantly, expecting to replace in 2011, instead of  
6           about 104 poles per year, approximately 700 poles per year.<sup>49</sup> This total  
7           increase—an additional 596 poles at \$1,049 per pole—is about \$625,000 for  
8           NSPM company-wide.<sup>50</sup>

9   **Q.    OF THE \$625,000 INCREASE TO NSPM, HOW MUCH HAS BEEN**  
10 **ALLOCATED TO THE NORTH DAKOTA JURISDICTION?**

11 A.    The North Dakota jurisdiction has been allocated 2.9% of the \$625,000,  
12        increasing its revenue requirement expenses by \$18,125.<sup>51</sup> The 2.9% allocation  
13        was determined based on the number of poles in the North Dakota jurisdiction as  
14        compared with NSPM as a whole. North Dakota has 1,900 or about 2.9% of  
15        NSPM's total 67,000 poles.<sup>52</sup>

16 **Q.    IN YOUR OPINION, IS THIS AN EQUITABLE MANNER IN WHICH TO**  
17 **ALLOCATE THE COSTS OF POLE REPLACEMENTS?**

18 A.    No. The North Dakota jurisdiction has historically required fewer replacements  
19        on a percentage basis than has the rest of NSPM. For example, while

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<sup>48</sup> Exhibit \_\_\_ (MJM-19) Data Request and Response AS-RR-167.

<sup>49</sup> Exhibit \_\_\_ (MJM-20) Company Workpaper A11-4 and Exhibit \_\_\_ (MJM-21) Data Request and Response AS-RR-166.

<sup>50</sup> Exhibit \_\_\_ (MJM-22) Company Workpaper A11-2.

<sup>51</sup> Exhibit \_\_\_ (MJM-22) Company Workpaper A11-2.

<sup>52</sup> Exhibit \_\_\_ (MJM-20) Company Workpaper A11-4.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           replacements for NSPM as a whole for 2007, 2008, and 2009 were 111, 111, and  
2           163, respectively, replacements in the North Dakota district were 1, 1, and 2,  
3           respectively for those same years.<sup>53</sup> Therefore, North Dakota’s historical average  
4           of replacements for those years was only 1.04% of replacements, which is less  
5           than the 2.9% for costs being allocated.

6   **Q.   WHAT SHOULD BE THE ALLOCATION FOR THE NORTH DAKOTA**  
7   **JURISDICTION?**

8   A.   Multiplying the NSPM company-wide increase of \$625,000 by the historical  
9        replacement trend of the North Dakota jurisdiction (1.04%) yields a lower  
10       allocated amount. Therefore, the Company’s revenue requirement should be  
11       reduced to reflect the 1.04% allocation of pole replacements in North Dakota.  
12       The impact to operating income would be an increase of \$7,069 as shown on  
13       Exhibit \_\_\_ (MJM-2) Schedule 4.10, Adjustment 10 Qwest Pole Replacements  
14       (Co. Adj. A11).

15       **Adjustment 11-Bad Debt Expense**

16   **Q.   PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY’S**  
17   **ADJUSTMENT TO BAD DEBT EXPENSE.**

18   A.   The level of bad debt expense included in the test year for the North Dakota  
19        electric jurisdiction is \$785,000. The total bad debt expense consists of two  
20        components: first, a commodity bad debt expense of \$777,000; and second, a non-

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<sup>53</sup> Exhibit \_\_\_ (MJM-19) Data Request and Response AS-RR-167.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 energy related bad debt expense of \$8,000.<sup>54</sup> The Company is recommending an  
2 update to the 2011 budget bad debt expense. The original budget calculation for  
3 bad debt expense was generated during the budget-create process in May of 2010.  
4 In preparing the test year income for the case statement, the Company reviewed  
5 its bad debt calculation and updated it with the revenue forecast included in the  
6 rate case test year. The result of this review indicated that the 2011 budget bad  
7 debt expense level assigned to the North Dakota Electric jurisdiction should be  
8 decreased by \$46,000.<sup>55</sup>

9 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENT?**

10 A. No.

11 **Q. PLEASE EXPLAIN.**

12 A. Based on a review of the Company's historical bad debt expenses for 2008  
13 through 2010, I found that there is a significant downward trend to bad debt  
14 expenses. As shown in the table below, NSPM's<sup>56</sup> uncollectible bad debt has  
15 been trending significantly downward since 2008 with a 23% reduction in 2009  
16 and another 19% in 2010 (total of 43% since 2008). Yet, NSP has budgeted  
17 nearly \$14 million which is 21% more than they experienced in 2010 bringing  
18 them back to slightly less than the level they incurred in 2009.

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<sup>54</sup> Direct Testimony of John M. Felling, page 59, lines 19-22.

<sup>55</sup> Direct Testimony of John M. Felling, pages 59-60, lines 26-27 & 1-4.

<sup>56</sup> This is Company total including North Dakota, Minnesota, and Wisconsin. North Dakota's jurisdictional amount is approximately 4.375%.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Table 1: Bad Debt (FERC Account 904) by Year

Year	FERC (904) - Bad Debt	Percent Change
2008	\$18,758,032	na
2009	\$14,379,366	-23%
2010	\$11,575,400	-19%
<b>Test year</b>	<b>\$13,954,946</b>	<b>21%</b>

**Q. DID NSP PROVIDE ANY EXPLANATION FOR USING THE AMOUNT THAT IT DID?**

A. Yes. The Company indicated that when the 2011 budget was developed in the spring of 2010, NSP used actual bad debt for the period April 2009 through March 2010.<sup>57</sup> The Company also provided additional explanation for the budget adjustment that it made to its original filing which was presented in the Company's workpapers.<sup>58</sup>

**Q. DO YOU AGREE THAT THIS BUDGET ADJUSTMENT IS SUFFICIENT?**

A. No. The Company's actual history in this regard clearly shows a downward trend. Further, in response to a data request, NSP stated,

"However, the 2010 year-end bad debt results were better than the historic period that was used to develop the budget. The lower actual bad debt expense in 2010 of \$5.6 million in FERC 904 is primarily due to three factors. These factors were less billed commodity revenues than budgeted, a favorable change to the bad debt reserve during the year, and less in write-offs than anticipated. For NSPM, the three factors primarily reflect: a) lower commodity prices as compared to recent prior periods, b) favorable changes in economic conditions, c) greater attention on collection related

<sup>57</sup> Exhibit \_\_\_ (MJM-23) Data Request and Response AS-RR-353.

<sup>58</sup> Exhibit \_\_\_ (MJM-23) Data Request and Response AS-RR-353.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 activities by Customer Care, and d) increased customer assistance  
2 payments.”<sup>59</sup>  
3

4 From this response, it is clear that the factors that led to the lower expense were as  
5 a result of factors which were both within and outside the Company’s control.  
6 The Company has not presented any evidence that would suggest that this trend  
7 would reverse during the test year.

8 **Q. WHAT DO YOU RECOMMEND?**

9 A. I recommend that absent compelling evidence to the contrary, NSP’s revenue  
10 requirement be established based on the 2010 known and measurable amount.  
11 This adjustment will result in an increase in operating income of \$164,881 as  
12 shown on Exhibit \_\_\_ (MJM-2) Schedule 4.11, Adjustment 11 Bad Debt (Co.  
13 Adj. A10).

14 **Adjustment 12-Economic Development Costs**

15 **Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO NSP’S PROPOSED**  
16 **ECONOMIC DEVELOPMENT COSTS.**

17 A. The Company makes contributions to a number of regional and local economic  
18 development organizations in its North Dakota jurisdictional operations. Witness  
19 Felling proffered that these organizations are positioned to combine resources for  
20 the purpose of maintaining and improving the long-term economic health of  
21 communities in its service territory or retaining employment opportunities and  
22 expanding the state and local tax base. Because all economic development costs

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<sup>59</sup> Exhibit \_\_\_ (MJM-24) Data Request and Response AS-RR-352.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           were recorded as below-the-line donations, the Company states that an adjustment  
2           is necessary to include economic development contributions. Witness Felling  
3           stated that their proposed treatment for these costs is consistent with prior  
4           regulatory treatment in North Dakota.<sup>60</sup> Witness Felling proposes to increase test-  
5           year revenue requirements by \$64,000.

6   **Q.    IS THIS \$64,000 100% OF THE COST ASSOCIATED WITH ECONOMIC**  
7   **DEVELOPMENT?**

8   A.    Yes. In reviewing the Company's workpapers, I found that this amount represents  
9           100% of the costs that NSP recorded as below-the-line in FERC account 426.1.<sup>61</sup>

10 **Q.    IS THE COMPANY PROPOSING TO RECOVER 100% OF THESE**  
11 **TYPES OF COSTS IN OTHER JURISDICTIONS?**

12 A.    No. The workpaper shows that in Minnesota the Company proposed to include  
13           50%, and in South Dakota, the Company proposed to include 50% of the 1<sup>st</sup>  
14           \$100,000 (or up to \$50,000).

15 **Q.    WHAT DO YOUR RECOMMEND?**

16 A.    I recommend that the Commission reject this adjustment in its entirety. The  
17           Company's proposed adjustment does not reflect that shareholders benefit from  
18           the long-term growth that economic development organizations strive to  
19           encourage. To be clear, I am not saying that these organizations are not worthy of  
20           support from local businesses. Quite the contrary, economic development

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<sup>60</sup> Direct Testimony of John M. Felling page 62, Lines 13-20.

<sup>61</sup> Exhibit \_\_\_ (MJM-25) Company Workpaper A15-3.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 organizations are valuable to promoting the business and economic interests in  
2 which they serve. They foster employment from increased business activity and  
3 recruitment. This is certainly positive. However, I believe that shareholders, not  
4 ratepayers, should bear the responsibility for funding such organizations.  
5 Therefore, I recommend that the \$64,000 supported by Witness Felling be  
6 removed from the company's revenue requirement. The result would be an  
7 increase to operating income of \$38,914 after taxes as shown in Exhibit \_\_\_  
8 (MJM-2) Schedule 4.12, Adjustment 12 Economic Development Costs (Co. Adj.  
9 A15).

10 **Adjustment 13-Charitable Contributions**

11 **Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S**  
12 **POSITION CONCERNING THE CHARITABLE CONTRIBUTIONS**  
13 **ADJUSTMENT.**

14 A. The Company reviewed Charitable Contributions (or Donations) to include only  
15 those contributions associated with the North Dakota jurisdiction.<sup>62</sup> The Company  
16 included 50%, or \$131,608, as an adjustment increasing operating expenses.<sup>63</sup>  
17 Presumably, the Company limited the charitable contributions associated with  
18 North Dakota to 50% to match the percentage agreed to in the Settlement of the  
19 last case.<sup>64</sup>

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<sup>62</sup> Direct Testimony of John M. Felling, page 63, line 26 – page 64, line 25 and Exhibit \_\_\_ (MJM-26) Company Workpaper A18-2.

<sup>63</sup> Direct Testimony of John M. Felling, page 63, lines 24-25 and Exhibit \_\_\_ (MJM-26) Company Workpaper A18-2).

<sup>64</sup> Exhibit \_\_\_ (MJM-27) December 22, 2008, Settlement Agreement – Charitable Contributions, PU-07-776, page 14, paragraph J.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    IS THE COMPANY-PROPOSED ADJUSTMENT EQUITABLE?**

2    A.    No. The implication that ratepayers are forced to pay charitable contributions to  
3       those charities decided on by the Company without measured benefit to the  
4       ratepayers is inappropriate. Charity by one party using the funds of another party  
5       ceases to be charity and becomes an obligated payment. Since the Company  
6       cannot provide documented and detailed value or benefit directly associated with  
7       this payment, it should not be the burden of the North Dakota ratepayers. For  
8       example, of the total \$263,216 allocated to the North Dakota jurisdiction, \$54,516  
9       (21%) is a donation to the United Way, an organization that seeks to improve the  
10      quality of life for those less fortunate through the specific goals of helping people  
11      improve education, achieve financial stability, and promote health. While the  
12      United Way is a world renowned charitable organization, ratepayers may  
13      individually decide to give to the United Way, but should not be required to do so  
14      through the mandate of their electric power provider.

15   **Q.    HOW SHOULD THE CHARITABLE CONTRIBUTIONS ADJUSTMENT**  
16       **BE MODIFIED?**

17    A.    The Company's charitable contributions adjustment should be disallowed in its  
18       entirety and removed from the test year. Therefore, I recommend that the  
19       \$131,608 supported by Witness Felling be removed from the company's revenue  
20       requirement. The result would be an increase to operating income of \$79,984  
21       after income taxes as shown in Exhibit \_\_\_ (MJM-2) Schedule 4.13, Adjustment  
22       13 Charitable Contributions (Co. Adj. A18).

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1            **Adjustments 14 & 15-Incentive Compensation**

2            **Q.    PLEASE DESCRIBE YOUR UNDERSTANDING OF WHAT THE**  
3            **COMPANY INCLUDED IN ITS 2011 TEST-YEAR COST OF SERVICE**  
4            **FOR INCENTIVE COMPENSATION?**

5            A.    The ND electric jurisdiction incentive pay included in the 2011 test year cost of  
6            service is \$1,329,426.<sup>65</sup> The Company used the 2011 budget as the basis for the  
7            test-year incentive compensation and then excluded the long-term portion of the  
8            officer's incentive compensation, any non-corporate incentive plan costs, and all  
9            incentive plan costs above fifteen percent of base pay.<sup>66</sup>

10          **Q.    DID THE COMPANY ALSO REMOVE THE PAYROLL TAXES**  
11          **ASSOCIATED WITH ITS ADJUSTMENT TO EXCLUDE THE LONG-**  
12          **TERM PORTION OF THE OFFICER'S INCENTIVE COMPENSATION,**  
13          **ANY NON-CORPORATE INCENTIVE PLAN COSTS, AND ALL**  
14          **INCENTIVE PLAN COSTS ABOVE FIFTEEN PERCENT OF BASE PAY?**

15          A.    No. The Company stated that the incentive adjustment did not include any  
16          adjustment for payroll taxes. The Company stated that an estimate of the  
17          Medicare payroll taxes associated with the \$512,569 excluding incentive would  
18          be \$7,432 ( $\$512,569 \times .0145$  [Medicare Tax Rate]). Regarding Social Security  
19          payroll taxes, an estimate of the maximum associated with the excluded incentive  
20          amount would be \$31,779 ( $\$512,569 \times .062$  [Social Security Tax Rate]). This  
21          calculation assumes no Social Security maximum has occurred and does not

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<sup>65</sup> Direct Testimony of Jill H. Reed, page 5, line 20-21.

<sup>66</sup> Direct Testimony of John M. Felling, page 66, lines 14-16.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 include any state unemployment rates. Due to employees potentially reaching  
2 Social Security maximums, the actual Social Security payroll tax associated with  
3 excluded incentive would be between zero and \$31,779.<sup>67</sup>

4 **Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO REMOVE**  
5 **PAYROLL TAXES FROM THE COMPANY'S EXCLUDED AMOUNT?**

6 A. Yes. I recommend removal of the payroll taxes associated with the excluded long-  
7 term portion of the officer's incentive compensation, any non-corporate incentive  
8 plan costs, and all incentive plan costs above fifteen percent of base pay. The  
9 result would be an increase to operating income of \$23,832 as shown in Exhibit  
10 \_\_\_ (MJM-2) Schedule 4.14, Adjustment 14 Payroll Taxes-Excluded Incentive  
11 Comp (Co. Adj. A26).

12 **Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S**  
13 **EXCLUSION OF INCENTIVE PLAN COSTS ABOVE FIFTEEN**  
14 **PERCENT OF BASE PAY.**

15 A. Annual incentive compensation is 85% of the budget for the test year. The  
16 Company testified that the budget target is less than the average of incentive  
17 compensation paid over the last four years. The four year average payout for 2006  
18 through 2009 was 89%.<sup>68</sup>

19 **Q. WHAT IS THE FOUR YEAR AVERAGE PAYOUT THROUGH 2010?**

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<sup>67</sup> Exhibit \_\_\_ (MJM-28) Data Request and Response AS-RR-350, parts d and e.

<sup>68</sup> Exhibit \_\_\_ (MJM-29) Exhibit \_\_\_ (JHR-1), Schedule 2.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The four year average payout for 2007 through 2010 is 83%.<sup>69</sup>

2 **Q. DO YOU RECOMMEND AN ADJUSTMENT FOR THIS DIFFERENCE?**

3 A. Yes, the annual incentive compensation included within the test year costs should  
4 be reduced by two percent (85% less 83% payout of the budget). The payroll  
5 taxes associated with this adjustment should also be removed. The result would be  
6 an increase in operating income of \$8,013 as shown on Exhibit \_\_\_\_ (MJM-2)  
7 Schedule 4.15, Adjustment 15 Incentive Compensation (Co. Adj. A26).

8 **Q. DID YOU REVIEW WHETHER THE COMPANY'S 2011 INCENTIVE**  
9 **COMPENSATION PLAN INCLUDED FINANCIAL INCENTIVE FOR**  
10 **EMISSION RELATED PROGRAMS?**

11 A. Yes, the Company was asked to provide the 2011 Corporate and Business area  
12 performance goals. The Company provided a series of tables which shows the key  
13 performance indicators (KPI) for Xcel Corporate and the individual operating  
14 companies including NSP-M.<sup>70</sup>

15 **Q. DID ANY OF THESE KPI'S INCLUDE THE POTENTIAL FOR**  
16 **INCENTIVES TO BE PAID BASED ON, IN PART, EMISSION RELATED**  
17 **REDUCTIONS ASSOCIATED WITH GREENHOUSE GAS PROGRAMS?**

18  
19 A. No. From the information provided, I have determined that none of the programs  
20 are related to emissions related programs.

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<sup>69</sup> Exhibit \_\_\_\_ (MJM-30) Data Request and Response AS-RR-140.

<sup>70</sup> Exhibit \_\_\_\_ (MJM-31) Data Request and Response AS-RR-351.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1   **Q.    WAS THIS ALWAYS THE CASE?**

2    A.    No. In 2010, Xcel clearly had KPI's associated with emissions related programs.  
3           The Company corporate level, emissions reduction goals accounted for up to 10%  
4           of the weighted KPI.<sup>71</sup> The goals on an individual company level are not as  
5           obviously emission related goals as they are identified as "Environmental  
6           Performance (MN, CO, NM Electric Energy Efficiency (GWh))."<sup>72</sup> However,  
7           other areas with the Company clearly show emission related incentives.

8   **Q.    CAN YOU CONFIRM THAT EMISSIONS RELATED GOALS HAVE**  
9           **BEEN REMOVED FROM THE COMPANY'S INCENTIVE**  
10          **COMPENSATION PLANS AND THAT NO EMISSIONS RELATED**  
11          **INCENTIVES ARE BEING ALLOCATED OR DIRECTLY CHARGED TO**  
12          **NORTH DAKOTA RATEPAYERS IN THE 2011 TEST YEAR AND 2012**  
13          **STEP UP?**

14   A.    As of the time of this testimony, I do not have confirmation. I would ask that the  
15          Company provide that confirmation in its rebuttal.

16          **Adjustment 16-Aviation Expense**

17   **Q.    PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMPANY'S**  
18          **POSITION CONCERNING THE AVIATION ADJUSTMENT.**

19   A.    Xcel Energy owns two aircraft for use by company personnel. Expenses for the  
20          aircraft are allocated among the Xcel Energy companies. NSP was allocated

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<sup>71</sup> Exhibit \_\_\_ (MJM-31) Data Request and Response AS-RR-351, Attachment A, page 1 of 17.

<sup>72</sup> Exhibit \_\_\_ (MJM-31) Data Request and Response AS-RR-351, Attachment A, page 2 of 17.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           \$98,772 of NSPM’s \$1,654,923 allocation.<sup>73</sup> The Company stated that after  
2           “carefully reviewing the costs and benefits of these aircraft,” they reduced the  
3           costs by half (i.e., \$49,386), effectively removing the costs of one of the aircraft.<sup>74</sup>

4   **Q.    IS THE COMPANY-PROPOSED ADJUSTMENT EQUITABLE?**

5    A.    The Company could not provide the documentation of their review so that  
6           equitability could be established. Instead, the Company’s position is that the  
7           “aviation adjustment was not based upon the examination of specific costs.”<sup>75</sup>

8   **Q.    HOW DOES THIS IMPACT THE VERIFICATION OF COSTS**  
9           **ALLOCATED TO NORTH DAKOTA FOR REVENUE REQUIREMENT**  
10          **DETERMINATION?**

11   A.    Without a basis whereby the Company can demonstrate the benefit to North  
12          Dakota for the use of these aircraft, none of the Aviation expenses should be a  
13          part of the revenue requirement calculation. Therefore, the Company-proposed  
14          adjustment of reducing Revenue Requirement expense by 50% of the aviation  
15          expense should be modified to a reduction of 100% of the aviation expense. My  
16          adjustment would increase operating income by \$30,014 as shown on Exhibit \_\_\_\_  
17          (MJM-2) Schedule 4.16, Adjustment 16 Aviation Expense (Co. Adj. A28).

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<sup>73</sup> Exhibit \_\_\_\_ (MJM-32) Company Workpaper A28-2.  
<sup>74</sup> Direct Testimony of John M. Felling, page 67, lines 22-24.  
<sup>75</sup> Exhibit \_\_\_\_ (MJM-33) Data Request and Response AS-RR-299.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1            **Adjustment 17-Nuclear Waste Disposal Litigation Costs**

2            **Q.    PLEASE SUMMARIZE THE PAST AND CURRENT EVENTS**  
3            **REGARDING NUCLEAR WASTE DISPOSAL LITIGATION COSTS.**

4            A.    In 1998 NSPM sued the Department of Energy (DOE) for breach of contract for  
5            failure to begin acceptance and removal of spent fuel. In 2007 NSPM was  
6            awarded a judgment of \$116,000,000 for damages through 2004. Subsequently, in  
7            February 2008, the DOE filed an appeal. To date a decision has not been  
8            reached.<sup>76 77</sup>

9                        In August 2007 the Company filed a second complaint against the DOE,  
10            again claiming breach of contract damages. This lawsuit covered the period  
11            January 2005 through December 2008 and includes costs associated with the  
12            storage of spent nuclear fuel at the Prairie Island and Monticello Nuclear Power  
13            Plants as well as costs for complying with the state regulations for Nuclear Fuel.  
14            A trial was expected in 2011.<sup>78</sup>

15                      On July 8, 2011, Xcel Energy (NSPM's parent company) filed a letter  
16            with the Commission indicating that the Company had settled the lawsuit with  
17            DOE. Xcel stated:

18                                “The settlement resolves over a decade of on-going litigation that  
19                                continues to have no clearly foreseeable resolution in the courts.  
20                                Under the terms of the settlement, the DOE will make an initial  
21                                payment of just under \$100 million (total Company) to cover spent  
22                                nuclear fuel storage costs incurred through December 31, 2008.  
23                                The settlement also provides a mechanism for the Company to  
24                                recover its spent nuclear fuel storage damages through December  
25                                31, 2013. We believe that the additional damage payments through

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<sup>76</sup> Direct Testimony Dennis L. Koehl, page 30, lines 22-26.

<sup>77</sup> Exhibit \_\_\_ (MJM-34) 2010 Form 10-K page 45, legal contingencies.

<sup>78</sup> Direct Testimony of Dennis L. Koehl, page 31, lines 1-8.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           2013 will total roughly an additional \$100 million on a total  
2           Company basis. The first supplemental payment, covering 2009  
3           and 2010, is expected to be received in the first quarter of 2012.  
4           Payments covering the costs incurred by the Company in 2011,  
5           2012 and 2013 are expected to be received by year end of 2012,  
6           2013 and 2014 respectively (assuming the claim amounts are  
7           resolved 'without the need for binding arbitration and the attendant  
8           delay). The settlement does not address potential claims beyond  
9           2013.”<sup>79</sup>

10   **Q.    HOW DOES ALL THIS IMPACT THE RATE CASE?**

11   A.    At the direction of Advocacy Staff, the treatment of this settlement will be  
12           handled in a separate proceeding. However, the legal fees that are no longer  
13           necessary to litigate this case were included in the Company’s test year.<sup>80</sup>

14   **Q.    WHAT DO YOU RECOMMEND?**

15   A.    In response to a data request, NSP stated that \$29,000 had been allocated to NSP  
16           from the Company’s corporate services legal budget for this litigation.<sup>81</sup> I  
17           recommend that the legal fees associated with this litigation be removed from the  
18           test year as they will be netted against the proceeds from the settlement. My  
19           adjustment would increase operating income by \$17,625 as shown in Exhibit \_\_\_\_  
20           (MJM-2) Schedule 4.17, Adjustment 17 Nuclear Waste Disposal Litigation Costs.

21           **Adjustment 18-Directors’ and Officers’ Insurance**

22   **Q.    PLEASE EXPLAIN YOUR ADJUSTMENT REGARDING DIRECTORS’**  
23           **AND OFFICERS’ (D&O) INSURANCE.**

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<sup>79</sup> Exhibit \_\_\_\_ (MJM-35) Data Request and Response AS-RR-238 supplemental Xcel Letter on DOE Settlement dated July 8, 2011

<sup>80</sup> Exhibit \_\_\_\_ (MJM-36) Data Request and Response AS-RR-238.

<sup>81</sup> Exhibit \_\_\_\_ (MJM-35) Data Request and Response AS-RR-238 supplemental.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The Company has included \$91,182 in the test year for Directors' and Officers'  
2 (D&O) insurance.<sup>82</sup> I am recommending that the costs incurred by the Company  
3 in connection with D&O liability insurance be shared between shareholders and  
4 ratepayers. The purpose of D&O insurance is to protect shareholders from the  
5 decisions of their Board of Directors. It is the Company's shareholders who elect  
6 the Board of Directors, and it is the Board of Directors who is responsible for the  
7 selection of the Company's officers. The ratepayers have no role in choosing the  
8 Board of Directors or determining whom the Board appoints as Company officers.  
9 In the event that the Company's officers and directors are sued successfully by its  
10 shareholder, the shareholder, not the ratepayers, will be compensated by the  
11 insurance companies for the losses incurred due to management's mistakes or  
12 improprieties. The ratepayers receive some benefit as D&O insurance enables the  
13 Company to attract and retain qualified directors and officers and protects the  
14 utility's balance sheet from losses. Therefore, I recommend a 50/50 sharing of the  
15 D&O insurance. My adjustment would increase operating income by \$55,416 as  
16 shown in Exhibit \_\_\_ (MJM-2), Schedule 4.18, Adjustment 18 Directors' and  
17 Officers' Insurance.

18 **Adjustments 19, 20 & 21-Amortization Adjustments**

19 **Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE COMPANY'S**  
20 **PROPOSED AMORTIZATION ADJUSTMENTS FOR RATE CASE**  
21 **EXPENSES, SO2 ALLOWANCES, AND DSM.**

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<sup>82</sup> Exhibit \_\_\_ (MJM-37) Data Request and Response AS-RR-205, Attachment D.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. In each of these adjustments, the Company is requesting that the recovery of the  
2 expenses be over a two-year amortization period--essentially, one half in the 2011  
3 test year and the other half in 2012.<sup>83</sup> Listed below are the Company's total  
4 request and amortization amounts for the test year.<sup>84</sup>

5 **Table 2: Amortization Request for Rate Case Expenses, SO2 Allowances and DSM**

Line no	Item	Requested Amount		
		Total	Amortization	Amount
1	2011 Rate Case Expenses	\$ 562,000	2 years	\$ 281,000
2	2011 SO2 Emission Allowances	\$ (260,000)	2 years	\$ (130,000)
3	2011 DSM	\$ 451,000	2 years	\$ 225,500
4	Total	\$ 753,000	2 years	\$ 376,500

6  
7 **Q. WHAT IS THE BASIS OF THE AMORTIZATION PERIOD?**

8 A. Witness Felling states that he is recommending the two-year amortization period  
9 for these items "because we anticipate filing another electric general rate case  
10 within two years."<sup>85</sup> I would presume that the Company would intend to have a  
11 zero balance for these amortization items upon filing its next rate case.

12 **Q. DO YOU AGREE WITH THIS AMORTIZATION PERIOD?**

13 A. No. I would recommend amortization over a three-year period.

14 **Q. ON WHAT BASIS?**

15 A. First, to ease the burden on customers. They are being asked to endure a  
16 proposed 12% increase in rates, after only recently experiencing a 7.4% percent

<sup>83</sup> Direct Testimony of John M. Felling, pages 70 and 71.

<sup>84</sup> Direct Testimony of John M. Felling, for 2011 Rate Case Expense, page 70, lines 3-6; for 2011 SO2 Emissions Allowance, page 70, lines 19-22; and for 2011 DSM, page 71, lines 10-12.

<sup>85</sup> Direct Testimony of John M. Felling, page 69, lines 5-7.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           increase in 2008,<sup>86</sup> with the prospect of an additional step increase in 2012 and an  
2           additional filing in 2012 (as noted by Witness Felling). Second, if the intent is to  
3           have a zero balance for these amortization balances by the time new rates are  
4           approved and implemented in the next case, then a 3-year period would  
5           accomplish that goal since the amortization would be coming down as the next  
6           case is litigated. Finally, this would then make all the amortization periods  
7           consistent. Witness Felling noted that the private fuel storage costs will be fully  
8           amortized in three years.<sup>87</sup>

9   **Q.    WHAT IS THE IMPACT OF YOUR RECOMMENDED AJDUSTMENTS?**

10  **A.    My recommended adjustments would result in the following impacts:**

- 11           • 2011 Rate Case Expenses – operating income would increase by \$56,865 as  
12           shown on Exhibit\_\_\_(MJM-2) Schedule 4.19
- 13           • ND EPA Emission Credit Auction Proceeds – operating income would  
14           decrease by \$26,356 as shown on Exhibit\_\_\_(MJM-2) Schedule 4.20
- 15           • 2011 Demand Side Management – operating income would increase by  
16           \$116,704 as shown on Exhibit\_\_\_(MJM-2) Schedule 4.21

17           **Adjustment 22-Cash Working Capital**

18  **Q.    WHAT ADJUSTMENT HAVE YOU MADE TO CASH WORKING**  
19  **CAPITAL?**

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<sup>86</sup> Exhibit \_\_\_ (MJM-38) Case No. PU-07-776 December 31, 2008 Order Adopting Settlement.

<sup>87</sup> Direct Testimony of John M. Felling, page 69, line 5-6.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. I calculated the impact of my recommended adjustment using the Company's  
2 cash working capital calculations. The result is a reduction to rate base of  
3 \$18,313 as shown on Exhibit\_\_\_ (MJM-2) Schedule 22, Adjustment 22 Cash  
4 Working Capital.

5 **Adjustment 23-Interest Synchronization**

6 **Q. WHAT IS YOUR ADJUSTMENT TO INTEREST SYNCHRONIZATION?**

7 A. The impact of my adjustments on interest synchronization would result in an  
8 increase to operating income of \$24,000 as shown on Exhibit\_\_\_ (MJM-2)  
9 Schedule 23, Adjustment 23 Interest Synchronization.

10 **STAFF'S RECOMMENDATIONS FOR 2012 STEP**

11 **Q. PLEASE DESCRIBE YOUR ADJUSTMENTS TO THE COMPANY'S 2012**  
12 **STEP REVENUE REQUIREMENTS.**

13 A. I used the Company's revised proposed 2012 step and updated it with the  
14 adjustments previously discussed. In summary, I recommend that the Company's  
15 2012 Step revised proposed rate increase of \$20,365,000<sup>88</sup> should be adjusted by  
16 (\$6,691,000) resulting in a revenue requirement for 2012 of \$13,674,000 as  
17 shown in Exhibit\_\_\_ (MJM-2) Schedule 5 Comparison of Company's 2012 Step  
18 Up Revenue Requirements and Staff's Proposal.

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<sup>88</sup> Exhibit \_\_\_ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission, Revised Schedule 7.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 VI. RELIABILITY

2 Q. DO YOU HAVE ANY CONCERNS RELATED TO NSP'S RELIABILITY  
3 IN NORTH DAKOTA?

4 A. Yes.

5 Q. PLEASE EXPLAIN.

6 A. At the request of Advocacy Staff, I was asked to conduct a high level review of  
7 the Company's reliability indicators and expenses associated with NSP's  
8 maintenance of its distribution system in North Dakota. I was provided an  
9 example of a recent customer concern which appears to indicate that NSP's  
10 reliability is not satisfactory. The customer wrote to Advocacy Staff Mr. Michael  
11 Diller on June 28, 2011,

12 *"Dear Mike,*

13 *You and I talked about the poor service record of Xcel energy in the Fargo*  
14 *area and eastern North Dakota a few months ago. I can understand*  
15 *problems when 70 mph winds blow through town, but, again today,*  
16 *gorgeous outside...probably the nicest day of the year and yet the radio is*  
17 *reporting "thousands without power from Sabin, MN to West Fargo and*  
18 *surrounding area plus most of downtown Fargo. Fortunately for me we*  
19 *have power at this moment. But with Xcel, it's gotten so bad one worries*  
20 *about the power going out constantly; totally with expectation or reason.*

21 *I do not understand this. Before and after "the storm" - during nice*  
22 *weather - Xcel goes down, literally out of the blue. During the storm*  
23 *clean-up, of course, I understand those temporary outages as crews work*  
24 *to get power restored. But that encompassed a few weeks at most. We are*  
25 *well beyond that period and, when I first talked with you about this issue,*  
26 *we were well ahead of that time period and we had reasonably good*  
27 *seasonal weather.*

28 *I would like the Commission, led by Commissioner Cramer or somebody*  
29 *out there to start collecting reports on Xcel outages and outages from all*  
30 *power companies serving the Commission's jurisdiction. Make it*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1            *mandatory that these power companies, particularly Xcel, official report*  
2            *when they go down.*

3            *The Commission should look at the record as an ongoing duty and find out*  
4            *if it's true that Xcel A) does not know what they're doing in Fargo, eastern*  
5            *ND, and western MN....I'm mostly concerned about Fargo....and B) the*  
6            *Commission should have a truly independent electrical grid consultant*  
7            *look at Xcel operations and infrastructure and provide a report. I think*  
8            *there are serious deficiencies Xcel will not admit.”<sup>89</sup>*

9  
10           In addition, Advocacy Staff has informed me that they have been reviewing the  
11           reliability issue and that its review would be enhanced by my assessment.

12        **Q.    WHAT SPECIFICALLY DID YOU ASSESS, AND WHAT DID YOU**  
13           **CONCLUDE?**

14        A.    My high level review covered NSP’s SAIFI and CAIDI indexes for 2006-2010.  
15           In addition, I reviewed the level of distribution maintenance expenses on dollar  
16           per miles of distribution line basis. I also requested that the Company provide a  
17           description of the programs and/or projects it has in place to address the reliability  
18           of its distribution system. Based on this high-level assessment, recent trends in  
19           some of the statistics, and customer perception (as shown above), I recommend  
20           that the Commission order an operational audit of NSP’s reliability program in  
21           North Dakota to address these concerns.

22        **Q.    PLEASE CONTINUE AND EXPLAIN WHAT YOUR ASSESSMENT**  
23           **REVEALED?**

24        A.    I reviewed the report entitled, “Annual Report of Northern States Power  
25           Company, A Minnesota Corporation to The North Dakota Public Service

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<sup>89</sup> Exhibit \_\_\_\_ (MJM-39) Email from Mr. Larry Gauper to Mr. Michael Diller, dated June 28, 2011.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 Commission for the Year Ending December 31, 2010 North Dakota Jurisdiction  
2 Electric and Natural Gas Utilities.” The document contains the Company’s  
3 reliability index performance reports for the commonly used reliability indicators,  
4 SAIFI and CAIDI. SAIFI (System Average Interruption Frequency Index)  
5 provides the average number of service interruptions that a customer experienced  
6 during the reporting period. It is roughly calculated as the number of interruptions  
7 divided by the number of customers.

8 **Q. WOULD AN INCREASE IN SAIFI FROM ONE PERIOD TO ANOTHER**  
9 **INDICATE A WORSENING OF THE RELIABILITY OF THE SYSTEM?**

10 A. It might. There are many variables that go into determining whether the system is  
11 experiencing a worsening of reliability. If there is a period of increased accidents  
12 or third party damage that result in an outage, the system average SAIFI would  
13 increase. Similarly, if there is an equipment failure, such as electric feeder lines  
14 or transformers, the system average SAIFI will increase. These types of failures  
15 could be indicative of a bigger systemic problem of the Company not providing  
16 sufficient resources to properly maintain the equipment.

17 **Q. HAS THE 2010 SAIFI SCORE INCREASED OR DECREASED FROM**  
18 **PREVIOUS YEARS?**

19 A. The 2010 SAIFI score of 1.20 is a significant increase (worsening) from previous  
20 years. The 2009 score was 0.68, and the average for the previous four years was  
21 0.72. The chart below displays the trend.<sup>90</sup>

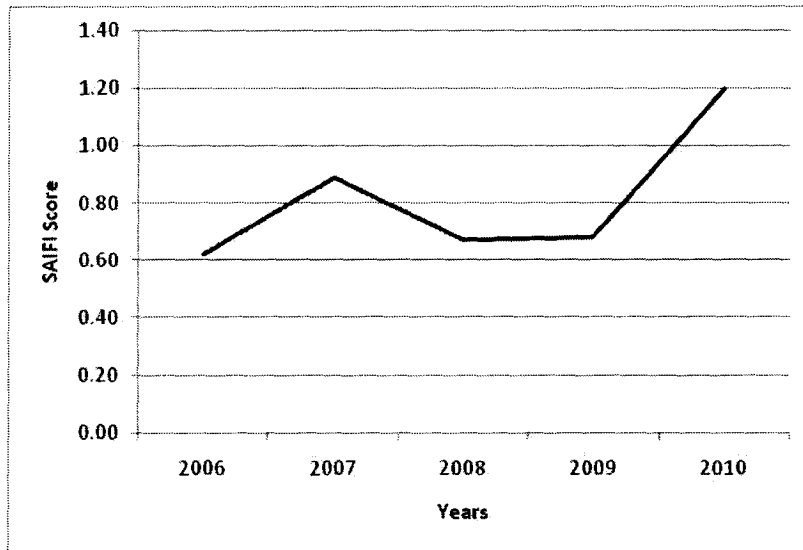
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<sup>90</sup> Exhibit \_\_\_ (MJM-40) Data Request and Response AS-RR-333.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1

Figure 1: SAIFI Score by Year



2

3 **Q. WAS THE INCREASE IN 2010 CONSISTENT ACROSS ALL REGIONS?**

4 A. No. Of the five major substations, two (Cass County and Souris) actually  
5 improved. Of the other three (Red River, Gateway, and Nordic), Gateway and  
6 Nordic experienced the most significant increases: Gateway rose from 0.19 in  
7 2009 to 0.68 in 2010 while Nordic rose from 0.55 in 2009 to 2.27 in 2010.

8 **Q. HOW DOES THE COMPANY EXPLAIN THE INCREASE?**

9 A. The Company provided information that shows that most of the causes were  
10 related to vegetation encroachment and feeder cable failures.<sup>91</sup> NSP also provided  
11 a list of major outage events at the major substation areas that caused significant  
12 SAIFI increases.

13 **Q. WHAT IS CAIDI?**

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<sup>91</sup> Exhibit \_\_\_ (MJM-41) Data Request and Response AS-RR-343, Attachment B.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. CAIDI (Customer Average Interruption Duration Index) provides an indication of  
2 the average outage duration that customers experienced during the reporting  
3 period. It is roughly calculated by dividing the sum of all customer interruption  
4 durations by the total number of customer interruptions. This indicator is useful  
5 for gauging response time to customer outages. Again an increasing trend in this  
6 statistic indicates a worsening of the Company's ability to restore customers'  
7 service in as short a time as reasonably possible.

8 **Q. WHAT WAS THE CAIDI SCORE FOR THE COMPANY IN 2010?**

9 A. The Company's CAIDI score for 2010 was 62.81, representing an improvement  
10 from the 91.55 score for 2009 and the past four year average of 85.42. This could  
11 lead me to conclude that the Company does work to improve its performance  
12 when restoring customer service. However, a closer look at the data shows that  
13 two of the major substation regions, Cass County and Souris, experienced  
14 significant increases in their scores: Cass County rose from 87.60 in 2009 to  
15 127.11 in 2010, a 45% increase, and Souris rose from 58.00 in 2009 to 76.52 in  
16 2010, a 32% increase. Obviously, such significant increases should be reviewed  
17 and evaluated for the causes of the increase. One would expect that customers  
18 served by these substations should not experience degradation in restoration time.

19 **Q. WHAT DO YOU CONCLUDE REGARDING THE RELIABILITY**  
20 **INDEXES?**

21 A. The scores (especially the SAIFI) indicate that the Company's reliability in 2010  
22 was in a downturn. Likewise, CAIDI in certain areas has also experienced a

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           downturn. Whether this was due to program weaknesses is not readily  
2           determinable.

3   **Q.   WHAT ELEMENTS ARE NECESSARY TO HAVE A ROBUST**  
4           **RELIABILITY PROGRAM?**

5   A.   A reliability program should be coordinated and comprehensive and include  
6           several fundamental components, such as emphasis on vegetation management,  
7           priority feeders, load growth, distribution automation, cable replacements, and  
8           substation improvements.

9   **Q.   DOES THE COMPANY HAVE A RELIABILITY PROGRAM OF**  
10           **COORDINATION, COMPREHENSION, AND APPROPRIATE**  
11           **COMPONENTS?**

12   A.   In response to a data request,<sup>92</sup> the Company provided a list of the programs  
13           aimed at reliability of the electric distribution system in North Dakota. NSP's  
14           programs include:

- 15           • Mainline Cable Replacements
- 16           • Tap Cable Replacements
- 17           • Pole inspections
- 18           • Pole Replacements
- 19           • Feeder Improvement Program (FPIP)
- 20           • REMS

21   **Q.   IN YOUR OPINION IS ANYTHING MISSING FROM THIS LIST?**

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<sup>92</sup> Exhibit \_\_\_\_ (MJM-42) Data Request and Response AS-RR-334.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. Yes. Vegetation management should be included. Other areas I would expect  
2 would be a transformer performance area and substations. However, these two  
3 areas may be covered in the Feeder program or REMS.

4 **Q. WHAT DID YOU OBSERVE CONCERNING THE LEVEL OF**  
5 **RESOURCES COMMITTED TO THESE PROGRAMS?**

6 A. As shown in the table below, NSP's expenditures for these programs have been  
7 swinging up and down from year to year. This may be one of the variables that is  
8 reflected in the SAIFI and CAIDI statistics. It is somewhat intuitive that spending  
9 less on maintenance in one year may cause a worsening of the system in a  
10 subsequent year as there is a lag between spending and performance.

11 **Table 3: Program Expenditures by Year<sup>93</sup>**

Total North Dakota Jurisdiction						
Program	2007	2008	2009	2010	2011	
Mainline Cable Replacement	\$ 165,691	\$ 692,876	\$ 120,616	\$ 370,862	\$ 504,784	
Tap Cable Replacements	\$ 12,498	\$ 263,794	\$ 134,663	\$ 551,860	\$ 107,000	
Pole Inspections	\$ 29,685	\$ -	\$ 73,393	\$ 86,094	\$ 72,654	
Pole Replacements	\$ 4,814	\$ 77,693	\$ 37,048	\$ 194,222	\$ 238,000	
Feeder Improvement Program (FPIP)	\$ 107,205	\$ 852	\$ 5,656	\$ -	\$ 54,000	
REMS	\$ -	\$ 5,031	\$ 4,936	\$ 30,920	\$ 6,000	
<b>Total</b>	<b>\$ 319,893</b>	<b>\$ 1,040,246</b>	<b>\$ 376,312</b>	<b>\$ 1,233,958</b>	<b>\$ 982,438</b>	
<b>New to 2011</b>						
Tap Improvement Program					\$ 9,000	
Install Remote Fault Indicators					\$ 63,000	
 					<b>\$ 1,054,438</b>	

12 Source: Response to Data Request AS-RR-334

13 **Q. WHAT ELSE DID YOU OBSERVE FROM THIS?**

14 A. As one can see, the test year budget for these initiatives is significantly less than  
15 in 2010 (\$1,054,438 vs. \$1,233,958), a 14% reduction.

<sup>93</sup> Exhibit \_\_\_\_ (MJM-42) Data Request and Response AS-RR-334.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

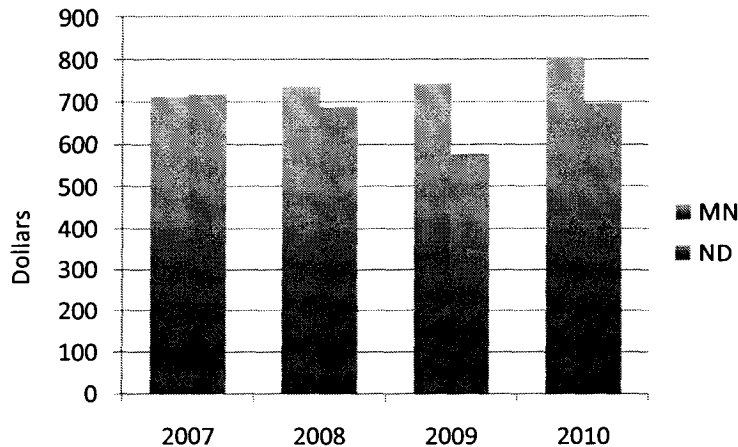
1   **Q.    IS THERE ANY OTHER INDICATOR THAT WOULD SUPPORT A**  
2       **MORE FOCUSED REVIEW OF THE COMPANY’S RELIABILITY?**

3    A.    I also reviewed the level of distribution maintenance expenses to see whether  
4        there was a trend that might indicate that the Company was spending more or less  
5        on a per mile basis. This is also a high level indicator of whether the Company is  
6        increasing or decreasing the resources it commits to distribution maintenance.

7   **Q.    WHAT DID THE RESULTS OF THIS ANALYSIS SHOW?**

8    A.    As shown in the chart below, in recent years, NSPM has been spending more  
9        maintenance dollars per mile of distribution mains. In addition, based on my  
10       estimate of number of distribution line miles in 2011, this trend continues into the  
11       test year.

12                   **Figure 2: Maintenance Dollars by Year by Jurisdiction**  
                          Maintenance Dollars per Line Mile



13  
14        A closer look at the data shows a significant difference in the later years 2009 and  
15        2010 and 2011.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

**Table 4: Distribution Maintenance Dollars/Line by Year by Jurisdiction**

Distribution Maintenance \$/Line	2007	2008	2009	2010	2011
Minnesota	\$ 711.89	\$ 736.38	\$ 740.91	\$ 805.56	\$ 793.55
North Dakota	\$ 716.80	\$ 688.46	\$ 576.74	\$ 694.39	\$ 624.56
MN greater/(less than) ND	\$ (4.91)	\$ 47.93	\$ 164.17	\$ 111.17	\$ 168.99

This table clearly shows that at a high level, NSPM is spending more on maintenance in the other jurisdictions than it does in North Dakota. I acknowledge that this is a high level assessment and that accounting treatments in various jurisdictions could impact the analysis of dollars per line mile. However, my recommendation is not based on a single variable or analysis. It is based on (1) customer perception, (2) an apparent degradation of the SAIFI and CAIDI in certain locations within the Company's service territory, (3) the possible exclusion of certain programs from the Company's reliability program, (4) the change in the level of funding for the Company's reliability program, and (5) the high level assessment of the dollars per line mile between the jurisdictions. All of these factors lead me to the conclusion that a more in-depth review of NSP's reliability is warranted.

**Q. WHAT DO YOU RECOMMEND?**

A. Based on my assessment of the indicators of reliability, I recommend an in-depth, focused operational audit of the Company's reliability program. Elements of the audit would include the following:

- Review of the Company's program and frequency of update
- Review type, frequency, and distribution of program reports
- Evaluate how normal operation is factored into the program (load growth, vegetation management, corrosion and declension, etc.)

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

- 1           • Review equipment deterioration records and how that information is
- 2           incorporated into the program
- 3           • Evaluate outage handling:
- 4           ○ Root cause investigations
- 5           ○ Lessons Learned processing
- 6           • Review special project impact (substation improvements, selective
- 7           underground replacements, etc.)
- 8           ○ Review reliability projects with regard to criteria, priority, funding
- 9           and tracking
- 10          • Evaluate Performance metrics such as CAIDI and SAIFI for accuracy
- 11          • Evaluate corrective action process and tracking
- 12          • Review reliability program backlog
- 13          • Review program employment of best practices in engineering and
- 14          economic principles
- 15          • Review customer/government communication/interaction

16   **VII. PRAIRIE ISLAND DECOMMISSIONING TRUST FUND**

17   **Q.   PLEASE EXPLAIN YOUR CONCERNS WITH THE PRAIRIE ISLAND**  
18   **DECOMMISSIONING TRUST FUND.**

19   A.   The Company has filed for a new operating license that would extend the  
20   remaining life of the Prairie Island Nuclear Power Plant (Prairie Island). If  
21   approved, the life of the plant will be extended by approximately 23.3 years.<sup>94</sup>

22   **Q.   HOW DOES EXTENDING THE REMAINING LIFE OF PRAIRIE**  
23   **ISLAND BECOME AN ISSUE?**

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<sup>94</sup> Exhibit \_\_\_ (MJM-43) Data Request and Response AS-2-RR-53

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1 A. The life extension of Prairie Island will also extend the period of time the  
2 Company has to fund decommissioning costs. NSP-M is currently funding based  
3 on the original plant life. Based on a new operating license, which extends the  
4 remaining plant life, the Decommissioning Trust fund will more than likely be  
5 overfunded. This situation is the same as what happened when the Monticello  
6 Nuclear Power Plant was granted a new operating license that extended the  
7 remaining life of that plant.

8 **Q. HOW DOES THIS POTENTIAL OVERFUNDING IMPACT THE RATE**  
9 **CASE AND WHEN WILL IT BE KNOWN?**

10 A. To the extent that NSP-M has over accrued in the Decommissioning Trust fund  
11 for Prairie Island, as they did with Monticello, it will require a refund to the  
12 customers. That means former and current ratepayers have potentially overpaid  
13 decommissioning fund expenses.

14 **Q. CAN YOU ESTIMATE THE AMOUNT OF THE REFUND DUE**  
15 **RATEPAYERS?**

16 A. The Company indicated that they are in the early stages of evaluating if the Prairie  
17 Island Nuclear Plant Decommissioning Trust fund is overfunded based on a new  
18 remaining plant life.<sup>95</sup> A Triennial review of the fund is due in 2011 with the  
19 results known in early 2012. Those results will be submitted to the MPUC by

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<sup>95</sup> Exhibit \_\_\_ (MJM-44) Data Request and Response AS-2-RR-94.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

1           October 2011.<sup>96</sup> Therefore, the amount of any potential over funding may not be  
2           available until 2012.

3   **Q.    ARE THERE ANY FACTORS THAT COULD IMPACT FUTURE**  
4           **FUNDING OF THE PRAIRIE ISLAND DECOMMISSIONING TRUST**  
5           **THAT MIGHT RESULT IN THE TRUST FUND NOT BEING**  
6           **OVERFUNDED AS THE MONTICELLO PLANT?**

7   A.    Yes. Enhanced on-site storage and the possible extension of the post plant  
8           remaining life decommissioning time frame could impact any potential  
9           overfunding.<sup>97</sup>

10 **Q.    WHAT DO YOU RECOMMEND?**

11 A.    I recommend that any overfunding that result from the Triennial review in 2011  
12           be given back to the ratepayer using the same method that was used for the  
13           Monticello plant. The Monticello plant refund was \$23.5 million for the  
14           Minnesota retail jurisdiction and was withdrawn from the external  
15           Decommissioning Trust fund in December 2009 and refunded on customer bills  
16           in February 2010.<sup>98</sup>

17 **Q.    DOES THIS CONCLUDE YOUR TESTIMONY?**

18 A.    Yes.

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<sup>96</sup> Exhibit \_\_\_ (MJM-45) Data Request and Response AS-RR-280.

<sup>97</sup> Exhibit \_\_\_ (MJM-44) Data Request and Response AS-2-RR-94.

<sup>98</sup> Exhibit \_\_\_ (MJM-46) Xcel Energy Form 10-K Year Ended December 31, 2010, page 145 para 2.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

**Appendix A - Qualification of Michael J. McGarry, Sr.**

***Summary***

Mr. McGarry's professional experience spans thirty years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

***Project Management***

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

***Regulatory and Rate Case Management***

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

***Testimony and Witness Preparation***

Mr. McGarry has proffered and /or supported testimony in Colorado, Delaware, Illinois, Maine, Michigan, Maryland, New York, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

***Utility Management and Operational Audits***

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices,

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

***Restructuring, Unbundling, and Cost Allocation***

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

***Training and Public Speaking***

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

***Education***

Potsdam College, B.A., Economics, 1981

University at Buffalo School of Management, MBA, 1996

***Regulatory Experience***

**Before the Connecticut Department of Public Utility Control (CTDPUC)**

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*

On behalf of the CTDPUC, April-August 2010

Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.*

On behalf of the Staff of the CTDPUC, July 2008-June 2009

Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a \$122 million customer information system known as CustomerCentral or C2.

**Before the Delaware Public Service Commission (DEPSC)**

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates, September 2009-May 2010*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Project Manager. Oversaw rate case analysis and assessment of company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates*, October 2007-April 2008  
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Gas Corporation's implementation of a Gas Hedging program*, June-August 2007  
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the Company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a \$15M increase in gas base rates*, October 2006-March 2007  
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to \$8.4M (56%).

**Before the District of Columbia Public Service Commission (DCPSC)**

Formal Case No. 1076 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*.

On Behalf of the DCPSC, July-June 2010

Project Manager. Advised Commission Staff on the Company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a \$50.4 million increase in base rates*, February 2007-June 2008

Project Manager. Provide technical expertise to Commission in evaluating the Company's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*

On Behalf of the DCPSC, January-March 2005

Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 Company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

On Behalf of the DCPSC, June-December 2003

Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

**Before the Hawaii Public Utilities Commission**

Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework*, June-November 2005

Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the Company.

**Before the Illinois Commerce Commission (ILCC)**

Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago*, November 2005-May 2006

Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or \$320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the Company's Controller.

**Before Maine Public Utilities Commission (MEPUC)**

Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*

On behalf of Maine Public Advocate, July 2008-July 2010

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the Company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*

On behalf of Maine Public Advocate, November 2004-March 2005

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

**Before the Maryland Public Service Commission**

Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company* December-March 2008  
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO*, January-June 2007

Project Manager. Reviewed and analyzed company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of Company's original request.

Case No. 9062 *On behalf of the Staff of the Commission in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service*, May-October 2006

Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

**Before the Massachusetts Department of Public Utilities (MADPU)**

Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company*, February-August 2010

Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the Company's revenue requirements calculations in the Company's base rate request.

**Before the Michigan Public Service Commission**

Case No. U-16432 *On behalf of the Attorney General of the State of Michigan in the matter of Consumers Energy Company's Application to Implement a Power Supply Cost Recovery Plan for 2011* February-June 2011

Project Manager. Reviewed cost recovery plan requirements and provided analysis and testimony concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the Attorney General of the State of Michigan in the matter of Detroit Edison Company's Application to Implement a Power Supply Cost Recovery Plan for 2011* February-June 2011

Project Manager and Testifying Witness. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Case No. U-16472 *In the matter of the application of The Detroit Edison Company (DetEd) for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* February-June 2011

Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and potential witness to same.

Case No. U-16407 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system.* Nov 2010-May 2011

Project Manager and Testifying Witness. Reviewed Company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805.* November 2010-January 2011

Project Manager and Testifying Witness. Reviewed the Company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the Company.

Case No. U-16356 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011

Project Manager and Testifying Witness. Reviewed the Company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs.

Case No. U-15675-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for the reconciliation of power supply cost recovery (PSCR) costs and revenues for the calendar year 2009,* October 2010-January 2011

Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of The Detroit Edison Company for reconciliation of its PSCR plan for the calendar year 2009,* September-December 2010

Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the Company.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Case No. U-16047 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity, January-May 2010*  
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs, May-November 2009*  
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise.

Case No. U-15806/U-15890 *On behalf of the Attorney General of the State of Michigan in the matter of DetEd and MichCon to comply with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP), March-June 2009*  
Project Manager and Testifying Witness. Reviewed the EOPs of both DetEd and MichCon and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the Attorney General of the State of Michigan in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP, March-June 2009*  
Project Manager and Testifying Witness. Reviewed the EOP of CECO and provided analysis of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity, January 2009-June 2010*  
Project manager. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008, January-March 2008*  
Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the Attorney General of the State of Michigan in the matter of the application of Midland Cogeneration Venture Limited Partnership for the Commission to eliminate the “availability caps” which limit CECO’s recovery of capacity payments with respect to its power purchase agreement with Midland Cogeneration Venture Limited Partnership, October 2007-June 2008*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief*, July 2007-April 2008

Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the Attorney General of the State of Michigan in the matter of the application of DetEd for authority to increase its electric base rates*, September 2007-October 2008

Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the Attorney General of the State of Michigan in Base Rate Proceeding for CECO*, March-September 2007

Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the Attorney General of the State of Michigan in Gas Cost Recovery (GCR) 2007/08 Plan proceeding*, March-August 2007

Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program.

Case No. U-15001 *On behalf of the Attorney General of the State of Michigan in PSCR 2007/08 Plan proceeding*, November 2006-August 2007

Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-14701-R *On behalf of the Attorney General of the State of Michigan in PSCR 2006/07 reconciliation proceeding*, June-November 2007

Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the Attorney General of the State of Michigan in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief*, December 2005-April 2006

Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

**New Mexico Public Service Commission (NMPSC)**

*Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT, August 2010*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

**Before the North Dakota Public Service Commission (NDPSC)**

*Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55) April 2011-present*  
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

**Before the Nova Scotia Utility and Review Board**

Case No. P-886 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power, December 2006-March 2007*  
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the Company's management performance and operational efficiency within the context of that proceeding.

**Before the Public Utilities Commission of Ohio (PUCO)**

Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service. (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power.), September 2008-March 2009*  
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO

- Case #08-0072-GA-AIR *Columbia Gas of Ohio for an increase in gas rates, April-August 2008*
- Case #07-0829-GA-AIR *Dominion East Ohio for an increase in gas rates, November 2007-July 2008*
- Case #07-0589-GA-AIR *Duke Energy Ohio for an increase in gas rates, November 2007-February 2008*

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the Company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of First Energy Ohio (and its operating companies Ohio Edison, Cleveland*

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

*Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval, August 2007-April 2008*  
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing First Energy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service over,* May-August 2007

Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the Company's proposal and impact on City's project energy costs.

**Oregon Public Utilities Commission (OPUC)**

Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues*  
Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board, August 2005-January 2006

Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure Company compliance with orders, rules and regulations of the OPUC, with Company policy and with Generally Accepted Accounting Principles.

**Utah Division of Public Utilities**

Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* June-December 2009

Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case,* July-December 2009

Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the Company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the Company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervenor NPC issues as well as analyzing additional issues as raised by the Company and testified to hedging issues.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

**Before the Washington Utilities and Transportation Commission (WUTC)**

*Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff, Phase I: July-October 2009; Phase II: October 2009-September 2010*

Project Manager: Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

**Before the Public Utilities Commission of the State of Colorado (COPUC)**

Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*

On behalf of the COPUC Staff, March-September 2004

Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

**South Carolina State Senator**

Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

**Before the Missouri Public Service Commission**

Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

**Southern Connecticut Gas**

Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the Company, completed the capital budgeting area of the audit.

**Before the New York Public Service Commission**

Case: 94-C-0657

Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry

Case: 97-M-0567

Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company / Brooklyn Union Gas. Analyzed the proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*

Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*

Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the Company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*

Commission Staff. Comprehensive operational audit of the company's management and implementation of a \$150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding Regarding the Operations and Management of Jamaica Water*

Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the Company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*

Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

*Case: 92-M-0973 Management Audit of RG&E*

Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

*Case: 93-E-0918 Operational Audit of the Demand Side Management Function at RG&E*

Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

*Case: 88005 Operational Audit of Materials and Supply Function at National Fuel Gas*

Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

*Operational Audit of the Fuel Procurement and Contracting of LILCO*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

*Operational Audit of the Fuel Procurement and Contracting of ConEd*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

*Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

*Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

*Operational Audit of the Fuel Procurement and Contracting of RG&E*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

*Case: 88-E-115 Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*

Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received \$125M credit.

*Case: 87003 Operational Audit of the HCCCP*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

*Case: 87003 Operational Audit of the Fuel Procurement and Contracting of NYSEG*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

*Case: 86007 Operational Audit of the Field Crew Supervision and Utilization of NYSEG*

Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

*Case: 86005 Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*

Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving \$66M credit.

*Case: 86005 Operational Audit of the Fuel Procurement and Contracting of NIMO*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

*Case: 85001 Operational Audit of the Research and Development Function of ConEd*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

***Testimony filed by Mr. McGarry***

**Before the Delaware Public Service Commission**

- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

**Before the Illinois Commerce Commission**

- Commonwealth Edison - Case: 05-0597

**Before Maine Public Utilities Commission**

- Northern Utilities Inc. - Case No. 2008-151

Direct Testimony and Exhibits of  
Michael J. McGarry, Sr. – Case No. PU-10-657 and Case No. PU-11-55

- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Detroit Edison - Case No. U-16434
- Detroit Edison - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities, Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-886

Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 98-E-115

*Rev 7/19/2011*

<u>Line #</u>	<u>Schedule #</u>	<u>Description</u>
1	<u>Schedule 1</u>	Comparison of Company's 2011 Revenue Requirements and Staff's Proposal
2	<u>Schedule 2</u>	Rate of Return Calculation
3	<u>Schedule 2.1</u>	Impact of Staff's Rate of Return on Company's Proposed Revenue Requirements
5	<u>Schedule 3.1</u>	Summary of Adjustments to Company's Proposed Rate Base
6	<u>Schedule 3.2</u>	Summary of Staff's Adjustments to Company's Proposed Operating Income
7	<u>Schedule 4.1</u>	Adjustment 1 Mercury Emissions (Co. Adj. A38)
8	<u>Schedule 4.2</u>	Adjustment 2 Remove Transmission-Pleasant Valley/Bryon Not in Service
9	<u>Schedule 4.3</u>	Adjustment 3 Sale of Lakefield Junction/Fox Lake Transmission Line
10	<u>Schedule 4.4</u>	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)
11	<u>Schedule 4.5</u>	Adjustment 5 Customer Deposits (Co. Adj. A19)
12	<u>Schedule 4.6</u>	Adjustment 6 Bargaining Unit Wage Adjustment
13	<u>Schedule 4.7</u>	Adjustment 7 Employee Benefits
14	<u>Schedule 4.8</u>	Adjustment 8 Employee Retirement Programs (Co. Adj. O2)
15	<u>Schedule 4.9</u>	Adjustment 9 Mercury Sorbent Reduction (Co. Adj. A14)
16	<u>Schedule 4.10</u>	Adjustment 10 Qwest Pole Replacements (Co. Adj. A11)
17	<u>Schedule 4.11</u>	Adjustment 11 Bad Debt (Co. Adj. A10)
18	<u>Schedule 4.12</u>	Adjustment 12 Economic Development Costs (Co. Adj. A15)
19	<u>Schedule 4.13</u>	Adjustment 13 Charitable Contributions (Co. Adj. A18)
20	<u>Schedule 4.14</u>	Adjustment 14 Payroll Taxes-Excluded Incentive Comp (Co. Adj. A26)
21	<u>Schedule 4.15</u>	Adjustment 15 Incentive Compensation (Co. Adj. A26)
22	<u>Schedule 4.16</u>	Adjustment 16 Aviation Expense (Co. Adj. A28)
23	<u>Schedule 4.17</u>	Adjustment 17 Nuclear Waste Disposal Litigation Costs
24	<u>Schedule 4.18</u>	Adjustment 18 Directors' and Officers' Insurance
25	<u>Schedule 4.19</u>	Adjustment 19 2011 Rate Case Expenses (Co. Adj. A31)
26	<u>Schedule 4.20</u>	Adjustment 20 ND EPA Emission Credit Auction Proceeds (Co. Adj. A32)
27	<u>Schedule 4.21</u>	Adjustment 21 2011 Demand Side Management (Co. Adj. A33)
28	<u>Schedule 4.22</u>	Adjustment 22 Cash Working Capital
29	<u>Schedule 4.23</u>	Adjustment 23 Interest Synchronization
30	<u>Schedule 5</u>	Comparison of Company's 2012 Step Up Revenue Requirements and Staff's Proposal

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit\_\_\_(MJM-2), Schedule 1  
 Page 1 of 1

**Northern States Power Company - Electric**  
 Twelve Months Ending December 31, 2011  
 Comparison of Company's 2011 Revenue Requirements and Staff's Proposal

(in thousands)

Line	Description (A)	Company 2011 Test Year <sup>1</sup> (B)	Proposed Adjustment (C)	Staff's Position (D)	Adjustment Reference (E)
1	<b>Rate Base</b>				
2	Electric Plant in Service	\$ 752,278	\$ (1,769)	\$ 750,509	Schedule 3.1
3	Less: Accumulated Depreciation and Amortization	(370,100)	163	(369,937)	Schedule 3.1
4	Net Plant in Service	\$ 382,178	\$ (1,606)	\$ 380,571	
5	Construction Work in Progress	\$ 2,100		\$ 2,100	
6	Accumulated Deferred Income Taxes	(78,577)	292	(78,285)	Schedule 3.1
7	Other Rate Base:				
8	Cash Working Capital	2,082	(18)	2,064	Schedule 3.1
9	Materials and Supplies	6,186		6,186	
10	Fuel Inventory	5,674		5,674	
11	Non-Plant Assets & Liabilities	(6,173)		(6,173)	
12	Prepays & Other	4,024	(34)	3,990	Schedule 3.1
13	Total Rate Base	\$ 317,494	\$ (1,367)	\$ 316,127	
14	Rate of Return	8.74%		7.85%	Schedule 2
15	Return Requirement	\$ 27,749	\$ (2,922)	\$ 24,827	
16	<b>Operating Revenues</b>				
17	Retail	\$ 164,504	\$ -	\$ 164,504	
18	Other Operating	42,445		42,445	
19	Total Operating Revenues	\$ 206,949	\$ -	\$ 206,950	
20	<b>Operating Expenses</b>				
21	Fuel & Purchased Energy	\$ 81,392		\$ 81,392	
22	Labor Related	n/a	\$ (295)	(295)	Schedule 3.2
23	Power Production	42,844	(256)	42,588	Schedule 3.2
24	Transmission	11,347		11,347	
25	Distribution	6,292	(12)	6,280	Schedule 3.2
26	Customer Accounting	4,339	(271)	4,068	Schedule 3.2
27	Customer Service & Information	548		548	
28	Sales, Econ Dvlp & Other	66	(64)	2	Schedule 3.2
29	Administrative & General	13,322	(314)	13,008	Schedule 3.2
30	Total Operating Expenses	\$ 160,150	\$ (1,211)	\$ 158,939	
31	Depreciation and Amortization	\$ 18,153	\$ (500)	\$ 17,653	Schedule 3.2
33	Taxes:				
34	Property and Other than Income Taxes	\$ 7,468	\$ (52)	\$ 7,416	Schedule 3.2
35	Deferred Income Tax & ITC	11,140	4	11,144	Schedule 3.2
36	State & Federal Income Tax	(6,777)	704	(6,073)	Schedule 3.2
38	Total Taxes	\$ 11,831	\$ 656	\$ 12,487	
39	<b>Total Expenses</b>	\$ 190,134		\$ 189,079	
40	AFUDC	-		-	
41	<b>Total Operating Income</b>	\$ 16,815	\$ -	\$ 17,871	
42	<b>Income Deficiency</b>	\$ 10,934		\$ 6,955	
43	Revenue Conversion Factor	1.64541	-	1.64541	
44	<b>Revenue Deficiency</b>	\$ 17,991	\$ (6,545)	\$ 11,446	
45	Revenue Deficiency Percent Change	<sup>17,991</sup>	36.38%	63.62%	

<sup>1</sup> Exhibit\_\_\_(JMF-1), Schedule 7 and Schedule 8a, Revised 5/9/11

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 2  
 Page 1 of 1

**Northern States Power Company - Electric**  
 Twelve Months Ending December 31, 2011  
 Rate of Return Calculation

<u>Line</u>	<u>Description</u> (A)	<u>Capital Structure</u> (B)	<u>Ratio</u> (C)	<u>Cost %</u> (D)	<u>Weighted Cost %</u> (E)	<u>Reference</u> (F)
<b><u>Company Rate of Return</u></b>						
1	Long-Term Debt	\$ 3,399,494	46.29%	6.07%	2.81%	
2	Short-Term Debt	83,926	1.14%	2.06%	0.02%	
3	Common Equity	3,859,990	52.56%	11.25%	5.91%	
4	Total	<u>\$ 7,343,410</u>	<u>100.00%</u>		<u>8.74%</u>	

Source: JMF-1, Schedule 8a and COC Workpaper

<b><u>Staff Rate of Return</u></b>						
5	Long-Term Debt	\$ 3,399,494	46.29%	6.07%	2.810%	Testimony of S. Keith Berry. Ph.D.
6	Short-Term Debt	83,926	1.14%	2.06%	0.024%	Testimony of S. Keith Berry. Ph.D.
7	Common Equity	3,859,990	52.56%	9.55%	5.020%	Testimony of S. Keith Berry. Ph.D.
8	Total	<u>\$ 7,343,410</u>	<u>100.00%</u>		<u>7.853%</u>	

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 2.1  
 Page 1 of 1

**Northern States Power Company - Electric**

Twelve Months Ending December 31, 2011

Impact of Staff's Rate of Return on Company's Proposed Revenue Requirements

(in thousands)

Line	Description (A)	Company 2011 Test Year (B)	Proposed Adjustment (C)	Staff's Position (D)	Adjustment Reference (E)
1	<b>Total Rate Base</b>	\$ 317,494		\$ 317,494	
2	Rate of Return	8.74%	-0.89%	7.85%	Schedule 2
3	Return Requirement	<u>\$ 27,749</u>		<u>\$ 24,934</u>	
4	<b>Operating Revenues</b>				
5	Retail	\$ 164,504		\$ 164,504	
6	Other Revenues	42,445		42,445	
7	Total Operating Revenues	<u>\$ 206,949</u>		<u>\$ 206,950</u>	
8	<b>Operating Expenses</b>				
9	O&M Expenses	\$ 160,150		\$ 160,150	
10	Depreciation and Amortization	18,153		18,153	
11	Taxes	11,831		11,831	
12	Total Expenses	<u>\$ 190,134</u>		<u>\$ 190,134</u>	
13	Net Operating Income Before Taxes	\$ 16,815		\$ 16,816	
14	AFUDC	-		-	
15	<b>Operating Income for ROR Calculation</b>	<u>\$ 16,815</u>		<u>\$ 16,816</u>	
16	<b>Income Deficiency</b>	\$ 10,934		\$ 8,118	
17	Revenue Conversion Factor	<u>1.64541</u>		<u>1.64541</u>	
18	<b>Revenue Deficiency</b>	<u>\$ 17,991</u>	<u>\$ (4,633)</u>	<u>\$ 13,358</u>	
19	Revenue Deficiency Percent Change		-25.75%		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 3.1  
 Page 1 of 1

**Northern States Power Company - Electric**

Twelve Months Ending December 31, 2011  
 Summary of Adjustments to Company's Proposed Rate Base

Line	Description (A)	Reference (B)	Impact to Rate Base (C)	Staff Proposed Cost of Capital	
				Impact on Return Requirement (D)	Revenue Requirement Impact (E)
1	<b>Electric Plant in Service</b>				
2	Adjustment 1 Mercury Emissions (Co. Adj. A38)	Schedule 4.1	\$ (331)	\$ (26)	\$ (43)
3	Adjustment 2 Remove Transmission-Pleasant Valley/Bryon Not in Service	Schedule 4.2	(195)	(15)	(25)
4	Adjustment 3 Sale of Lakefield Junction/Fox Lake Transmission Line	Schedule 4.3	(958)	(75)	(124)
5	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)	Schedule 4.4	(278)	(22)	(36)
6	Adjustment 6 Bargaining Unit Wage Adjustment	Schedule 4.6	(8)	(1)	(1)
7	Total Electric Plant in Service		<u>\$ (1,769)</u>	<u>\$ (139)</u>	<u>\$ (229)</u>
8	<b>Accumulated Depreciation</b>				
9	Adjustment 1 Mercury Emissions (Co. Adj. A38)	Schedule 4.1	\$ 23	\$ 2	\$ 3
10	Adjustment 2 Remove Transmission-Pleasant Valley/Bryon Not in Service	Schedule 4.2	1	0	0
11	Adjustment 3 Sale of Lakefield Junction/Fox Lake Transmission Line	Schedule 4.3	128	10	17
12	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)	Schedule 4.4	11	1	1
13	Total Accumulated Depreciation		<u>\$ 163</u>	<u>\$ 13</u>	<u>\$ 21</u>
14	<b>Accumulated Deferred Income Taxes</b>				
15	Adjustment 1 Mercury Emissions (Co. Adj. A38)	Schedule 4.1	\$ 55	\$ 4	\$ 7
16	Adjustment 2 Remove Transmission-Pleasant Valley/Bryon Not in Service	Schedule 4.2	79	6	10
17	Adjustment 3 Sale of Lakefield Junction/Fox Lake Transmission Line	Schedule 4.3	121	9	16
18	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)	Schedule 4.4	38	3	5
19	Total Accumulated Deferred Income Taxes		<u>\$ 292</u>	<u>\$ 23</u>	<u>\$ 38</u>
20	<b>Cash Working Capital</b>				
21	Adjustment 22 Cash Working Capital	Schedule 4.22	<u>\$ (18)</u>	<u>\$ (1)</u>	<u>\$ (2)</u>
22	<b>Prepays &amp; Other</b>				
23	Adjustment 5 Customer Deposits (Co. Adj. A19)	Schedule 4.5	<u>\$ (34)</u>	<u>(3)</u>	<u>(4)</u>
24	Total Prepaid & Other		<u>\$ (34)</u>	<u>\$ (3)</u>	<u>\$ (4)</u>
25	Total Change to Rate Base		<u>\$ (1,367)</u>	<u>\$ (107)</u>	<u>\$ (177)</u>
26	Company Rate Base		<u>\$ 317,494</u>		
27	Adjusted Rate Base		<u>\$ 316,127</u>		

**Notes and Source**

Col C:	See referenced schedule		
Col D:	Computed using Rate of Return recommended by Staff	7.85%	
Col E:	Computed using Revenue Conversion Factor		1.64541

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 3.2  
 Page 1 of 2

**Northern States Power Company - Electric**  
 Twelve Months Ending December 31, 2011  
 Summary of Staff's Adjustments to Company's Proposed Operating Income

Line	Description	Reference	O&M Adjustment (C)	Other Taxes & ITC	State Income Tax (D)	Federal Income Tax (E)	NOI Adjustment (F)	Estimated Revenue Requirement Impact (G)
1	<b>Revenue</b>							
2								
3	Total Revenue		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4	<b>Expenses</b>							
5	<b>Operating Expense: Labor Related</b>							
6	Adjustment 6 Bargaining Unit Wage Adjustment	Schedule 4.6	\$ (36)	\$ (3)	\$ 3	\$ 13	\$ 24	\$ (14)
7	Adjustment 7 Employee Benefits	Schedule 4.7	(178)		12	58	108	(66)
8	Adjustment 8 Employee Retirement Programs (Co. Adj. O2)	Schedule 4.8	(81)		5	26	49	(39)
9	Total Operating Expense: Labor Related		\$ (295)	\$ (3)	\$ 19	\$ 97	\$ 181	\$ (110)
10	<b>Operating Expense: Power Production</b>							
11	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)	Schedule 4.4	\$ (3)	\$ 4	\$ 3	\$ 16	\$ (20)	\$ 12
12	Adjustment 9 Mercury Sorbent Reduction (Co. Adj. A14)	Schedule 4.9	(253)		16	83	154	(93)
13	Total Operating Expense: Power Production		\$ (256)	\$ 4	\$ 20	\$ 99	\$ 133	\$ (81)
14	<b>Operating Expense: Distribution</b>							
15	Adjustment 10 Qwest Pole Replacements (Co. Adj. A11)	Schedule 4.10	\$ (12)		\$ 1	\$ 4	\$ 7	\$ (4)
16	Total Operating Expense: Distribution		\$ (12)	\$ -	\$ 1	\$ 4	\$ 7	\$ (4)
17	<b>Operating Expense: Customer Accounting</b>							
18	Adjustment 11 Bad Debt (Co. Adj. A10)	Schedule 4.11	\$ (271)		\$ 18	\$ 89	\$ 165	\$ (100)
19	Total Operating Expense: Customer Accounting		\$ (271)	\$ -	\$ 18	\$ 89	\$ 165	\$ (100)
20	<b>Operating Expense: Econ Dvlp &amp; Other</b>							
21	Adjustment 12 Economic Development Costs (Co. Adj. A15)	Schedule 4.12	\$ (64)		\$ 4	\$ 21	\$ 39	\$ (24)
22	Total Operating Expense: Econ Dvlp & Other		\$ (64)	\$ -	\$ 4	\$ 21	\$ 39	\$ (24)
23	<b>Operating Expense: Administrative &amp; General</b>							
24	Adjustment 13 Charitable Contributions (Co. Adj. A18)	Schedule 4.13	\$ (132)		\$ 9	\$ 43	\$ 80	\$ (49)
25	Adjustment 14 Payroll Taxes-Excluded Incentive Comp (Co. Adj. A26)	Schedule 4.14		\$ (39)	3	13	24	(14)
26	Adjustment 15 Incentive Compensation (Co. Adj. A26)	Schedule 4.15	(12)	(1)	1	4	8	(5)
27	Adjustment 16 Aviation Expense (Co. Adj. A28)	Schedule 4.16	(49)		3	16	30	(18)
28	Adjustment 17 Nuclear Waste Disposal Litigation Costs	Schedule 4.17	(29)		2	9	18	(11)
29	Adjustment 18 Directors' and Officers' Insurance	Schedule 4.18	(91)		6	30	55	(34)
30	Adjustment 23 Interest Synchronization	Schedule 4.23			2	12	(14)	9
31	Total Operating Expense: Administrative & General		\$ (314)	\$ (40)	\$ 25	\$ 128	\$ 201	\$ (122)
32	<b>Depreciation and Amortization</b>							
33	Adjustment 1 Mercury Emissions (Co. Adj. A38)	Schedule 4.1	\$ (14)		\$ 1	\$ 5	\$ 8	\$ (5)
34	Adjustment 2 Remove Transmission-Pleasant Valley/Bryon Not in Service	Schedule 4.2	(159)		10	52	97	(59)
35	Adjustment 3 Sale of Lakefield Junction/Fox Lake Transmission Line	Schedule 4.3	(34)	(10)	3	14	27	(16)
36	Adjustment 4 Remove Wind2Battery Project and ITC (Co. Adj. A5)	Schedule 4.4	(50)		0	0	50	(31)
37	Adjustment 19 2011 Rate Case Expenses (Co. Adj. A31)	Schedule 4.19	(94)		6	31	57	(35)
38	Adjustment 20 ND EPA Emission Credit Auction Proceeds (Co. Adj. A32)	Schedule 4.20	43		(3)	(14)	(28)	16
39	Adjustment 21 2011 Demand Side Management (Co. Adj. A33)	Schedule 4.21	(192)		12	63	117	(71)
40	Total Depreciation and Amortization		\$ (500)	\$ (10)	\$ 30	\$ 150	\$ 329	\$ (200)
41	<b>Tax totals</b>			\$ (49)	\$ 116	\$ 588		
42	State and Federal Income Tax Total					\$ 704		
			\$ (940)					

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
Exhibit (MJM-2), Schedule 3.2  
Page 2 of 2

Northern States Power Company - Electric  
Twelve Months Ending December 31, 2011  
Summary of Staff's Adjustments to Company's Proposed Operating Income

**Notes and Source**

Col C: See referenced schedule

Col E: Computed using Gross Up Factor

0.60775

Revenue Requirement Gross-Up Factor	60.7750%
Revenue Conversion Factor	1.64541 JMF-1, Schedule 10
State of North Dakota Tax rate	6.50%
Federal Statutory Tax rate	35.00%
Federal Effective Tax rate (1-State rate*Federal rate)	32.73%
Total North Dakota Composite Tax rate	39.23%
Minor differences due to rounding.	

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.1  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 1**

Mercury Emissions (Co. Adj. A38)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Rate Base:					
2	Plant in Service	\$ 330,704	\$ (330,704)	\$ -		Line 18
3	Depreciation Reserve	\$ (23,243)	\$ 23,243	\$ -		Line 19
4	Accumulated Deferred Taxes	\$ (54,982)	\$ 54,982	\$ -		Line 20
5	<b>Impact to Rate Base</b>	<u>\$ 252,479</u>	<u>\$ (252,479)</u>	<u>\$ -</u>		
6	Expense:					
7	Depreciation	\$ 14,457	\$ (14,457)	\$ -	Company Workpaper A38-4	
8	Amortization Deferred Taxes	(601)	601	-	Company Workpaper A38-4	
9	Total Depreciation and Amortization	<u>\$ 13,856</u>	<u>\$ (13,856)</u>	<u>\$ -</u>		
10	State Income Tax Rate	6.5%		6.5%		
11	Effect on State income tax expense	<u>\$ (901)</u>	<u>\$ 901</u>	<u>\$ -</u>		
12	Federal Taxable	\$ 12,955		\$ -		
13	Federal Income Tax Rate	35%		35%		
14	Effect on Federal income tax expense	<u>\$ (4,534)</u>	<u>\$ 4,534</u>	<u>\$ -</u>		
15	Total Expense	<u>\$ 8,421</u>		<u>\$ -</u>		
16	<b>Impact to Operating Income</b>	<u>\$ (8,421)</u>	<u>\$ 8,421</u>	<u>\$ -</u>		
17	<u>Rate Base: Mercury Emissions</u>	<u>BOY</u>	<u>EOY</u>	<u>Average</u>		
18	Plant Investment	\$ 328,091	\$ 333,317	\$ 330,704	Company Workpaper A38-4	
19	Depreciation Reserve	\$ (16,015)	\$ (30,471)	\$ (23,243)	Company Workpaper A38-4	
20	Accumulated Deferred Taxes	\$ (55,283)	\$ (54,682)	\$ (54,982)	Company Workpaper A38-4	

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.2  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 2**

Remove Transmission-Pleasant Valley/Bryon Not in Service

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Rate Base:					
2	Plant Investment	\$ 195,000	\$ (195,000)	\$ -	Response to AS-RR-22	
3	Depreciation Reserve	\$ (1,000)	\$ 1,000	\$ -	Response to AS-RR-22	
4	Accumulated Deferred Taxes	\$ (79,000)	\$ 79,000	\$ -	Response to AS-RR-22	
5	<b>Impact to Rate Base</b>	<u>\$ 115,000</u>	<u>\$ (115,000)</u>	<u>\$ -</u>		
6	Expense:					
7	Depreciation	\$ 2,000	\$ (2,000)	\$ -	Response to AS-RR-22	
8	Amortization Deferred Taxes	157,000	(157,000)	-	Response to AS-RR-22	
9	Total Depreciation and Amortization	159,000	(159,000)	-		
10	State Income Tax Rate	6.5%		6.5%		
11	Effect on State income tax expense	<u>\$ (10,335)</u>	<u>\$ 10,335</u>	<u>\$ -</u>		
12	Federal Taxable	\$ 148,665		\$ -		
13	Federal Income Tax Rate	35%		35%		
14	Effect on Federal income tax expense	<u>\$ (52,033)</u>	<u>\$ 52,033</u>	<u>\$ -</u>		
15	Total Expense	<u>\$ 96,632</u>		<u>\$ -</u>		
16	<b>Impact to Operating Income</b>	<u>\$ (96,632)</u>	<u>\$ 96,632</u>	<u>\$ -</u>		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**Northern States Power Company - Electric  
Adjustment 3**

Sale of Lakefield Junction/Fox Lake Transmission Line

Docket No. PU-10-657 & PU-11-55  
Exhibit (MJM-2), Schedule 4.3  
Page 1 of 1

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	<u>Rate Base:</u>					
2	Plant Investment	\$ 957,503	\$ (957,503)	\$ -	Response to AS-RR-13	
3	Depreciation Reserve	\$ (128,058)	\$ 128,058	\$ -	Response to AS-RR-13	
4	Accumulated Deferred Taxes	\$ (120,617)	\$ 120,617	\$ -	Response to AS-RR-13	
5	<b>Impact to Rate Base</b>	<u>\$ 708,828</u>	<u>\$ (708,828)</u>	<u>\$ -</u>		
6	<u>Expense:</u>					
7	Depreciation	\$ 23,203	\$ (23,203)	\$ -	Response to AS-RR-13	
8	Amortization Deferred Taxes	11,229	(11,229)	-	Response to AS-RR-13	
9	Total Depreciation and Amortization	\$ 34,432	\$ (34,432)	\$ -		
10	Property Taxes	\$ 9,510	\$ (9,510)	\$ -	Response to AS-RR-13	
11	Total Expenses	\$ 43,942	\$ (43,942)	\$ -		
12	State Income Tax Rate	6.5%		6.5%		
13	Effect on State income tax expense	\$ (2,856)	\$ 2,856	\$ -		
14	Federal Taxable	\$ 41,086		\$ -		
15	Federal Income Tax Rate	35%		35%		
16	Effect on Federal income tax expense	\$ (14,380)	\$ 14,380	\$ -		
17	Total Expense	\$ 26,706		\$ -		
18	<b>Impact to Operating Income</b>	<u>\$ (26,706)</u>	<u>\$ 26,706</u>	<u>\$ -</u>		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.4  
 Page 1 of 2

**Northern States Power Company - Electric**  
**Adjustment 4**  
 Remove Wind2Battery Project and ITC (Co. Adj. A5)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	<b>Rate Base:</b>					
2	Plant Investment	\$ 278,051	\$ (278,051)	\$ -		Page 2 of 2, Line 8
3	Depreciation Reserve	\$ (10,936)	\$ 10,936	\$ -		Page 2 of 2, Line 9
4	Accumulated Deferred Taxes	\$ (29,280)	\$ 29,280	\$ -		Page 2 of 2, Line 10
5	ITC-Accumulated Deferred Taxes	(8,285)	8,285	-		Company Workpaper A5-1
6	<b>Total Accumulated Deferred Taxes</b>	<b>\$ (37,565)</b>	<b>\$ 37,565</b>	<b>\$ -</b>		
7	<b>Impact to Rate Base</b>	<b>\$ 229,550</b>	<b>\$ (229,550)</b>	<b>\$ -</b>		
8	<b>Expense:</b>					
9	Operating Expense	\$ 3,099	\$ (3,099)	\$ -		Page 2 of 2, Line 13
10	Depreciation	\$ 20,457	\$ (20,457)	\$ -		Page 2 of 2, Line 15
11	Amortization Deferred Taxes	29,920	(29,920)	-		Page 2 of 2, Line 16
12	<b>Total Depreciation and Amortization</b>	<b>\$ 50,376</b>	<b>\$ (50,376)</b>	<b>\$ -</b>		
13	Investment Tax Credit	\$ (6,857)	\$ 6,857	\$ -		Company Workpaper A5-2
14	Property Taxes	\$ 3,145	\$ (3,145)	\$ -		Page 2 of 2, Line 14
15	<b>Total Expenses</b>	<b>\$ 49,764</b>	<b>\$ (53,521)</b>	<b>\$ -</b>		
16	State Income Tax Rate	6.5%		6.5%		
17	Effect on State income tax expense	\$ (3,235)	\$ 3,235	\$ -		
18	Federal Taxable	\$ 46,529		\$ -		
19	Federal Income Tax Rate	35%		35%		
20	Effect on Federal income tax expense	\$ (16,285)	\$ 16,285	\$ -		
21	<b>Total Expense</b>	<b>\$ 30,244</b>		<b>\$ -</b>		
22	<b>Impact to Operating Income</b>	<b>\$ (30,244)</b>	<b>\$ 30,244</b>	<b>\$ -</b>		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit\_\_\_\_(MJM-2), Schedule 4.4  
 Page 2 of 2

**Northern States Power Company - Electric**  
**Adjustment 4**  
 Remove Wind2Battery Project and ITC

<u>Line</u>	<u>Description</u>	<u>(A)</u>	<u>(B)</u>	<u>(C)</u>	<u>(D)</u>	<u>Adjustment Reference</u> <u>(E)</u>
1	<b>Rate Base</b>	<b>2010<sup>1</sup></b>	<b>2011<sup>1</sup></b>	<b>Average</b>		See footnote for reference
2	Plus CWIP Ending Balance	\$ (1,000,000)	\$ (1,000,000)	\$ (1,000,000)		
3	Plus Plant In Service	4,785,157	4,785,157	4,785,157		
4	Less Book Depreciation Reserve	(12,184)	(364,239)	(188,212)		
5	Less Accum Deferred Taxes	(246,447)	(761,351)	(503,899)		
6	End of Month Rate Base	<u>\$ 3,526,526</u>	<u>\$ 2,659,566</u>	<u>\$ 3,093,052</u>		
		<b>Average</b>	<b>Allocator<sup>2</sup></b>	<b>ND Jurisdiction</b>		See footnote for reference
7	Plus CWIP Ending Balance	\$ (1,000,000)	5.8107%	\$ (58,107)		
8	Plus Plant In Service	4,785,157	5.8107%	278,051		
9	Less Book Depreciation Reserve	(188,212)	5.8107%	(10,936)		
10	Less Accum Deferred Taxes	(503,899)	5.8107%	(29,280)		
11	End of Month Rate Base	<u>\$ 3,093,052</u>		<u>\$ 179,728</u>		
12	<b>Expenses</b>	<b>2011<sup>1</sup></b>	<b>Allocator<sup>2</sup></b>	<b>ND Jurisdiction</b>		See footnote for reference
13	Operating	\$ 53,340	5.8107%	\$ 3,099		
14	Property Taxes	54,120	5.8107%	3,145		
15	Book Depreciation	352,055	5.8107%	20,457		
16	Deferred Taxes	514,904	5.8107%	29,920		
17		<u>\$ 974,419</u>		<u>\$ 56,621</u>		

<sup>1</sup> Xcel MNPUC Petition Dated 4/1/09, Schedule 3, page 1 of 1

<sup>2</sup> Allocator-Company Workpaper B2

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.5  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 5**  
 Customer Deposits (Co. Adj. A19)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	<u>Rate Base Prepays &amp; Other:</u>					
2	Customer Deposits	\$ (2,791,162)	\$ (727,365)	\$ (3,518,527)	Workpaper A19-4	Response to AS-RR-231, Att A, p. 2
3	Electric Allocator	74.3703%		74.3703%	Workpaper A19-4	
4		(2,075,796)	(540,944)	(2,616,739)		
5	ND Electric Allocator	6.3189%		6.3189%	Workpaper A19-4	
6	ND Electric Customer Deposits	<u>\$ (131,167)</u>	<u>\$ (34,182)</u>	<u>\$ (165,349)</u>		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**Northern States Power Company - Electric  
Adjustment 6  
Bargaining Unit Wage Adjustment**

Docket No. PU-10-657 & PU-11-55  
Exhibit\_\_\_\_(I Schedule 4.6  
Page 1 of 2

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Regular Payroll	\$ 22,225,000	\$ (36,045)	\$ 22,188,955	Workpaper O1-1	Page 2, Line 8
2	Payroll Taxes	1,814,591	(2,757)	1,811,834	Workkpaper O1-2	Page 2, Line 18
3	Regular Payroll and Payroll Taxes	\$ 24,039,591	\$ (38,802)	\$ 24,000,789		
4	State Income Tax Rate	6.5%		6.5%		
5	Effect on State income tax expense	\$ (1,562,573)	\$ 2,522	\$ (1,560,051)		
6	Federal Taxable	\$ 22,477,018		\$ 22,440,738		
7	Federal Income Tax Rate	35%		35%		
8	Effect on Federal income tax expense	\$ (7,866,956)	\$ 12,698	\$ (7,854,258)		
9	Total Expense	\$ 14,610,062		\$ 14,586,480		
10	Impact to Operating Income	\$ (14,610,062)	\$ 23,582	\$ (14,586,480)		
11	Wages and Payroll Taxes Capitalized to Rate Base		\$ (8,197)	\$ (8,197)		Page 2, Line 38

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**Northern States Power Company - Electric**  
**Adjustment 6**  
 Bargaining Unit Wage Adjustment

1	<u>Calculations of Impact to Bargaining Unit Wage Difference:</u>		
2	NSPM Estimated 2011 Actual Base Pay	\$ 121,895,585	Response AS-RR-331
3	NSPM 2011 Budget Base Pay	\$ 122,490,198	Response AS-RR-331
4	NSPM Difference between Budget and Actual	<u>\$ (594,613)</u>	
5	<u>O&amp;M Impact</u>		
6	NSPM Difference between Budget and Actual	\$ (594,613)	Response AS-RR-331
7	ND Electric Average Allocation Factor	6.06%	Response AS-RR-331
8	ND Electric Wage Adjustment to Actual	<u>\$ 7,425,250</u>	<u>\$ (36,045)</u>
9	<u>O&amp;M Payroll Taxes</u>		
10	ND Electric Wage Adjustment to Actual	(36,045)	
11	Medicare Tax Rate	0.0145	
12	Total Medicare Taxes	<u>\$ (523)</u>	
13	ND Electric Wage Adjustment to Actual	\$ (36,045)	
14	% Employees with salaries > Social Security maximum	100%	
15	Estimated Wage Adjustment Subject to Social Security Tax	<u>\$ (36,045)</u>	
16	Social Security Tax Rate	0.062	
17	Total Social Security Taxes	<u>\$ (2,235)</u>	
18	Total Payroll Taxes for Wage Increase	<u>\$ (2,757)</u>	
19	<u>Rate Base Impact</u>		
20	NSPM Difference between Budget and Actual	\$ (594,613)	Response AS-RR-331
21	Estimated O&M % of Labor Costs	70.30%	Response AS-RR-331
22	NSPM Difference / O&M % of Labor Costs	(845,822)	
23	NSPM Difference between Budget and Actual	<u>(594,613)</u>	Response AS-RR-331
24	Estimated Incremental Capital Merit Spend	<u>\$ (251,209)</u>	
25	Rate Base Impact Assuming 1/2 year in service	\$ (125,605)	Response AS-RR-331
26	ND Electric Average Allocation Factor	6.06%	Response AS-RR-331
27	ND Electric Wage Adjustment to Rate Base	<u>\$ (7,614)</u>	
28	<u>Rate Base Related Payroll Taxes</u>		
29	ND Electric Wage Adjustment to Rate Base	(7,614)	
30	Medicare Tax Rate	0.0145	
31	Total Medicare Taxes	<u>\$ (110)</u>	
32	ND Electric Wage Adjustment to Rate Base	\$ (7,614)	
33	% Employees with salaries > Social Security maximum	100%	
34	Estimated Wage Adjustment Subject to Social Security Tax	<u>\$ (7,614)</u>	
35	Social Security Tax Rate	0.062	
36	Total Social Security Taxes	<u>\$ (472)</u>	
37	Total Payroll Taxes for Wage Increase related to Rate Base	<u>\$ (582)</u>	
38	Total Rate Base Wage and Payroll Tax Adjustment	<u>\$ (8,197)</u>	

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.7  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 7  
 Employee Benefits**

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Active Health Care Costs	\$ 2,516,761		\$ 2,516,761	Response to AS-RR-147	
2	Health Insurance Changes					Response to AS-RR-148
3	High Deductible Health Plan (HDHP)		(41,532)	(41,532)		Response to AS-RR-148
4	Health Savings Account (HSA)		(81,717)	(81,717)		Response to AS-RR-148
5	Out of Pocket Maximums		(51,183)	(51,183)		Response to AS-RR-148
6	Dental Cost Increase		8,465	8,465		Response to AS-RR-148
7	Total Health Insurance Changes		<u>(165,967)</u>	<u>(165,967)</u>		
8	Drug Program Changes					
9	Mandatory Pharmacy Mail Order		(4,239)	(4,239)		Response to AS-RR-149
10	Member Pay Difference for Pharmacy		(537)	(537)		Response to AS-RR-149
11	Selected Rx Drug Elimination		(552)	(552)		Response to AS-RR-149
12	Member Pay Difference & Mandatory Mail Order for Non-Bargaining		<u>(6,456)</u>	<u>(6,456)</u>		Response to AS-RR-149
13	Total Drug Program Changes		<u>(11,784)</u>	<u>(11,784)</u>		
14	Total Health Care Benefits Costs	<u>\$ 2,516,761</u>	<u>(177,751)</u>	<u>2,339,010</u>		
15	State Income Tax Rate	6.5%		6.5%		
16	Effect on State income tax expense	<u>\$ (163,589)</u>	<u>\$ 11,553</u>	<u>\$ (152,036)</u>		
17	Federal Taxable	\$ 2,353,172		\$ 2,186,974		
18	Federal Income Tax Rate	35%		35%		
19	Effect on Federal income tax expense	<u>\$ (823,610)</u>	<u>\$ 58,169</u>	<u>\$ (765,441)</u>		
20	Total Expense	<u>\$ 1,529,562</u>		<u>\$ 1,421,533</u>		
21	Impact to Operating Income	<u>\$ (1,529,562)</u>	<u>\$ 108,029</u>	<u>\$ (1,421,533)</u>		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.8  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 8  
 Employee Retirement Programs (Co. Adj. O2)**

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Pension and Benefits	68,833	(80,838)	(12,005)	Workpaper O2-5d	Data Request AS-RR-328
2	State Income Tax Rate	6.5%		6.5%		
3	Effect on State income tax expense	\$ (4,474)	\$ 5,254	\$ 780		
4	Federal Taxable	\$ 64,359		\$ (11,225)		
5	Federal Income Tax Rate	35%		35%		
6	Effect on Federal income tax expense	\$ (22,526)	\$ 26,455	\$ 3,929		
7	Total Expense	\$ 41,833		\$ (7,296)		
8	<b>Impact to Operating Income</b>	\$ (41,833)	\$ 49,129	\$ 7,296		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.9  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 9**  
 Mercury Sorbent Reduction (Co. Adj. A14)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Operating Expense: Power Production					
2	Sherco Unit 3 Mercury Sorbent Costs	70,194	(70,194)	-	Response to AS-RR-342 Revised	
3	King Mercury Sorbent Costs	182,474	(182,474)	-	Response to AS-RR-342 Revised	
4	Total Mercury Sorbent Costs	<u>252,668</u>	<u>(252,668)</u>	<u>-</u>		
5	State Income Tax Rate	6.5%		6.5%		
6	Effect on State income tax expense	<u>\$ (16,423)</u>	<u>\$ 16,423</u>	<u>\$ -</u>		
7	Federal Taxable	\$ 236,245		\$ -		
8	Federal Income Tax Rate	35%		35%		
9	Effect on Federal income tax expense	<u>\$ (82,686)</u>	<u>\$ 82,686</u>	<u>\$ -</u>		
10	Total Expense	<u>\$ 153,559</u>		<u>\$ -</u>		
11	Impact to Operating Income	<u>\$ (153,559)</u>	<u>\$ 153,559</u>	<u>\$ -</u>		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit\_\_\_\_(MJM-2), Schedule 4.10

**Northern States Power Company - Electric**  
**Adjustment 10**  
 Qwest Pole Replacements (Co. Adj. A11)

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
1	Operating Expense: Distribution					
2	Qwest Pole Replacement	\$ 18,125	\$ (11,631)	\$ 6,494	Workpaper A11-2	Line 15
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (1,178)	\$ 756	\$ (422)		
5	Federal Taxable	\$ 16,947		\$ 6,072		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (5,931)	\$ 3,806	\$ (2,125)		
8	Total Expense	\$ 11,016		\$ 3,947		
9	Impact to Operating Income	\$ (11,016)	\$ 7,069	\$ (3,947)		
10	Total NSPM replacements (2007-2009)			385	Response to DR AS-RR-167	
11	Total ND replacements (2007-2009)			4	Response to DR AS-RR-167	
12	ND percent replacements			1.04%		Line 11/Line 10
13	2011 Incremental Cost Estimate-NSPM			\$ 625,000	Company Workpaper A11-2	
14	ND jurisdictional allocation based on replacement history			1.04%		Line 12 x Line 13
15	2011 Incremental Cost Estimate-ND			\$ 6,494		Line 13 x Line 14

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.11  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 11  
 Bad Debt (Co. Adj. A10)**

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Operating Expense: Customer Accounting					
2	Bad Debt	777,721	(271,297)	506,424	Company Workpaper A10-2	Line 12
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (50,552)	\$ 17,634	\$ (32,918)		
5	Federal Taxable	\$ 727,169		\$ 473,506		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (254,509)	\$ 88,782	\$ (165,727)		
8	Total Expense	\$ 472,660		\$ 307,779		
9	<b>Impact to Operating Income</b>	\$ (472,660)	\$ 164,881	\$ (307,779)		
10	2010 Uncollectibles (Acct 904) - NSPM			11,575,400		Response AS-RR-352
11	ND Electric Allocator			0.04375		Company Workpaper A10-2
12	ND Electric Bad Debt			506,424		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.12  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 12  
 Economic Development Costs (Co. Adj. A15)**

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Operating Expense: Sales, Econ Dvlp & Other					
2	Economic Development Inclusion	\$ 64,029	\$ (64,029)	\$ -	Workpaper A15-2	
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (4,162)	\$ 4,162	\$ -		
5	Federal Taxable	\$ 59,867		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (20,953)	\$ 20,953	\$ -		
8	Total Expense	\$ 38,914		\$ -		
9	<b>Impact to Operating Income</b>	\$ (38,914)	\$ 38,914	\$ -		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.13  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 13**  
 Charitable Contributions (Co. Adj. A18)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Administrative & General:					
2	Charitable Contributions / Donations	\$ 131,608	\$ (131,608)	\$ -	Workpaper A18-2	
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (8,555)	\$ 8,555	\$ -		
5	Federal Taxable	\$ 123,053		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (43,069)	\$ 43,069	\$ -		
8	Total Expense	\$ 79,984		\$ -		
9	Impact to Operating Income	\$ (79,984)	\$ 79,984	\$ -		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.14  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 14**

Payroll Taxes-Excluded Incentive Comp (Co. Adj. A26)

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
1	Payroll Taxes	\$ 1,814,591	\$ (39,212)	\$ 1,775,379	Workpaper O1-2	
2	State Income Tax Rate	6.5%		6.5%		
3	Effect on State income tax expense	\$ (117,948)	\$ 2,548	\$ (115,400)		
4	Federal Taxable	\$ 1,696,643		\$ 1,659,979		
5	Federal Income Tax Rate	35%		35%		
6	Effect on Federal income tax expense	\$ (593,825)	\$ 12,832	\$ (580,993)		
7	Total Expense	\$ 1,102,818		\$ 1,078,986		
8	Impact to Operating Income	\$ (1,102,818)	\$ 23,832	\$ (1,078,986)		
9	<u>Calculations for Payroll Tax Adjustment:</u>					
10	Incentive Compensation Excluded by Company		(512,569)		Company Workpaper A26-2	Response to AS-RR-350
11	Medicare Tax Rate		0.0145			Response to AS-RR-350
12	Total Medicare Taxes		\$ (7,432)			Response to AS-RR-350
13	Incentive Compensation Excluded by Company		\$ (512,569)			Response to AS-RR-350
14	% Employees with salaries > Social Security maximum		100%			Actual not known, estimate
15	Estimated Incentive Compensation Subject to Social Security Tax		\$ (512,569)			
16	Social Security Tax Rate		0.062			Response to AS-RR-350
17	Total Social Security Taxes		\$ (31,779)			Response to AS-RR-350
18	Total Estimated Payroll Taxes for Incentive Comp excluded by Company		\$ (39,212)			

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.15  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 15**

Incentive Compensation (Co. Adj. A26)

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
1	Administrative & General:					
2	Incentive Compensation	\$ 1,329,426	\$ (12,426)	\$ 1,317,000	Workpaper A26-2	Line 18
3	Medicare Payroll Taxes	\$ 19,277	\$ (180)	\$ 19,097	Response to AS-RR-350	Line 22
4	Social Security Payroll Taxes	82,424	(578)	81,846	Response to AS-RR-350	Line 27
5	Total Payroll Taxes	\$ 101,701	\$ (758)	\$ 100,943		
6	Incentive Compensation and Payroll Taxes	\$ 1,431,127	\$ (13,184)	\$ 1,417,943		
7	State Income Tax Rate	6.5%		6.5%		
8	Effect on State income tax expense	\$ (93,023)	\$ 857	\$ (92,166)		
9	Federal Taxable	\$ 1,338,104		\$ 1,325,777		
10	Federal Income Tax Rate	35%		35%		
11	Effect on Federal income tax expense	\$ (468,336)	\$ 4,314	\$ (464,022)		
12	Total Expense	\$ 869,768		\$ 861,755		
13	Impact to Operating Income	\$ (869,768)	\$ 8,013	\$ (861,755)		
14	<u>Calculation from 15% to 17% of Target Exclusion</u>					
15	Incentive Comp Over 15%	(93,195)	(93,195)		Workpaper A26-2	
16	Gross up to 100%	(621,300)				Line 15 / .15
17	Incentive Comp Over 17%	(105,621)	(105,621)			Line 16 x .17
18	Difference		(12,426)			Line 17 - Line 15
19	<u>Calculations for Payroll Tax Adjustment:</u>					
20	Adjustment to Incentive Comp reduction from 15% to 17%		(12,426)			Response to AS-RR-350
21	Medicare Tax Rate		0.0145			Response to AS-RR-350
22	Total Medicare Taxes		\$ (180)			Response to AS-RR-350
23	Adjustment to Incentive Comp reduction from 15% to 17%		\$ (12,426)			Response to AS-RR-350
24	% Employees with salaries > Social Security maximum		75%			Actual not known, estimate
25	Estimated Incentive Compensation Subject to Social Security Tax		\$ (9,320)			
26	Social Security Tax Rate		0.062			Response to AS-RR-350
27	Total Social Security Taxes		\$ (578)			Response to AS-RR-350

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.16  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 16**  
 Aviation Expense (Co. Adj. A28)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Administrative & General:					
2	Corporate Aviation Allocation	\$ 49,386	\$ (49,386)	\$ -	Workpaper A28-2; 50% of Total	Remove 100%
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (3,210)	\$ 3,210	\$ -		
5	Federal Taxable	\$ 46,176		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (16,162)	\$ 16,162	\$ -		
8	Total Expense	\$ 30,014		\$ -		
9	Impact to Operating Income	\$ (30,014)	\$ 30,014	\$ -		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.17  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 17  
 Nuclear Waste Disposal Litigation Costs**

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Administration & General					
2	Professional Services-Legal	\$ 29,000	\$ (29,000)	\$ -	Response to AS-RR-238, Supplement	
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (1,885)	\$ 1,885	\$ -		
5	Federal Taxable	\$ 27,115		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (9,490)	\$ 9,490	\$ -		
8	Total Expense	\$ 17,625		\$ -		
9	Impact to Operating Income	\$ (17,625)	\$ 17,625	\$ -		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.18  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 18**  
 Directors' and Officers' Insurance

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Administrative & General					
2	Directors's and Officers' Insurance	\$ 91,182	\$ (91,182)	\$ -	Response to AS-RR-205	
3	State Income Tax Rate	6.5%		6.5%		
4	Effect on State income tax expense	\$ (5,927)	\$ 5,927	\$ -		
5	Federal Taxable	\$ 85,255		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	\$ (29,839)	\$ 29,839	\$ -		
8	Total Expense	\$ 55,416		\$ -		
9	Impact to Operating Income	\$ (55,416)	\$ 55,416	\$ -		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.19  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 19**  
 2011 Rate Case Expenses (Co. Adj. A31)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Total Rate Case Costs to Amortize	\$ 561,400	-	561,400	Company Workpaper A31-2	
2	Amortization Period (Years)	2	1	3		3-Year Amortization
3	Annual Amortization	280,700	(93,567)	187,133		
4	State Income Tax Rate	6.5%		6.5%		
5	Effect on State income tax expense	\$ (18,246)	\$ 6,082	\$ (12,164)		
6	Federal Taxable	\$ 262,454		\$ 174,969		
7	Federal Income Tax Rate	35%		35%		
8	Effect on Federal income tax expense	\$ (91,859)	\$ 30,620	\$ (61,239)		
9	Total Expense	\$ 170,595		\$ 113,730		
10	Impact to Operating Income	\$ (170,595)	\$ 56,865	\$ (113,730)		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.20  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 20**

ND EPA Emission Credit Auction Proceeds (Co. Adj. A32)

<u>Line</u>	<u>Description</u>	<u>Company Actual</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	ND EPA Emission Credit Auction Proceeds to Amortize	\$ (260,197)	-	(260,197)	Company Workpaper A32-2	3-Year Amortization
2	Amortization Period (Years)	2	1	3		
3	Annual Amortization	(130,099)	43,366	(86,732)		
4	State Income Tax Rate	6.5%		6.5%		
5	Effect on State income tax expense	\$ 8,456	\$ (2,818)	\$ 5,638		
6	Federal Taxable	\$ (121,643)		\$ (81,094)		
7	Federal Income Tax Rate	35%		35%		
8	Effect on Federal income tax expense	\$ 42,575	\$ (14,192)	\$ 28,383		
9	Total Expense	\$ (79,068)		\$ (52,711)		
10	Impact to Operating Income	\$ 79,068	\$ (26,356)	\$ 52,711		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.21  
 Page 1 of 1

**Northern States Power Company - Electric  
 Adjustment 21**

2011 Demand Side Management (Co. Adj. A33)

<u>Line</u>	<u>Description</u>	<u>Company Actual (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	2008-2010 DSM Deferred Balance to Amortize	451,096	-	451,096	Workpaper A33-2	
2	Remove Consumer Ed & Home Energy Audits Error	-	(457)	(457)		Response to AS-RR-304
3		451,096		450,639		
4	Amortization Period (Years)	2	1	3	Workpaper A33-2	Increase to 3 years
5		225,548	(75,335)	150,213		
6	2011 Budget Load Management Program Cost	266,904	(116,691)	150,213	Felling, p. 71, line 19-21	Actual from line 5
7	Total DSM Costs Amortization	492,452	(192,026)	300,426		
8	State Income Tax Rate	6.5%		6.5%		
9	Effect on State income tax expense	\$ (32,009)	\$ 12,481	\$ (19,528)		
10	Federal Taxable	\$ 460,443		\$ 280,898		
11	Federal Income Tax Rate	35%		35%		
12	Effect on Federal income tax expense	\$ (161,155)	\$ 62,841	\$ (98,314)		
13	Total Expense	\$ 299,288		\$ 182,584		
14	Impact to Operating Income	\$ (299,288)	\$ 116,704	\$ (182,584)		

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**Northern States Power Company - Electric**  
**Adjustment 22**  
Cash Working Capital

Docket No. PU-10-657 & PU-11-55  
Exhibit (MJM-2), Schedule 4.22  
Page 1 of 2

<u>Line</u>	<u>Description</u>	<u>Company Amount (A)</u>	<u>Adjustment (B)</u>	<u>Adjusted Amount (C)</u>	<u>Company Reference (D)</u>	<u>Adjustment Reference (E)</u>
1	Cash Working Capital	\$ 2,081	\$ (18,280)	\$ (16,199)		

NORTH DAKOTA PUBLIC SERVICE COMMISSION  
 Northern States Power Company - Electric  
 Adjustment 2  
 Cash Working Capital

Docket No. PU-10-067 & PU-11-65  
 Exhibit (M)M-2) Schedule 4.22  
 Page 2012

	ND Electric As Provided by Company		Adjustments		Reference Schedule 3.2	Adjusted	
	Lead Days	Dollars	Dollar x Days	Dollars		Dollar x Days	
<b>Includable Expenses</b>							
1 Fuel Expenses	21.08	22,115	466,184			22,115	466,184
2 Gas for Generation	38.45	11,327	435,523			11,327	435,523
3 Oil	22.51	43	988			43	988
4 Nuclear & EOL	0.00	6,982	0			6,982	0
5 Nuclear Disposal	76.00	649	49,324			649	49,324
6 Purchased Power		41,116	951,999			41,116	951,999
7 Purchases	28.12	54,286	1,526,522			54,286	1,526,522
8 Interchange	38.21	7,047	269,266			7,047	269,266
		61,333	1,795,788			61,333	1,795,788
<b>Labor &amp; Related Costs</b>							
9 Regular Payroll	12.31	22,236	273,725	(36,045)	Adj e	(13,809)	(189,988)
10 Incentive Compensation	255.05	1,329	338,961			1,329	338,961
11 Pension & Benefits	19.20	4,828	92,698	(258,589)	Adj 7 & 8	(253,761)	(4,872,211)
12 Subtotal Labor & Related		28,393	706,394			(266,241)	(4,703,238)
13							
14 All Other Operating Expenses	35.01	29,308	1,026,073	(645,030)	Adj 4, 6, 10, 12, 13	(615,722)	(21,556,424)
15 Property Tax	356.72	5,653	2,016,538	(9,510)	Adj 3	(3,857)	(1,375,869)
16 Employer's Payroll Taxes	26.56	1,815	48,206	(42,727)	Adj 6, 14, 15	(40,912)	(1,086,621)
17 Gross Earnings Tax	41.48	0	0			0	0
18 Federal Income Tax	37.75	(5,953)	(220,951)	587,756		581,903	21,966,838
19 State Income Tax	37.75	(924)	(34,934)	116,358		115,434	4,357,620
20 State Sales Tax Customer Billings	35.73	0	0			0	0
21 Total Expenses		160,841	6,288,144	(287,787)		(128,946)	350,093
22 Net Annual Expense Amount							959
<b>Revenues</b>							
23 Computer Billing	100.00%	164,504	7,477,151			164,504	7,477,151
24 Hand Billed	0.00%	0	0			0	0
25 Retail Revenue Adjustments	0.00	0	0			0	0
26 Interdepartmental	0.00	0	0			0	0
27 Late Payment	42.85	355	0			355	0
28 Connected and Trouble Charges	0.00	243	10,413			243	10,413
29 CIP Incentive	114.17	255	29,113			255	0
30 Rentals	38.21	26,889	1,027,429			26,889	3,407,429
31 Sales for Resale	37.10	9,166	340,059			9,166	340,059
32 Production Associated Revenues	37.10	403	14,951			403	14,951
33 MISO	14.00	775	10,850			775	10,850
34 Point to Point Firm	37.10	507	128,589			507	128,589
35 Services & Facilities	37.10	1,345	49,900			1,345	49,900
36 Ancillary	42.85	0	0			0	0
37 Distribution Associated Revenues	42.85	(652)	(27,940)			(652)	(27,940)
38 Other	37.10	(307)	(11,390)			(307)	(11,390)
39 JCA - Rev into PSC	0.00	0	0			0	0
40 JCA - Rev into PSC	0.00	0	0			0	0
41 (blank)	0.00	0	0			0	0
42 (blank)	0.00	0	0			0	0
43 (blank)	0.00	0	0			0	0
44 Total Revenues		206,949	9,067,935			206,949	9,067,935
45 Net Annual Amount							-0.6134
46 Expense / Revenue Factor			0.7772				(15,240)
47 Allocated Revenue Amount			18,308				(16,199)
48 Net Cash Working Capital			2,081				

Source: Response to AS-RR-303

Due to rounding, may not be exactly to rate base number.

**NORTH DAKOTA PUBLIC SERVICE COMMISSION**

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 4.23  
 Page 1 of 1

**Northern States Power Company - Electric**  
**Adjustment 23**  
 Interest Synchronization

(in thousands)

<u>Line</u>	<u>Description</u>	<u>Company Amount</u> (A)	<u>Adjustment</u> (B)	<u>Adjusted Amount</u> (C)	<u>Company Reference</u> (D)	<u>Adjustment Reference</u> (E)
1	Rate Base	\$ 327,428	(1,367)	326,061		Rate Base Impact per Schedule 3.1
2	Interest Component of Rate of Return	2.83%		2.83%		Line 14
3	Interest Attributable to Rate Base	9,266		9,228		
4	State Income Tax Rate	6.5%		6.5%		
5	Effect on State income tax expense	\$ (602)	\$ 2	\$ (600)		
6	Federal Taxable	\$ 8,664		\$ 8,628		
7	Federal Income Tax Rate	35%		35%		
8	Effect on Federal income tax expense	\$ (3,032)	\$ 12	\$ (3,020)		
9	Total Expense	\$ 5,632		\$ 5,608		
10	<b>Impact to Operating Income</b>	\$ (5,632)	\$ 24	\$ (5,608)		
11	Weighted Cost					
12	Long-Term Debt	2.81%		2.81%		Schedule 2
13	Short-Term Debt	0.02%		0.02%		
14	Interest Component of Rate of Return	2.83%		2.83%		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. PU-10-657 & PU-11-55  
 Exhibit (MJM-2), Schedule 5  
 Page 1 of 1

Northern States Power Company - Electric  
 Twelve Months Ending December 31, 2011 with 2012 Step Up  
 Comparison of Company's 2012 Step Up Revenue Requirements and Staff's Proposal

Line	Description (A)	Company 2011 Test Year <sup>1</sup> (B)	Company with 2012 Step <sup>2</sup> (C)	2011		2012 Step Up with 2011 Adjustments (E)	Adjustment Reference (F)
				Proposed Adjustment (D)	Adjustments (E)		
1	Rate Base	\$ 752,278	\$ 763,458	\$ (1,769)	\$	\$ 761,689	Schedule 3.1
2	Electric Plant in Service	(370,100)	(370,105)	163		(369,942)	Schedule 3.1
3	Less: Accumulated Depreciation and Amortization	\$ 382,178	\$ 393,353	\$ (1,606)	\$	\$ 391,746	Schedule 3.1
4	Net Plant in Service						
5	Construction Work in Progress	\$ 2,100	\$ 2,100	\$ 292	\$	\$ 2,100	Schedule 3.1
6	Accumulated Deferred Income Taxes	(78,577)	(80,259)			(79,967)	Schedule 3.1
7	Other Rate Base:						
8	Cash Working Capital	2,082	1,868	(18)		1,850	Schedule 3.1
9	Materials and Supplies	6,186	6,186			6,186	Schedule 3.1
10	Fuel Inventory	5,674	5,674			5,674	Schedule 3.1
11	Non-Plant Assets & Liabilities	(6,173)	(6,173)			(6,173)	Schedule 3.1
12	Prepays & Other	4,024	4,680	(34)		4,646	Schedule 3.1
13	Total Rate Base	\$ 317,494	\$ 327,429	\$ (1,367)	\$	\$ 326,062	Schedule 3.1
14	Rate of Return	8.74%	8.74%			7.85%	Schedule 2
15	Return Requirement	\$ 27,749	\$ 28,617	\$ (3,010)	\$	\$ 25,607	Schedule 2
16	Operating Revenues						
17	Retail	\$ 164,504	\$ 164,504			\$ 164,504	Schedule 3.2
18	Other Operating	42,445	42,445			42,445	Schedule 3.2
19	Total Operating Revenues	\$ 206,949	\$ 206,949	\$ -	\$	\$ 206,950	Schedule 3.2
20	Operating Expenses						
21	Fuel & Purchased Energy	\$ 81,392	\$ 81,392	\$ (295)	\$	\$ 81,392	Schedule 3.2
22	Labor Related	n/a	n/a			(295)	Schedule 3.2
23	Power Production	42,844	43,115	(256)		42,859	Schedule 3.2
24	Transmission	11,347	11,347			11,347	Schedule 3.2
25	Distribution	6,292	6,292	(12)		6,280	Schedule 3.2
26	Customer Accounting	4,339	4,339	(271)		4,068	Schedule 3.2
27	Sales, Econ Dvp & Other	548	548			548	Schedule 3.2
28	Customer Service & Information	66	66	(64)		2	Schedule 3.2
29	Sales, Econ Dvp & Other	13,322	13,322	(314)		13,008	Schedule 3.2
30	Administrative & General	\$ 160,150	\$ 160,421	\$ (1,211)	\$	\$ 159,210	Schedule 3.2
31	Total Operating Expenses	\$ 181,153	\$ 181,943	\$ (500)	\$	\$ 181,443	Schedule 3.2
32	Depreciation and Amortization						
33	Taxes:						
34	Property and Other than Income Taxes	\$ 7,468	\$ 7,726	\$ (52)	\$	\$ 7,674	Schedule 3.2
35	Deferred Income Tax & ITC	11,140	10,306	4		10,310	Schedule 3.2
36	State & Federal Income Tax	(6,777)	(6,688)	704		(5,984)	Schedule 3.2
37	Total Taxes	\$ 11,831	\$ 11,344	\$ 656	\$	\$ 12,000	Schedule 3.2
38	Total Expenses	\$ 190,134	\$ 190,708	\$ (1,055)	\$	\$ 189,653	Schedule 3.2
39	Total Expenses						
40	AFUDC	\$ 16,815	\$ 16,240	\$ 1,055	\$	\$ 17,297	Schedule 3.2
41	Total Operating Income	\$ 10,934	\$ 12,377	\$ (4,086)	\$	\$ 8,310	Schedule 3.2
42	Income Deficiency	\$ 1,64541	\$ 1,64541	\$ -	\$	\$ 1,64541	Schedule 3.2
43	Revenue Conversion Factor						
44	Revenue Deficiency	\$ 17,991	\$ 20,365	\$ (6,691)	\$	\$ 13,674	Schedule 3.2
45	Revenue Deficiency Percent Change	17.991%	20.365%	32.85%			

<sup>1</sup> Exhibit (JMF-1), Schedule 7 and Schedule 8a, Revised 5/9/11  
<sup>2</sup> Exhibit (JMF-1), Schedule 7 and Schedule 8b, Revised 5/9/11



2302 Gr. N. Drive  
Fargo, ND 58102

May 10, 2011

Darrell Nitschke, Executive Secretary  
North Dakota Public Service Commission  
Department 408  
600 East Boulevard Avenue  
Bismarck, ND 58505-0480

**Re: APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA**

**CASE NO. PU-10-657 (2011)  
CASE NO. PU-11-55 (2012)**

Dear Mr. Nitschke:

On April 8, 2011, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submitted a letter to the North Dakota Public Service Commission (the "Commission") regarding our termination of the Merricourt Wind Project ("Merricourt Project"). As part of that letter, we committed to provide an update by May 20, 2011 of the impact of the termination on our pending electric rate case. Therefore, the purpose of this letter is to provide the Merricourt Project termination adjustment to the Company's current electric rate application, which is pending in the above-referenced dockets.

With the termination of the Merricourt Project, the adjusted base (*i.e.*, nonfuel) rate increase becomes \$17.990 million or 10.94 percent, effective for electric service on and after February 18, 2011. This represents about a \$1.783 million decrease from our original request for 2011 of \$19.773 million (12.02 percent).

For the 2012 step increase, the termination modifies our requested increase to \$2.374 million or 1.44 percent. This is a \$1.852 million reduction from our original request of \$4.226 million (2.57 percent). In total, for both 2011 and the 2012 step increase, the adjusted overall increase in base rates sought is \$20.364 million or 12.38 percent, effective January 1, 2012. In total, the effect of terminating the Merricourt Project is a \$3.635 million

reduction from the original proposal of \$23.999 million (14.59 percent) as shown in the table below.

Test Year	Original (millions)	%	Revised (millions)	%	Change (millions)
2011	\$19.773	12.02	\$17.990	10.94	(\$1.783)
2012	\$4.226	2.57	\$2.374	1.44	(\$1.852)
Total	\$23.999	14.59	\$20.364	12.38	(\$3.635)

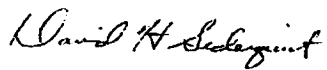
Enclosed with this letter are the following supporting schedules from the Direct Testimony of Mr. John M. Felling, revised to reflect updates related to the termination of the Merricourt Project:

- o JMF-1, Schedule 5A - Rate Base Bridge Schedule
- o JMF-1, Schedule 5B - Income Statement Bridge Schedule
- o JMF-1, Schedule 7 - Summary of Revenue Requirements
- o JMF-1, Schedule 8A - 2011 Cost of Service
- o JMF-1, Schedule 8B - 2012 Step Cost of Service

In light of the Merricourt Project termination adjustment, our revised estimate of the monthly bill impact of our rate application for the average residential (non-space heating) electric customer using 750 kWh is \$6.96 compared to the \$7.59 monthly increase in our original application.

You may direct any questions regarding this update to me at (701) 241-8632 or Matthew Loftus (612) 215-4501.

Sincerely,



David H. Sederquist  
Sr. Consultant, Regulation & Finance  
Xcel Energy

Enclosures

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-3) Schedule G  
 Revised May 9, 2011  
 Page 1 of 3

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 RATE BASE SCHEDULES  
 RATE BASE ADJUSTMENT SCHEDULES  
 2011 Unadjusted Test Year versus Final Adjusted Test Year  
 (\$100%)

Line No.	Description	Budget Adjustments										
		Line No.	Description	Amount	Line No.	Description	Amount	Line No.	Description	Amount	Line No.	Description
1	Electric Plant as Booked											
2	Production	478,047										
3	Transmission	112,510										
4	Distribution	125,117										
5	General	20,607										
6	Common	82,298										
	TOTAL Utility Plant in Service	\$703,076		\$0		\$0		\$290		\$209		\$489
7	Reserve for Depreciation											
8	Production	251,781										
9	Transmission	34,086										
10	Distribution	87,862										
11	General	98,419										
12	Common	17,290										
	TOTAL Reserve for Depreciation	\$370,138		\$0		\$0		\$4		\$12		\$31
13	Net Utility Plant in Service											
14	Production	326,266										
15	Transmission	77,724										
16	Distribution	67,455										
17	General	12,180										
18	Common	10,208										
	TOTAL Net Utility Plant in Service	\$393,833		\$0		\$0		\$256		\$197		\$488
19	Utility Plant Held for Future Use	\$0										
20	Construction Work in Progress	\$2,100										
21	Less: Accumulated Deferred Income Taxes	\$2,101		(\$24)		\$7,231		(\$8)		\$64		(\$19)
22	Cash Working Capital	\$1,772										
23	Other Rate Base Items:											
24	Materials and Supplies	\$6,186										
25	Fuel Inventory	\$5,674										
26	Non-Plant Assets & Liabilities	(\$6,173)										
27	Prepayments	\$1,018										
28	Nuclear Outage Amortization	\$2,712										
29	Customer Advances	(\$5)										
30	Customer Deposits	(\$131)										
	Other Working Capital	\$428										
31	Total Other Rate Base Items	\$8,711		\$0		\$0		\$0		\$0		\$0
32	Total Average Rate Base	\$335,320		(\$1,115)		(\$7,231)		\$8		\$254		\$133

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-1) Schedule 5a  
 Revised May 9, 2011  
 Page 3 of 3

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 RATE BASE SCHEDULE B  
 2011 Unadjusted Test Year versus Final Adjusted Test Year  
 (\$000's)

Line No.	Description	Rate Case Adjustments										Proposed 2011 Test Year (14)	
		Sizem Production Black Dog 3 & 4 (8)	Prairie Island Life Extension (9)	Steam Production Net Salvage (10)	Other Production Net Salvage (11)	Remove Handover (12)	Income Statement CMC (13)	Plant Retired	Other Production Net Salvage (11)	Remove Handover (12)	Income Statement CMC (13)		
1	Electric Plant as Booked												
2	Production												\$486,014
3	Transmission												\$110,945
4	Distribution												\$125,117
5	General												\$205,607
6	Common												\$27,696
	TOTAL Utility Plant in Service	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$752,278
7	Reserve for Depreciation												
8	Production	(\$204)	(\$26)	(\$263)	(\$33)	(\$57)	(\$2)						\$251,746
9	Transmission												\$34,883
10	Distribution												\$57,682
11	General												\$8,419
12	Common												\$17,390
	TOTAL Reserve for Depreciation	(\$204)	(\$26)	(\$263)	(\$33)	(\$57)	(\$2)					\$0	\$370,100
13	Net Utility Plant in Service												
14	Production	\$284	\$28	(\$263)	(\$33)	(\$10,444)	(\$435)						\$216,268
15	Transmission												\$76,062
16	Distribution												\$87,455
17	General												\$12,188
18	Common												\$10,206
19	Net Utility Plant in Service	\$284	\$28	(\$263)	(\$33)	(\$10,878)	\$0					\$0	\$382,176
19	Utility Plant Held for Future Use												\$0
20	Construction Work in Progress												\$2,100
21	Less: Accumulated Deferred Income Taxes	\$106	\$10	(\$101)	(\$13)	(\$775)							\$78,577
22	Cash Working Capital											\$310	\$2,032
23	Other Rate Base Items:												
24	Materials and Supplies												\$6,186
25	Field Inventory												\$5,874
26	Non-Plant Assets & Liabilities												(\$6,172)
27	Prepayments												\$1,016
28	Nuclear Charge Amortization												\$2,712
29	Customer Advances												(\$1)
30	Customer Deposits												(\$131)
	Other Working Capital												\$426
31	Total Other Rate Base Items	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$9,711
32	Total Average Rate Base	\$156	\$16	(\$163)	(\$20)	(\$10,199)	\$310	(\$10,199)	(\$310)	(\$310)	(\$310)	\$310	\$317,494

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 RATE BASE SCHEDULES  
 RATE BASE ADJUSTMENT SCHEDULES  
 2011 Unadjusted Test Year versus Final Adjusted Test Year  
 (0000')

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-3) Schedule A  
 Revised May 9, 2011  
 Page 3 of 3

Line No.	Description	Known and Measurable Adjustments							Final Proposed With 2012 State (20)
		Proposed 2011 Test Year (14)	Merchant (15)	Nuclear Production (16)	Nuclear Production - LCM/EPL (16)	Transmission Plant Amortization (17)	Nuclear Outage Amortization (18)	Income Statement CMC (19)	
1	Electric Plant as Booked								
2	Production	\$468,014	\$0	\$6,971		\$4,209		\$474,885	
3	Transmission	\$110,945						\$116,154	
4	Distribution	\$123,117						\$123,117	
5	General	\$20,607						\$20,607	
6	Common	\$27,596						\$27,596	
7	TOTAL Utility Plant in Service	\$750,279	\$0	\$6,971	\$4,209	\$4,209	\$0	\$765,655	
8	Reserve for Depreciation								
9	Production	\$251,746	\$0	(\$464)		\$669		\$250,882	
10	Transmission	\$24,083						\$24,083	
11	Distribution	\$57,682						\$57,682	
12	General	\$8,419						\$8,419	
13	Common	\$17,280						\$17,280	
14	TOTAL Reserve for Depreciation	\$370,180	\$0	(\$464)	\$669	\$669	\$0	\$370,180	
15	Net Utility Plant in Service								
16	Production	\$216,268	\$0	\$7,635	\$3,340			\$224,100	
17	Transmission	\$76,082						\$76,082	
18	Distribution	\$67,455						\$67,455	
19	General	\$12,188						\$12,188	
20	Common	\$19,295						\$19,295	
21	TOTAL Net Utility Plant in Service	\$382,178	\$0	\$7,635	\$3,340	\$0	\$0	\$393,153	
22	Utility Plant Held for Future Use	\$0						\$0	
23	Construction Work in Progress	\$2,100						\$2,100	
24	Less: Accumulated Deferred Income Taxes	\$79,577	\$0	\$738	\$677	\$208		\$80,259	
25	Cash Working Capital	\$2,082					(\$214)	\$1,868	
26	Other Rate Base Items:								
27	Materials and Supplies	\$6,186						\$6,186	
28	Fuel Inventory	\$5,074						\$5,074	
29	Non-Plant Assets & Liabilities	(\$6,173)						(\$6,173)	
30	Prepayments	\$1,018						\$1,018	
31	Nuclear Outage Amortization	\$2,712			\$657			\$3,369	
32	Customer Advances	(\$1)						(\$1)	
33	Customer Deposits	(\$131)						(\$131)	
34	Other Working Capital	\$428						\$428	
35	TOTAL Other Rate Base Items	\$9,711	\$0	\$0	\$0	\$657	\$0	\$10,367	
36	TOTAL Average Rate Base	\$517,404	\$0	\$7,007	\$2,663	\$289	(\$214)	\$527,429	

2011 Unadjusted Test Year versus 2011 Adjusted Test Year  
 (\$000's)

Line No.	Description	Data Corrections										Budget Adjustments				
		Unadjusted (1)	SMMPA Billing (2)	Wear Comp Charges to Billing (3)	Transmission Subscribers (3)	Transmission CAPX/2020 (4)	Bonus Tax Depreciation (5)	Wind to Battery/ITC (6)	Nuclear Production Milestone (7)	Nuclear Production MUR PI (8)	Transmission Intermittent Agreement (9)	Plant related				
<b>OPERATING REVENUES</b>																
1	Retail	\$164,504	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
2	Asset & Non Asset Margin Sharing															
3	Interdepartmental															
4	Other Operating	43,423	0	0	0	0	0	0	0	0	0	0	0	0		
5	Gross Earnings Tax															
6	Total Operating Revenues	\$207,927	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
<b>EXPENSES</b>																
7	Operating Expenses:															
8	Fuel & Purchased Energy	\$61,382	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
9	Power Production	\$43,062	\$0	(\$78)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
10	Transmission	\$11,387	\$0	\$80	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
11	Distribution	\$6,275	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
12	Customer Accounting	\$4,385	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
13	Customer Service & Information	\$548	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
14	Sales, Econ. Dev. & Other	\$2	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
15	Administrative & General	\$14,014	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
16	Total Operating Expenses	\$161,065	\$7	\$12	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
17	Depreciation Amortization	\$17,665	\$0	\$0	(\$2)	\$0	\$0	\$0	\$0	\$0	\$0	\$7	\$14	(\$1)		
18	Taxes:															
19	Property	\$5,653	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
20	Gross Earnings	\$12,369	\$0	\$0	\$0	(\$47)	\$485	\$0	\$4	(\$97)	\$4	(\$97)	\$43	(\$3)		
21	Deferred Income Tax & ITC	(\$7,816)	(\$3)	(\$5)	\$60	(\$74)	\$3	(\$4)	\$82	\$3	(\$4)	\$82	\$3	\$3		
22	Federal & State Income Tax	\$1,815	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
23	Payroll & Other	\$12,021	(\$3)	(\$5)	\$13	\$11	(\$4)	(\$15)	(\$15)	(\$15)	(\$15)	(\$15)	(\$15)	\$0		
24	Total Expenses	\$190,758	\$4	\$7	\$11	(\$4)	\$11	(\$4)	\$7	(\$11)	\$7	(\$11)	(\$11)	(\$1)		
25	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
26	Total Operating Income	\$17,169	(\$4)	(\$7)	(\$11)	(\$11)	(\$4)	(\$11)	(\$4)	(\$7)	(\$11)	(\$11)	(\$11)	\$1		
<b>Calculation of Revenue Requirements</b>																
27	Rate Base	\$33,320	\$0	\$0	(\$115)	(\$7,231)	\$8	\$254	\$133	(\$70)						
28	Required Operating Income	\$29,307	\$0	\$0	(\$98)	(\$638)	\$1	\$22	\$12	(\$8)						
29	Operating Income	\$17,169	(\$4)	(\$7)	(\$11)	(\$11)	(\$4)	(\$11)	(\$11)	(\$11)						
30	Revenue Efficiency	\$12,138	\$4	\$7	(\$27)	(\$229)	(\$4)	(\$29)	(\$11)	(\$11)						
31	Revenue Requirements	\$19,872	\$7	\$12	(\$143)	(\$864)	(\$8)	\$48	\$17	(\$11)						
<b>Calculation of Income Taxes</b>																
32	Operating Revenue	\$207,927	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
33	- Operating Exp	\$181,065	\$7	\$12	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
34	- Amortizations	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
35	- Taxes other than Inc	\$7,458	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
36	Operating Income before Adj	\$39,387	(\$7)	(\$12)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
37	Additions to Income	\$12,572	\$0	\$4	\$0	\$0	\$23	(\$18)	(\$3)	(\$3)						
38	Deduct from Income	\$58,708	\$0	\$0	(\$114)	\$1,187	(\$17)	\$25	(\$18)	(\$18)						
39	Debt Synchronization	\$8,490	\$0	\$0	(\$234)	\$8	\$4	(\$4)	(\$4)	(\$4)						
40	State Taxable Income	(\$19,299)	(\$7)	(\$12)	\$154	(\$853)	\$7	(\$10)	\$209	(\$2)						
41	State Income Tax before Credits	(\$1,066)	(\$3)	(\$5)	\$10	(\$82)	\$0	(\$1)	\$14	(\$1)						
42	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0						
43	Federal Taxable Income	(\$15,142)	(\$7)	(\$11)	\$144	(\$881)	\$8	(\$10)	\$185	(\$8)						
44	Fed Income Tax before Credits	(\$3,309)	(\$3)	(\$4)	\$50	(\$312)	\$2	(\$5)	\$80	(\$5)						
45	Federal Tax Credits	\$1,420	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0						
46	Income Tax	(\$7,616)	(\$3)	(\$5)	\$50	(\$374)	\$3	(\$5)	\$82	(\$3)						

2011 Unadjusted Test Year versus 2011 Adjusted Test Year  
 (\$000's)

Line No.	Description	Budget Adjustments				Traditional Adjustments						
		Transmission Tree Trimming (LIDAR) (10)	Bad Debt (11)	Quest Pole Replacement (12)	Joint Zonal Rate Update (13)	Nuclear Fees (14)	Mercury Sorbent Reduction at Site 3 (15)	Economic Development (16)	Advertising (17)	Association Dues (18)	Donations (19)	Interest on Customer Deposits (20)
<b>Diagnostic Revenues</b>												
1	Retail	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2	Asset & Non Asset Margin Sharing											
3	Intendement											
4	Other Operating											
5	Gross Earnings Tax											
6	Total Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Expenses</b>												
7	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8	Power Production	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Transmission	(\$10)	\$0	\$0	(\$46)	\$0	(\$52)	\$0	\$0	\$0	\$0	\$0
10	Distribution	\$0	\$0	\$18	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11	Customer Accounting	\$0	(\$46)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12	Customer Service & Information	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
13	Sales, Econ Dvlp & Other	\$0	\$0	\$0	\$0	\$0	\$0	\$64	\$0	\$0	\$0	\$0
14	Administrative & General	\$0	\$0	\$0	\$0	\$0	\$0	\$52	\$0	\$0	\$0	\$0
15	Total Operating Expenses	(\$10)	(\$46)	\$18	(\$46)	(\$43)	(\$52)	\$64	(\$214)	(\$3)	\$132	\$1
16	Depreciation	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
17	Amortization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Taxes</b>												
18	Property	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
19	Gross Earnings	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
20	Deferred Income Tax & ITC	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
21	Federal & State Income Tax	\$4	\$18	(\$7)	\$17	\$33	\$20	(\$25)	\$54	\$1	(\$92)	(\$0)
22	Payroll & Other	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
23	Total Taxes	\$4	\$18	(\$7)	\$17	\$33	\$20	(\$25)	\$54	\$1	(\$92)	(\$0)
24	Total Expenses	(\$6)	(\$28)	\$11	(\$28)	(\$10)	(\$32)	\$39	(\$130)	(\$2)	\$00	\$1
25	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
26	Total Operating Income	\$6	\$28	(\$13)	\$26	\$56	\$32	(\$38)	\$130	\$2	(\$80)	(\$1)
<b>Calculation of Revenue Requirements</b>												
27	Rate Base	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
28	Required Operating Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
29	Operating Income	\$6	\$28	(\$11)	\$26	\$56	\$32	(\$39)	\$130	\$2	(\$80)	(\$1)
30	Revenue Deficiency	(\$0)	(\$28)	\$11	(\$26)	(\$56)	(\$32)	\$39	(\$130)	(\$2)	\$80	\$1
31	Revenue Requirements	(\$10)	(\$46)	\$18	(\$43)	(\$43)	(\$52)	\$64	(\$214)	(\$3)	\$132	\$1
<b>Calculation of Income Taxes</b>												
32	Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
33	- Operating Exp	(\$10)	(\$46)	\$18	(\$46)	(\$43)	(\$52)	\$64	(\$214)	(\$3)	\$132	\$1
34	- Taxes	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
35	- Taxes left after Inc	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Operating Income before Apts	\$10	\$46	(\$18)	\$43	\$43	\$52	(\$64)	\$214	\$3	(\$132)	(\$1)
37	Additional Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
38	Deduct from Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
39	State Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
40	State Taxable Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
41	State Income Tax before Credits	\$1	\$3	(\$1)	\$3	\$3	\$3	(\$4)	\$14	(\$1)	(\$9)	(\$0)
42	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
43	Federal Taxable Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
44	Federal Income Tax before Credits	\$3	\$15	(\$6)	\$14	\$14	\$17	(\$17)	\$200	\$3	(\$123)	(\$1)
45	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
46	Income Tax	\$4	\$18	(\$7)	\$17	\$33	\$20	(\$25)	\$54	\$1	(\$92)	(\$0)

2011 Unadjusted Test Year versus 2011 Adjusted Test Year  
 (\$000's)

Line No.	Description	Rate Case Adjustments									
		Plant Related					Non-Plant Related				
		Steam Production	Black Dog 3 & 4 Life Extension	Steam Production Net Salvage	Other Production Net Salvage	Asset & Non-Asset Margin Sharing	Wholesale Billing	Incentive Pay	Lease Expense for Vacated Buildings	Aviation	Employee Expenses
		(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
1	Retail	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2	Asset & Non Asset Margin Sharing										
3	Interdepartmental										
4	Other Operating	0	0	0	0	(975)	0	0	0	0	0
5	Gross Earnings Tax										
6	Total Operating Revenues	\$0	\$0	\$0	\$0	(\$975)	\$0	\$0	\$0	\$0	\$0
<b>Expenses</b>											
<b>Operating Expenses:</b>											
7	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
8	Power Production	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
9	Transmission	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
10	Distribution	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11	Customer Accounting	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
12	Customer Service & Information	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
13	Sales, Econ Dvp & Other	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14	Administrative & General	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Total Operating Expenses	\$0	\$0	\$0	\$0	\$0	(\$11)	(\$813)	(\$18)	(\$49)	(\$26)
16	Depreciation	(\$527)	(\$51)	\$526	\$56	\$0	\$0	\$0	\$0	\$0	\$0
17	Amortization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Taxes:</b>											
18	Property	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
19	Gross Earnings	\$215	\$20	(\$201)	(\$26)	\$0	\$0	\$0	\$0	\$0	\$0
20	Deferred Income Tax & ITC	(\$2)	(\$9)	\$2	\$6	(\$382)	\$4	\$201	\$8	\$18	\$10
21	Federal & State Income Tax	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
22	Payroll & Other	\$213	\$20	(\$199)	(\$26)	(\$382)	\$4	\$201	\$8	\$18	\$10
23	Total Taxes	(\$314)	(\$31)	\$327	\$44	(\$382)	(\$17)	(\$312)	(\$15)	(\$30)	(\$16)
24	Total Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
25	Allowance for Funds Used During Construction	\$314	\$31	(\$327)	(\$44)	(\$382)	\$17	\$312	\$15	\$30	\$16
26	Total Operating Income	\$156	\$14	(\$14)	(\$2)	\$0	\$0	\$0	\$0	\$0	\$0
27	Rate Base	\$14	\$14	(\$14)	(\$2)	\$0	\$0	\$0	\$0	\$0	\$0
28	Required Operating Income	\$300	\$300	(\$300)	(\$30)	(\$300)	\$30	\$300	\$30	\$30	\$30
29	Operating Income	(\$144)	(\$186)	(\$186)	(\$188)	(\$186)	(\$186)	(\$186)	(\$186)	(\$186)	(\$186)
30	Revenue Deficiency	\$144	\$186	\$186	\$188	\$186	\$186	\$186	\$186	\$186	\$186
31	Revenue Requirements	\$144	\$186	\$186	\$188	\$186	\$186	\$186	\$186	\$186	\$186
<b>Calculation of Income Taxes</b>											
32	Operating Revenue	\$0	\$0	\$0	\$0	(\$975)	\$0	\$0	\$0	\$0	\$0
33	Operating Exp	\$0	\$0	\$0	\$0	\$0	(\$11)	(\$813)	(\$18)	(\$49)	(\$26)
34	Amortizations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
35	Taxes on Plant Inc	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
36	Operating Income before Ads	\$0	\$0	\$0	\$0	(\$975)	\$11	\$13	\$24	\$49	\$26
37	Additions to Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
38	Deduct from Income	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
39	State Income Tax	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
40	State Synchronization	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
41	State Taxable Income	\$0	\$0	\$0	\$0	(\$975)	\$11	\$13	\$24	\$49	\$26
42	State Income Tax before Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
43	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
44	Federal Taxable Income	\$0	\$0	\$0	\$0	(\$975)	\$10	\$12	\$22	\$46	\$24
45	Fed Income Tax before Credits	\$0	\$0	\$0	\$0	(\$975)	\$4	\$4	\$8	\$16	\$9
46	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-3) Schedule 05  
 Revised May 9, 2011  
 Page 4 of 5

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 INCOME STATEMENT SCHEDULES  
 INCOME STATEMENT ADJUSTMENT SCHEDULES

2011 Unadjusted Test Year versus 2011 Adjusted Test Year  
 (\$000's)

Line No.	Description	Amortizations					Proposed 2011 Test Year (18)
		2008 Private Fuel Storage (31)	2011 Rate Case (32)	2011 Emissions Credit (33)	2011 DSM (34)	Remove Meritcount (35)	
<b>Operating Revenues</b>							
1	Retail	\$0	\$0	\$0	\$0	\$0	\$164,504
2	Asset & Non Asset Margin Sharing						\$0
3	Interdepartmental						\$0
4	Other Operating	0	0	0	0	0	\$42,445
5	Gross Earnings Tax						\$0
6	Total Operating Revenues	\$0	\$0	\$0	\$0	\$0	\$206,949
<b>Expenses</b>							
7	Operating Expenses:						
7	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0	\$81,362
8	Power Production	\$0	\$0	\$0	\$0	\$0	\$42,844
9	Transmission	\$0	\$0	\$0	\$0	\$0	\$11,347
10	Distribution	\$0	\$0	\$0	\$0	\$0	\$6,292
11	Customer Accounting	\$0	\$0	\$0	\$0	\$0	\$4,339
12	Customer Service & Information	\$0	\$0	\$0	\$0	\$0	\$548
13	Sales, Econ Dvlp & Other	\$0	\$0	\$0	\$0	\$0	\$66
14	Administrative & General	\$0	\$0	\$0	\$0	\$0	\$13,322
15	Total Operating Expenses	\$0	\$0	\$0	\$0	(\$72)	\$160,160
16	Depreciation	\$0	\$0	\$0	\$0	(\$118)	\$17,579
17	Amortization	\$190	\$281	(\$130)	\$228	\$0	\$574
<b>Taxes:</b>							
18	Property	\$0	\$0	\$0	\$0	\$0	\$5,653
19	Gross Earnings	\$0	\$0	\$0	\$0	(\$1,572)	\$11,140
20	Deferred Income Tax & ITC	(\$75)	(\$110)	\$51	(\$88)	\$1,576	(\$6,777)
21	Federal & State Income Tax	\$0	\$0	\$0	\$0	\$0	\$1,915
22	Payroll & Other	(\$75)	(\$110)	\$51	(\$88)	\$4	(\$4)
23	Total Taxes	\$115	\$171	(\$79)	\$137	(\$186)	(\$4)
24	Total Expenses	\$0	\$0	\$0	\$0	\$0	\$180,134
25	Allowance for Funds Used During Construction	(\$118)	(\$171)	\$79	(\$137)	\$186	\$4
26	Total Operating Income	\$0	\$0	\$0	\$0	\$0	\$16,815
<b>Calculation of Revenue Requirements</b>							
27	Rate Base	\$0	\$0	\$0	\$0	(\$10,104)	\$310
28	Required Operating Income	\$0	\$0	\$0	\$0	(\$688)	\$11
29	Operating Income	(\$115)	(\$171)	\$79	(\$137)	\$186	\$4
30	Revenue Deficiency	\$115	\$171	(\$79)	(\$137)	(\$1,075)	\$23
31	Revenue Requirements	\$190	\$281	(\$130)	\$228	(\$1,789)	\$28
<b>Calculation of Income Taxes</b>							
32	Operating Revenue	\$0	\$0	\$0	\$0	\$0	\$0
33	- Operating Exp	\$0	\$0	\$0	\$0	(\$72)	\$0
34	- Amortizations	\$190	\$281	(\$130)	\$228	\$0	\$0
35	- Taxes on Plant Inc	\$0	\$0	\$0	\$0	\$0	\$0
36	Operating Income before Adjs	(\$190)	(\$281)	\$130	(\$228)	\$72	\$0
37	Additions to Income	\$0	\$0	\$0	\$0	(\$445)	\$0
38	Deducted from Income	\$0	\$0	\$0	\$0	(\$4,164)	\$0
39	State Synchronization	(\$180)	(\$281)	\$130	(\$228)	\$71	\$10
40	State Taxable Income	(\$180)	(\$281)	\$130	(\$228)	\$4,017	(\$10)
41	State Income Tax before Credits	(\$12)	(\$10)	\$5	(\$15)	(\$6)	(\$10)
42	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0
43	Federal Taxable Income	(\$178)	(\$283)	\$122	(\$211)	\$3,756	(\$9)
44	Federal Income Tax before Credits	(\$42)	(\$40)	\$43	(\$74)	\$1,315	(\$23)
45	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0
46	Income Tax	(\$75)	(\$110)	\$51	(\$88)	\$1,376	(\$4)

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-3) Schedule 5b  
 Revised May 9, 2011  
 Page 5 of 5

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 INCOME STATEMENT SCHEDULES  
 INCOME STATEMENT ADJUSTMENT SCHEDULES

2011 Unadjusted Test Year versus 2011 Adjusted Test Year  
 (\$000's)

Line No.	Description	Proposed 2011 Test Year (38)	Mortgage (40)	Production Monies - LCM/REPU (46)	Transmission Plant Amortization (41)	Nuclear Outage Amortization (42)	Chg in Cost of Capital (45)	Income Statement CYC (44)	Final Adjusted w/2012 Imp (43)
<b>Operating Revenues</b>									
1	Retail	\$184,604	\$0	\$0	\$0	\$0	\$0	\$0	\$184,604
2	Asset & Non Asset Margin Sharing	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	Interdepartmental	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
4	Other Operating	\$42,445	\$0	\$0	\$0	\$0	\$0	\$0	\$42,445
5	Gross Earnings Tax	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
6	Total Operating Revenues	\$226,949	\$0	\$0	\$0	\$0	\$0	\$0	\$226,949
<b>EXPENSES</b>									
<b>Operating Expenses:</b>									
7	Fuel & Purchased Energy	\$81,382	\$0	\$0	\$0	\$0	\$0	\$0	\$81,382
8	Power Production	\$42,844	\$0	\$0	\$0	\$271	\$0	\$0	\$43,115
9	Transmission	\$11,347	\$0	\$0	\$0	\$0	\$0	\$0	\$11,347
10	Distribution	\$6,292	\$0	\$0	\$0	\$0	\$0	\$0	\$6,292
11	Customer Accounting	\$4,338	\$0	\$0	\$0	\$0	\$0	\$0	\$4,338
12	Customer Service & Information	\$548	\$0	\$0	\$0	\$0	\$0	\$0	\$548
13	Salaries, Etern Dtg & Other	\$66	\$0	\$0	\$0	\$0	\$0	\$0	\$66
14	Administrative & General	\$13,322	\$0	\$0	\$0	\$0	\$0	\$0	\$13,322
15	Total Operating Expenses	\$180,150	\$0	\$0	\$0	\$271	\$0	\$0	\$180,421
16	Depreciation	\$17,078	\$0	\$704	\$86	\$0	\$0	\$0	\$18,389
17	Amortization	\$574	\$0	\$0	\$0	\$0	\$0	\$0	\$574
18	Property	\$5,653	\$0	\$159	\$89	\$0	\$0	\$0	\$5,911
19	Gross Earnings	\$11,140	\$0	(\$1,131)	\$287	\$0	\$0	\$0	\$10,286
20	Deferred Income Tax & ITC	(\$6,777)	\$0	\$574	(\$108)	\$16	\$0	\$0	(\$6,689)
21	Federal & State Income Tax	\$1,815	\$0	\$0	\$0	\$0	\$0	\$0	\$1,815
22	Payroll & Other	\$11,831	\$0	(\$398)	(\$7)	(\$99)	\$16	\$0	\$11,344
23	Total Taxes	\$180,134	\$0	\$306	\$79	\$172	\$16	\$0	\$180,706
24	Total Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
25	Allowance for Funds Used During Construction	\$18,815	\$0	(\$208)	(\$79)	(\$172)	(\$16)	(\$3)	\$18,241
26	Total Operating Income	\$317,494	\$0	\$7,087	\$2,653	\$398	\$0	(\$214)	\$327,429
27	Rate Base	\$27,748	\$0	\$825	\$234	\$34	(\$8)	(\$19)	\$28,617
28	Required Operating Income	\$18,815	\$0	(\$208)	(\$79)	(\$172)	(\$16)	(\$3)	\$18,241
29	Operating Income	\$10,904	\$0	\$650	\$313	\$226	\$10	(\$16)	\$12,278
30	Revenue Deficiency	\$17,990	\$0	\$1,631	\$515	\$339	\$16	(\$27)	\$20,354
31	Revenue Requirements	\$206,949	\$0	\$0	\$0	\$0	\$0	\$0	\$206,949
32	Operating Revenue	\$180,150	\$0	\$0	\$0	\$0	\$0	\$0	\$180,150
33	- Operating Exp	\$574	\$0	\$0	\$0	\$0	\$0	\$0	\$574
34	- Amortization	\$7,468	\$0	\$158	\$89	\$0	\$0	\$0	\$7,725
35	- Taxes on Non-PC	\$12,033	\$0	(\$453)	(\$99)	(\$271)	\$0	\$0	\$11,851
36	Operating Income before Adjs	\$55,385	\$0	(\$2,304)	\$86	\$198	\$0	\$0	\$54,175
37	Adjustments to Income	\$4,885	\$0	\$228	\$86	\$13	(\$40)	\$17	\$5,268
38	Deferred Income	(\$13,900)	\$0	\$1,463	(\$271)	(\$1,011)	\$40	(\$3)	(\$13,822)
39	State Income Tax	(\$182)	\$0	\$6	(\$18)	(\$66)	\$0	\$0	(\$188)
40	State Income Tax before Credits	\$41	\$0	\$0	\$0	\$0	\$0	\$0	\$41
41	State Tax Credits	(\$12,898)	\$0	\$1,388	(\$253)	(\$148)	\$37	\$6	(\$12,453)
42	Federal Income Tax	(\$4,433)	\$0	\$479	(\$31)	(\$331)	\$13	\$2	(\$4,353)
43	Federal Income Tax before Credits	\$1,420	\$0	\$0	\$0	\$0	\$0	\$0	\$1,420
44	Federal Tax Credits	(\$6,777)	\$0	\$574	(\$108)	(\$176)	\$16	\$3	(\$6,689)

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota  
 SUMMARY OF REVENUE REQUIREMENTS  
 Test Year Ending December 31, 2011  
 (\$000's)

Case No. PU-10-657 & PU-11-55  
 Exhibit\_\_\_\_(JMF-1) Schedule 7  
 Revised May 9, 2011  
 Page 1 of 1

<u>Line</u>	<u>Description</u>	<u>Adjusted Proposed Test Year 2011</u>	<u>Final Proposed With 2012 Step</u>
1	Average Rate Base	\$317,494	\$327,429
2	Operating Income (Before AFUDC)	\$16,815	\$16,241
3	Allowance for Funds Used During Construction	\$0	\$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	\$16,815	\$16,241
5	Overall Rate of Return (Line 4 / Line 1)	5.30%	4.96%
6	Required Rate of Return	8.74%	8.74%
7	Operating Income Requirement (Line 1 x Line 6)	\$27,749	\$20,617
8	Income Deficiency (Line 7 - Line 4)	\$10,934	\$12,377
9	Gross Revenue Conversion Factor	1.64541	1.64541
10	Revenue Deficiency (Line 8 x Line 9)	\$17,991	\$20,365
11	Retail Related Revenue Under Present Rates	\$164,504	\$164,504
13	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	10.94%	12.38%

**ROE = 4.69%**  
**Deficiency = \$17,990**  
**% Increase = 10.94%**  
**Required ROE = 11.25%**

Case No. PU-10-657 & PU-11-55

Exhibit\_\_\_(JMF-1) Schedule 8a

Revised May 9, 2011

Page 1 of 6

**Northern States Power Company, a Minnesota Corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**2011 Test Year Adj for Merricourt**

**Summary Reports**

**May 9, 2011**

Rate Base Summary

	<u>Total Company Electric</u>			<u>ND Retail Electric</u>			<u>All Other</u>		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
1 Plant Investment	12,961,679	14,334,477	13,648,078	712,931	791,624	752,278	12,248,748	13,542,853	12,895,800
2 Depreciation Reserve	<u>(6,422,757)</u>	<u>(6,779,294)</u>	<u>(6,601,026)</u>	<u>(360,611)</u>	<u>(379,589)</u>	<u>(370,100)</u>	<u>(6,062,146)</u>	<u>(6,399,705)</u>	<u>(6,230,926)</u>
3 Net Utility Plant	6,538,922	7,555,183	7,047,052	352,320	412,035	382,178	6,186,602	7,143,148	6,664,874
4 C.W.I.P.	38,545	26,653	32,599	2,501	1,698	2,100	36,044	24,955	30,499
5 Accumulated Deferred Taxes	(1,308,721)	(1,517,904)	(1,413,313)	(72,163)	(84,990)	(78,577)	(1,236,558)	(1,432,914)	(1,334,736)
Other Rate Base:									
6 Cash Working Capital	20,907	20,907	20,907	2,082	2,082	2,082	18,825	18,825	18,825
7 Materials & Supplies	105,544	105,544	105,544	6,186	6,186	6,186	99,358	99,358	99,358
8 Fuel Inventory	90,609	90,609	90,609	5,674	5,674	5,674	84,935	84,935	84,935
9 Non-Plant Assets & Liab	(113,973)	(91,197)	(102,585)	(6,866)	(5,480)	(6,173)	(107,107)	(85,717)	(96,412)
10 Prepays & Other	62,822	69,020	65,921	3,849	4,198	4,024	58,973	64,822	61,897
<b>11 Total Rate Base</b>	<b>5,434,655</b>	<b>6,258,815</b>	<b>5,846,734</b>	<b>293,583</b>	<b>341,403</b>	<b>317,494</b>	<b>5,141,072</b>	<b>5,917,412</b>	<b>5,529,240</b>

**Income Statement Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Operating Revenues</u></b>			
1 Retail	3,034,853	164,504	2,870,349
2 CIP Adjustment to Program Costs	0	-	0
3 Interdepartmental	607	-	607
4 Other Operating	717,960	42,445	675,515
5 Gross Earnings Tax	0	-	0
6 <b>Total Operating Revenues</b>	<b>3,753,420</b>	<b>206,949</b>	<b>3,546,471</b>
<b><u>Expenses</u></b>			
<b>Operating Expenses:</b>			
7 Fuel & Purchased Energy	1,309,223	81,392	1,227,831
8 Power Production	728,867	42,844	686,023
9 Transmission	195,275	11,347	183,928
10 Distribution	105,263	6,292	98,971
11 Customer Accounting	61,413	4,339	57,074
12 Customer Service & Information	87,277	548	86,729
13 Sales, Econ Dvlp & Other	268	66	202
14 Administrative & General	205,270	13,322	191,948
15 <b>Total Operating Expenses</b>	<b>2,692,856</b>	<b>160,150</b>	<b>2,532,706</b>
16 Depreciation	343,491	17,579	325,912
17 Amortization	15,949	574	15,375
<b>Taxes:</b>			
18 Property	115,650	5,653	109,997
19 Gross Earnings	0	-	0
20 Deferred Income Tax & ITC	181,172	11,140	170,032
21 State & Federal Income (see Page 3)	(38,780)	(6,777)	(32,003)
22 Payroll & Other	30,033	1,815	28,218
23 <b>Total Taxes</b>	<b>288,075</b>	<b>11,831</b>	<b>276,244</b>
24 <b>Total Expenses</b>	<b>3,340,370</b>	<b>190,134</b>	<b>3,150,237</b>
25 AFUDC	0	-	0
26 <b>Total Operating Income</b>	<b>413,050</b>	<b>16,815</b>	<b>396,234</b>

**Income Tax Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b>Income Before Taxes</b>			
1 Total Operating Revenues	3,753,420	206,949	3,546,471
2 less: Total Operating Expenses	(2,692,856)	(160,150)	(2,532,706)
3 Book Depreciation & Amortization	(359,440)	(18,153)	(341,287)
4 Taxes (Other Than Current Income)	<u>(326,855)</u>	<u>(18,608)</u>	<u>(308,247)</u>
5 Total Before Tax Book Income	374,269	10,038	364,231
<b>Tax Additions</b>			
6 Book Depreciation	343,491	17,579	325,912
7 Deferred Income Taxes & ITC	181,172	11,140	170,032
8 Nuclear Fuel Burn (ex D&D)	111,477	6,478	104,999
9 Nuclear Outage Accounting	59,245	3,580	55,665
10 Avoided Tax Interest	34,779	1,975	32,804
11 Open Line	0	0	0
12 Open Line	0	0	0
13 Open Line	0	0	0
14 Open Line	0	0	0
15 Open Line	0	0	0
16 Other Book Additions	0	0	0
17 Total Tax Additions	730,164	40,752	689,412
<b>Tax Deductions</b>			
18 Debt Interest Expense	165,463	8,985	156,477
19 Tax Depreciation & Removal	952,706	53,949	898,757
20 Manufacture Production Deduction	0	0	0
21 Open	0	0	0
22 Open	0	0	0
23 Open	0	0	0
24 Other Tax/Book Timing Differences	23,807	1,446	22,361
25 Net Preferred Stock Deduction	0	0	0
26 Total Tax Deductions	<u>1,141,976</u>	<u>64,380</u>	<u>1,077,595</u>
27 State Taxable Income	(37,542)	(13,590)	(23,952)
28 State Income Tax Rate	9.03%	6.50%	N/A
29 State Taxes before Credits	(3,389)	(883)	(2,505)
30 State Credits	1,180	41	1,139
31 Total State Income Taxes	<u>(4,569)</u>	<u>(924)</u>	<u>(3,644)</u>
32 Federal Taxable Income	(32,974)	(12,666)	(20,308)
33 Federal Income Tax Rate	35.00%	35.00%	35.00%
34 Federal Tax before Credits	(11,541)	(4,433)	(7,108)
35 Federal Tax Credits	22,671	1,420	21,251
36 Total Federal Income Taxes	<u>(34,212)</u>	<u>(5,853)</u>	<u>(28,359)</u>
37 Total Federal & State Income Taxes	<u>(38,780)</u>	<u>(6,777)</u>	<u>(32,003)</u>

**Revenue Requirement & Return Summary**

<u>Capital Structure</u>				<u>Composite Income Tax Rates</u>		
	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>			
1	Long Term Debt	6.0700%	46.3000%	2.8100%	State of North Dakota Tax rate	6.50%
2	Short Term Debt	2.0600%	1.1400%	0.0200%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	32.73%
4	Common Equity	11.2500%	52.5600%	5.9100%	Total North Dakota Composite Tax Rate	39.23%
5	Required Rate of Return		8.7400%		Total Corporate Composite Tax Rate	40.87%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<u>Rate of Return (ROR)</u>				
6	Total Operating Income	413,050	16,815	396,234
7	Total Average Rate Base	5,846,734	317,494	5,529,240
8	ROR (Operating Income / Rate Base)	7.06%	5.30%	7.17%
<u>Return on Equity (ROE)</u>				
9	Total Operating Income	413,050	16,815	396,234
10	Debt Interest (Rate Base * Weighted Debt Cost)	(165,463)	(8,985)	(156,477)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	247,587	7,830	239,757
13	Equity Rate Base (Rate Base * Equity Ratio)	3,073,043	166,875	2,906,168
14	ROE (Earnings for Common / Equity Rate Base)	8.06%	4.69%	8.25%
<u>Revenue Deficiency</u>				
15	Require Operating Income (Rate Base * Required Return)	511,005	27,749	483,256
16	Operating Income	413,050	16,815	396,234
17	Operating Income Deficiency	97,955	10,934	87,021
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	1.69110	1.64541	N/A
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	165,652	17,990	147,662
<u>Total Retail Revenue Requirements</u>				
20	Retail Related Revenues	3,035,460	164,504	2,870,956
21	Revenue Deficiency	165,652	17,990	147,662
22	Total Retail Revenue Requirements	3,201,112	182,494	3,018,618
23	<u>Percentage Increase (Decrease)</u>	5.46%	10.94%	5.14%

Case No. PU-10-657 & PU-11-55  
 Exhibit (MJM-3) Schedule B  
 Revised May 9, 2011  
 Page 6 of 6

Northern States Power Company, a Minnesota Corporation  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost: Ranked May 9, 2011  
 2011 Test Year Adj for Merricourt  
 (Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Line #	Description	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollars x Days	Dollars	Dollars x Days	Dollars	Dollars x Days
1	Fuel Expenses	343,157	7,444,550	22,115	486,184	331,042	6,978,365
2	Coal & Rail Transport	180,864	5,954,990	11,327	435,523	169,537	6,519,467
3	Oil	663	15,374	43	968	640	14,408
4	Nuclear & EOL	111,499	0	6,982	0	104,517	0
5	Nuclear Disposal	11,164	849,464	849	49,324	10,315	799,140
6		657,387	15,263,378	41,118	951,999	618,271	14,311,378
7	Purchased Power	894,154	25,143,610	54,286	1,526,522	839,868	23,617,088
8	Purchases	119,783	4,577,291	7,047	299,206	112,736	4,268,025
9	Interchange	1,013,947	29,720,901	81,333	1,795,788	932,614	27,925,113
10	Regular Payroll	387,828	4,527,963	22,238	273,725	345,592	4,254,238
11	Incentive Compensation	21,732	5,942,747	1,329	338,081	20,403	5,203,746
12	Pension & Benefits	79,188	1,519,872	4,828	82,688	74,360	1,437,174
13	Subtotal Labor & Related	468,720	11,590,581	28,395	705,384	440,327	10,865,197
14	All Other Operating Expenses	592,802	19,359,595	29,308	1,026,073	523,494	18,337,622
15	Property Tax	115,650	41,254,868	5,653	2,015,938	109,997	39,238,130
16	Employer's Payroll Taxes	30,003	797,676	1,815	48,208	28,218	749,470
17	Gross Earnings Tax	0	0	0	0	0	0
18	Federal Income Tax	(34,212)	(1,291,498)	(6,853)	(220,951)	(28,359)	(1,070,547)
19	State Income Tax	(4,569)	(172,464)	(924)	(34,894)	(3,644)	(137,570)
20	State Sales Tax Customer Billings	136,596	4,951,999	0	0	136,596	4,951,999
21	Total Expenses	2,938,363	127,469,537	180,841	6,298,144	2,777,513	115,180,893
22	Net Annual Expense Amount		332,791		-7,223		315,564
23	Revenue	3,034,853	137,942,263	184,504	7,477,151	2,870,349	130,465,112
24	Compass Billing	0	0	0	0	0	0
25	Hand Billed	0	0	0	0	0	0
26	Retail Revenue Adjustments	0	0	0	0	0	0
27	Interdepartmental	5,490	0	365	0	5,135	0
28	Late Payment	2,281	96,868	243	10,413	2,038	86,475
29	Connect and Trouble Charges	0	0	0	0	0	0
30	CIP Incentive	4,002	460,333	255	29,113	3,777	431,220
31	Rentals	446,657	17,068,754	26,889	1,027,429	419,768	16,039,335
32	Sales for Retail	148,763	5,519,846	9,166	340,039	139,617	5,179,781
33	Production Associated Revenues	8,436	238,776	603	14,961	6,033	223,824
34	MISO	13,342	186,786	775	10,850	12,567	175,928
35	Power to Point Firm	99,651	2,213,062	3,466	128,588	56,185	2,084,484
36	Services & Facilities	8,828	327,519	507	18,910	8,321	308,709
37	Ancillary	23,146	899,791	1,345	49,900	21,803	808,981
38	Distribution Associated Revenues	1,872	80,219	(652)	(27,940)	1,872	80,219
39	Other	2,356	100,859	(907)	(11,390)	3,008	128,999
40	JOA - Rev W/o PSC	(4,896)	(181,642)	0	0	(4,896)	(170,282)
41	(blank)	0	0	0	0	0	0
42	(blank)	0	0	0	0	0	0
43	(blank)	0	0	0	0	0	0
44	Total Revenues	3,753,420	184,910,560	206,949	9,067,935	3,546,471	155,842,605
45	Net Annual Amount		481,810		24,844		456,966
46	Expense / Revenue Factor		353,898		19,538		18,826
47	Allocated Revenue Amount		20,907		2,081		18,826
48	Net Cash Working Capital						

**ROE = 4.05%**  
**Deficiency = \$20,364**  
**% Increase = 12.38%**  
**Required ROE = 11.25%**

Case No. PU-10-657 & PU-11-55

Exhibit \_\_ (JMF-1) Schedule 8b

Revised May 9, 2011

Page 1 of 6

**Northern States Power Company, a Minnesota Corporation**  
**Electric Utility - North Dakota Retail Jurisdiction**  
**Cost of Service Study**  
**Final Proposed with 2012 Step Adj for Merricourt**

**Summary Reports**

**May 9, 2011**

Rate Base Summary

	<u>Total Company Electric</u>			<u>ND Retail Electric</u>			<u>All Other</u>		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
1 Plant Investment	13,205,280	14,339,231	13,772,256	731,050	795,865	763,458	12,474,230	13,543,366	13,008,798
2 Depreciation Reserve	<u>(6,377,573)</u>	<u>(6,796,485)</u>	<u>(6,587,029)</u>	<u>(358,804)</u>	<u>(381,406)</u>	<u>(370,105)</u>	<u>(6,018,769)</u>	<u>(6,415,079)</u>	<u>(6,216,924)</u>
3 Net Utility Plant	6,827,707	7,542,746	7,185,227	372,246	414,459	393,353	6,455,461	7,128,287	6,791,874
4 C.W.I.P.	38,545	26,653	32,599	2,501	1,698	2,100	36,044	24,955	30,499
5 Accumulated Deferred Taxes	(1,331,817)	(1,521,541)	(1,426,679)	(74,263)	(86,255)	(80,259)	(1,257,554)	(1,435,286)	(1,346,420)
Other Rate Base:									
6 Cash Working Capital	18,822	18,822	18,822	1,868	1,868	1,868	16,954	16,954	16,954
7 Materials & Supplies	105,544	105,544	105,544	6,186	6,186	6,186	99,358	99,358	99,358
8 Fuel Inventory	90,609	90,609	90,609	5,674	5,674	5,674	84,935	84,935	84,935
9 Non-Plant Assets & Liab	(113,973)	(91,197)	(102,585)	(6,866)	(5,480)	(6,173)	(107,107)	(85,717)	(96,412)
10 Prepays & Other	62,822	69,020	65,921	4,142	5,218	4,680	58,680	63,802	61,241
<b>11 Total Rate Base</b>	<b>5,698,259</b>	<b>6,240,656</b>	<b>5,969,458</b>	<b>311,488</b>	<b>343,368</b>	<b>327,429</b>	<b>5,386,771</b>	<b>5,897,288</b>	<b>5,642,029</b>

**Income Statement Summary**

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<b><u>Operating Revenues</u></b>			
1 Retail	3,034,853	164,504	2,870,349
2 CIP Adjustment to Program Costs	0	-	0
3 Interdepartmental	607	-	607
4 Other Operating	717,960	42,445	675,515
5 Gross Earnings Tax	0	-	0
6 <b>Total Operating Revenues</b>	<b>3,753,420</b>	<b>206,949</b>	<b>3,546,471</b>
<b><u>Expenses</u></b>			
<b>Operating Expenses:</b>			
7 Fuel & Purchased Energy	1,309,223	81,392	1,227,831
8 Power Production	728,867	43,115	685,752
9 Transmission	195,275	11,347	183,928
10 Distribution	105,263	6,292	98,971
11 Customer Accounting	61,413	4,339	57,074
12 Customer Service & Information	87,277	548	86,729
13 Sales, Econ Dvlp & Other	268	66	202
14 Administrative & General	205,270	13,322	191,948
15 <b>Total Operating Expenses</b>	<b>2,692,856</b>	<b>160,421</b>	<b>2,532,435</b>
16 Depreciation	356,330	18,369	337,961
17 Amortization	15,949	574	15,375
<b>Taxes:</b>			
18 Property	117,651	5,911	111,740
19 Gross Earnings	0	-	0
20 Deferred Income Tax & ITC	193,522	10,306	183,216
21 State & Federal Income (see Page 3)	(60,599)	(6,688)	(53,911)
22 Payroll & Other	30,033	1,815	28,218
23 <b>Total Taxes</b>	<b>280,607</b>	<b>11,344</b>	<b>269,263</b>
24 <b>Total Expenses</b>	<b>3,345,742</b>	<b>190,708</b>	<b>3,155,034</b>
25 AFUDC	0	-	0
26 <b>Total Operating Income</b>	<b>407,678</b>	<b>16,241</b>	<b>391,437</b>

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Income Before Taxes</u>			
1 Total Operating Revenues	3,753,420	206,949	3,546,471
2 less: Total Operating Expenses	(2,692,856)	(160,421)	(2,532,435)
3 Book Depreciation & Amortization	(372,279)	(18,943)	(353,336)
4 Taxes (Other Than Current Income)	<u>(341,206)</u>	<u>(18,032)</u>	<u>(323,174)</u>
5 Total Before Tax Book Income	347,079	9,553	337,526
<u>Tax Additions</u>			
6 Book Depreciation	356,330	18,369	337,961
7 Deferred Income Taxes & ITC	193,522	10,306	183,216
8 Nuclear Fuel Burn (ex D&D)	111,477	6,478	104,999
9 Nuclear Outage Accounting	59,245	3,851	55,394
10 Avoided Tax Interest	26,389	1,522	24,867
11 Open Line	0	0	0
12 Open Line	0	0	0
13 Open Line	0	0	0
14 Open Line	0	0	0
15 Open Line	0	0	0
16 Other Book Additions	0	0	0
17 Total Tax Additions	746,963	40,526	706,437
<u>Tax Deductions</u>			
18 Debt Interest Expense	168,936	9,266	159,669
19 Tax Depreciation & Removal	992,230	52,729	939,501
20 Manufacture Production Deduction	0	0	0
21 Open	0	0	0
22 Open	0	0	0
23 Open	0	0	0
24 Other Tax/Book Timing Differences	23,807	1,446	22,361
25 Net Preferred Stock Deduction	0	0	0
26 Total Tax Deductions	<u>1,184,973</u>	<u>63,441</u>	<u>1,121,531</u>
27 State Taxable Income	(90,931)	(13,362)	(77,568)
28 State Income Tax Rate	9.03%	6.50%	N/A
29 State Taxes before Credits	(8,207)	(869)	(7,339)
30 State Credits	1,180	41	1,139
31 Total State Income Taxes	<u>(9,387)</u>	<u>(910)</u>	<u>(8,478)</u>
32 Federal Taxable Income	(81,543)	(12,453)	(69,090)
33 Federal Income Tax Rate	35.00%	35.00%	35.00%
34 Federal Tax before Credits	(28,540)	(4,358)	(24,182)
35 Federal Tax Credits	22,671	1,420	21,251
36 Total Federal Income Taxes	<u>(51,211)</u>	<u>(5,778)</u>	<u>(45,433)</u>
37 Total Federal & State Income Taxes	<u>(60,599)</u>	<u>(6,688)</u>	<u>(53,911)</u>

**Revenue Requirement & Return Summary**

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	6.0700%	46.3000%	2.8100%	State of North Dakota Tax rate	6.50%
2	Short Term Debt	2.0600%	1.1400%	0.0200%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	32.73%
4	Common Equity	11.2500%	52.5600%	5.9100%	Total North Dakota Composite Tax Rate	39.23%
5	Required Rate of Return			8.7400%	Total Corporate Composite Tax Rate	40.87%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
<b>Rate of Return (ROR)</b>				
6	Total Operating Income	407,678	16,241	391,437
7	Total Average Rate Base	5,969,458	327,429	5,642,029
8	ROR (Operating Income / Rate Base)	6.83%	4.96%	6.94%
<b>Return on Equity (ROE)</b>				
9	Total Operating Income	407,678	16,241	391,437
10	Debt Interest (Rate Base * Weighted Debt Cost)	(168,936)	(9,266)	(159,669)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	238,742	6,975	231,767
13	Equity Rate Base (Rate Base * Equity Ratio)	3,137,547	172,097	2,965,450
14	ROE (Earnings for Common / Equity Rate Base)	7.61%	4.05%	7.82%
<b>Revenue Deficiency</b>				
15	Require Operating Income (Rate Base * Required Return)	521,731	28,617	493,113
16	Operating Income	407,678	16,241	391,437
17	Operating Income Deficiency	114,053	12,376	101,677
18	Revenue Conversion Factor ( 1/(1-Composite Tax Rate) )	1.69110	1.64541	N/A
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	192,875	20,364	172,511
<b>Total Retail Revenue Requirements</b>				
20	Retail Related Revenues	3,035,460	164,504	2,870,956
21	Revenue Deficiency	192,875	20,364	172,511
22	Total Retail Revenue Requirements	3,228,335	184,868	3,043,467
23	Percentage Increase (Decrease)	6.35%	12.38%	6.01%

Case No. PU-10-657 & PU-11-45  
 Exhibit (MJM-3) Schedule 6B  
 Revised May 9, 2011  
 Page 6 of 6

Northern States Power Company (ND)  
 Electric Utility - North Dakota Retail Jurisdiction  
 Cost of Service Study  
 Final Proposed with 2012 Step Adj for Merrickourt  
 (Dollars in Thousands)

Rate Base Detail - Cash Working Capital

Expense	Total Company Electric		ND Retail Electric		All Other	
	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Includable Expenses</b>						
Fuel Expenses						
1 Coal & Rail Transport	21.06	7,444,550	22,115	486,184	331,042	6,978,365
2 Gas for Generation	36.45	180,884	11,327	435,523	169,557	6,519,467
3 Oil	22.51	683	43	968	640	14,406
4 Nuclear & EOL	0.00	0	6,982	0	104,517	0
5 Nuclear Deposit	76.00	11,184	648	48,324	10,513	788,140
6		657,387	41,116	951,999	616,271	14,311,376
<b>Purchased Power</b>						
7 Purchases	26.12	694,154	54,286	1,526,522	639,868	23,617,069
8 Insurance	39.21	119,793	7,047	269,266	112,748	4,308,025
		1,013,947	61,333	1,795,788	952,814	27,925,113
<b>Lease &amp; Related Costs</b>						
9 Regular Payroll	12.31	367,828	22,236	273,726	345,592	4,254,238
10 Incentive Compensation	255.05	21,732	1,329	339,961	20,403	5,203,785
11 Pension & Benefits	19.20	79,160	4,828	92,898	74,832	1,427,174
12 Subtotal Labor & Related		466,720	28,393	706,584	440,327	10,885,197
13 All Other Operating Expenses	35.01	562,802	29,579	1,035,561	523,223	18,318,034
14 Property Tax	356.72	117,851	5,911	2,106,572	111,740	39,859,893
15 Employer's Payroll Taxes	26.56	30,033	1,816	48,206	28,218	749,470
16 Gross Earnings Tax	41.46	0	0	0	0	0
17 Federal Income Tax	37.75	(51,211)	(5,778)	(218,136)	(45,433)	(1,715,063)
18 State Income Tax	37.75	(6,307)	(910)	(34,335)	(8,478)	(320,039)
19 State Sales Tax Customer Billings	35.73	138,565	4,951,999	0	136,585	4,961,999
20 Total Expenses	41.58	2,918,538	181,459	6,393,036	41,700	2,757,077
21		121,359,002	39,600	17,515	114,885,963	314,975
22 Net Annual Expense Amount		332,490		17,515		314,975
<b>Revenues</b>						
23 Computer Billing	45.45	3,034,853	164,504	7,477,151	2,870,349	130,465,112
24 Meter Billing	43.07	0	0	0	0	0
25 Retail Revenue Adjustments	0.00	0	0	0	0	0
26 Interannual	0.00	607	355	0	607	0
27 Late Payment	0.00	5,480	243	10,413	5,135	86,475
28 Contract and Trouble Charges	42.85	2,251	255	29,113	2,018	86,475
29 CIP Incentive	0.00	4,002	255	29,113	3,777	431,220
30 Rentals	114.17	446,857	26,689	1,027,429	419,766	16,039,135
31 Interchange Revenues	39.21	148,783	9,166	340,059	138,817	5,178,791
32 Sales for Retail	37.10	6,436	403	14,951	6,033	223,824
33 Production Associated Revenues	37.10	13,342	775	10,850	12,567	175,938
34 MISO	14.00	59,651	3,465	128,599	96,185	2,064,464
35 Point to Point Firm	37.10	8,828	507	18,810	8,321	308,706
36 Services & Facilities	37.10	23,148	1,345	49,900	21,903	808,891
37 Ancillary	42.85	1,872	(652)	(27,940)	1,872	80,219
38 Distribution Associated Revenues	42.85	2,356	(307)	(11,390)	3,006	128,999
39 Other	37.10	(4,856)	0	0	(4,589)	(170,252)
40 JOA - Rev Into PSC	0.00	0	0	0	0	0
41 (Share)	0.00	0	0	0	0	0
42 (Share)	0.00	0	0	0	0	0
43 (Share)	0.00	0	0	0	0	0
44 Total Revenues	43.94	3,753,420	206,949	8,067,935	3,548,471	155,942,625
45 Net Annual Amount		451,810		24,844		426,895
46 Expense / Revenue Factor		0.7776		0.7802		
47 Allocated Revenue Amount		351,312		19,363		16,955
48 Net Cash Working Capital		18,822		1,856		

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-302

Date Received: May 27, 2011

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Question:

Subject: Mercury Emissions

Is the mercury control program required for the ND jurisdiction? Please explain.

Response:

Yes. The Company operates an integrated generation system where all generation benefits all jurisdictions.

Northern States Power Company, a Minnesota corporation (“NSPM”) spent monitoring and engineering dollars in preparation for compliance with three different requirements: (1) the U.S. Environmental Protection Agency’s (“EPA”) Clean Air Mercury Rule (“CAMR”) – finalized on May, 2005; (2) the Minnesota Mercury Emission Reduction Act of 2006 (“MMERA”) (applicable to plants located in Minnesota) – finalized May 2006; and (3) a potential Federal Maximum Achievable Control Technology (“MACT”) standard for mercury – proposed May 2011.

The Minnesota rules required continuous mercury monitoring to begin by July 1, 2007, while CAMR required continuous mercury monitoring to begin by January 1, 2009.

On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the CAMR. On October 17, 2008, the EPA filed a petition with the U.S. Supreme Court requesting review of the D.C. Circuit’s decision in *New Jersey v. EPA* vacating the CAMR and the EPA’s rule delisting coal- and oil-fired electric generating units (“EGUs”) from regulation under § 112 of the Clean Air Act (the “Delisting Rule”). For all intents and purposes, CAMR was repealed at this point, regardless of the compliance efforts that utility companies had already put into motion for this regulation.

In 2007 through 2009, NSPM moved forward with identifying and installing mercury control technology on generating units at the Sherburne County Generating (“Sherco”) Plant and the Allen S. King Generating (“King”) Plant. It was determined that the same emission control technology (Sorbent Injection) would be used to comply with either the Federal or Minnesota State requirements. The only difference between the Minnesota mercury monitoring requirements and those contained in the EPA’s CAMR was the timing.

Once CAMR was vacated, EPS began working to draft new Federal mercury rules under the National Emission Standards for Hazardous Air Pollutants (“NESHAP”) provisions, commonly referred to as Maximum Achievable Control Technology (“MACT”) rules. On May 3, 2011, EPA published the Electric Generating Unit (“EGU”) MACT rule in the Federal Register, which proposes regulation for mercury and other hazardous air pollutants. NSPM is still in the process of evaluating and offering comment on these proposed regulations, but is confident that the monitoring and control technologies installed at the Sherco and King Plants will satisfy the new EGU MACT regulations.

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Preparer: Deborah Hoffmeister / Richard Rosvold  
Title: Project Manager / Air Quality Manager  
Department: Sherco Plant / Environmental Services  
Telephone: 763-261-3023 / 612-330-7879  
Date: June 23, 2011

**System Performance/Interconnection Projects Affecting 2011 Test Year and 2012 Step-In Adjustment**

**Table 1**  
**Additions to Plant in Service (\$ in millions)**

Project	2009	2010	2011	2012
New Ulm Expansion:		\$13.3		
Mankato 115 kV Loop		\$ 8.9		
Pleasant Valley – Byron*			\$ 8.0	
North Mankato Project		\$ 0.1	\$ 1.5	\$17.1
St. Cloud Loop**				\$ 9.0
Midtown-Hiawatha**			\$ 5.9	\$ 8.9
Southwest Twin Cities Project**			\$ 6.0	\$13.2
Fenton 69 kV Tie			\$ 7.2	
Chisago-Apple River Project		\$15.4	\$18.6	
Chanarambie 4 <sup>th</sup> Collector Transformer	\$ 5.0			
Buffalo Ridge Incremental Generation Outlet (BRIGO)	\$68.6			

\* In-service date now expected to be in 2012

\*\* Additional plant in service investments are expected in 2013

**1. New Ulm Expansion**

This project constructs a five mile 115 kV line and 115-69 kV substation to the southwest side of the City of New Ulm, Minnesota. This project is required to provide network transmission service to the City's 52 MW of load and mitigate low voltages under transmission outages. The project is included in the 2011 test year.

**2. Mankato 115 kV Loop**

This project will construct 7.5 miles of new 115 kV transmission line and two 115-69 kV substations around the City of Mankato, Minnesota. This is part of a joint development with Great River Energy ("GRE"), and is required to meet load growth in Mankato and to eliminate low voltage and equipment overloads during transmission outages. The project is included in the 2011 test year.

**3. Pleasant Valley-Byron**

This project will construct a new 161 kV transmission line between GRE's Pleasant Valley Substation and the Southern Minnesota Municipal Power Agency ("SMMPA") Byron substation to increase the transmission system capacity to allow interconnection of a wind generation farm at Pleasant Valley substation near Rochester, Minnesota. This project includes approximately 20 miles of new 161 kV transmission line along with other substation upgrades by other Minnesota utilities. This project will allow for the development of up to approximately 300 MW of wind generation in the region south of Rochester.

**4. North Mankato Project**

This project will construct a new 345-115 kV and a new 115-69 kV substation plus associated transmission. This project is needed to mitigate unacceptable low voltages and line loadings on the

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-22

Date Received: April 28, 2011

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Question:

Reference: Plant Investment

Reference Company witness Benson Exhibit IRB-1, schedule 4 page 1 of 3.

The expected in-service date of the Pleasant Valley – Byron project has changed from 2011 to 2012. Has this project been excluded from ratebase in 2011? If not why not?

Response:

No, this project was not excluded from rate base in the 2011 test year. Including the project in the test year rate base was an oversight and the Company proposes to remove the project in its Rebuttal Testimony.

Excluding the Pleasant Valley – Byron project from the test year reduces test year revenue requirements by \$28,000. Please see Attachment A to this response for the revenue requirement calculation of excluding the project from the test year.

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Witness: John M. Felling

Preparer: John M. Felling

Title: Consultant

Department: Revenue Requirements North

Telephone: 612-330-6539

Date: May 26, 2011

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-13

Date Received: April 28, 2011

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Question:

Reference: Plant Investment

Please provide a breakdown of all properties sold or transferred from the company books in 2011. For each transaction provide the following:

- a) Date property was sold or transferred
- b) the Sales price
- c) the book value at the time of sale
- d) the gain/loss recorded on the company books
- e) whether the property sold was included in a rate case filing
- f) whether the sale or transfer was made to an affiliated company. If sold to an affiliate please provide the fair market value at the time of sale or transfer and provide the workpapers in support of the calculation of the fair market value.

Response:

In 2011, there was one transaction involving a property that was sold or transferred from the Company books, the sale of the Lakefield Junction-Fox Lake transmission line. Details of the transaction are as follows:

- a) Sold on January 7, 2011
- b) Sales Price: \$17,308,946.93
- c) Net Book Value: \$17,308,946.93
- d) No gain or loss recognized
- e) Fox Lake was included in the rate case filing as the sale was not final at the time we filed the case. Please see AS-2-RR-013 Attachment A for the

revenue requirement impact of removing the data that was in the test year which is slightly different at the time of the sale. This will reduce revenue requirements by approximately \$122,000.

- f) The sale was not made to an affiliate.

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Witness: John Felling  
Preparer: Amber Zobeck / John Stinson/Shari Cardille  
Title: Accounting Analyst/Senior Accounting Analyst/Principal Rate  
Department: Capital Asset Accounting/Capital Asset Accounting/Revenue Requirements  
Telephone: 612-330-5758 / 806-378-2476 / 612-330-1974  
Date: May 19, 2011

Northern States Power Company, a Minnesota corporation  
 Lakefield Junction - Fox Lake 161 kV Transmission Line

(\\$)                      (\\$)

<u>Rate Analysis</u>	<u>Total Company</u>	<u>ND Jurisdiction</u>
<b>Average Rate Base</b>		
Plus Plant Investment	19,646,089	957,503
Less Depreciation Reserve	<u>2,627,505</u>	<u>128,058</u>
Net Plant	17,018,584	829,445
Plus CWIP	-	-
Less Accumulated Deferred Taxes	<u>2,474,827</u>	<u>120,617</u>
	14,543,757	708,828
Average 2011 Rate Base	14,543,757	708,828

<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.2500%	52.5600%	<u>5.9100%</u>
Required Rate of Return			8.7400%
Tax Rate (ND)	39.2300%		

<u>Revenue Requirements</u>		
Debt Return	411,600	20,100
Equity Return	859,500	41,900
Current Income Tax Requirement	333,900	16,300
Book Depreciation	476,078	23,203
Annual Deferred Tax	230,401	11,229
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	1,048,725	51,112
AFUDC Expenditure	-	-
Book Depreciation Cleared to Operating	-	-
Avoided Tax Interest	-	-
Property Tax	195,126	9,510
<b>Total Revenue Requirements</b>	<b>2,506,605</b>	<b>122,242</b>

<u>2011</u>	
Demand ND Jur %	5.8107%
IA Demand MN Co %	83.8756%
Composite ND Jur Allocation	<b>4.8738%</b>



414 Nicollet Mall  
Minneapolis, Minnesota 55401

April 10, 2009

—VIA ELECTRONIC FILING—

Burl W. Haar  
Executive Secretary  
Minnesota Public Utilities Commission  
121 7<sup>th</sup> Place East, Suite 350  
St. Paul, Minnesota 55101

RE: IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, REGARDING THE ELIGIBILITY OF THE WIND2BATTERY PROJECT FOR RECOVERY UNDER THE RENEWABLE ENERGY STANDARD RIDER AND APPROVAL AS AN AFFILIATED INTEREST ARRANGEMENT  
DOCKET NO. E002/M-09-\_\_\_\_/E002/AI-09-\_\_\_\_

Dear Dr. Haar:

Attached for filing, please find Northern States Power Company's, a Minnesota corporation ("Xcel Energy" or the "Company"), petition for approval of our Wind2Battery project as eligible for recovery in our Renewable Energy Standard ("RES") Rider and as an affiliated interest arrangement.

The Wind2Battery project is a 1 MW sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind project in Luverne, Minnesota. By storing energy for Minwind, we are able to manage some of the variable production associated with wind power from this project to the benefit of our customers. In addition, the Wind2Battery project will give us valuable experience and information that will allow us to assess and improve the viability of scaling up battery storage on our system as more and more wind power is added to meet the renewable policies in the states we serve.

While the battery itself is proven technology, the application of the battery as support for wind energy has not been tested on a large scale. The integration equipment and

the study of the use of the battery for this purpose will be funded through a Renewable Development Fund (“RDF”) grant. In addition to the Company, the University of Minnesota, Great Plains Institute and the National Renewable Energy Laboratories are assisting in the research and receiving a portion of the RDF grant. Because the grant proceeds and all project costs will be recorded in the same NSPM sub-ledger account, there will be no cross subsidization of costs between the grant funds and the costs that we expect to receive approval to recover through the RES Rider.

We have served a copy of this submission on the Office of the Attorney General – Residential Utilities Division, and summaries of this filing on all parties on the attached service lists.

Please call me at (612) 330-6270 if you have any questions regarding this filing.

Sincerely,

/s/

AL KRUG  
MANAGING DIRECTOR, GOVERNMENT AND REGULATORY AFFAIRS

Enclosures  
c: Service Lists

STATE OF MINNESOTA  
BEFORE THE  
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis A. Reha	Commissioner
Betsy Wergin	Commissioner

IN THE MATTER OF THE PETITION OF  
NORTHERN STATES POWER COMPANY,  
A MINNESOTA CORPORATION,  
REGARDING THE ELIGIBILITY OF THE  
WIND2BATTERY PROJECT FOR  
RECOVERY UNDER THE RENEWABLE  
ENERGY STANDARD RIDER AND  
APPROVAL AS AN AFFILIATED  
INTEREST ARRANGEMENT

DOCKET NO. E002/M-09-\_\_\_\_/  
E002/AI-09-\_\_\_\_

**PETITION**

**INTRODUCTION**

Northern States Power Company, a Minnesota corporation (“Xcel Energy” or the “Company”), submits this Petition to the Minnesota Public Utilities Commission (“Commission”) seeking the Commission’s determination that our Wind2Battery project is an “eligible energy technology” under Minn. Stat. § 216B.1691 as it is designed to support wind renewable resources. If approved, the project will be eligible to be included in our Renewable Energy Standard (“RES”) Rider pursuant to Minn. Stat. § 216B.1645, subd. 1. We furthermore request approval of the project as an affiliated interest arrangement.

The Wind2Battery project is a 1 MW sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind power generating facility near Luverne, Minnesota. By storing energy from Minwind, we are able to manage some of the variable production associated with the Minwind project to benefit customers. The Wind2Battery project will also provide valuable experience and information that will allow us to assess and improve upon the viability of scaling up battery storage on our system as more and more wind power is added to meet the renewable policies in

the states we serve, permitting the Company to meet our renewable objectives in the most cost effective manner possible.

The Wind2Battery project has been funded, in part, with a grant from the Renewable Development Fund (“RDF”) as authorized by the Commission in Docket No. E002/M-07-675 to support the development aspects of the project associated with using the battery for wind energy storage. This petition seeks RES Rider eligibility determination for the capital costs that remain after the grant is applied, approximately \$3.5 million. We also seek approval to recover approximately \$54,000 of annual operating and maintenance (“O&M”) costs until such time that we can incorporate the project costs and annual O&M into base rates.

**I. Summary of Filing**

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing accompanies this petition.

**II. Service on Other Parties**

Pursuant to Minn. R. 7829.1300, subp. 2, we have served a copy of this petition on the Office of the Attorney General-Residential Utilities Division. A summary of the filing has also been served on all parties on Xcel Energy’s miscellaneous electric service list and the service list from the 2009 Rider filing (Docket No. E002/M-08-1033).

**III. General Filing Information**

Pursuant to Minn. R. 7829.1300, subp. 3, Xcel Energy provides the following required information.

**A. Name, Address, and Telephone Number of Utility**

Xcel Energy  
414 Nicollet Mall  
Minneapolis, Minnesota 55401  
(612) 330-5500

**B. Name, Address, and Telephone Number of Utility Attorney**

Christopher B. Clark  
Managing Attorney  
Xcel Energy  
414 Nicollet Mall, 5<sup>th</sup> Floor  
Minneapolis, Minnesota 55401  
(612) 215-4593

**C. Date of Filing and Proposed Effective Date of Rates**

The date of this filing is April 10, 2009. The Commission's determination of RES Rider eligibility is the first of two steps necessary to include the project costs in the RES Rider. If the Commission approves this eligibility request, the Wind2Battery costs will be included in our September 1, 2009 petition for the 2010 RES Rider Adjustment Factor to be applied to customer bills in 2010.

**D. Statutes Controlling Schedule for Processing the Filing**

Minn. Stat. § 216B.1645 allows for recovery of investments or expenditures entered into by a public utility in connection with the development of renewable energy to meet the requirements of Minn. Stat. § 216B.1691. This Petition is made pursuant to Minn. Stat. § 216B.16, subd. 1, which prescribes general time lines for rate and tariff changes, including, but not limited to, a requirement of 60-days notice prior to any rate or tariff change.

Commission Rules define this filing as a "miscellaneous rate change" under Minn. R. 7829.0100, subp. 11 since no determination of Xcel Energy's overall revenue requirement is necessary. The accounting process that we will use to track revenues and costs and record the differences in the RES Tracker account will be in compliance with Accounting Standards prescribed under Minn. Stat. § 216B.10.

**E. Utility Employee Responsible for Filing**

Al Krug  
Managing Director, Government and Regulatory Affairs  
Xcel Energy  
414 Nicollet Mall, 7<sup>th</sup> Floor  
Minneapolis, Minnesota 55401  
(612) 330-6270

#### IV. Description and Purpose of Filing

##### A. Background

###### *Project Description*

The Sodium Sulfur (“NaS”) battery is a proven technology and is in service in 30 locations in Japan. From Japan’s experience, we know that the battery functions well as a storage technology on the transmission and distribution system. We will utilize the battery to harness wind energy and improve the value of the Minwind project by being able to supply power to the grid even when the wind is not blowing. If our experience provides the results that we anticipate, we will be able to install batteries at other wind projects and improve the value of these projects as well.

This project and future additional applications will also allow us to better leverage transmission in the future, as we will be able to store wind energy when the grid is at full capacity and move the energy onto the transmission grid when the bottlenecks have been removed. In summary, batteries will add to the value of wind projects now and in the future because of their ability to charge off-peak and discharge on-peak as well as during times of transmission constraints. We currently plan to complete our studies by the end of 2009, with associated findings and recommendations developed during the first half of 2010.

NaS technology has been selected for this project because of its high storage capacity, its ability to handle the large number of charge-recharge cycles associated with intermittent renewable energy sources, its large scale and potential for even larger scalability, its dynamic response to system changes, and its commercial availability.

With this project we will review:

- The ability of large-scale battery-storage technology to effectively ‘firm’ wind energy, enabling a shift of wind-generated energy from off-peak to on-peak availability. We believe batteries will increase the value of wind-generated energy as well as a decrease the need for intermediate and peaking facilities.
- The ability of battery-storage technology to reduce the need to compensate for the variability and limited predictability of wind generation resources. This includes reductions in carbon-based spinning reserves or supplemental reserve requirements, as well as reductions in contingency recovery costs, such as generator black start support.

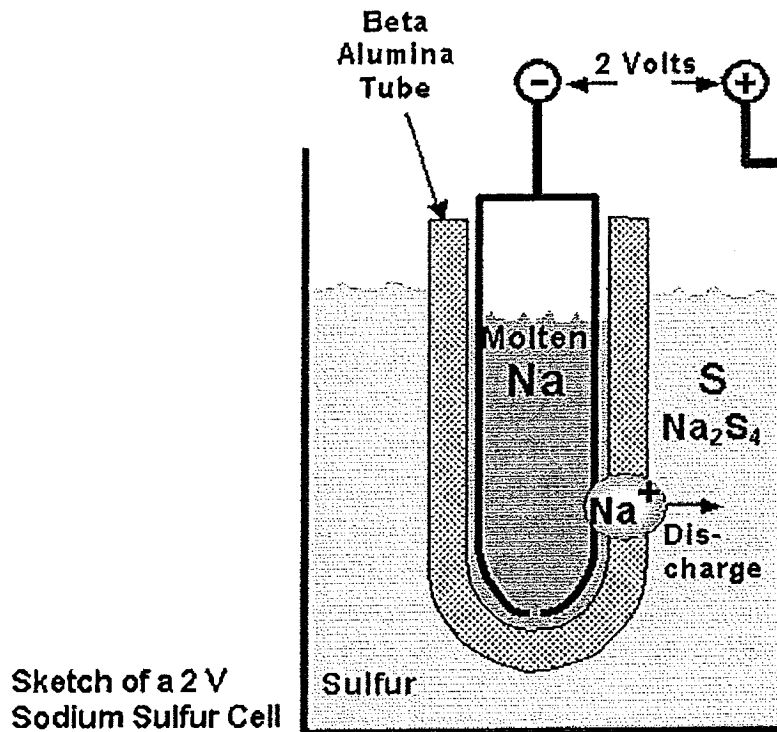
- The potential for battery-storage technology to more effectively integrate wind into transmission system operations. We believe batteries will help to maintain and maximize the integrity of the grid by providing frequency, voltage and reliability support.

The project includes the following components:

- **NaS Battery System:** The NaS battery system is modular in design. Each battery contains twenty 50-kw modules, which in turn each contain an array of 320 individual cells within a thermally insulated enclosure equipped with electric heaters to maintain an operating temperature of approximately 300°C. Cells are closely spaced, connected in series and/or parallel, and packed in sand. A vacuum is drawn on the gap between the inner and outer walls of the enclosure lid. This modularity allows flexibility in configuring the system as well as ease of increasing the size of the system.

The electrochemistry of the cell includes a solid beta alumina electrolyte made with a sodium ion conductive ceramic material, which serves as both the electrolyte and the separator between the sodium (-) and sulfur (+) electrodes. To ensure safety, the NaS cell includes a 'safety tube' inside the beta-alumina tube that controls the amount of sodium and sulfur that can potentially combine. This reduces heat generation that could rupture cells.

- **Power conversion equipment:** The power conversion equipment handles the interconnections between AC and DC power to and from the battery. There are a number of challenges that need to be addressed, such as low voltage ride-through capability, the role of power-electronics based transformers, and different topologies of the converters. We will review these issues to determine how to retain the most value for overall system efficiency and effectiveness.



- **Backup power for emergency battery temperature regulation:** The primary function of backup power is to provide emergency backup to external heaters that are needed to keep the battery maintained at an elevated temperature at all times to accomplish the energy storage function. These heaters are only needed on battery start up or when the batteries are in an idle state. Backup power will be a separate diesel-driven generator.
- **Grid interconnection:** We will utilize the existing interconnection between the wind project and the grid. We also plan to review a direct interconnection in order to better evaluate the ability to provide ancillary services in addition to electric energy.
- **Wind project interface:** We will examine options to determine the best approach to interfacing the battery with the wind project. The wind project interface will be the common bus that connects all the wind turbines. The challenge was to design the interconnection to the battery so that energy over the 1.2 MW battery capacity is integrated directly into the transmission grid.

- **Local and remote performance monitoring equipment, data collection equipment, system control equipment, and associated communication equipment:** Remote system control will be used to communicate with the battery and control the mode of operation (such as charge or discharge). This equipment will also capture data from the project and make it accessible via the internet to the project partners for analysis.

*Implementation Schedule*

**Critical Path Schedule**

Major Task	Deliverable	Target End Date
<b>Specifications &amp; Contract Negotiations</b>		
Collection of system design and performance requirements and site selection	Common set of general requirements, agreed to by all project partners; site selected	COMPLETE
Contract negotiations with NGK and power conditioning vendor/general contractor	Signed contracts / purchase orders	COMPLETE
System specifications and conceptual design	Process Flow Diagram (“One-line diagram”)	COMPLETE
Permitting – distribution and transmission interconnects, site permits per state/local codes & standards	Permitting complete	COMPLETE
<b>Engineering &amp; Design</b>		
Detailed system and process design; Engineering	Full set of drawings – electrical, mechanical and civil drawings	COMPLETE
<b>Construction &amp; Installation</b>		
Construction: Site preparation and development	Site ready – survey, layout, fencing, foundations, conduit, metering, ground grid, stone yard	COMPLETE
Construction: Equipment Delivery and Installation	System ready for start-up testing	COMPLETE
Individual component testing and system start-up testing	Safety and performance checks, ready to begin full scale operations	COMPLETE
Initial Start-up	Testing and data collection initiated	COMPLETE
<b>Research Plan</b>		
Detailed Research Plan	Plan completed on 9/30/08 -- specifies data to be collected, data source/collection process, specific analysis to be performed, roles & responsibilities of each partner involved	COMPLETE

Major Task	Deliverable	Target End Date
	in the analysis	
<b>Data Collection &amp; Analysis</b>		
Operations & maintenance	Monitor for system performance and address any issues	Ongoing after start-up
Data collection	Data points needed for performance analysis related to the objectives of the project	12/31/2009 (1 yr after start-up)
Performance Analysis	Evaluation of the overall effectiveness of NaS battery performance in a wind energy storage application.	12/31/2009 (1 yr after start-up)
Economic Analysis	Economic impact of wind energy storage using NaS batteries from a total system perspective.	12/31/2009 (1 yr after start-up)
Public Policy Analysis	List of policy considerations and implication; identification and explanation of potential public costs and benefits	1st Quarter 2011
<b>Reporting</b>		
Final report and recommendation (excludes public policy analysis)	Final Report and Recommendation	1st Quarter 2010
Outreach and Education regarding findings and opportunities	IREE sponsored Public Seminar/Forum/workshop	1st Quarter 2010

*Project Costs*

As shown on the attached Schedule 1, the total project cost is approximately \$5.0 million. The project was approved for a \$1 million RDF grant. The RDF payment will be distributed \$797,527 to capital project costs and \$202,473 to fund research costs by project partners. Project partners, including NREL, the University of Minnesota, and Great Plains Institute are also contributing toward the project research, at an estimated value of \$368,322. The total capital project cost of this project, less the RDF payments, is approximately \$3.5 million.

### *Reasonableness of Project Costs*

The Company took numerous steps to insure that the costs were reasonable and prudent:

- We researched a number of technologies. The technologies we considered included: compressed air energy storage (“CAES”), pumped hydro, vanadium redox batteries, zinc bromine batteries, lead acid batteries, lithium ion batteries and NaS batteries.

CAES and pumped hydro were eliminated from consideration because these technologies cannot be implemented quickly and require a much larger scale to be economical. We are still considering these technologies for the longer term, as part of a portfolio of energy storage on our system.

We found the NaS battery system to be the only technology that is being used commercially, has proven round-trip efficiency, is capable of handling the number of charge and discharge cycles we require, is available in various MW-scales, and can provide power for at least 6 hours. Vanadium redox batteries, for example, are still hand-assembled and are only reaching 40-50% round-trip efficiency; whereas the NaS battery has been manufactured on a commercial scale since early 2003 and is consistently achieving 75% round-trip efficiency. As these other technologies evolve and become commercially viable, with inherent cost, quality and efficiency improvements associated with improved manufacturing processes, we will consider them for future incorporation into our energy storage portfolio.

- We contacted New York Power Authority, which has recently installed a NaS system for peak shaving purposes, to identify the costs in addition to the NaS battery and discuss other ‘lessons learned’ that would help us during project budgeting and planning.
- We selected S&C Electric to serve as general contractor for the construction and installation of the complete system. S&C installed a NaS battery for power reliability for American Electric Power Company, Inc. Using an experienced contractor allowed us to better maintain schedules and budget requirements.

### *Benefits of the project in promoting the development of renewable energy*

Wind resources will play an important role in our future resource portfolio and batteries will be necessary to support wind resources. The Commission recognized

this critical role when it directed the Company to review the current state of wind energy storage research in its July 28, 2006 Order in our 2004 Resource Plan (Docket No. E-002/RP-04-1752). The legislature and governor recognized this as well when legislation was passed in 2008 specifically clarifying that energy storage facilities were eligible for cost recovery in a renewable energy rider. Minn. Statute § 216B.1645, subd. 1(2).

Because it is impractical to quickly ramp base load units, the ability to store wind energy temporarily for use when loads are higher during on-peak periods will be very beneficial to system operations.

In summary, the Wind2Battery project will evaluate the ability of NaS battery technology to provide four primary benefits to promote the development of renewable energy by:

- Providing On-peak Energy: Storing wind energy temporarily for use when loads are higher during on-peak periods. This will be beneficial as wind resources become a larger part of our generation mix, and may allow wind energy to provide more on-peak energy.
- Support System Ramping: The ability of the battery discharge and charge process to support system ramping, such as discharging while daily system loads are increasing or charging as daily system loads are decreasing.
- Grid Support: Supporting the grid by adding voltage support, reactive load support, frequency support and suppressing voltage fluctuations.
- Curtailment Offset: While we are optimistic that the planned increase in transmission facilities such as CAPx will reduce and, or eliminate the need for curtailments in the future, battery storage can also provide a useful hedge against curtailment by storing energy if and when curtailments are necessary.

We also believe that there are other potential benefits to wind energy storage in the long term. We believe that battery storage can mitigate baseload bottoming and function as a spinning reserve. If wind storage can be proven to provide spinning reserve capabilities, batteries can reduce dispatch costs caused when wind energy is more or less than forecasted. If actual wind energy is greater than forecasted at any point during the day, the value of day-ahead contracts is not realized and day-ahead nominated gas is not used. Conversely, if actual wind is less than forecasted at any point during the day, we must purchase on the spot market and, or maintain peaking resources in spinning status. In both cases, power plants are currently being cycled to

accommodate the excess or shortage of wind. We anticipate that wind storage can reduce dispatch costs and function as a spinning reserve resource.

## **B. Determination of Eligibility**

We request that the Commission find that the Wind2Battery is an “eligible energy technology” under Minn. Stat. § 216B.1691 as it is designed to support wind renewable resources and it is eligible for RES Rider cost recovery under Minn. Stat. § 216B.1645. Minn. Stat. § 216B.1645 allows for recovery of all investments or expenditures entered into by a public utility in connection with the development of renewable energy to meet the requirements of Minn. Stat. § 216B.1691. We believe Wind2Battery meets this statutory requirement.

Minn. Stat § 216B.1645 subd 2(a) (3) states the Commission may approve, a rate schedule that:

*“allows recovery of other expenses incurred that are directly related to a renewable energy project, **including expenses for energy storage**, provided that the utility demonstrates to the commission’s satisfaction that the expenses improve project economics, ensure project implementation, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market;”(emphasis added)*

As shown in the attached Schedule 6, if the Commission determines that the project is eligible for RES Rider cost recovery, we will propose to request a total of \$399,904 in the fall 2009 RES Rider update filing as the 2010 adjustment associated with the Wind2Battery Project. The calculation of revenue requirements is provided in the enclosed Attachment. We calculated the revenue requirements consistent with our previous rider calculations and in accordance with Minn. Stat. § 216B.1645.

The costs we are proposing to recover for our Wind2Battery Project are not included in base rates since this project was not in the 2006 test year used in our last state of Minnesota rate case (Docket No. E002/GR-05-1428). Additionally, our current pending Minnesota electric rate case (Docket No. E002/GR-08-1065) included a rate case adjustment to exclude costs anticipated for recovery through the RES Rider. This adjustment included the Wind2Battery Project.

## **V. Affiliated Interest**

We believe the RDF grant award and Project falls under the definition of an “arrangement” between affiliated interests pursuant to Minn. Stat. § 216B.48. It is

important to note the Wind2Battery project was selected for an RDF grant by the RDF advisory board. The RDF advisory board selects projects for awards pursuant to a scoring mechanism previously reviewed and approved by the Commission in its July 29, 2003 order in Docket No. E002/M-00-1583. The RDF advisory board includes a majority representation that is independent of Xcel Energy, Inc., its affiliates and wholly owned subsidiaries. In addition to the use of the scoring mechanism, the RDF advisory board has in place an effective set of controls and procedures that further serve to maintain an independent selection process that were discussed in the same Commission order as the scoring mechanism.

The RDF advisory board's selection of this Project was also approved by the Commission in its April 1, 2008 order in Docket No. E002/M-07-675, fully recognizing that the award would flow back to the Company with the proceeds being used to offset project costs. Accordingly, we request approval of the arrangement as an affiliated interest.

**VI. Miscellaneous Information**

Pursuant to Minn. R. 7829.0700, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

Christopher B. Clark  
Managing Attorney  
Xcel Energy  
414 Nicollet Mall, 5<sup>th</sup> Floor  
Minneapolis, Minnesota 55401

SaGonna Thompson  
Records Specialist  
Xcel Energy  
414 Nicollet Mall, 7<sup>th</sup> Floor  
Minneapolis, Minnesota 55401



STATE OF MINNESOTA  
BEFORE THE  
MINNESOTA PUBLIC UTILITIES COMMISSION

David C. Boyd	Chair
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
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DOCKET NO. E002/M-09-\_\_\_\_  
E002/AI-09-\_\_\_\_

PETITION

**SUMMARY OF FILING**

Please take notice that on April 10, 2009 Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") submitted to the Minnesota Public Utilities Commission ("Commission") a Petition for approval of the eligibility of the Wind2Battery Project for recovery under the Renewable Energy Standard ("RES") Rider. Consistent with the provisions of Minn. Stat. § 216B.1645, this rider is designed to recover costs associated with the Company's acquisition of renewable generation projects proposed to meet the renewable energy standards in Minn. Stat. § 216B.1691. If approved, the Company proposes to include the 2010 revenue requirement associated with this project in our 2009 filing for recovery in 2010. In this filing we also seek approval of the arrangement of this project as an affiliated interest.

## Attachment

- Schedule 1 – Wind2Battery Project Expenses
- Schedule 2 - RES Rider Revenue Requirement Calculation by Month
- Schedule 3 – Five Year Summary of the Annual Revenue Requirements
- Schedule 4 - RES Projected Tracker Activity for 2009-2013
- Schedule 5 – RES Rider Monthly Tracker Activity for 2010 and 2011
- Schedule 6 – 2010 and 2011 RES Rider Factor Calculations

Schedule 1

Wind to Battery Project Expenses

<b>Xcel Energy Capital</b>		2007	2008	2009	2010	Grand Total	
Total Capital	\$	73,377	\$ 1,868,155	\$ 2,375,756	\$ 9,704	\$ 4,326,992	
<b>Xcel Energy O&amp;M</b>		2007	2008	2009	2010	Grand Total	
Total O&M	\$	-	\$ 4,425	\$ 51,390	\$ 52,356	\$ 108,171	
<b>Partners in Research</b>		2007	2008	2009	2010	Grand Total	
University of MN	Technical Research	\$	99,793	\$ 249,502		\$ 349,295	
Great Plains Institute	Policy Research	\$	-	\$ 54,000		\$ 54,000	
NREL	Technical Research	\$	49,265	\$ 118,235		\$ 167,500	
Total Partners		\$	149,057	\$ 421,737		\$ 570,795	
<b>PROJECT GRAND TOTAL</b>		<b>\$</b>	<b>73,377</b>	<b>\$ 2,021,637</b>	<b>\$ 2,848,883</b>	<b>\$ 62,060</b>	<b>\$ 5,005,958</b>

<b>RDF Funding Distribution</b>		2007	2008	2009	2010	Grand Total
Xcel Energy - W2B Project		\$	14,545	\$ 523,009	\$ 259,973	\$ 797,527
University of MN		\$	36,190	\$ 54,283		\$ 90,473
Great Plains Institute		\$	-	\$ 12,000		\$ 12,000
NREL		\$	49,265	\$ 50,735		\$ 100,000
Total RDF Reimbursements		\$	100,000	\$ 640,027	\$ 259,973	\$ 1,000,000

<b>Partner Contributions to Research</b>		2007	2008	2009	2010	Grand Total
University of MN		\$	63,603	\$ 195,219		\$ 258,822
Great Plains Institute		\$	-	\$ 42,000		\$ 42,000
NREL		\$	-	\$ 67,500		\$ 67,500
Partnership Benefits		\$	63,603	\$ 304,719	\$ -	\$ 368,322

<b>Xcel Energy Net Project Capital Costs</b>		2007	2008	2009	2010	Grand Total	
Capital	\$	73,377	\$ 1,868,155	\$ 2,375,756	\$ 9,704	\$ 4,326,992	
RDF Funding	\$		(14,545)	(523,009)	(259,973)	(797,527)	
<b>Xcel Energy Capital Project Total</b>		<b>\$</b>	<b>73,377</b>	<b>\$ 1,853,610</b>	<b>\$ 1,852,747</b>	<b>\$ (250,269)</b>	<b>\$ 3,529,465</b>

Xcel Energy Renewable Energy Standard Rider  
Revenue Requirements

Wind To Battery	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Annual
<b>Rate Base</b>													
Plus CWIP Ending Balance	78,801	82,147	86,504	118,919	500,480	705,496	735,397	1,332,644	1,354,172	1,443,581	1,924,752	1,993,743	1,993,743
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum Deferred Taxes	(296)	(371)	(421)	(485)	(719)	(1,300)	(1,995)	(2,994)	(4,300)	(5,664)	(7,288)	(9,080)	(9,080)
End Of Month Rate Base	79,096	82,518	86,925	119,404	501,199	706,796	737,392	1,335,638	1,358,472	1,449,245	1,932,039	2,002,822	2,002,822
Average Rate Base (BOM/EOM)	77,202	80,807	84,721	103,164	310,301	603,998	722,094	1,036,515	1,347,055	1,403,856	1,690,642	1,967,431	785,649
<b>Calculation of Return</b>													
Plus Debt Return	216	226	237	289	869	1,691	2,022	2,902	3,772	3,931	4,734	5,509	26,398
Plus Equity Return	351	367	385	469	1,409	2,743	3,280	4,708	6,118	6,376	7,678	8,935	42,818
Total Return	567	593	622	757	2,278	4,434	5,301	7,610	9,890	10,307	12,412	14,444	69,216
<b>Income Statement Items</b>													
Plus Operating Expense	0	0	0	0	0	0	0	0	0	0	0	4,425	4,425
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(74)	(75)	(50)	(64)	(235)	(581)	(695)	(999)	(1,306)	(1,364)	(1,624)	(1,792)	(6,658)
Plus Gross Up for Income Tax	462	485	476	585	1,800	3,620	4,328	6,214	8,095	8,453	10,180	11,730	56,429
Less AFUDC	499	536	601	704	2,128	4,198	4,992	7,165	9,182	9,726	11,720	13,596	65,046
Less AFUDC Gross Up for Income Tax	352	378	424	497	1,502	2,962	3,522	5,055	6,479	6,863	8,270	9,593	45,897
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	(463)	(504)	(598)	(680)	(2,064)	(4,121)	(4,881)	(7,005)	(8,871)	(9,500)	(11,434)	(8,826)	(58,947)
<b>Total Revenue Requirements</b>	<b>104</b>	<b>89</b>	<b>24</b>	<b>78</b>	<b>214</b>	<b>314</b>	<b>420</b>	<b>805</b>	<b>1,018</b>	<b>807</b>	<b>978</b>	<b>5,618</b>	<b>10,268</b>
<b>MN Jurisdictional Revenue Requirement</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

**Xcel Energy Renewable Energy Standard Rider  
Revenue Requirements**

<b>Wind To Battery</b>	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09	Annual
<b>Rate Base</b>													
Plus CWIP Ending Balance	1,484,277	1,537,546	1,551,540	1,644,895	1,737,012	1,758,075	1,779,280	1,820,791	1,842,419	1,864,192	1,886,113	4,572,979	4,572,979
Plus Plant In-Service	0	0	0	0	0	0	0	0	0	0	0	(537,554)	(537,554)
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Accum. Deferred Taxes	(11,296)	(13,542)	(15,819)	(18,149)	(20,574)	(23,055)	(25,551)	(28,075)	(30,626)	(33,194)	(35,778)	(39,548)	(39,548)
End Of Month Rate Base	1,495,573	1,551,088	1,587,380	1,663,044	1,757,588	1,781,130	1,804,831	1,848,886	1,873,045	1,897,386	1,921,891	4,074,973	4,074,973
Average Rate Base (BOM/EOM)	1,749,198	1,523,330	1,559,224	1,615,202	1,710,315	1,769,358	1,792,981	1,828,849	1,860,955	1,885,215	1,909,638	2,998,432	1,850,058
<b>Calculation of Return</b>													
Plus Debt Return	4,898	4,265	4,366	4,523	4,789	4,954	5,020	5,115	5,211	5,279	5,347	8,396	62,162
Plus Equity Return	7,944	6,918	7,081	7,336	7,768	8,036	8,143	8,297	8,452	8,562	8,673	13,618	100,828
<b>Total Return</b>	12,842	11,184	11,447	11,858	12,557	12,990	13,163	13,412	13,663	13,841	14,020	22,013	162,990
<b>Income Statement Items</b>													
Plus Operating Expense	4,283	4,283	4,283	4,283	4,283	4,283	4,283	4,283	4,283	4,283	4,283	4,283	51,390
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Deferred Taxes	(2,216)	(2,245)	(2,277)	(2,330)	(2,425)	(2,480)	(2,497)	(2,524)	(2,551)	(2,567)	(2,584)	(3,770)	(30,468)
Plus Gross Up for Income Tax	11,449	10,980	11,085	11,411	11,975	12,320	12,449	12,640	12,832	12,964	13,097	19,890	152,791
Less AFUDC	13,544	13,768	13,994	14,355	14,979	15,359	15,501	15,712	15,924	16,070	16,217	23,513	188,936
Less AFUDC Gross Up for Income Tax	9,557	9,715	9,875	10,129	10,569	10,837	10,938	11,086	11,236	11,339	11,443	16,591	133,315
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Total Income Statement Expense</b>	(9,585)	(10,568)	(10,779)	(11,120)	(11,715)	(12,075)	(12,204)	(12,400)	(12,597)	(12,730)	(12,964)	(19,902)	(148,538)
<b>Total Revenue Requirements</b>	3,257	616	668	738	842	915	959	1,012	1,066	1,111	1,156	2,112	14,452
<b>MN Jurisdictional Revenue Requirement</b>	0	0	0	0	0	0	0	0	0	0	0	0	0

**Xcel Energy Renewable Energy Standard Rider  
Revenue Requirements**

<b>Wind To Battery</b>	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Annual
<b>Rate Base</b>													
Plus CWIP Ending Balance	4,572,979	4,578,683	4,578,683	4,580,683	4,580,683	4,582,683	4,582,683	4,582,683	4,582,683	4,582,683	4,582,683	(1,000,000)	(1,000,000)
Plus Plant In-Service	(697,527)	(697,527)	(697,527)	(797,527)	(797,527)	(797,527)	(797,527)	(797,527)	(797,527)	(797,527)	(797,527)	4,785,157	4,785,157
Less Book Depreciation Reserve	0	0	0	0	0	0	0	0	0	0	0	12,184	12,184
Less Accum Deferred Taxes	(49,465)	(59,441)	(69,478)	(79,570)	(89,718)	(99,923)	(110,185)	(120,503)	(130,875)	(141,303)	(151,787)	246,447	246,447
End Of Month Rate Base	3,924,917	3,940,598	3,950,634	3,862,726	3,872,875	3,885,080	3,895,342	3,905,659	3,916,031	3,926,459	3,936,943	3,526,526	3,526,526
Average Rate Base (BOM/EOM)	3,999,945	3,932,757	3,945,616	3,906,680	3,867,801	3,878,977	3,890,211	3,900,500	3,910,845	3,921,245	3,931,701	3,731,734	3,901,501
<b>Calculation of Return</b>													
Plus Debt Return	11,200	11,012	11,048	10,939	10,830	10,881	10,893	10,921	10,950	10,979	11,009	10,449	131,090
Plus Equity Return	18,166	17,861	17,920	17,743	17,566	17,617	17,668	17,715	17,762	17,809	17,856	16,948	212,632
Total Return	29,366	28,873	28,967	28,682	28,396	28,478	28,561	28,636	28,712	28,788	28,865	27,397	343,722
<b>Income Statement Items</b>													
Plus Operating Expense	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	4,363	52,356
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(507)	(6,080)
Plus Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	12,184	12,184
Plus Deferred Taxes	(9,917)	(9,977)	(10,036)	(10,092)	(10,149)	(10,205)	(10,262)	(10,317)	(10,372)	(10,428)	(10,484)	398,233	285,994
Plus Gross Up for Income Tax	22,963	22,809	22,911	22,843	22,776	22,870	22,964	23,054	23,143	23,234	23,324	(395,162)	(142,270)
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Income Statement Expense	16,902	16,689	16,731	16,608	16,484	16,521	16,559	16,593	16,627	16,662	16,697	19,112	202,185
<b>Total Revenue Requirements</b>	<b>46,269</b>	<b>45,561</b>	<b>45,698</b>	<b>45,289</b>	<b>44,880</b>	<b>45,000</b>	<b>45,119</b>	<b>45,229</b>	<b>45,339</b>	<b>45,450</b>	<b>45,562</b>	<b>46,509</b>	<b>545,907</b>
<b>MN Jurisdictional Revenue Requirement</b>	<b>33,894</b>	<b>33,376</b>	<b>33,476</b>	<b>33,177</b>	<b>32,877</b>	<b>32,964</b>	<b>33,052</b>	<b>33,133</b>	<b>33,213</b>	<b>33,295</b>	<b>33,376</b>	<b>34,070</b>	<b>399,904</b>

**Xcel Energy Renewable Energy Standard Rider  
Revenue Requirements**

<b>Wind To Battery</b>	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
<b>Rate Base</b>													
Plus CWIP Ending Balance	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)
Plus Plant In-Service	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157	4,785,157
Less Book Depreciation Reserve	41,522	70,860	100,198	129,536	158,874	188,212	217,550	246,888	276,226	305,564	334,902	364,239	364,239
Less Accum Deferred Taxes	289,342	332,252	375,162	418,072	460,982	503,892	546,801	589,711	632,621	675,531	718,441	761,351	761,351
End Of Month Rate Base	3,454,292	3,382,044	3,309,796	3,237,549	3,165,301	3,093,053	3,020,805	2,948,557	2,876,310	2,804,062	2,731,814	2,659,566	2,659,566
Average Rate Base (BOM/EOM)	3,490,409	3,418,168	3,345,920	3,273,672	3,201,425	3,129,177	3,056,929	2,984,681	2,912,434	2,840,186	2,767,938	2,695,690	3,093,052
<b>Calculation of Return</b>													
Plus Debt Return	9,773	9,571	9,369	9,166	8,964	8,762	8,559	8,357	8,155	7,953	7,750	7,548	103,927
Plus Equity Return	15,852	15,524	15,196	14,868	14,540	14,212	13,884	13,555	13,227	12,899	12,571	12,243	188,571
<b>Total Return</b>	25,625	25,095	24,565	24,034	23,504	22,973	22,443	21,913	21,382	20,852	20,321	19,791	272,498
<b>Income Statement Items</b>													
Plus Operating Expense	4,445	4,445	4,445	4,445	4,445	4,445	4,445	4,445	4,445	4,445	4,445	4,445	53,340
Plus Accrued Costs / Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus Property Taxes	4,510	4,510	4,510	4,510	4,510	4,510	4,510	4,510	4,510	4,510	4,510	4,510	54,120
Plus Book Depreciation	29,338	29,338	29,338	29,338	29,338	29,338	29,338	29,338	29,338	29,338	29,338	29,338	352,055
Plus Deferred Taxes	42,896	42,910	42,910	42,910	42,910	42,910	42,910	42,910	42,910	42,910	42,910	42,910	514,904
Plus Gross Up for Income Tax	(32,083)	(32,329)	(32,561)	(32,792)	(33,024)	(33,256)	(33,487)	(33,719)	(33,950)	(34,182)	(34,413)	(34,645)	(400,441)
Less AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
Less AFUDC Gross Up for Income Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Total Income Statement Expense</b>	49,105	48,873	48,642	48,410	48,179	47,947	47,716	47,484	47,253	47,021	46,790	46,558	573,979
<b>Total Revenue Requirements</b>	74,731	73,968	73,207	72,445	71,683	70,921	70,159	69,397	68,635	67,873	67,111	66,349	846,477
<b>MN Jurisdictional Revenue Requirement</b>	54,744	54,186	53,627	53,069	52,511	51,953	51,395	50,837	50,278	49,720	49,162	48,604	620,087

**Xcel Energy**  
**Renewable Energy Standard Rider**  
**Revenue Requirement - 5 Year Summary**

	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>
<b>Wind To Battery</b>					
<b><u>Rate Base</u></b>					
Plus CWIP Ending Balance	4,572,979	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)
Plus Plant In-Service	(537,554)	4,785,157	4,785,157	4,785,157	4,785,157
Less Book Depreciation Reserve	0	12,184	364,239	716,295	1,068,350
Less Accum Deferred Taxes	(39,548)	246,447	761,351	1,015,572	1,112,318
End Of Month Rate Base	4,074,973	3,526,526	2,659,566	2,053,290	1,604,488
<b>Average Rate Base (BOM/EOM)</b>	<b>1,850,058</b>	<b>3,901,501</b>	<b>3,093,052</b>	<b>2,356,428</b>	<b>1,828,889</b>
<b><u>Calculation of Return</u></b>					
Plus Debt Return	62,162	131,090	103,927	79,176	61,451
Plus Equity Return	100,828	212,632	168,571	128,425	99,674
<b>Total Return</b>	<b>162,990</b>	<b>343,722</b>	<b>272,498</b>	<b>207,601</b>	<b>161,125</b>
<b><u>Income Statement Items</u></b>					
Plus Operating Expense	51,390	52,356	53,340	54,343	55,365
Plus Accrued Costs / Benefits	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0
Plus Property Taxes	0	(6,080)	54,120	54,120	54,120
Plus Book Depreciation	0	12,184	352,055	352,055	352,055
Plus Deferred Taxes	(30,468)	285,994	514,904	254,221	96,746
Plus Gross Up for Income Tax	152,791	(142,270)	(400,441)	(162,102)	(21,298)
Less AFUDC	188,936	0	0	0	0
Less AFUDC Gross Up for Income Tax	133,315	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0
<b>Total Income Statement Expense</b>	<b>(148,538)</b>	<b>202,185</b>	<b>573,979</b>	<b>552,638</b>	<b>536,988</b>
<b>Total Revenue Requirements</b>	<b>14,452</b>	<b>545,907</b>	<b>846,477</b>	<b>760,240</b>	<b>698,113</b>
<b>MN Jurisdictional Revenue Requirement</b>	<b>0</b>	<b>399,904</b>	<b>620,087</b>	<b>556,913</b>	<b>511,403</b>

Xcel Energy - Electric (State of Minnesota)  
 Renewable Energy Standards Rider

RES Projected Tracker Activity for 2009-2013					
	2009	2010	2011	2012	2013
Wind to Battery (1)	-	-	-	-	-
Balance Forward (2)	-	399,904	620,087	556,913	511,403
<b>Total Expense (3)</b>	<b>\$ -</b>	<b>\$ 399,904</b>	<b>\$ 630,198</b>	<b>\$ 565,154</b>	<b>\$ 519,643</b>
Revenues	-	389,792	621,958	560,314	519,643
<b>Balance (4)</b>	<b>-</b>	<b>10,112</b>	<b>8,241</b>	<b>4,840</b>	<b>-</b>

Notes:

- (1) Revenue Requirements calculated for Wind To Battery in Schedule 2.
- (2) Balance over or under recovered from the prior year.
- (3) Total Expense represents the total revenue requirements for 2009-2013.
- (4) Balance is the amount (over) under collected or the difference between the total revenue requirements and the amount of revenue received from customers under this rider.

Xcel Energy - Electric (State of Minnesota)  
Renewable Energy Standards Rider

RES Projected Tracker Activity for 2010													
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	2010 Total
Wind to Battery (1)	-	-	-	-	-	-	-	-	-	-	-	-	\$ -
Balance Forward (2)	33,894	33,376	33,476	33,177	32,877	32,964	33,052	33,133	33,213	33,295	33,376	34,070	\$ 399,904
Total Expense (3)	\$ 33,894	\$ 33,376	\$ 33,476	\$ 33,177	\$ 32,877	\$ 32,964	\$ 33,052	\$ 33,133	\$ 33,213	\$ 33,295	\$ 33,376	\$ 34,070	\$ 399,904
Revenues	32,434	30,207	31,502	29,224	30,377	33,711	37,941	36,577	31,924	32,562	30,677	32,658	\$ 389,792
Balance (4)	1,461	4,629	6,604	10,557	13,057	12,310	7,422	3,978	5,267	6,000	8,700	10,112	\$ 10,112

Notes:

- (1) Revenue Requirements calculated for Wind To Battery in Schedule 2.
- (2) Balance over or under recovered from the prior year.
- (3) Total Expense represents the total revenue requirements for 2010.
- (4) Balance is the amount (over) under collected or the difference between the total revenue requirements and the estimated amount of revenue received from customers under this rider.

Xcel Energy - Electric (State of Minnesota)  
Renewable Energy Standards Rider

RES Projected Tracker Activity for 2011	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	2011 Total
	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	
Wind to Battery (1)	-	-	-	-	-	-	-	-	-	-	-	-	\$ -
	54,744	54,186	53,627	53,069	52,511	51,953	51,395	50,837	50,278	49,720	49,162	48,604	\$ 620,087
Balance Forward (2)	10,112	-	-	-	-	-	-	-	-	-	-	-	\$ 10,112
<b>Total Expense (3)</b>	<b>\$ 64,856</b>	<b>\$ 54,186</b>	<b>\$ 53,627</b>	<b>\$ 53,069</b>	<b>\$ 52,511</b>	<b>\$ 51,953</b>	<b>\$ 51,395</b>	<b>\$ 50,837</b>	<b>\$ 50,278</b>	<b>\$ 49,720</b>	<b>\$ 49,162</b>	<b>\$ 48,604</b>	<b>\$ 630,198</b>
Revenues	51,739	48,234	50,273	46,638	48,486	53,765	60,511	58,361	50,935	51,940	48,987	52,090	\$ 621,958
<b>Balance (4)</b>	<b>13,117</b>	<b>19,069</b>	<b>22,423</b>	<b>28,855</b>	<b>32,880</b>	<b>31,068</b>	<b>21,951</b>	<b>14,427</b>	<b>13,771</b>	<b>11,551</b>	<b>11,727</b>	<b>8,241</b>	<b>\$ 8,241</b>

Notes:

- (1) Revenue Requirements calculated for Wind To Battery in Schedule 2.
- (2) Balance over or under recovered from the prior year.
- (3) Total Expense represents the total revenue requirements for 2011.
- (4) Balance is the amount (over) under collected or the difference between the total revenue requirements and the estimated amount of revenue received from customers under this rider.

Schedule 6  
Page 1 of 2

**Xcel Energy - Electric (State of Minnesota)**  
**Renewable Energy Standards Rider Factor Calculation**  
**Projected 2010**

All customers are subject to the same energy cost per kWh.

<u>Description</u>	<u>All Classes</u>
Minnesota Annual Cost (1)	\$399,904
Forecasted Minnesota MWH (2)	32,482,705
Energy Factor / kWh	\$0.000012
Residential bill impact / Month (3)	\$0.01

**Notes:**

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- (1) Annual cost includes true-up adjustment to Tracker Account for the previous year's over- or under-recovery.
- (2) Consistent with 2009 Budget sales (Oct 2008 Vintage) forecast. Includes Interdepartmental sales and reflects calendar month sales.
- (3) Assumes 750 kWh per month.

**Xcel Energy - Electric (State of Minnesota)  
Renewable Energy Standards Rider Factor Calculation  
Projected 2011**

All customers are subject to the same energy cost per kWh.

<u>Description</u>	<u>All Classes</u>
Minnesota Annual Cost (1)	\$630,198
Forecasted Minnesota MWH (2)	32,734,622
Energy Factor / kWh	\$0.000019
Residential bill impact / Month (3)	\$0.01

**Notes:**

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- (1) Annual cost includes true-up adjustment to Tracker Account for the previous year's over- or under-recovery.
- (2) Consistent with 2009 Budget sales (Oct 2008 Vintage) forecast. Includes Interdepartmental sales and reflects calendar month sales.
- (3) Assumes 750 kWh per month.

**CERTIFICATE OF SERVICE**

I, Carole Wallace, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

**DOCKET NO.: NORTHERN STATES POWER WIND TO BATTERY PROJECT PETITION FOR RECOVERY UNDER THE RENEWABLE ENERGY STANDARD RIDER AND AFFILIATED INTEREST ARRANGEMENT: MISCELLANEOUS ELECTRIC SERVICE LIST**

**DOCKET NO. E002/M-09-\_\_\_\_\_ E002/AI-09-\_\_\_\_\_**

Dated this 10<sup>th</sup> day of April 2009

\_\_\_\_\_/s/\_\_\_\_\_  
Carole Wallace  
Regulatory Coordinator

Northern States Power Company,  
a Minnesota corporation ("Xcel Energy")  
Miscellaneous Electric Service List

3/01/2009

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

David Boyd  
J. Dennis O'Brien  
Phyllis Reha  
Thomas Pugh  
Betsy Wergin

Chair  
Commissioner  
Commissioner  
Commissioner  
Commissioner

Al Krug  
Managing Director, Government and Regulatory Affairs  
Xcel Energy  
414 Nicollet Mall, 7th Floor  
Minneapolis, MN 55401

SERVICE DATE: September 14, 2009

DOCKET NO. E-002/AI-09-379

In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation,  
Regarding the Eligibility of the Wind2Battery Project for Recovery Under the Renewable  
Energy Standard and Approval as an Affiliated Interest Arrangement

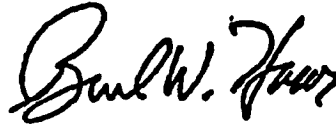
The above entitled matter has been considered by the Commission and the following disposition  
made:

1. **Xcel Energy's investment in the Wind2Battery Project is approved as an affiliated interest under Minn. Stat. § 216B.48.**
2. **Xcel's investment in the Wind2Battery Project is approved, with the following findings and requirements.**
3. **The Wind2Battery project is found eligible for recovery under Minn. Stat. § 216B.1645.2a (a) 3 (as recently amended by Minnesota Session Laws 2009, Chapter 110, Section 11).**
4. **The proposed project is found reasonable and directly related to advancing research and understanding of how storage devices improve renewable energy sources for meeting its RES obligations, based on the costs and facts represented by Xcel in this filing.**
5. **Xcel may recover only up to the level of costs requested in its petition, offset by any and all revenues as a result of this research project.**
6. **Before any future costs recovery above the costs approved in this Order is allowed, Xcel shall fully explain and justify any such cost recovery.**
7. **Xcel shall share information from the results of the research project and credit to ratepayers any and all revenues and any other income due to the research project.**

8. **Within a year of this Order, Xcel shall make a compliance addressing whether and to what extent the expenses incurred in the Wind2Battery Project have improved the economics of the Minwind power generating facility.**

The Commission agrees with and adopts the recommendations of the Office of Energy Security, contained in comments dated July 10, 2009 with the addition of #8 as stated above.

BY ORDER OF THE COMMISSION



Burl W. Haar  
Executive Secretary

(S E A L)

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[www.commerce.state.mn.us](http://www.commerce.state.mn.us)

July 10, 2009

**PUBLIC DOCUMENT**

Burl W. Haar  
Executive Secretary  
Minnesota Public Utilities Commission  
121 7th Place East, Suite 350  
St. Paul, Minnesota 55101-2147

**RE: PUBLIC Comments of the Minnesota Office of Energy Security**  
Docket No. E002/AI-09-379

Dear Dr. Haar:

Attached are the **PUBLIC** comments of the Minnesota Office of Energy Security (OES) in the following matter:

Petition of Northern States Power Company, a Minnesota Corporation, Regarding the Eligibility of the Wind2Battery Project for Recovery under the Renewable Energy Standard and Approval as an Affiliated Interest Arrangement.

The petition was filed on April 10, 2009 by:

Al Krug  
Managing Director, Government and Regulatory Affairs  
Xcel Energy  
414 Nicollet Mall, 7<sup>th</sup> Floor  
Minneapolis, MN 55401

The OES recommends **approval with filing requirements**. The OES is available to answer any questions the Commission may have.

Sincerely,

/s/ SAMIR OUANES  
Rates Analyst

SO/ja  
Attachment



**PUBLIC DOCUMENT**

**BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**

**PUBLIC COMMENTS OF THE  
MINNESOTA OFFICE OF ENERGY SECURITY**

**DOCKET NO. E002/AI-09-379**

**I. SUMMARY**

On April 10, 2009, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed a petition (Petition) requesting the Minnesota Public Utilities Commission's (Commission) approval of an Affiliated Interest Arrangement (Arrangement) pursuant to Minnesota Statute Section 216B.48. The Arrangement is related to a Commission-approved renewable development fund (RDF) project to explore the viability of coupling a 1 MW sodium-sulfur battery storage facility, Wind2Battery, with the 11 MW Minwind power generating facility near Luverne, Minnesota.<sup>1</sup>

Xcel also requests the Commission to find that Wind2Battery is "an eligible energy technology" under Minnesota Statute Section 216B.1691 and is eligible for the Renewable Energy Standard (RES) Rider cost recovery (for the capital cost that remain after a \$1 million RDF grant and contribution of about \$368,000 from the University of Minnesota, the Great Plains Institute and the National Renewable Energy laboratory (NREL) is applied, about \$3.5 million) under Minnesota Statute Section 216B.1645, subdivision 2a (a) (3).<sup>2</sup>

Finally, Xcel requests approval to recover about \$54,000 of annual operating and maintenance (O&M) costs until such time that the Company can incorporate Wind2Battery's costs and annual O&M into base rates.

The Minnesota Office of Energy Security (OES) addresses each of these requests below.

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<sup>1</sup> See Attachment 1 for background information on the RDF grant: OES's May 8, 2009 letter in Docket No. E002/M-07-675.

<sup>2</sup> The Commission-approved RES Rider is provided under Attachment 2 of these comments.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 2

## **II. OES ANALYSIS**

The OES provides its analysis based on the information provided in the filing and in the Company's response to discovery.

### **A. *FILING REQUIREMENTS FOR THE AFFILIATED-INTEREST ARRANGEMENT***

An affiliated-interest arrangement must comply with Minnesota Statute Section 216B.48 and Minnesota Rule Part 7825.2200. The statute and rule include requirements for a utility to:

- file for Commission approval of transactions with the affiliated interest; and
- provide detailed information regarding the contract or arrangement, and the reasons why it is in the public interest.

Minnesota Statutes Section 216B.48, subdivision 3, states in relevant part:

The commission shall approve the contract or arrangement made or entered into ... only if it clearly appears and is established upon investigation that it is reasonable and consistent with the public interest.... The burden of proof to establish the reasonableness of the contract or arrangement is on the public utility.

As a result, Xcel has the burden of proof to establish the reasonableness of the Arrangement, and the Commission shall approve the Arrangement only if the Commission finds that the Arrangement is reasonable and consistent with the public interest.

Minnesota Rule Part 7825.2200, subpart B, requires that petitions for approval of affiliated-interest contracts or agreements must be accompanied by the following:

- 1) a descriptive title of each contract or agreement;
- 2) a copy of the contract or agreement, or modifications or revisions of an existing contract or agreement;
- 3) a list and the past history of all contracts or agreements outstanding between the petitioner and affiliated interest, the consideration received by the affiliated interest for such contracts or agreements, and a verified summary of the relevant cost records pertaining to the same;
- 4) a descriptive summary of the pertinent facts and reasons why such contract or agreement is in the public interest;

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 3

- 5) competitive bidding: (a) if invitations for sealed written public proposals for the furnishing of the service sought under the contract or agreement have been made, a summary of the terms of the proposals received, including the name of each bidder or representative of a bidding group; and as an exhibit to the petition, a copy of each proposal received; (b) if invitations for sealed written proposals have not been made, an explanation of the decisions to that effect will be submitted.

In its review of the initial filing, the OES noted that the affiliated-interest filing requirements had not been met. However, following discovery from the OES, the Company substantially provided the above-required information.<sup>3</sup>

#### **B. ANALYSIS OF THE AFFILIATED-INTEREST ARRANGEMENT**

In this section, the OES summarizes Xcel's arguments regarding why the Arrangement should be found to be reasonable and in the public interest. The OES then provides its analysis and overall conclusion about whether the Arrangement should be found to be reasonable and in the public interest.

##### *1. Xcel's Arguments*

The Company provided the following discussion in support of the proposed Arrangement:

- Xcel states that the Arrangement should be approved as an affiliated interest because Wind2Battery was selected by the RDF Board (under the Research and Development category for a one million dollars grant) and approved by the Commission in its April 1, 2008 Order *Approving Selected RDF Projects With Exceptions and Revising Procedures For Future Cycles* in Docket No. E002/M-07-675.<sup>4</sup>
- The Company also states that the Utility Innovations division of Xcel Energy Services, Inc (Grantee) applied for funding from the RDF for the purpose of researching the sodium-sulfur battery technology for use as a wind energy storage facility and its potential to enable further integration of wind. Xcel states that all services performed by Xcel Energy Services, Inc. (XES) in conjunction with this project are provided at "cost" and XES does not earn any profit from the provision of the services. Thus, the Company concludes that there are no disadvantages to the customer as a result of this relationship.<sup>5</sup>

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<sup>3</sup> See Attachments 3, 4, 5 and 6 to these comments.

<sup>4</sup> Source: pp. 11-12 of the instant filing.

<sup>5</sup> Source: page 2 of Xcel's response to OES's Information Request No. 4, Attachment 7 to these comments.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 4

- The Company states that XES took the following steps to ensure that the costs of Wind2Battery were reasonable and prudent: (1) XES researched technologies that could be deployed on a 1-MW scale and at a multiple MW scale, provide a minimum of six hours of continuous discharge, handle an estimated 300 charge-discharge cycles annually for a number of years, provide fast response in order to demonstrate frequency regulation and voltage support in addition to simple time-shifting of a renewable resource, and are commercially available so that it could be deployed quickly and demonstrate consistent performance;<sup>6</sup> (2) XES used lessons learned from the other two installations within the U.S. that also use a Sodium Sulfur (NaS) battery technology, although neither were connected to wind;<sup>7</sup> and (3) XES selected an experienced contractor, S&C Electric, which installed a NaS battery for power reliability for one of these installations.
- Xcel states that Wind2Battery is in the public interest because it improves intermittent resource economics, ensures intermittent resource implementation, advances research and understanding of how storage devices may improve renewable energy projects and facilitates coordination with the development of transmission.<sup>8</sup>
- Xcel states that the Commission recognized that batteries would be necessary to support wind resources when it directed the Company to review the current state of wind energy storage research in its July 28, 2006 Order in Docket No. E002/RP-04-1752.<sup>9</sup>
- The Company states that the Minnesota Legislature and the Governor recognized that batteries would be necessary to support wind resources when legislation was passed in 2008 specifically clarifying that energy storage facilities were eligible for cost recovery in a renewable energy rider (Minnesota Statute Section 216B.1645).

## 2. *OES's Analysis*

The OES agrees with the Company that the proposed Arrangement should be considered as an affiliated interest. However, the OES notes that approval of a project in an RDF process does not indicate, by itself, that the costs of a project in addition to the amount approved in RDF are reasonable for recovery. Instead, the project should be reviewed to assess whether the costs are reasonable

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<sup>6</sup> Source: p. 9 of the instant filing and pp. 5-7 of Xcel's response to OES's Information Request No. 4.

<sup>7</sup> Source: Xcel's response to OES's Information Request No. 6, Attachment 8 to these comments.

<sup>8</sup> Source: page 2 of Xcel's response to OES's Information Request No. 4, Attachment 7 to these comments.

<sup>9</sup> The OES notes that Xcel complied with the 2006 Order and filed the required report in its December 14, 2007 resource plan filing in Docket No. E002/RP-07-1572).

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 5

compared to other alternatives for meeting the stated goals. Further, the outcome of the Third Funding Cycle of the RDF does not provide a reasonable basis for a competitive bidding process for the purpose of the current proceeding.

The OES notes that the criteria used for the selection and approval of Research and Development projects in the Third Funding Cycle of the RDF are different from the criteria used for approval of an affiliated-interest arrangement. In particular, the competitive bidding required for this petition is not the competitive bidding which occurs for RDF projects. Rather, the competitive bidding in this proceeding refers to Xcel's efforts to explore options to achieve the specific goals of Wind2Battery, including the goal of firming up wind.

The OES stresses the importance of the competitive bidding process in ensuring that the affiliated-interest arrangement is an arm's length transaction when the parties to the arrangement have shared interests which may differ from the interests of ratepayers. The OES notes that the parties in this filing appear to be Xcel and XES based on the information provided in Xcel's April 10, 2009 compliance filing in Docket No. E002/M-07-675 (RDF Third Cycle). Competitive bidding is required when products or services are competitively available, and is the OES's preferred method to ensure that utilities are not favoring their affiliates.

However, as discussed below, Wind2Battery appears to be the only currently available option satisfying all of the specific objectives assigned to this project. In addition, Xcel stated that "XES does not earn any profit from the provision of the services." Under these particular circumstances, the OES does not object to the fact that Xcel has not used a competitive bidding process in this proceeding. However, the OES considers the proposal to be a pilot and research project rather than a typical utility infrastructure project. It is important for such a project to have clear goals.

In response to discovery from the OES, Xcel stated:<sup>10</sup>

The specific objectives for the W2B [Wind2Battery] project are to:

- Evaluate the ability of large-scale battery-storage technology to effectively 'firm' wind energy, enabling a shift of wind-generated energy from off-peak to on-peak availability.
- Evaluate the ability of battery-storage technology to reduce the need to compensate for the variability and limited predictability of wind generation resources.
- Evaluate the optimal ratio of energy storage to total wind capacity that would allow the wind energy storage system to be a viable peak-load resource.

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<sup>10</sup> Source: page 5 of Xcel's response to OES's Information Request No. 4, Attachment 7 to these comments.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 6

- Evaluate whether or not the battery is responsive enough to qualify as spinning reserves, and evaluate any special relay requirements for a spinning reserve frequency response characteristic.
- Evaluate the potential for battery-storage technology to support the transmission and distribution systems and therefore allow for more effective integration of wind into our system operations. This includes the ability of the battery discharge and recharge process to be used to buffer and/or smooth the wind generation output ramp rates; the optimal mix of battery uses between demand shaping, generator leveling and contingency reserve response; the ability to provide reactive load support and frequency support.
- Assess cold weather effects on the performance and integrity of the NaS Battery system.

Xcel also stated in response to this discovery:

At the time of our analysis (summer of 2007) the following technologies were evaluated:

- Compressed Air Energy Storage and pumped hydro were determined not to be feasible due to the inability to conduct a small-scale demonstration.
- Lead Acid batteries could not handle the number of cycles required for long-term deployment and were therefore eliminated.
- Flywheels and ultra-capacitors did not pass the six-hour duration requirement.
- Lithium Ion batteries had not been demonstrated as capable of the multiple-MWh scale that would be required for future deployment.
- Zinc Bromine batteries were not yet commercially available at the 1-MW scale and had no proven commercial track record for the functional requirements of our application.
- Vanadium Redox batteries did not have a proven commercial track record for the functional requirements of our application.
- Sodium Sulfur (NaS) batteries had been deployed extensively on a commercial scale for reliability, back-up power or peak-shaving purposes (over 200 MW total, world-wide) and the modular approach enabled utility-scale deployment.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 7

For completeness of the record, the OES requests the Company to provide in reply comments a laymen's explanation of the need to provide "a minimum of six hours of continuous discharge" (emphasis added), as it relates to the stated specific objectives for Wind2Battery.

Legislation was passed in 2009 specifically clarifying that expenses for energy storage were eligible for cost recovery in a renewable energy rider if the utility demonstrates to the Commission's satisfaction that the expenses "advance research and understanding of how storage devices may improve renewable energy projects" (Minnesota Statute Section 216B.1645, subdivision 2a(a)(3)).<sup>11</sup> Based on its review of the instant filing and Xcel's response to discovery, the OES concludes that Wind2Battery will advance research and understanding of how storage devices may improve renewable energy projects.

However, the OES concludes that the new language places a responsibility on Xcel to share the results of the research project, which would be fully funded by Xcel's ratepayers under the Company's proposal. In addition, Xcel's ratepayers should receive any and all future revenues and sources of income due to this research project.

Although Xcel has not demonstrated that Wind2Battery is cost-effective (or that it would "improve [renewable energy] project economics") compared to the use of peaking units or other available resources that can fulfill a more general goal "to reduce impact from the variability and limited predictability of wind generation resources," the OES concludes that the Arrangement, with the above requirement, is reasonable and consistent with the public interest. This conclusion is based on the following:

1. Wind2Battery would be the only currently available option satisfying the specific objectives assigned,
2. XES does not earn any profit from the provision of the services,
3. Xcel demonstrated that Wind2Battery will advance research and understanding of how storage devices may improve renewable energy projects, which should be shared with the public, and
4. Xcel's ratepayers would be credited with any and all revenues and other income due to the research project.

### **C. ELIGIBLE ENERGY TECHNOLOGY**

The Company requests that the Commission find that the Wind2Battery project is an "eligible energy technology" under Minnesota Statute Section 216B.1691 because it is designed to support wind energy resources.

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<sup>11</sup> See Attachment 9, and the underlined language added to the revised Minnesota Statute section 216B.1645, subdivision 2a.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 8

Minnesota Statute Section 216B.1691, subdivision 1 defines “eligible energy technology” as an energy technology that generates electricity from specific renewable energy sources, including wind.

The OES notes that Xcel states that Wind2Battery will evaluate the ability of NaS battery technology to provide four primary benefits to promote the development of renewable energy by:<sup>12</sup>

- **Providing On-Peak Energy:** Storing wind energy, temporarily for use when loads are higher during on-peak periods. Xcel expects this storage and redeployment to be beneficial as wind resources become a larger part of the generation mix, and may allow wind energy to provide more on-peak energy.
- **Support System Ramping:** The ability of the battery discharge and charge process to support system ramping, such as discharging while daily system loads are increasing or charging as daily system loads are decreasing.
- **Grid Support:** Supporting the grid by adding voltage support, reactive load support, frequency support and suppressing voltage fluctuations.
- **Curtailment Offset:** While we are optimistic that the planned increase in transmission facilities such as CAPx will reduce and/or eliminate the need for curtailments in the future, battery storage can also provide a useful hedge against curtailment by storing energy if and when curtailments are necessary.

Therefore, while Wind2Battery is certainly designed to support wind energy resources, it does not appear to have the capacity to generate electricity from wind as required by Minnesota Statute Section 216B.1691, subdivision 1. However, the OES notes that this issue may not be relevant since, as discussed above, legislation was passed in 2009 specifically clarifying that expenses for energy storage are eligible for cost recovery in a renewable energy rider if the utility demonstrates to the Commission's satisfaction that the expenses advance research and understanding of how storage devices may improve renewable energy projects (Minnesota Statute Section 216B.1645, subdivision 2a(a)(3)).

#### *D. COST RECOVERY*

Minnesota Statute Section 216B.1645 (Statute) as amended in the 2009 Session (new language underlined) provides the mechanisms for cost recovery as indicated in Attachment 9 to these comments. Specifically, Xcel seeks Commission approval to recover expenses for energy storage (Wind2Battery) pursuant to subdivision 2a (a) (3) of the Statute.

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<sup>12</sup> Source: p. 10 of the instant filing.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 9

This provision allows for the automatic adjustment of charges (through the RES Rider) to recover prudently incurred costs for eligible energy facilities that: (1) are directly related to a renewable energy project, and (2) the utility demonstrates to the Commission's satisfaction meet the requirements of the law.

As discussed in Section B, the OES concludes that: (1) Wind2Battery is directly related to renewable energy, (2) will advance research and understanding of how storage devices may improve renewable energy projects and thus (3) the Arrangement is reasonable and consistent with the public interest.

In addition, following discovery from the OES, Xcel stated that the Company will allocate Wind2Battery costs to the NSP-M jurisdictions (Minnesota, North Dakota, South Dakota and Wholesale) based on a demand allocator.<sup>13</sup> The OES agrees with Xcel that "demand is the appropriate allocation method because this project is a fixed asset expressly designed to store energy, and effectively 'firm' wind energy, enabling a shift of wind-generated energy from off-peak to on-peak availability."

Finally, following discovery from the OES, Xcel demonstrated that the Wind2Battery costs were not included in base rates in the Company's current rate case.<sup>14</sup>

Therefore, the OES recommends that the Commission:

1. Approve the investment and expenditure for Wind2Battery as requested by Xcel;
2. Require Xcel to file a rate adjustment under its renewable rider, when practical, as required by Minnesota Statute Section 216B.1645;
3. Require Xcel to share information from the results of the research project and to credit to ratepayers any and all revenues and any other income due to the research project; and
4. Allow Xcel to recover only up to the level of costs requested in this petition, offset by any and all revenues as noted above. Xcel must fully explain and justify any future cost recovery above the costs approved in this Order before any further cost recovery is allowed.

### **III. OES RECOMMENDATION**

Based on its analysis and conclusions, the OES recommends that the Commission:

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<sup>13</sup> See Attachment 11.

<sup>14</sup> See Attachment 10.

Docket No. E002/AI-09-379  
Analyst assigned: Samir Ouanes  
Page 10

1. Approve the Affiliated Interest Arrangement;
2. Approve the investment and expenditure for Wind2Battery as requested by Xcel;
3. Require Xcel to file a rate adjustment under its renewable rider, when practical, as required by Minnesota Statute Section 216B.1645;
4. Require Xcel to share information from the results of the research project and to credit to ratepayers any and all revenues and any other income due to the research project; and
5. Allow Xcel to recover only up to the level of costs requested in this petition, offset by any and all revenues as noted above. Require Xcel to fully explain and justify any future cost recovery above the costs approved in this Order, before any future cost recovery is allowed.

/ja

STATE OF MINNESOTA)  
                                          )SS  
COUNTY OF RAMSEY )

AFFIDAVIT OF SERVICE

I, Robin Benson, being first duly sworn, deposes and says:

That on the 14th day of September, 2009 she served the attached  
ORDER.

MNPUC Docket Number: E-002/AI-09-379

- XX By depositing in the United States Mail at the City of St. Paul, a true and correct copy thereof, properly enveloped with postage prepaid
- XX By personal service
- XX By inter-office mail

to all persons at the addresses indicated below or on the attached list:

Christopher Fittipaldi  
Docketing - OES  
Julia Anderson - OAG  
John Lindell- OAG

Robin Benson

Subscribed and sworn to before me,  
a notary public, this 14<sup>th</sup> day of  
September, 2009

Margie Ann DeLahunt  
Notary Public



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- Non Public Document – Contains Trade Secret Data  
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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-231

Date Received: April 29, 2011

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Question: Subject: Prepayments & Other Working Capital

Reference Company witness Felling direct testimony, page 38, line 4-6. Please provide the actual 13 month balances for the period December 2009 through December 2010 related to Prepayments, customer advances, deposits and any other components included in Other Working Capital.

Response:

Please see Attachment A for the actual 13-month balances for the period December 2009 through December 2010 related to prepayments, customer advances, and customer deposits.

---

Preparer: Shari Cardille  
Title: Principal Rate Analyst  
Department: Revenue Requirements North  
Telephone: 612-330-1974  
Date: May 31, 2011

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-130

Date Received: April 28, 2011

---

Question:

Reference: Wages and Salaries

Reference: Reed Direct, page 4, lines 10-11

Please provide the list of assumptions used to develop the 2011 budget test year for wages for bargaining unit employees.

Response:

The salary level included in the test year for bargaining employees was 3.0%. The salary level used for bargaining unit employees was based upon an agreement that was effective until December 31, 2010. Since the time our rate case application was submitted to the Commission, binding interest-based arbitration took place in order to finalize the new labor agreement. The resulting base salary increase for bargaining employees is 2.5%. In our Rebuttal Testimony, the Company will make a downward adjustment to reflect the 2.5% increase in base salary in 2011 for bargaining employees based upon the new labor agreement. The Company negotiated over the course of 20 full-day sessions for significant reductions in various areas and for a reasonable wage increase.

---

Witness: Jill Reed

Preparer: Eric Bachman

Title: Director, Workforce Strategy & Consulting

Department: Workforce Relations

Telephone: 612-330-7981

Date: June 9, 2011

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-148

Date Received: April 28, 2011

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Question:

Reference: Employee Health and Welfare Benefit Program

Reference: Reed Direct, page 15, lines 20-24

Was the 2011 budget test year adjusted to recognize the savings associated with the reductions in the High Deductible Health Plan (HDHP) plan for non-bargaining and certain bargaining employees to be implemented in 2011?

Response:

The savings associated with the reductions in the HDHP plan were not reflected in the 2011 test year due to the timing of finalizing these plans and ongoing labor negotiations with our NSP unions. However, these HDHP design changes have since been implemented for 2011 for all non-bargaining and bargaining NSP employees. The impact to the 2011 test year for the ND electric jurisdiction resulting from this initiative is approximately a savings of \$174,000. Offsetting this HDHP decrease is a cost increase of approximately \$8,000 resulting from the NSPM bargaining dental cost share change of 60 percent employer and 40 percent employee to a cost share of 75 percent employer and 25 percent employee.

Please see Attachment A of this response for the derivation of these amounts.

---

Witness: Jill H. Reed

Preparer: Todd Degrugillier

Title: Manager, Employee Taxes and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: May 31, 2011

**AS-2-RR-148 Attachment A  
HDHP Savings**

NSPM Remaining Plan Changes		
HDHP changes: 10% coinsurance after deductible with new out of pocket maximums	HSA elimination on original contribution amounts of \$670/\$1,340	
Total Cost Amount	(1,183,234)	(2,328,108)
Percent to NSPM electric O&M	64.7%	64.7%
Amount to NSPM electric O&M	(766,129)	(1,507,421)
Percent to North Dakota Jurisdiction	5.42%	5.42%
Total NSPM Electric O&M for North Dakota Jurisdiction	(41,532)	(81,717)

**MN**

Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to NSPM electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Nonbarg 10% coinsurance, new out of pocket maximums	
Total Cost - Medical and Pharmacy	(727,120)
Percent to NSPM electric O&M	64.7%
Amount to MN electric O&M	(470,801)
Total Cost - Medical and Pharmacy	(1,526,951)
Percent to NSPM electric O&M	31.00%
Amount to MN electric O&M	(473,355)
Total amount to MN electric O&M	(944,156)
Percent to North Dakota Jurisdiction	5.42%
Total NSPM Electric O&M for North Dakota Jurisdiction	(51,183)

**MN**

Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

**XS**

Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Total amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Grand Total

(1,183,234)
-------------

**Dental Cost Increase**

Dental cost share change from 60/40 to 75/25	
Total Cost Amount	241,175
Percent to NSPM electric O&M	64.7%
Amount to MN electric O&M	156,158
Percent to North Dakota Jurisdiction	5.42%
Total NSPM Electric O&M for North Dakota Jurisdiction	(51,183)

**MN**

Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-149

Date Received: April 28, 2011

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Question:

Reference: Employee Health and Welfare Benefit Program

Reference: Reed Direct, page 15, lines 24-27

Was the 2011 budget test year adjusted to recognize the savings associated with the mandatory drug programs that will be added in 2011 that will reduce costs for prescription drug coverage.

Response:

The savings associated with the two mandatory drug programs were not reflected in the 2011 test year due to the timing of finalizing these program changes and ongoing labor negotiations with our NSP unions. However, these prescription drug plan design changes have since been implemented in 2011 for all non-bargaining and bargaining NSP employees. The impact to the 2011 test year for the ND electric jurisdiction resulting from this initiative is approximately a savings of \$12,000. Please see Attachment A to this response for the derivation of this amount.

---

Witness: Jill H. Reed

Preparer: Todd Degrugillier

Title: Manager, Employee Taxes and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: May 27, 2011

**Pharmacy Savings**

**MN**

Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

NSPM Bargaining Plan Changes		
Mandatory mail order for pharmacy	Member Pay the Difference for pharmacy	Selected prescription drug elimination
(120,776)	(15,299)	(15,724)
64.7%	64.7%	64.7%
(78,201)	(9,906)	(10,181)
5.42%	5.42%	5.42%
(4,239)	(537)	(552)

**MN**

Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

**XS**

Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Total amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Member Pay the Difference & mandatory mail order for nonbargs
(91,717)
64.7%
(59,386)
(192,606)
31.00%
(59,708)
(119,093)
5.42%
(6,456)

(11,784)

**PUBLIC DOCUMENT**  
**TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED**

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 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-151

Date Received: April 28, 2011

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Question:

Reference: Employee Retirement Program

Reference: Electric 2011 Budget Workpapers ND – Rate Case, tab O2 – 5 Pension  
Please provide a copy of the 2011 Towers Watson Update that supports the numbers in the workpapers.

Response:

The Northern States Power Company-Minnesota ("NSPM") O&M electric North Dakota jurisdiction amount of \$68,833, from page two of the above-referenced workpapers, represents the net difference between the original 2011 budget amount and the 2011 test year amount. The amount is comprised of qualified pension, non-qualified pension (less the SERP portion), postretirement benefits (FAS 106), FAS 112 long-term disability and FAS 112 workers compensation. Please see Attachment A to this response for a copy of the full actuarial study, dated October 1, 2010, which supports the 2011 test year amounts. The amounts reported on these actuarial studies are total NSPM Company.

Attachment B to this response is a reconciliation of these total Company amounts to the total net adjusted North Dakota jurisdictional amount. Also note that NSPM has received an update to 2011 actual actuarial costs from Towers Watson by report dated May 10, 2011, including actual discount rates and experience information. The May 10 report is included as Attachment C to this response.

Attachments A and C are marked as "Non-Public" in their entirety, as they contain proprietary information of a privileged nature that the Company considers to be Trade Secret.

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**PUBLIC DOCUMENT**  
**TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED**

Witness: Mark P. Moeller  
Preparer: Todd M. Degrugillier  
Title: Manager, Employee Tax and Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: June 15, 2011

**PUBLIC DOCUMENT**  
**TRADE SECRET INFORMATION--NON-PUBLIC DATA EXCISED**

Northern States Power Company, a Minnesota corporation  
Electric Utility - North Dakota  
Test Year Ending December 31, 2011

Case Nos. PU-10-657 / PU-11-55  
Data Request AS-2-RR-151  
Attachment A - Multiple Pages

**Towers Watson Actuarial Study**  
**October 1, 2010**  
**2011-2015 Pension Expense Estimates**

***[TRADE SECRET BEGINS***

***TRADE SECRET ENDS]***

(\$)	FAS 87 Qualified Pension			FAS 106 Expense			FAS 87 Nonqualified Pension			FAS 112 LTD			FAS 112 WC			Total		
	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)
Legal Entity																		
NSP&N	12,394,000	10,127,000	2,267,000	11,561,000	11,833,000	(272,000)	504,000	504,000	0	1,578,000	1,728,000	(150,000)	1,088,000	578,000	510,000	27,175,000	23,970,000	3,205,000
NSP&N Nuclear	877,000	1,125,000	(248,000)	(89,000)	(84,000)	(5,000)	122,000	118,000	4,000	87,000	57,000	30,000	-	-	-	25,000,000	1,149,000	18,851,000
RES	21,632,000	19,998,000	1,634,000	824,000	793,000	31,000	2,512,000	3,354,000	(842,000)	1,885,000	1,185,000	700,000	1,088,000	578,000	510,000	54,113,000	48,131,000	5,982,000
Total Cost from Towers Watson	35,003,000	31,250,000	3,753,000	12,467,000	12,332,000	135,000	4,138,000	3,976,000	162,000	1,665,000	1,185,000	480,000	1,088,000	578,000	510,000	2,396,000	824,000	1,572,000
Amount to NSP&N O&M Electric																		1,311,555
Remove SERP																		69,833
Total NSP&N O&M Electric Excluding SERP																		1,381,388
Total After Interchange Agreement																		1,311,555
Total Adjustment to NSP&N O&M Electric ND																		69,833

**PUBLIC DOCUMENT**  
**TRADE SECRET INFORMATION--NON-PUBLIC DATA EXCISED**

Northern States Power Company, a Minnesota corporation  
Electric Utility - North Dakota  
Test Year Ending December 31, 2011

Case Nos. PU-10-657 / PU-11-55  
Data Request AS-2-RR-151  
Attachment C - Multiple Pages

**Towers Watson Report**  
**May 10, 2011**  
**2011 Valuation Results and 2012-2016 Contribution and Cost Estimates**

***[TRADE SECRET BEGINS***

***TRADE SECRET ENDS]***

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-196

Date Received: April 29, 2011

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Question:

Subject: Pension

Please provide an explanation of the procedure used to develop the 2011 budget for pensions.

Response:

The Company developed its initial 2011 pension budget in May 2010 following the timeline of the overall corporate budget. This budget was developed using a combination of year-end assumptions from December 31, 2009 and updated demographic information. The Company then updated the budget and related assumptions in September 2010 to address significant market changes, most notably the decrease in discount rates in the second and third quarters of 2010 which led to an update of the discount rate from 6.00 percent to 5.25 percent. Other changes included updated pension contributions and assumed asset return for the current year. This was the final budget that was used as the basis for this rate case filing. Note that final updated information that establishes actual 2011 pension cost, including an update of the discount rate from 5.25 percent to 5.50 percent, has been obtained from Towers Watson, the Company's independent actuary, in a report dated May 10, 2011. This report was included as the Non-Public Attachment C to the Company's response to Blue Ridge Consulting's Data Request No. AS-2-RR-151 submitted in this proceeding.

Please see Attachment A to the Company's response to Blue Ridge Consulting's Data Request No. AS-RR-197 submitted in this proceeding for the actuarial workpaper and assumptions used for the 2011 test year budget for pension cost.

---

Witness: Mark P. Moeller  
Preparer: Todd M. Degrugillier  
Title: Manager, Employee Tax and Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: June 15, 2011

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-328

Date Received: June 24, 2011

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Question:

Subject: Pensions

Follow up to Data Request AS-2-RR-151: The Company's adjustment for pension and benefits of \$68,833 [which includes qualified pension, non-qualified pension (less the SERP portion), postretirement benefits (FAS 106), FAS 112 long-term disability, and FAS 112 workers compensation] is based upon the difference between the original 2011 budget and the 2011 test year amount from the 2011 Towers Watson estimated expenses. Please update this adjustment for the ND electric jurisdiction using the format in AS-2-RR-151 Attachment B based on the update to the actual 2011 actuarial costs from Towers Watson dated May 10, 2011.

Response:

Please see Attachment A to this response for the North Dakota electric jurisdiction benefit adjustment based on a comparison of the original 2011 budget and the update to the 2011 actuarial costs received from Towers Watson on May 10, 2011.

Using the revised costs provided on May 10, 2011, the Company has calculated an adjustment from the original budget of -\$12,005. In our filed case, we made an adjustment of \$68,833 using the Towers Watson estimates from October 1, 2010. . We would therefore recommend a reduction in expense from our filed case of -\$80,838.

---

Preparer: Todd M. Degrugillier

Title: Manager, Employee Tax and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: July 13, 2011



**Backup Summary for Correction to Mercury Sorbent Expenses for Sherco 3  
Reflecting the Credit for SMMPA Sharing and Interchange Agreement Impact  
For 2011**

<b>Change to FERC 502</b>	<b>Account</b>	<b>Starting Totals</b>
Currently in Budget	230934.714080	4,180,000
SMMPA Credit in Budget	230934.714081.90	(1,671,568)
<b>Net</b>		<b>2,508,432</b>
New Budget Amount	230934.714080	2,400,000
New SMMPA Credit	230934.714081.90	(959,752)
<b>Net</b>		<b>1,440,248</b>
Adjustment with Interchange Agreement Impact		<u>(895,946)</u>

<b>36 mth Interchange Demand Allocator</b>			<b>83.8756%</b>	
<b>Jurisdictional Allocators</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	<b>Whisl</b>
<b>Demand</b>	88.4924%	5.8107%	5.5779%	0.1190%

<b>Net Correction To Production O&amp;M</b>	<b>(792,844)</b>	<b>(52,061)</b>	<b>(49,975)</b>	<b>(1,066)</b>
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*A14-2*

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-342

Date Received: June 29, 2011

REVISED

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Question:

Subject: Mercury Sorbent

Please provide the total NSPM company and ND jurisdictional costs for mercury sorbent by power plant for 2009, 2010, and included in the 2011 test year budget.

Response:

Please see Attachment A to this response for the mercury sorbent cost detail for Northern States Power Company-Minnesota and the North Dakota jurisdiction, electric utility, by plant, by year, including the 2011 budget adjustment discussed in the Direct Testimony of Mr. John Felling.

Variations in year-to-year comparison of mercury sorbent usage reflect the testing and evaluation of the activated carbon injection systems at Sherco Unit 3 and the King plant discussed in Ms. Pamela Graika's Direct Testimony. Standards established by state and federal regulators will require usage of greater amounts of mercury sorbent than used during the testing/evaluation period.

REVISED:

We reviewed our response to this data request upon receiving Data Request No. AS-RR-355. As a result, we have modified Attachment A to this response and also included the modified version in our response to AS-RR-355.

---

Preparer: Mary Dupre

Title: Senior Rate Analyst

Department: Revenue Requirements North

Telephone: 612-330-5862

Date: July 8, 2011

REVISED: July 15, 2011

Northern States Power Company, a Minnesota corporation  
Electric Utility - State of North Dakota Jurisdiction

Case No. PU-10-657 & 11-55  
Data Request AS-RR-342 - REVISED  
Attachment A - REVISED

**Mercury Sorbent Costs**

	NSPM company		ND jurisdictional	
	Sherco	King	Sherco	King
2009	\$0	\$0	\$0	\$0
2010	\$753,483	\$0	\$35,154	\$0
2011	\$2,508,432	\$3,744,000	\$122,255	\$182,474
2011 adj	-\$895,946	\$0	-\$52,061	\$0
2011 total	\$1,612,486	\$3,744,000	\$70,194	\$182,474

Note: This revised attachment is also included as Attachment A to AS-RR-355

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-167

Date Received: April 29, 2011

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Question: Subject: Qwest Pole Replacements

Please respond to the following questions/requests concerning the calculation of the adjustment cost for the Qwest Pole Adjustment:

- a. Is the total adjustment of \$625,000 for NSP(MN) based on 700 replacements per year?
- b. Please provide the basis for the \$892.86 per pole line reattachment (\$625,000 adjustment divided by 700 pole replacements).
- c. Please provide both the number of pole replacements and total cost of line reattachments actually realized for NSP(MN) total company in years 2007 through 2010.
- d. Please provide both the number of pole replacements and total cost of line reattachments actually realized for the ND jurisdiction in years 2007 through 2010.
- e. Please provide the amount in the 2011 budget that had been included for line reattachments based on Qwest pole replacements (prior to the adjustment).
- f. Is the adjustment based on total pole replacements anticipated or the increase of pole replacements over the base norm?

Response:

- a. The \$625,000 O&M adjustment is for the overall NSPM Company level, but is to be applied to the incremental number of pole transfers driven by Qwest's formal inspection program over and above the average annual "base" transfers the Company experienced prior to 2009 when our average number of Qwest transfers first started increasing. We have determined the "base" amount for Qwest transfers to be approximately \$109,000 annually. So, it is the total "base"

plus “incremental”, or \$734,000, that is the basis for the 700 annual replacements (transfers), equating to approximately \$1,049 O&M per pole transfer.

- b. As indicated in a. above, the Company has determined the average O&M cost per Qwest pole transfer to be \$1,049. The basis for this amount is our actual average O&M cost per transfer experienced (as conducted by Xcel Energy internal line resources) for the years 2006 through 2009.
- c. Please note that we did not set-up a mechanism to specifically track the volume and spend associated with Qwest “pole transfers” prior to 2010. As a result, our method for capturing this information for the years prior to 2010 have had to rely on work orders “titles” and may not necessarily be comprehensive. The following table provides the total O&M spend and quantity of Qwest transfers for NSPM Company from 2007 through 2010:

**NSPM Company Qwest Transfer Actuals**

	2007	2008	2009	2010
O&M	\$106,127	\$107,937	\$189,970	\$875,178
Poles	111	111	163	0

- d. The following table provides the total O&M spend and quantity of Qwest transfers for the North Dakota Jurisdiction from 2007 through 2010:

**North Dakota Qwest Transfer Actuals**

	2007	2008	2009	2010
O&M	\$983	\$161	\$1,786	\$0
Poles	1	1	2	0

- e. Per our answer in part a. above, the original “base” budget (prior to adjustment) for Qwest pole transfers included in the 2011 test year for NSPM Company level is approximately \$109,000.
- f. Yes. The adjustment of \$625,000 for the NSPM Company level is based on the increase of pole replacements (transfers) over the base norm number of transfers.

---

Preparer: Joseph P. Mansur  
Title: Manager, Planning & Operational Performance  
Department: Construction Ops Maintenance  
Telephone: (612) 229-2286  
Date: June 6, 2011

A11-4

From: Marul, Joseph P  
To: Franer, Thomas E  
Cc:  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

Hi Tom, We have about 6000 "Like" amount of pole transfers for Qwest in prior years, but this has been more on the level of approximately 75 poles per year. Starting this year, we are now looking at 700 pole transfer requests per year listed on a new formal inspection program that Qwest has recently undertaken. We do not account for this significant spike in either this year's budget nor in the 2011/2012 Budgets.

From: Franer, Thomas E  
Sent: Wednesday, September 29, 2010 1:40 PM  
To: Marul, Joseph P  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

Thanks for the update. In talking with Pat Silbert this morning she was wondering why this is considered an incremental cost for the rate case? Is it a new cost beginning in 2011 or did Qwest notify us that the annual number of poles being replaced was increasing over prior years normal levels and therefore the current level in the 2011 and 2012 budgets was too low?

Thanks

Tom

From: Marul, Joseph P  
Sent: Wednesday, September 29, 2010 1:26 PM  
To: Franer, Thomas E  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

Hi Tom: I need to revise the estimated percent split between MN, ND, and SO

Total NSP/Qwest pole attachments = 67,889

MN Attachments = 53,000 (84.0%)  
ND Attachments = 1,300 (2.0%)  
SO Attachments = 2,100 (3.1%)

From: Marul, Joseph P  
To: Franer, Thomas E  
Cc: Fran, Stephen R, Gagne-Gosselin, Elizabeth H  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

Hi Tom, please see my responses to your questions in red below

From: Franer, Thomas E  
Sent: Monday, September 27, 2010 1:58 PM  
To: Marul, Joseph P  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

not afternoon Joe,

... putting the rate case adjustment together for this item and have a couple questions or clarification points.

1<sup>st</sup> Is this incremental cost estimate 100% assignable to the distribution operations group in MN or are there some costs for ND and SO as well? If they are split do you have a breakdown by state? - the 1% of the number for NSP/M Company, including any transfer requests we may get from Qwest for our service territory in ND and SO. According to our records, the annual cost of the replacement of 67,889 Qwest poles in MN/ND/SO at which approximately 63,000 of these attachments are within the State of Minnesota. So, going back to number of attachments in each state, approximately 57% of the attachments (38,500) would be assigned to MN.

2<sup>nd</sup> Do you have a breakdown for this estimate by object account or at least type of costs (i.e. indirect labor, materials, contractor, etc.) Since this is incremental to the 2011 Budget base, we do not have this broken down specifically within the budget panels. Also, at the same time, we have not decided on whether the bulk of these replacement requests will be done by local repair companies, or a combination of each. However, the total requests have been done by local crews and break down as follows: Labor = 67.7%, Materials = 12.6%, Contract = 2.0%, Transportation = 16.2%.

3<sup>rd</sup> Is this cost to NSP to transfer from Qwest poles to NSP poles or to re-aging our equipment on new Qwest poles? I am still a little fuzzy on what activity is actually happening. I will refer to the fact sheet attached to existing Qwest poles to see if Qwest poles (re-aging the existing poles).

Thanks

Tom Krueger

From: Marul, Joseph P  
To: Franer, Thomas E, Franer, John A, Silbert, Patricia S  
Cc:  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

From: Marul, Joseph P  
Sent: Tuesday, September 21, 2010 4:40 PM  
To: Franer, Thomas E  
Cc: Franer, John A, Franer, Stephen R, Gagne-Gosselin, Elizabeth H, Gagne-Gosselin, Patricia S, Pelling, John M, Carillo, Shari M  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

If the electrical facilities involved in these transfers will vary from pole to pole. Could be as simple as transferring a secondary service to an existing or as complex as building a 30 degree three-phase primary substation (backbone) structure. Possible facility transfers would include any one or a combination of the following:

- Single phase primary conductor transfer (including neutral wire, insulators, pin, conductor hardware)
- Two-phase primary conductor transfer (including neutral wire, crossarm, insulators, pins, conductor hardware, associated hardware)
- Three-phase primary conductor transfer (including neutral wire, crossarm, insulators, pins, conductor hardware, associated hardware)
- Secondary line conductor transfers (single-phase, two-phase, or three-phase)
- Service conductors (single-phase, two-phase, or three-phase)
- T-locks/locks
- Arresters
- Transformers
- Various other electrical equipment

From: Marul, Joseph P  
Sent: Tuesday, September 21, 2010 4:20 PM  
To: Franer, Thomas E  
Cc: Franer, John A, Franer, Stephen R, Gagne-Gosselin, Elizabeth H, Gagne-Gosselin, Patricia S, Pelling, John M, Carillo, Shari M  
Subject: RE: 2010-149 Elec Case: Info needed to do Qwest pole budget adjustment -2011 and beyond

Also, the unbilled incremental Distribution O&M associated with Qwest pole transfers we would like to include in your testimony in \$625,000 for 2011 and then increased 3% for each successive year for a total of \$1,250 in 2012. This unbilled O&M is based on NSP/M Distribution transferring our electric business attached to Qwest owned poles assuming an estimated 700 Qwest pole replacement annually. The amount of Distribution O&M would be budgeted under FERC account 383 - Dist. Mkt. of Overhead Lines.

Let me know if you need any further information or have any questions. Thanks,

Joe Marul

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-166

Date Received: May 3, 2011

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Question: Subject: Qwest Pole Replacements

Please provide the source documentation informing NSP that the increase in Qwest pole replacements for 2011 will be normative in future years.

Response:

Please see Attachment A for a memo from Qwest, dated September 7, 2010, informing the Company of Qwest's formal pole inspections and replacement program being initiated in 2008 for their operations in Minnesota. Qwest also indicates their program will be an annual program conducted on a "10 year perpetual inventory and inspection cycle". The memo goes on to acknowledge that Qwest's pole replacement volume has increased the past two seasons (due to their new formal program) and that Qwest expects a similar pole replacement rate (requiring Xcel Energy transfer of facilities) in 2011 as was experienced in 2010. Additionally, representatives from the Company and Qwest meet on a routine basis throughout the year to review the progress of pole transfer activities requested by both companies. At these meetings, Qwest has communicated verbally as to the establishment of their 10 year inspection/replacement program as well as the approximate incremental volume of Qwest-owned pole replacements and associated transfer-requests to Xcel Energy that would result.

Even though this memo is specific to Qwest's Minnesota Operations, we have been informed that this same type of program is being administered within Qwest service territory in the state of North Dakota as well.

---

Preparer: Joseph P. Mansur  
Title: Manager, Planning & Operational Performance  
Department: Construction Ops Maintenance  
Telephone: (612) 229-2286  
Date: May 25, 2011

Local Network  
6244 Cedar Avenue South  
Richfield, MN 55423

September 7, 2010



John Cesare  
Qwest Engineering Manager  
6244 Cedar Ave S  
Richfield, MN 55423  
612-861-8158

Tom Breuckman  
Xcel Energy  
825 Rice St  
St. Paul, MN 55117  
651-229-2224

Tom,

Thank you for your recent request for information regarding Qwest's projected pole replacement volumes for calendar year 2011.

As you know, Qwest is committed to providing the highest level of safety and security to those who work on or around our equipment. Given this, Qwest operations in Minnesota embarked on a 10 year perpetual inventory and inspection cycle in 2008. Pole replacement volumes continue to be driven by storm damages, common requirements to relocate for road projects and private right of way requests, and fair wear and tear found during inspection.

Qwest's pole replacement volume had increased in the Metropolitan MN area the past two seasons; however we expect a consistent replacement rate from 2010 to 2011, based upon high level forecast of the items previously stated.

As always, Qwest will continue to work with Xcel to create the most professional, safe and proficient work environment. If there are any questions please call me.

Sincerely,

A handwritten signature in black ink, appearing to be 'John Cesare', written over the word 'Sincerely,'.

John Cesare

FERC	Reg Bus Area	Business Unit Hierarchy	IS/BS Rpt Desc	FERC Description	2011 Incremental Cost Estimate	Allocators	MN	ND	SD	WHISL	CK
593	Utilities Group	MN Utility President	Distribution	Dist Mtc of Overhead Lines	625,000		587,500	18,125	19,375		-
Total Incremental Estimate					<u>625,000</u>		<u>587,500</u>	<u>18,125</u>	<u>19,375</u>		-

94.00% 2.90% 3.10%  
 Estimated split based upon poles in state to total Qwest poles.  
 Per Joe Mansur e-mail

- Non Public Document – Contains Trade Secret Data  
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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-353

Date Received: July 12, 2011

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Question:

Reference: AS-RR-155 - Based on information provided by the Company, 2010 Actual for Uncollectibles (FERC Acct 904) is \$11,575,400, while the Company budget for 2011 is \$15,099,518. (see AS-RR-155 Att A to D.xls, spreadsheet tab "O&M Bud"). Please explain the rationale for increasing the 2011 Budget by 30% from the actual levels in 2010.

Response:

The Company did not produce the 2011 bad debt budget by increasing the 2010 actual calendar year level of bad debt. Rather, the 2011 Bad Debt Budget was created during the Spring of 2010 and was primarily developed based on actual bad debt results experienced from April 2009 through March 2010.

As noted in response to AS-RR-155, the budget values presented in that response for 2011 do not include regulatory adjustments which were made to improve the accuracy of the 2011 test year. In preparing the revenue requirement for the 2011 Minnesota rate case, the Company reviewed the overall 2011 budget to assure its accuracy. As part of that review, the forecast of revenues and forecast fuel costs were lowered. In combination, those lower forecasts also resulted in a lower 2011 projected bad debt expense. The same adjusted 2011 budget was used in preparing the North Dakota 2011 rate case. The bad debt expense reduction on an NSPM total Company basis was \$822,000, of which the North Dakota jurisdictional portion of the reduction was \$46,000. The adjusted 2011 bad debt expense budget amounts included in the North Dakota test year are \$778,000 related to customer accounts plus \$8,000 related to damage claim third party billings for a total bad debt adjusted budget of \$786,000.

---

Preparer: Charles E. Anderson / John M. Felling  
Title: Director, TTC Business Area Finance / Rate Consultant  
Department: TTC Finance / Revenue Requirements North  
Telephone: (303) 294-2360 / 612-330-6539  
Date: July 26, 2011

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-352

Date Received: July 12, 2011

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Question:

Reference: AS-RR-155 - Based on information provided in Northern States Power Company (Minnesota)'s FERC Form 1 for 2010, Uncollectibles (Acct 904) for Company total – Electric is \$11,575,400, while the Budget Amount for 2010 is \$17,221,258 (see AS-RR-155 Att A to D.xls, spreadsheet tab "O&M Bud"). Please explain the cause(s) for this significant variance.

Response:

FERC 904 reflects actuals, while the 2010 Budget was based primarily on actual revenues and write-off expense. This approach was consistent with the Company's methodology, which used historic results in order to budget future bad debt expense. Based on that information, bad debt expense was budgeted at 0.54%. The reasonableness of that forecast was initially confirmed by the 2009 actuals, which were at 0.54 percent.

However, the 2010 year-end bad debt results were better than the historic period that was used to develop the budget. The lower actual bad debt expense in 2010 of \$5.6 million in FERC 904 is primarily due to three factors. These factors were less billed commodity revenues than budgeted, a favorable change to the bad debt reserve during the year, and less in write-offs than anticipated. For NSPM, the three factors primarily reflect: a) lower commodity prices as compared to recent prior periods, b) favorable changes in economic conditions, c) greater attention on collection related activities by Customer Care, and d) increased customer assistance payments.

The information in Table 1 below reflects that \$5.3 million of the variance in FERC 904 is related to the activities of the Customer Care Business Organization for commodity and non-commodity bad debt expense.

Table 1

Total Bad Debt Expense	2010 Actual	2010 Budget	Difference
NSP MN Electric Commodity Bad Debt Expense (1)	\$ 11,067,263	\$ 16,280,016	\$ (5,212,753)
NSP MN Electric Non Commodity Bad Debt Expense (1)	44,328	122,232	(77,904)
NSP MN Electric Bad Debt Expense (2)	463,809	819,009	(355,200)
Total NSP MN Bad Debt Expense FERC 904	\$ 11,575,400	\$ 17,221,257	\$ (5,645,857)
Billed Electric Commodity Revenue	\$ 2,956,377,920	\$ 3,271,036,161	\$ (314,658,242)
Variance Due to Revenue			\$ (1,566,061)
Variance Due to Less Write Offs and Favorable Reserve Change			(3,646,692)
Total Commodity Bad Debt Expense variance supported by Customer Care			\$ (5,212,753)

(1) NSP MN electric bad debt expense relating to customer accounts supported by Customer Care.

(2) Made up of bad debt expenses managed outside the Customer Care organization (example: damage claim third party billing).

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Preparer: Charles E. Anderson  
 Title: Director, TTC Business Area Finance  
 Department: TTC Finance  
 Telephone: (303) 294-2360  
 Date: July 26, 2011

A15-3

311 Budget Economic Development Donations

Adjustment moves 50% of the Economic Development Donations that are charged to below the line regulatory expense into the O&M costs for recovery. Regulatory precedence permits cost sharing of these ED donations equally between Rate Payers and Shareholders. These donations are not charitable in nature but are made to ED oriented organizations.

Utility	FERC	Align	Rollup	24	Functional Class	RL Account Description	Location	Labor	2011 Budget	MIN	ND	SD	WHSI	Object Account	Financial Business Unit
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	2,287.00	2,287.00				723633 - Charitable Contributions	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	494.00	494.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	3,868.00	3,868.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	1,372.00	1,372.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	65,127.00	65,127.00				723637 Economic Development-Contrib	811203 Econ Develop-Common MN SA9122
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	North Dakota	Non-Labor	64,029.00	64,029.00				723637 Economic Development-Contrib	804103 Com Gov & Reg Rel ND AG921
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	South Dakota	Non-Labor	97,873.00	97,873.00				723637 Economic Development-Contrib	805002 Com Gov Reg Relation SD AG921
Electric	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	9,127.00	9,127.00				723637 Economic Development-Contrib	805002 Com Gov Reg Relation SD AG921
								Total Electric	248,942.00	75,913.00	64,029.00	107,000.00			
								Cost Sharing Calculation:							
								50% of Below The Line Donations Qualifying For Recovery State of Min	37,956.50	37,956.50	64,029.00	50,000.00			
								100% of Below The Line Donations Qualifying For Recovery State of ND	64,029.00	64,029.00					
								50% of first 3100% of Below The Line Donations Qualifying For Recovery State of SD	50,000.00			50,000.00			
								Total Electric Adjustment	151,985.50	37,956.50	64,029.00	50,000.00			

Recalls from SD Gas

Utility	FERC	Align	Rollup	24	Functional Class	RL Account Description	Location	Labor	2011 Budget	MIN	ND	SD	WHSI	Object Account	Financial Business Unit
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	213.00	213.00				723633 - Charitable Contributions	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	65.00	65.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	65.00	65.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	46.00	46.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	65.00	65.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	362.00	362.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	128.00	128.00				723634 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL G	Minnesota	Non-Labor	6,073.00	6,073.00				723637 Economic Development-Contrib	811203 Econ Develop-Common MN SA9122
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL G	North Dakota	Non-Labor	5,971.00	5,971.00				723637 Economic Development-Contrib	804103 Com Gov & Reg Rel ND AG921
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	9,127.00	9,127.00				723637 Economic Development-Contrib	805002 Com Gov Reg Relation SD AG921
Gas	426.1	MIN	Utility	President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	19,127.00	19,127.00				723637 Economic Development-Contrib	805002 Com Gov Reg Relation SD AG921
								Total Gas	12,044.00	7,077.00	5,971.00				
								Cost Sharing Calculation:							
								50% of Below The Line Donations Qualifying For Recovery State of Min	3,026.50	3,026.50	5,971.00	8,271.00			
								100% of Below The Line Donations Qualifying For Recovery State of ND	5,971.00	5,971.00					
								Total Gas Adjustment	8,027.50	3,026.50	5,971.00				

Recalls to SD Electric

A18-2

**NORTHERN STATES POWER CO d/b/a XCEL ENERGY**  
**Charitable Contributions / Donations**  
**YEAR ENDED 12-31-11**  
**FERC 426.1**

<b>ELECTRIC</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	<b>WHLSL</b>
<i>Corporate Contributions</i>					
Total Corporate Contributions	\$267,476	\$234,519	\$16,902	\$16,055	\$1
<i>Focus Area Grants</i>					
Total Focus Area Grants	\$ 1,980,752	\$ 1,736,693	\$ 125,162	\$ 118,893	\$ 4
<i>Matching Gifts Program</i>					
Total Matching Grants	\$ 224,673	\$ 196,990	\$ 14,197	\$ 13,486	\$ 0
<i>United Way</i>					
Total United Way	\$ 862,745	\$ 756,442	\$ 54,516	\$ 51,785	\$ 2
<i>Other Donations</i>					
Total Electric	\$ 4,021,067	\$ 3,757,263	\$ 263,216	\$ 225,253	\$ 8
<b>MN &amp; ND - 50% Electric Inclusion</b>	<b>\$2,010,244</b>	<b>\$1,878,632</b>	<b>\$131,608</b>	<b>\$0</b>	<b>\$4</b>

<b>GAS</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>
<i>Corporate Contributions</i>			
Total Corporate Contributions	\$24,943	\$22,509	\$2,434
<i>Focus Area Grants</i>			
Total Focus Area Grants	\$184,714	\$ 166,688	\$ 18,026
<i>Matching Gifts Program</i>			
Total Matching Grants	\$211,187	\$ 196,990	\$ 14,197
<i>United Way</i>			
Total United Way	\$80,455	\$ 72,603	\$ 7,852
<i>SEE Other Donations</i>			
Total Gas	\$ 374,230	\$ 339,690	\$ 34,540
<b>MN &amp; ND 50% Gas Inclusion</b>	<b>\$187,115</b>	<b>\$169,845</b>	<b>\$17,270</b>

<b>Electric - PTD Adjustment</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>check</b>
Allocated	1,149,457	237,008	623,779	
	\$ 1,149,457	\$ 237,008	623,779	\$ 2,010,244
PTD Allocator	57.1800%	11.7900%	31.0300%	



**RECEIVED**

**VIA ELECTRONIC FILING AND U.S. MAIL**

DEC 29 2008

December 22, 2008

**PUBLIC SERVICE COMMISSION**

Darrell Nitschke  
Executive Secretary and Director of Administration  
North Dakota Public Service Commission  
State Capital  
600 East Boulevard  
Bismarck, ND 58505-0480

Re: IN THE MATTER OR 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 Mr. Nitschke:

Attached is a Settlement Agreement dated December 22, 2008 between Northern States Power Company, a Minnesota corporation operating in North Dakota and the Advocacy Staff of the North Dakota Public Service Commission ("Commission") in the above referenced matter. It replaces entirely the Settlement Agreement dated December 17, 2008 and the Amendment to Settlement Agreement dated December 19, 2008, which have been combined into this replacement Settlement Agreement.

We have also included a legislative version of the Settlement Agreement so that the Commission can readily determine the changes made to the December 17<sup>th</sup> Settlement Agreement. To avoid confusion, we note that we have not provided legislative-format versions of the schedules, but rather are providing schedules that simply match the terms of this combined Agreement.

The Parties respectfully request the Commission to approve the Settlement Agreement and are available to provide any additional information the Commission may require.

Please contact us with any questions.

believe this approach is reasonable. Attachment D shows these costs.

**I. Renewable Development Fund**

For purposes of determining the overall revenue requirement, the Parties agree to remove the test year expenses related to Renewable Development Fund research and development grants and disbursements. The adjustment reduces the rate increase request by \$170,000.

**J. Charitable Contributions**

For purposes of determining the overall revenue requirement, the Parties agree to remove the Company's costs associated with 50 percent of its charitable contributions. The adjustment reduces the rate increase request by \$86,000.

**K. Incentive Compensation Cap**

For purposes of determining the overall revenue requirement, the Parties agree to a reduction in the cap on incentive compensation from the Company's proposed level of 25 percent to 15 percent of base salary. Accordingly, costs associated with the incentive compensation of the employee's total compensation is capped at 15 percent of an individual's base salary, and costs for incentive compensation in excess of 15 percent of the employee's base salary will not be included in rates. The adjustment reduces the rate increase request by \$35,000.

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-350

Date Received: July 12, 2011

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Question:

Subject: Payroll Taxes

Follow up to AS-RR-192

- a. Did the Company include payroll taxes for the 2011 budget?
- b. Are payroll taxes included in the test year for incentive compensation?
- c. How much are the payroll taxes for the \$1,329,426 included in the test year for incentive compensation?
- d. Have the payroll taxes for the amount excluded for incentive compensation (\$512,569) been removed from the test year?
- e. How much are the payroll taxes for the \$512,569 excluded incentive compensation in the test year?
- f. Please provide the workpaper calculating the payroll taxes for both the included and excluded amounts for incentive compensation.

Response:

- a. Yes, estimated payroll taxes are included in the 2011 budget. The total amount of payroll taxes assigned to North Dakota is identified on 2011 Budget Workpaper O1-2.
- b. Incentive pay is one of the labor components included in the development of the payroll tax labor additive rate used to develop the payroll tax budgeted cost for the period. Payroll taxes are calculated as a labor additive percentage on budgeted productive labor and not on the individual labor components.
- c. There is not a specific calculation of payroll taxes directly associated with incentive pay amount. Therefore no specific calculation is made on the \$1,329,426 incentive amount. An estimate of the Medicare payroll taxes associated with the \$1,329,426 incentive would be \$19,277 ( $\$1,329,426 \times .0145$  [Medicare Tax Rate]). Regarding Social Security payroll taxes, an estimate of the maximum associated with the incentive amount would be \$82,424 ( $\$1,329,426 \times .062$  [Social Security Tax Rate]). This calculation assumes no Social Security maximum has occurred and does not include any state

- unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with incentive pay would be between zero and \$82,424.
- d. The incentive adjustment did not include any adjustment for estimated payroll taxes.
  - e. As discussed in the response to section d. above, no calculation was made in the adjustment calculation. An estimate of the Medicare payroll taxes associated with the \$512,569 excluded incentive would be \$7,432 ( $\$512,569 \times .0145$  [Medicare Tax Rate]). Regarding Social Security payroll taxes, an estimate of the maximum associated with the excluded incentive amount would be \$31,779 ( $\$512,569 \times .062$  [Social Security Tax Rate]). This calculation assumes no Social Security maximum has occurred and does not include any state unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with excluded incentive would be between zero and \$31,779.
  - f. The calculation of the estimated stand alone payroll taxes for the amounts included in the test year and the amounts excluded from the test year are identified in the answers to subparts c and e to this Response.
- 

Preparer: Thomas E Kramer  
Title: Principal Rate Analyst  
Department: Revenue Requirements - North  
Telephone: 612-330-5866  
Date: July 13, 2011

**NSP Minnesota Company Base Incentive Compensation  
Amount Paid Compared to 100% of Target Amounts**

\$ in 000

<b>Year</b>	<b>Amt. Paid</b>	<b>100% of Target</b>	<b>% Paid to Target</b>
2005	\$5,046	\$13,580	37%
2006	\$16,334	\$12,773	128%
2007	\$14,720	\$12,665	116%
2008	\$0	\$13,655	0%
2009	\$27,891	\$24,708	113%
<b>4 Year Average Payout ( 2009 through 2006)</b>			<b>89%</b>
<b>4 Year Average Payout ( 2008 through 2005)</b>			<b>70%</b>

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-140

Date Received: April 28, 2011

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Question:

Reference: Annual Incentive Compensation

Reference: Reed Direct, Exhibit (JHR-1) Schedule 2

Please provide the dollar amount of incentive compensation paid, 100% of Target, and % Paid to Target using the same format and basis used in Schedule 2 for 2010.

Response:

Please see Attachment A to this response, which is an updated Schedule 2 to Ms. Reed's Direct Testimony.

The four year average payout including 2010 dropped to 83% from the 89% indicated in the originally-filed Exhibit\_\_\_(JHR-1), Schedule 2, which is below the 85% requested in rates. The reason is because the 2006 program year had a 128% payout and it has been "replaced" in the 4 year average with the 2010 program year which had a 103% payout.

---

Witness: Jill H. Reed

Preparer: Carol Mikita / Kris Lindemann

Title: Principal Consultant / Key Financial Consultant

Department: Executive Compensation / Payroll and Benefits Accounting

Telephone: 612-330-2911 / 612-330-5508

Date: June 8, 2011

**NSP Minnesota Company Base Incentive Compensation  
Amount Paid Compared to 100% of Target Amounts**

\$ in 000

<b>Year</b>	<b>Amt. Paid</b>	<b>100% of Target</b>	<b>% Paid to Target</b>
2005	\$5,046	\$13,580	37%
2006	\$16,334	\$12,773	128%
2007	\$14,720	\$12,665	116%
2008	\$0	\$13,655	0%
2009	\$27,891	\$24,708	113%
2010	\$28,218	\$27,283	103%
<b>4 Year Average Payout ( 2010 through 2007)</b>			<b>83%</b>
<b>4 Year Average Payout ( 2009 through 2006)</b>			<b>89%</b>
<b>4 Year Average Payout ( 2008 through 2005)</b>			<b>70%</b>

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-351

Date Received: July 12, 2011

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Question:

Subject: Payroll Taxes

Follow up to AS-RR-191, please provide the 2011 Corporate and business area performance goals.

Response:

The 2011 corporate and business area Key Performance Indicators (“KPIs”) are included as Attachment A to this response.

---

Preparer: Vicki McCarl

Title: Strategy and Planning Consultant

Department: EM Business Planning

Telephone: 303-294-2308

Date: July 18, 2011

2011 Key Performance Indicators  
 Corporate

KPI Name	2011			Weight	Definition
	Threshold 50% Level	Target 100% Level	Maximum 150% Level	Empl	
Demand Side Management	661 GWh	760 GWh	859 GWh	16.66%	Achieve targeted GWh reduction through DSM and CIP programs in Minnesota, Colorado, and New Mexico. Achievement of 662 through 759 GWh will be prorated between 50% and 100%. Achievement of 761 through 858 GWh will be prorated between 100% and 150%. There will be no payout greater than 150%. The threshold is set at the total of the regulatory goals in Minnesota, Colorado and New Mexico. Achieving no more than the regulatory goal results in a 50% incentive payout.
Efficiency & Technology Projects	Achieve 7 of 12 Projects	Achieve 9 of 12 Projects	Achieve 12 of 12 Projects	16.67%	This KPI encompasses completing a number of efficiency and technology projects. The 12 projects are listed on the Efficiency Technology Projects tab and are equally weighted. Threshold (50%) Payout: Complete 7 of the 12 projects. Target (100%) Payout: Complete 9 of the 12 projects. Maximum (150%) payout: Complete all 12 projects. If 8 projects are completed, payout will be 75%. If 10 or 11 projects are completed, payout will be prorated between 100% and 150%. There will be no payout greater than 150%.
OSHA	1.91	1.74	1.48	16.67%	The number of on-the-job OSHA recordable injuries for all company employees related to a common exposure base of 100 full-time workers. (Calculation = Number of OSHA Recordable Cases x (100 x 2000) / Annual Hours Worked). Threshold is set with a 10% spread between target and threshold. Even though the threshold is 0.01 worse than 2010 performance, the number of injuries is 220 compared to 221 injuries in 2010.
DART	1.08	0.98	0.83	16.66%	The number of on-the-job Days Away and Restricted Time recordable injuries for all company employees related to a common exposure base of 100 full-time workers. (Calculation = Number of Days Away and Restricted Time Recordable Cases x (100 x 2000) / Annual Hours Worked). Threshold is set with a 10% spread between target and threshold. Even though the threshold is 0.01 worse than 2010 performance, the number of injuries is 124 compared to 125 injuries in 2010.
Earnings per Share	\$1.65	\$1.70	\$1.75	33.34%	Continuing Operations diluted earnings per share. Payout level will be at CEO discretion. EPS target on corporate scorecard published for employees is the earnings guidance range. When the company changes its earnings guidance, management will decide whether to change the incentive compensation payout levels.
				100.0%	

2011 Key Performance Indicators  
 NSPM Distribution

KPI Name	2011			Range Calculation	Weight Empl	Definition
	Threshold 50% Level	Target 100% Level	Maximum 150% Level			
Safety (OSHA Recordable Incident Rate) Distribution Employees	3.25	2.87	1.80	Threshold = 2009 results Maximum = 2015 goal	15%	The number of on-the-job OSHA recordable injuries related to a common exposure base of 100 full-time workers. (Calculation = Number of OSHA Recordable Cases x (100 x 2000) / Actual Exposure Hours). Includes employees in organizations reporting directly to the NSPM OpCo CEO.
Safety (DART Days Away, Restricted or Transferred Rate) Distribution Employees	1.88	1.80	0.93	Threshold = 2009 results Maximum = 2015 goal	10%	The number of on-the-job injuries resulting in restricted duty or lost work days, related to a common exposure base of 100 full-time workers. (Calculation = Number of Lost Work Day (LWD) Cases + Restricted Work Day Cases x 200,000 / Actual Exposure Hours). Includes employees in organizations reporting directly to the NSPM OpCo CEO.
System Reliability (Distribution SAIDI) D-Line & 1/2 D-Sub	92.95	85.75	71.35	Threshold = - 1/2 standard deviation Maximum = -1 standard deviation	25%	System reliability measured by the Distribution System Average Interruption Duration Index (D-SAIDI), which is designed to provide information about the average time annually the customers' electric service is interrupted. The calculation includes distribution line outages plus 1/2 of the distribution substation outages; calculation based on sustained, storm-normalized system outages greater than five minutes in length and determined by multiplying the average frequency of customer outages by the average customer interruption duration for NSPM.
Customer Satisfaction (percent positive) All Customers	91%	94%	Maximum payout is 100%	Threshold at 1% below the survey sampling margin of error, maximum payout capped at 100%	15%	The Voice of the Customer (VOC) measures All Customers satisfaction across Xcel Energy via an ongoing survey. Respondents rate their satisfaction using a 0 to 10 scale (0 = very dissatisfied and 10 = very satisfied.) Results reflect the percent responding favorably, defined as those that are 6 or higher on this scale. Customers may or may not have had an actual contact with the company during the survey period, thus recent media representations concerning the company, recent rate increases or other events may impact the customers' "overall satisfaction" with Xcel Energy. Target is equal to last year's performance due to expected rate case impacts in 2011.
Electric Energy Efficiency (Managed Accounts (GWh))	210.0	240.0	270.0	See Threshold and Maximum cells	10%	Achieve targeted GWh reduction through DSM programs in Minnesota. The reduction will be the total reduction achieved for Managed Accounts.
Gas Distribution Compliance Plan (Milestones Met)	Complete 5 of 7 Milestones with gas emergency response time of 56 minutes	Complete 6 of 7 Milestones with gas emergency response time of 49 minutes	Complete 7 of 7 Milestones with gas emergency response time at or better than 46.5 minutes	See Threshold and Maximum cells	25%	The achievement of the gas distribution compliance plan will increase regulatory compliance, improve public and employee safety and give us a better understanding of the risks associated with our gas distribution system. See the gas compliance index tab for a detailed definition for each milestone.
Distribution Capital (\$ in millions)	Manage distribution capital spend between (+/-) 2.01% - 5% of the approved budget	Manage distribution capital spend between (+/-) 2% of the approved target of \$172.6M	Maximum payout is 100%	See Threshold and Maximum cells	0%	The total amount of approved NSPM distribution capital expenditures in 2011 (as adjusted).
Distribution O&M (\$ in millions)	\$149.7	\$146.7	\$143.8	Threshold at 102% of target. Max. at 98% of target	0%	The total amount of approved NSPM distribution O&M expenditures in 2011 (as adjusted).

100.0%

**2011 Corporate Aviation Adjustment**  
**Adjustment To A&G - Includes Payroll Taxes**  
 Adjustment to remove 50% of Budgeted Amount

Allocated to Jurisdiction Using 2Factor Allocator

Electric	Total	MN	ND	SD	Whisl
Amount Budgeted *	1,654,923	1,460,302	98,772	94,489	1,359
Adjustment Amount at 50%	(827,462)	(730,151)	(49,386)	(47,245)	(680)
P 57.18%	(473,142)	(417,500)	(28,239)	(27,014)	(389)
T 11.79%	(97,558)	(86,085)	(5,823)	(5,570)	(80)
D 31.03%	(256,761)	(226,566)	(15,324)	(14,660)	(211)
	<u>(827,462)</u>	<u>(730,151)</u>	<u>(49,386)</u>	<u>(47,245)</u>	<u>(680)</u>

\* This adjustment does not include any of the payroll taxes associated with Aviation Costs

*138-2*

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-299

Date Received: May 27, 2011

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Question:

Subject: Aviation

Please provide the detailed reasoning behind eliminating 50% of aviation costs, including (1) which costs were deemed not justified, (2) which costs were deemed justified, (3) why 50 % and not 40% or 60%, and (4) any further detail to assist in understanding why and the actual amount of costs not deemed justified for inclusion in test year.

Response:

- (1& 2) The aviation adjustment was not based upon the examination of specific costs.
- (3) The 50% adjustment represents the approximate cost for one of the two corporate aircrafts leased by the Company.
- (4) As explained in Mr. John M. Felling's Direct Testimony, we adjusted our 2011 test year budget for Corporate Aviation Expense by removing \$49,000. This \$49,000 adjustment represents one-half of the corporate aviation budget allocated to the State of North Dakota electric jurisdiction.

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Witness: John M. Felling  
Preparer: Tim Searle  
Title: Director, Special Projects  
Department: Data Coordination/Quality  
Telephone: (612) 330-6881  
Date: June 23, 2011

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**  
Washington, D.C. 20549  
**FORM 10-K**

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2010

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number: 1-3034

**Xcel Energy Inc.**

(Exact name of registrant as specified in its charter)

**Minnesota**

(State or other jurisdiction of incorporation or organization)

**41-0448030**

(I.R.S. Employer Identification No.)

**414 Nicollet Mall**

**Minneapolis, MN 55401**

(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, \$2.50 par value per share	New York
Rights to Purchase Common Stock, \$2.50 par value per share	New York
Cumulative Preferred Stock, \$100 par value:	
Preferred Stock \$3.60 Cumulative	New York
Preferred Stock \$4.08 Cumulative	New York
Preferred Stock \$4.10 Cumulative	New York
Preferred Stock \$4.11 Cumulative	New York
Preferred Stock \$4.16 Cumulative	New York
Preferred Stock \$4.56 Cumulative	New York
\$7.60 Junior Subordinated Notes, Series due 2068	New York

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.  Yes  No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.  Yes  No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.  Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).  Yes  No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.  Large accelerated filer  Accelerated filer  Non-accelerated filer (Do not check if a smaller reporting company)  Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).  Yes  No

As of June 30, 2010, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was \$9,472,921,126 and there were 459,627,420 shares of common stock outstanding.

As of Feb. 17, 2011, there were 482,686,603 shares of common stock outstanding, \$2.50 par value.

**DOCUMENTS INCORPORATED BY REFERENCE**

The Registrant's Definitive Proxy Statement for its 2011 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

## Legal Contingencies

**Nuclear Waste Disposal Litigation** — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the DOE failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of \$100 million through Dec. 31, 2004. In September 2007, the court awarded NSP-Minnesota \$116.5 million in damages. In February 2008, the DOE filed an appeal to the U.S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. It is uncertain when the Court will issue a decision. Results of the judgment will not be recorded in earnings until the appeal, regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have an effect on Xcel Energy's consolidated results of operations, cash flows or financial position.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the U.S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. Per the court's scheduling order, NSP-Minnesota believes that it has suffered damages in excess of \$250 million. The DOE claims NSP-Minnesota is entitled to at most approximately \$55 million. Trial is expected to take place in 2011.

## Additional Information

See Note 14 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 13 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

## Item 4 — Reserved

## PART II

## Item 5 — Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

### Quarterly Stock Data

Xcel Energy's common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2010 and 2009 and the dividends declared per share during those quarters.

<u>2010</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First quarter.....	\$ 21.76	\$ 19.82	\$ 0.2450
Second quarter.....	22.14	19.81	0.2525
Third quarter.....	23.28	20.47	0.2525
Fourth quarter.....	24.36	23.02	0.2525
<u>2009</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First quarter.....	\$ 19.13	\$ 16.01	\$ 0.2375
Second quarter.....	18.98	16.83	0.2450
Third quarter.....	20.29	17.44	0.2450
Fourth quarter.....	21.94	18.53	0.2450

Book value per share at Dec. 31, 2010, was \$16.76. The number of common shareholders of record as of Dec. 31, 2010 was approximately 79,461. The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's holding company capitalization ratio at Dec. 31, 2010 and 2009 was 84 percent and 85 percent, respectively. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends. See Item 7 and Note 7 to the consolidated financial statements for further discussion of Xcel Energy's dividend policy.

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Xcel Energy  
Docket No.: PU-10-657 & PU-11-55  
Response To: Blue Ridge Consulting Data Request No.  
Requestor: Michael McGarry AS-RR-238  
Date Received: May 3, 2011 SUPPLEMENT

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Question: Subject: Nuclear Spent Fuel Storage

Reference company witness Koehl's direct testimony page 30, lines 20-24

- a. How much has been spent by the company to sue the DOE and either charged or allocated to ND Electric Jurisdiction? In which FERC accounts are the expenses recorded?
- b. Are any of those costs included in the 2011 test year or 2012 step-in adjustment? If so how much?

Response:

The first suit against the DOE is under appeal in the United States Circuit Court of Appeals for the Federal Circuit and the second suit is pending in the Court of Federal Claims. Total litigation expenditures related to a pending matter are highly confidential and subject to the attorney-client privilege. In addition, disclosing the exact amounts included for this matter in the 2011 test year could give other parties insight into our litigation strategy and are therefore also highly confidential and subject to the attorney-client privilege. Our anticipated costs for this matter are included in the total legal department budget. Once the matter is resolved, either through settlement or litigation, the Company will update this response.

SUPPLEMENT:

The Company is still compiling the total litigation costs. Based upon our review so far, the Company has, to date, spent \$6,876,000 on the DOE litigation starting in the year 2000. These costs are still being finalized and costs incurred from 1997-2000 are still being compiled. The Total Company budget for 2011 is \$225,000 in FERC Account 921 (Legal-Other), and \$275,000 in FERC Account 923 (Consulting-Professional Services-Legal). The amount of the total \$500,000 included in the North Dakota 2011 test year is \$29,000.

By letter dated July 8, 2011, provided as Attachment A, the Company advised the North Dakota Commission that a settlement has been reached with the Department of Energy that resolves the referenced litigation through 2013.

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Witness: Dennis L. Koehl  
Preparer: Deborah R. Meuwissen  
Title: Manager  
Department: Legal Administration  
Telephone: 612-215-4545  
Date: May 31, 2011      **SUPPLEMENT:** July 13, 2011



*Laura McCarten*  
*Regional Vice President*  
*NSP-Minnesota*

414 Nicollet Mall  
Minneapolis, Minnesota 55401  
(612) 330-5723

July 8, 2011

Mr. Darrell Nitschke  
Director of Administration and Executive Secretary  
North Dakota Public Service Commission  
State Capitol Building, Dept. 408  
600 East Boulevard  
Bismarck, ND 58505-0480

Re: Notice of Settlement with U.S. Government on Nuclear Spent Fuel Storage Costs

Dear Mr. Nitschke:

In 1998, Northern States Power Company ("NSPM") filed the first of two suits against the United States Department of Energy ("DOE") seeking to recover damages associated with storage of spent nuclear fuel at our Prairie Island and Monticello nuclear generating plants. The Company's claims were for partial breach of the Standard Contracts for Disposal of Spent Nuclear Fuel ("Standard Contracts") for failing to take title to, transport, and dispose of spent nuclear fuel beginning no later than January 31, 1998.<sup>1</sup> The first lawsuit sought damages through 2004; the second sought damages through 2008. Our lawsuits were among 74 filed by utilities alleging a partial breach by the DOE. The Company has recently reached a settlement with the U.S. Government on these suits and we received a copy of the signed Settlement Agreement on July 7, 2011.

The settlement resolves over a decade of on-going litigation that continues to have no clearly foreseeable resolution in the courts. Under the terms of the settlement, the DOE will make an initial payment of just under \$100 million (total Company) to cover spent nuclear fuel storage costs incurred through December 31, 2008.

The settlement also provides a mechanism for the Company to recover its spent nuclear fuel storage damages through December 31, 2013. We believe that the additional damage payments through 2013 will total roughly an additional \$100 million on a total Company basis. The first supplemental payment, covering 2009 and 2010, is expected to be received in the first quarter of 2012. Payments covering the costs incurred by the Company in 2011, 2012 and 2013 are expected to be received by year end of 2012, 2013

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<sup>1</sup> See 10 C.F.R. § 961.11 (1983) for a description of the Standard Contracts' provisions.

Mr. Darrell Nitschke  
July 8, 2011  
Page 2

and 2014 respectively (assuming the claim amounts are resolved without the need for binding arbitration and the attendant delay). The settlement does not address potential claims beyond 2013.

Under the settlement, the DOE has agreed to pay for costs associated with their failure to begin taking spent fuel in 1998 including: a) any additional pool storage costs and other plant modifications; b) dry casks storage and costs directly related to such storage (e.g. internal labor, and overhead, operation and maintenance, training and security); and c) additional property taxes resulting from the on-site dry cask storage or other plant modifications.

While the Company prevailed on a portion of our claim in the first lawsuit at the Court of Federal Claims, *Northern States Power Co. v. United States*, 78 Fed. Cl. 449 (Fed. Cl. 2007), the United States appealed the decision to the Court of Appeals for the Federal Circuit. *See* Court of Appeals for the Federal Circuit Docket Nos. 2008-5037, 2008-5041. Recent decisions in other cases from the Federal Circuit raised issues concerning some of the factors in NSP's case, and, based on those new developments, we proceeded to take actions that resulted in the settlement identified here.

The Company will deposit the settlement proceeds into a segregated bank account established specifically and solely for the settlement proceeds as the NSPM and NSPW operating companies prepare filings for their state commissions to consider how the funds can appropriately be returned to customers. Our filing with the North Dakota Public Service Commission will further describe the nature of the litigation, the resulting settlement amount applicable to the North Dakota retail jurisdiction, and will address any interest earned on the account and costs incurred in obtaining the settlement proceeds. We will be contacting you to discuss the filing in the near future.

Very truly yours,



Laura McCarten  
Regional Vice President  
NSP-Minnesota

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-238

Date Received: April 29, 2011

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Question: Subject: Nuclear Spent Fuel Storage

Reference company witness Koehl's direct testimony page 30, lines 20-24

- a. How much has been spent by the company to sue the DOE and either charged or allocated to ND Electric Jurisdiction? In which FERC accounts are the expenses recorded?
- b. Are any of those costs included in the 2011 test year or 2012 step-in adjustment? If so how much?

Response:

The first suit against the DOE is under appeal in the United States Circuit Court of Appeals for the Federal Circuit and the second suit is pending in the Court of Federal Claims. Total litigation expenditures related to a pending matter are highly confidential and subject to the attorney-client privilege. In addition, disclosing the exact amounts included for this matter in the 2011 test year could give other parties insight into our litigation strategy and are therefore also highly confidential and subject to the attorney-client privilege. Our anticipated costs for this matter are included in the total legal department budget. Once the matter is resolved, either through settlement or litigation, the Company will update this response.

---

Witness: Dennis L. Koehl  
Preparer: Deborah R. Meuwissen  
Title: Manager  
Department: Legal Administration  
Telephone: 612-215-4545  
Date: May 31, 2011

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-205

Date Received: May 3, 2011

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Question:

Subject: Insurance and Security Costs

Please provide a list of insurance policies in which costs have been allocated to the ND Electric Jurisdiction in 2009 and 2010. Include type insurance, a brief description of the insurance, carrier, policy period, policy year premium, why the insurance is necessary, and the costs included within the test year.

Response:

Attachments A through D to this response provide the requested information pertaining to insurance that encompass the specified years.

Please see Attachments A, B and C for insurance policy information as of January 1, 2009, January 1, 2010 and December 31, 2010 respectively for Xcel Energy Inc. (Premium amounts are for total corporate coverage across all operating companies.)

See Attachment D, arranged by FERC object account number, for a summary of 2009 and 2010 actual insurance costs and 2011 budgeted amounts for Northern States Power Company-Minnesota ("NSPM") and for insurance costs included in the 2011 test year for the North Dakota jurisdiction.

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Preparer: John T. Hernick  
Title: Administrator, Insurance  
Department: Hazard Insurance  
Telephone: 612-215-5349  
Date: July 8, 2011

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction

Case No. PU-10-657 and 11-55  
 Data Request AS-RR-205  
 Attachment D - Page 1 of 1

924 A&G Property Insurance Object Account Allocated	2009 NSPM	2010 NSPM	2011 NSPM	2011 ND
	Total Company Actuals	Total Company Actuals	Total Company Budget	Test Year
723510 Property Insurance	\$ 3,478,760	\$ 3,624,105	\$ 3,995,569	\$ 238,472
723535 Auto Liab/Physical Damage	\$ 464,711	\$ 438,693	\$ 374,582	\$ 22,357
723572 Nuclear Property Insurance	\$ 3,084,484	\$ 3,238,090	\$ 3,378,375	\$ 196,307
723574 Nuclear Interupt Insurance	\$ 1,516,407	\$ 1,532,946	\$ 1,779,012	\$ 103,373
723576 Nuclear Liability Insurance	\$ 1,820,794	\$ 2,470,257	\$ 2,475,552	\$ 147,751
723577 Nuclear Liability ICRP	\$ (508,450)	\$ (438,009)	\$ (371,064)	\$ (22,147)
723578 NEIL Surplus Insurance	\$ 2,259	\$ (2,609,819)	\$ -	\$ -
	<u>\$ 9,858,965</u>	<u>\$ 8,256,262</u>	<u>\$ 11,632,026</u>	<u>\$ 686,113</u>

925 A&G Injures & Damages	2009 NSPM	2010 NSPM	2011 NSPM	2011 ND
	Total Company Actuals	Total Company Actuals	Total Company Budget	Test Year
Workers Compensation	\$2,728,035	\$2,953,994	\$3,011,562	\$ 183,086
723520 General Liability Insurance	\$3,490,380	\$4,743,432	\$3,543,695	\$ 211,502
723530 Excess Liability Insurance	\$2,640,303	\$3,132,009	\$3,674,135	\$ 219,287
723540 Directors and Officers Insuran	\$1,425,203	\$1,527,819	\$1,527,752	\$ 91,182
723545 Fiduciary Insurance	\$485,020	\$473,196	\$494,566	\$ 29,518
723550 Other Insurance	\$59,064	\$51,332	\$171,316	\$ 10,225
	<u>\$10,828,005</u>	<u>\$12,881,782</u>	<u>\$12,423,026</u>	<u>\$744,800</u>

**STATE OF NORTH DAKOTA  
PUBLIC SERVICE COMMISSION**

**Northern States Power Company  
Electric Rate Increase  
Application**

**Case No. PU-07-776**

**ORDER ADOPTING SETTLEMENT**

**December 31, 2008**

**Appearances**

Commissioners Susan E. Wefald, Kevin Cramer, and Tony Clark.

Megan J. Hertzler, Assistant General Counsel, Xcel Energy, 414 Nicollet Mall, Fifth Floor, Minneapolis, Minnesota 55402, and Michael J. Bradley, Attorney at Law, Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402, attorneys for Northern States Power Company.

Douglas A. Bahr, Solicitor General, Office of the Attorney General, 500 North Ninth Street, Bismarck, North Dakota 58501, attorney for the Advocacy Staff.

Illona A. Jeffcoat-Sacco, General Counsel, Public Service Commission, 600 E. Boulevard Avenue, Department 408, Bismarck, North Dakota 58505-0480, attorney for the Public Service Commission.

Al Wahl, Administrative Law Judge, Office of Administrative Hearings, 1701 North Ninth Street, Bismarck, North Dakota 58501-1882, appearing as hearing officer.

**Preliminary Statement**

On December 7, 2007, Northern States Power Company (NSP) filed its application and direct testimony seeking a general revenue increase of \$17,950,000 or 12.15 percent of total revenues with the North Dakota Public Service Commission (Commission).

On December 21, 2007, the Commission suspended NSP's general rate increase application.

On January 16, 2008, the Commission issued a Notice of Public Input Session and Intervention Deadline.

On January 30, 2008, the Commission issued its Order on Interim Rates authorizing the Company to collect interim rates.

On March 23, 2008, the Commission issued its Notice of Hearing setting the dates for hearing and specifying the issues to be considered:

1. What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
3. What is a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on NSP's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are NSP's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Other relevant information or proposals concerning the proceeding.

The Notice of Public Input Session and Intervention Deadline provided that any person wishing to intervene as a party in this proceeding must file a petition for intervention by March 28, 2008. No one petitioned to intervene as a party in the proceeding.

On May 14, 2008, a public input session was held via interactive television in Fargo, Grand Forks, Minot, and Bismarck, North Dakota.

On May 21, 2008, the Commission Advocacy Staff filed direct testimony.

On June 13, 2008, NSP filed rebuttal testimony.

On June 23 through June 25, 2008, the hearing was held in the Commission Hearing Room at the State Capitol in Bismarck, North Dakota.

On December 17, 2008, NSP filed a partially executed settlement agreement. On December 19, 2008, NSP filed a partially executed amendment to the settlement agreement filed on December 17<sup>th</sup>. On December 29, 2008, NSP filed a fully executed Settlement Agreement providing among other things for:

- (a) a rate increase to provide additional annual revenue of approximately \$10,855,000 or 7.4% effective for service rendered on or after March 1, 2009;

(b) a moratorium prohibiting further electric rate increases from becoming effective prior to January 1, 2011;

(c) an earnings sharing mechanism if net income exceeds 10.75% return on equity; and

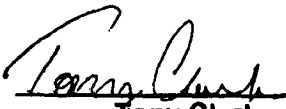
(d) accounting treatment for Midwest ISO Day-2 Energy Market costs.

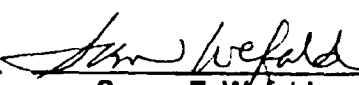
Having considered this matter, the Commission finds the December 29, 2008 Settlement Agreement is reasonable and should be approved. Therefore, the Commission issues the following:

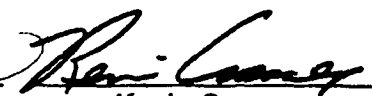
#### Order

1. The Settlement Agreement filed December 29, 2008, a copy of which is attached to this Order and made a part of this Order, is APPROVED.
2. NSP shall file compliance tariffs consistent with this Order and Settlement Agreement to implement final rates for service rendered on or after March 1, 2009, to yield an annual revenue increase of not more than \$12,785,000, which is expected to yield a net annual revenue increase of approximately \$10,855,000 when combined with projected fuel cost adjustment decreases resulting from off-system sales margin sharing.
3. Interim rates approved by the Commission will remain in effect for all customer classes thru February 28, 2009. Refunds, in the form of one-time bill credits, must be issued to customers within 90 days of the implementation of final rates for the difference between the interim revenue level and the approved March 1, 2009 revenue requirement. NSP shall file a final refund report with the Commission upon completion of the refunding.
4. This Order supersedes the interim accounting treatment ordered in Case No. PU-05-147 for Midwest ISO Day 2 Energy Market costs and Case No. PU-05-147 shall be closed.

#### PUBLIC SERVICE COMMISSION

  
Tony Clark  
Commissioner

  
Susan E. Wefald  
President

  
Kevin Cramer  
Commissioner

From: Larry Gauper [mailto:larryg@cableone.net]  
Sent: Tuesday, June 28, 2011 9:05 AM  
To: Diller, Michael R.  
Subject: More Fargo power outages

Dear Mike,

You and I talked about the poor service record of Xcel energy in the Fargo area and eastern North Dakota a few months ago. I can understand problems when 70 mph winds blow through town, but, again today, gorgeous outside...probably the nicest day of the year and yet the radio is reporting "thousands without power from Sabin, MN to West Fargo and surrounding area plus most of downtown Fargo. Fortunately for me we have power at this moment. But with Xcel, it's gotten so bad one worries about the power going out constantly; totally with expectation or reason.

I do not understand this. Before and after "the storm" - during nice weather - Xcel goes down, literally out of the blue. During the storm clean-up, of course, I understand those temporary outages as crews work to get power restored. But that encompassed a few weeks at most. We are well beyond that period and, when I first talked with you about this issue, we were well ahead of that time period and we had reasonably good seasonal weather.

I would like the Commission, led by Commissioner Cramer or somebody out there to start collecting reports on Xcel outages and outages from all power companies serving the Commission's jurisdiction. Make it mandatory that these power companies, particularly Xcel, official report when they go down.

The Commission should look at the record as an ongoing duty and find out if it's true that Xcel A) does not know what they're doing in Fargo, eastern ND, and western MN....I'm mostly concerned about Fargo....and B) the Commission should have a truly independent electrical grid consultant look at Xcel operations and infrastructure and provide a report. I think there are serious deficiencies Xcel will not admit.

I see now Xcel is trying to spin the proposed rate increase as "helping" the reliability situation in Fargo. What a crock. I don't believe that and if "reliability" was as important as they say it is - more important than their bird-watching website (unbelievable but true!) - then they should have been working on reliability a long, long time ago. It should be their #1 concern and the #1 concern of the North Dakota Public Service Commission.

Please send my concerns to Commissioner Cramer and anyone else in the dept. that you deem appropriate.

Thank you,  
Larry L. Gauper

621 Hackberry Drive S.  
Fargo, ND 58104-6222  
Verizon cell: 701-361-7733  
Home land line: 701-237-5079

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-333

Date Received: June 27, 2011

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Question:

Subject: Reliability

Regarding the Annual Report of Northern States Power Company (North Dakota Jurisdiction) to the North Dakota Public Service Commission for year ending 2010 (filed as PU-11-147):

- a. Regarding the CAIDI and SAIFI indexes on page E-5, please confirm that the CAIDI/SAIFI averages incorporate North Dakota jurisdiction data only.
- b. Please provide the Reliability information (i.e., sections V, VI, and VII of the report on pages E-5, E-6, and E-7 respectively) for the years 2007, 2008, and 2009, including all charts and data provisions in the manner included in the 2010 report.

Response:

- a. The reliability results that we have reported since 2008 in the Annual Report to the North Dakota Public Service Commission (“Commission”) include a very small portion of our system in Minnesota that is maintained and serviced out of our Fargo Service Center. In fact, based on customers, approximately 96 percent of the system reliability data is for customers located in North Dakota. For internal management purposes, trend comparisons, and administrative efficiency, we have maintained this reporting structure for over two decades.
- b. Reliability information included in the 2010 report is identical to what was provided in the 2008 and 2009 Annual Reports on file with the Commission. Even though reliability information was not required in 2007, the information provided each year from 2008 to 2010 included five years’ of history, so 2007 reliability results is provided in those reports.

**Preparer:** David Sederquist  
**Title:** Senior Regulatory & Financial Consultant  
**Department:** ND Jurisdictional Mgmt  
**Telephone:** 701-241-8632  
**Date:** July 1, 2011

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-343

Date Received: July 6, 2011

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Question:

Subject: Reliability

Regarding the Annual Report of Northern States Power Company to the North Dakota Public Service Commission for year ending 2010 (filed as PU-11-147):

- a. Concerning, the SAIFI table on page E-5 (Reliability Performance – Overall ND System), please explain in detail the causes for the significant index increase (76.5%) from 2009 to 2010 (0.68 to 1.20). Also, has the Company addressed the cause of this increase? Specifically, what programs and/or other corrective actions have been put in place to address the cause of this increase?
- b. Concerning the SAIFI table on page E-6 (Reliability Performance - 5 Largest Substations), please explain in detail the causes for the significant index increases from 2009 to 2010 for the following:
  - i. Red River – 0.96 to 1.68 (75% increase)
  - ii. Gateway – 0.19 to 0.68 (257.9% increase)
  - iii. Nordic – 0.55 to 2.27 (312.7% increase)
- c. Concerning the SAIFI table on page E-6 (Reliability Performance - 5 Largest Substations), please explain in detail the cause for the significant index increase from 2008 to 2009 for Cass County – 0.34 to 0.72 (111.8% increase). Also, has the Company addressed the cause of this increase? Specifically, what programs and/or other corrective actions have been put in place to address the cause of this increase?
- d. Concerning the SAIFI table on page E-6 (Reliability Performance - 5 Largest Substations), please explain in detail the cause for the significant index increase

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from 2007 to 2008 for Nordic – 0.25 to 0.57 (128% increase). Also, has the Company addressed the cause of this increase? Specifically, what programs and/or other corrective actions have been put in place to address the cause of this increase?

Response:

- a. The Company experienced good reliability in 2009 largely due to an extremely mild weather year. 2010 was a much more active weather year and along with other types of outage events, resulted in poorer reliability performance (it should be noted that not all outages caused by weather-related factors (such as lightning, wind, etc.) are removed as part of the “normalization” process). Attachment A shows a list of the most significant outages in 2010 which contributed to the increased 2010 SAIFI result. Further information on the causes and corrective actions take for these outage events is discussed in items b. to d. of this response.

Overall, the North Dakota system has performed well in recent years – the five year average for SAIFI of 0.81 is among the best among the states we serve. Xcel Energy has a set of programs focused on improving reliability. Our response to AS-RR-334 includes a list of these activities and their funding levels. In addition, the Annual Report filed in Case No. PU-11-147 contains a summary of the Company’s 2011 Reliability Plan.

- b. As noted in item a, 2010 was an active weather year which impacted reliability performance compared to more mild weather years.
- i. Attachment B, Table 1 shows a list of the most significant outages in 2010 for the portion of our system served by the Red River substation. The causes for the most significant outages in 2010 are varied. The substation equipment has been inspected and surveyed with an infra-red camera to identify heating components and nothing was identified. The Transmission line has been inspected and no additional items of concern have been identified. Xcel Energy has an extensive program to notify customers and private tree contractors to stay away from overhead lines.

Vegetation Management in North Dakota is on a four-year cycle. From time to time, favorable conditions can result in a faster growing tree to come into conflict before the four-year cycle is complete. Xcel Energy has instituted a mid-cycle inspection program aimed at identifying these quick growing trees. It should also be noted that some tree contacts come from trees outside the

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maintenance corridor, where the Company does not have the rights to maintain.

- ii. Attachment B, Table 2 shows a list of the most significant outages in 2010 for the portion of our system served by the Gateway substation. Xcel Energy installs lightning arresters to mitigate the impacts of lightning; however arresters do fail on occasion resulting in customer outages. The arrester involved in the August 20, 2010 outage has been replaced. Regarding the July 31, 2010 outage, the “unknown outage” designation means that after investigation, no definite cause for the outage could be determined. Some of the items that could have caused this are an animal contact, a tree contact, or other outside influences contacting the line.
- iii. Attachment B, Table 3 shows a list of the most significant outages in 2010 for the portion of our system served by the Nordic substation. The August 18, 2010 outage was due to a lightning strike. As noted above, even with the installation of lightning arrestors, lightning may still result in customer outages. Regarding the June 29, 2010 outage, the Company installs and maintains wildlife protection to keep animals out of its substations. The animal protection at Gateway has been surveyed and any required repairs have been completed. The remaining large outages were due to cable failure. Xcel Energy has a program aimed at identifying and replacing cables that are at end of life. Generally, when we see two failures within a two- year period, we flag a cable for replacement. The cable involved in the May 24<sup>th</sup> and October 15 outage event events has been scheduled for replacement with the estimated completion mid-August 2011.
- c. Overall, the portion of our system served by the Cass County substation has had good reliability, with a five-year average SAIFI of 0.43. There were several major events causing the increase from 2008 to 2009. Attachment A, Table 4 lists the largest events for 2009. The March 30<sup>th</sup> outage event was due to a cable splice failure and the August 30<sup>th</sup> outages event was caused by a general cable failure and because the causes were not directly related this segment cable did not meet our guidelines for replacement. Public damage to an overhead line caused the July 6<sup>th</sup> outage event.. As previously mentioned, Xcel Energy has an extensive program to notify customers and private tree contractors to stay away from overhead lines. In 2010 the SAIFI for Cass County was 0.46, indicating that our corrective actions were appropriate.
- d. Attachment B, Table 5 shows a list of the 2008 largest events for the portion of our system served by the Nordic substation. The cable on the feeder for the

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January 7<sup>th</sup> and January 30<sup>th</sup> outages events was replaced with the project complete on May 19<sup>th</sup>, 2008. The cable involved with the July 29<sup>th</sup> and September 25<sup>th</sup> outages did not meet our guidelines for replacement.

A portion of Attachments A & B include information Xcel Energy considers to be "security data." The Company believes the information could be used to reveal the location and size of certain facilities. The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt the electrical grid for political or other reasons may learn which facilities to target to create the greatest disruption. For this reason, we have excised this data from the public version of response.

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Preparer: David A. Clark / Joel H. Limoges  
Title: Corporate Reliability Analyst / Mgr, Elec. Area Engineering  
Department: Elec. Distribution Systems Performance / MN Area Engineering  
Telephone: 612-330-4078 / 651-229-2316  
Date: July 26, 2011

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Northern States Power Company, a Minnesota Corporation  
 Electric Utility - State of North Dakota Jurisdiction  
 Large Outage Events Contributing to an Increase in SAIFI

Case No PU-10-657 / 11-55  
 Data Request AS-RR-343  
 Attachment A - Page 1 of 1

Dur: duration of outage in minutes  
 SCI: number of sustained customer interruptions (greater than 5 minutes)  
 CMO: customer minutes out

North Dakota: 2010 Largest Outages by SAIFI Impact  
 2009 SAIFI: 0.68  
 2010 SAIFI: 1.20

Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
			<b>[NON-PUBLIC BEGINS</b>						
10/8/10 3:42 PM	Pole/Crossarm Broken	Transmission Line/System		11	10,235	112,585	0.18	1.99	56,532
8/18/10 6:08 AM	Lightning Strike	Dist Substation Bus/Transformer		26	5,397	140,322	0.10	2.48	56,532
6/29/10 11:22 AM	Animal Contact Other	Dist Substation Bus/Transformer		8	4,596	36,768	0.08	0.65	56,532
4/25/10 12:52 AM	Breaker Failure Oil Circuit Bkr	Dist Substation Bus/Transformer		54	3,648	196,992	0.06	3.48	56,532
5/22/10 1:19 PM	Veg Tree Inside Maint Corridor	Feeder		126	2,493	314,118	0.04	5.56	56,532
8/9/10 9:00 AM	Public Damage Non-Xcel Tree Trim	Overhead Primary		40	2,434	97,360	0.04	1.72	56,532
			<b>NON-PUBLIC ENDS]</b>			Sum	0.51	15.89	

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Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction  
 Large Outage Events Contributing to an Increase in SAIFI

Case No PU-10-657 / 11-55  
 Data Request AS-RR-343  
 Attachment B - Page 1 of 3

Dur: duration of outage in minutes  
 SCI: number of sustained customer interruptions (greater than 5 minutes)  
 CMO: customer minutes out

TABLE 1									
Substation: Red River		2009 SAIFI: 0.96							
		2010 SAIFI: 1.68							
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
[NON-PUBLIC BEGINS]									
10/8/10 3:42 PM	Pole/Crossarm Broken	Transmission Line/System		11	10,235	112,585	0.54	5.94	18,945
5/22/10 1:19 PM	Veg Tree Inside Maint Corridor	Feeder		126	2,493	314,118	0.13	16.58	18,945
8/9/10 9:00 AM	Public Damage Non-Xcel Tree T	Overhead Primary		40	2,434	97,360	0.13	5.14	18,945
4/25/10 12:52 AM	Breaker Failure Oil Circuit Bkr	Dist Substation Bus/Transformer		54	2,318	125,172	0.12	6.61	18,945
7/27/10 6:59 AM	Veg Tree Outside Main Corridor	Feeder		61-79	1,801	130,309	0.10	6.88	18,945
1/25/10 9:12 AM	Veg Tree Outside Main Corridor	Feeder		29-44	1,547	46,423	0.08	2.45	18,945
3/10/10 3:03 PM	Cable Failure Pri Unjacketed	Feeder		41-59	1,229	69,290	0.06	3.66	18,945
Sum:							1.16	47.26	
[NON-PUBLIC ENDS]									

TABLE 2									
Substation: Gateway		2009 SAIFI: 0.19							
		2010 SAIFI: 0.68							
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
[NON-PUBLIC BEGINS]									
8/20/10 5:10 PM	Lightning Arrester Porcelain	Feeder		40	1,096	43,840	0.26	10.28	4,266
7/31/10 8:55 PM	Unknown Cause Not Determined	Feeder		10	1,089	10,890	0.26	2.55	4,266
Sum:							0.51	12.83	
[NON-PUBLIC ENDS]									

**PUBLIC DOCUMENT: NON-PUBLIC INFORMATION, SECURITY DATA EXCISED**

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction  
 Large Outage Events Contributing to an Increase in SAIFI

Case No PU-10-657 / 11-55  
 Data Request AS-RR-343  
 Attachment B - Page 2 of 3

Dur: duration of outage in minutes  
 SCI: number of sustained customer interruptions (greater than 5 minutes)  
 CMO: customer minutes out

TABLE 3										
Substation: Nordic		2009 SAIFI: 0.55						SAIFI	SAIDI	YE Cust
		2010 SAIFI: 2.27						Impact	Impact	Served
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served	
<b>[NON-PUBLIC BEGINS]</b>										
8/18/10 6:08 AM	Lightning Strike	Dist Substation Bus/Transformer		26	5,397	140,322	0.61	15.97	8,789	
6/29/10 11:22 AM	Animal Contact Other	Dist Substation Bus/Transformer		8	4,596	36,768	0.52	4.18	8,789	
10/7/10 7:04 PM	Cable Failure Pri Unjacketed	Feeder		65	1,485	96,525	0.17	10.98	8,789	
10/15/10 10:46 PM	Cable Failure Pri Unjacketed	Feeder		70	1,146	80,220	0.13	9.13	8,789	
9/20/10 8:07 AM	Cable Failure Pri Jacketed	Feeder		39-45	1,066	41,694	0.12	4.74	8,789	
5/6/10 6:37 AM	Cable Failure Pri Jacketed	Feeder		63-75	942	59,622	0.11	6.78	8,789	
5/24/10 5:40 PM	Cable Failure Pri Unjacketed	Feeder		100	803	80,300	0.09	9.14	8,789	
Sum:							1.76	60.92		
<b>[NON-PUBLIC ENDS]</b>										

TABLE 4										
Substation: Cass County		2008 SAIFI: 0.34						SAIFI	SAIDI	YE Cust
		2009 SAIFI: 0.72						Impact	Impact	Served
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served	
<b>[NON-PUBLIC BEGINS]</b>										
3/30/09 12:41 PM	Splice UG Primary Premolded	Overhead Primary		54-179	1,706	96,078	0.22	12.44	7,722	
8/30/09 7:11 PM	Cable Failure Primary P&L	Overhead Primary		67-101	1,699	115,005	0.22	14.89	7,722	
7/6/09 12:25 PM	Public Damage OH Line Contact	Overhead Primary		35-102	1,107	104,137	0.14	13.49	7,722	
Sum:							0.58	40.82		
<b>[NON-PUBLIC ENDS]</b>										

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Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction  
 Large Outage Events Contributing to an increase in SAIFI

Case No PU-10-657 / 11-55  
 Data Request AS-RR-343  
 Attachment B - Page 3 of 3

Dur: duration of outage in minutes  
 SCI: number of sustained customer interruptions (greater than 5 minutes)  
 CMO: customer minutes out

TABLE 5									
Substation: Nordic		2007 SAIFI: 0.25							
		2008 SAIFI: 0.57							
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
			<i>NON-PUBLIC BEGINS</i>						
1/30/08 12:00 AM	Cable Failure Pri Unjacketed	Feeder		54	1,104	59,616	0.13	6.84	8,711
1/7/08 12:00 AM	Cable Failure Pri Jacketed	Feeder		56	1,103	61,768	0.13	7.09	8,711
7/29/08 12:00 AM	Splice UG Primary Cold Shrink	Feeder		78-93	881	70,023	0.10	8.04	8,711
9/25/08 12:00 AM	Cable Failure Primary LC	Feeder		35-77	449	26,854	0.05	3.08	8,711
Sum:							0.41	25.06	
			<i>NON-PUBLIC ENDS</i>						

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-334

Date Received: June 27, 2011

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Question:

Subject: Reliability

Please provide the major reliability projects in the North Dakota jurisdiction by major geographic sub-region (i.e., Bismarck, Fargo, Minot, etc.) for the years 2007, 2008, 2009, 2010, and the budget test year. Please include descriptions and dollars spent.

*Note: Blue Ridge Consulting revised the above inquiry on June 29, 2011 as follows:*

**REVISED:** Please provide a **prioritized** list of the major reliability projects in the North Dakota jurisdiction by major geographic sub-region (i.e., Bismarck, Fargo, Minot, etc.) for the years 2007, 2008, 2009, 2010, and the budget test year. Please include descriptions and dollars spent **and the basis for the project's position on the prioritized list.**

Response:

Following is the 2007 thru 2010 reliability program spend in the North Dakota jurisdiction by major geographic sub-region:

**Fargo**

<u>Program</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>
Mainline Cable Replacements	\$ -	\$ 364,678	\$ 37,420	\$ (913)
Tap Cable Replacements	\$ 12,498	\$ 168,163	\$ 89,937	\$ 160,960
Pole Inspections	\$ 29,685	\$ -	\$ 7,878	\$ -
Pole Replacements	\$ 4,814	\$ 77,693	\$ 10,355	\$ 20,847
Feeder Improvement Program (FPIP)	\$ 31,888	\$ -	\$ 5,656	\$ -
REMS	\$ -	\$ -	\$ -	\$ 1,368
<b>TOTAL</b>	<b>\$ 78,885</b>	<b>\$ 610,534</b>	<b>\$ 151,246</b>	<b>\$ 182,262</b>

**Grand Forks**

<u>Program</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>
Mainline Cable Replacements	\$ 68,357	\$ 232,241	\$ 83,107	\$ 371,774
Tap Cable Replacements	\$ -	\$ 28,128	\$ 7,360	\$ 261,644
Pole Inspections	\$ -	\$ -	\$ 28,651	\$ 37,020
Pole Replacements	\$ -	\$ -	\$ -	\$ 75,821
Feeder Improvement Program (FPIP)	\$ 75,317	\$ 852	\$ -	\$ -
REMS	\$ -	\$ 5,031	\$ 3,701	\$ 21,995
<b>TOTAL</b>	<b>\$ 143,674</b>	<b>\$ 266,252</b>	<b>\$ 122,819</b>	<b>\$ 768,255</b>

**Minot**

<u>Program</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>
Mainline Cable Replacements	\$ 97,334	\$ 95,956	\$ 89	\$ -
Tap Cable Replacements	\$ -	\$ 67,503	\$ 37,366	\$ 129,256
Pole Inspections	\$ -	\$ -	\$ 36,864	\$ 49,074
Pole Replacements	\$ -	\$ -	\$ 26,693	\$ 97,554
Feeder Improvement Program (FPIP)	\$ -	\$ -	\$ -	\$ -
REMS	\$ -	\$ -	\$ 1,235	\$ 7,556
<b>TOTAL</b>	<b>\$ 97,334</b>	<b>\$ 163,459</b>	<b>\$ 102,246</b>	<b>\$ 283,440</b>

**Total North Dakota Jurisdiction**

<u>Program</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>
Mainline Cable Replacements	\$ 165,691	\$ 692,876	\$ 120,616	\$ 370,862
Tap Cable Replacements	\$ 12,498	\$ 263,794	\$ 134,663	\$ 551,860
Pole Inspections	\$ 29,685	\$ -	\$ 73,393	\$ 86,094
Pole Replacements	\$ 4,814	\$ 77,693	\$ 37,048	\$ 194,222
Feeder Improvement Program (FPIP)	\$ 107,205	\$ 852	\$ 5,656	\$ -
REMS	\$ -	\$ 5,031	\$ 4,936	\$ 30,920
<b>TOTAL</b>	<b>\$ 319,893</b>	<b>\$ 1,040,246</b>	<b>\$ 376,312</b>	<b>\$ 1,233,957</b>

The test year budget for these same programs in 2011, listed in prioritized order (highest to lowest), is as follows:

**North Dakota Reliability Programs Test Year Budget**

<u>Program</u>	<u>2011B</u>
Pole Inspections	\$ 72,654
Pole Replacements	\$ 238,000
Feeder Improvement Program (FPIP)	\$ 54,000
Tap Improvement Program (TPIP)	\$ 9,000
Install Remote Fault Indicators	\$ 63,000
Tap Cable Replacements	\$ 107,000
Mainline Cable Replacements	\$ 504,784 *
REMS	\$ 6,000
<b>TOTAL</b>	<b>\$ 1,054,438</b>

\*Note Mainline Cable Program Budgeted at NSPM Company Level. Funding is then allocated to each jurisdiction based on need and number of cables meeting replacement criteria. \$504,784 value listed for ND Mainline Cable Replacements based on 4-year historical percentage spend in ND for this program which is 13.9% of total NSPM Mainline Cable Replacement expenditures.

Please note that the test year budget cannot be supplied by major geographic sub-region, because capital programs for North Dakota are budgeted at the overall state level, and actual expenditures are then allocated to the three main geographic sub-regions based on need.

When prioritizing funding for Reliability activities, the basis for each program's position on the above prioritized listing includes, but is not necessarily limited to, the following criteria:

- Public and employee safety;
- Ability to keep equipment reliably in-service;
- Number of customers impacted;
- Amount of load (MVA) at risk;
- Historical outages caused by equipment;
- Speed of service restoration.

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Preparer: Joel H. Limoges  
Title: Mgr. Elec. Area Engineering  
Department: MN Area Engineering  
Telephone: 651-299-2316  
Date: July 8, 2011

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-53

Date Received: April 28, 2011

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Question:

Reference: Life Extension of the Monticello and Prairie Island Nuclear Power Plants

Please provide the amount spent to obtain a new operating license and the accounting for those costs in the test year and the step in adjustment in 2012?

Response:

The amount to obtain a new operating license for the Monticello Power Plant is \$32,257,984.19 and it is being amortized over 19.8 years as of the beginning of 2011. The amount for the Prairie Island Power Plant is \$46,362,759.60 with \$27,742,337.65 of it being placed in-service in 2011 and this amount will be amortized over 23.3 years as of the beginning of 2011.

Regarding the 2012 step in adjustment, the life extension operating license is not part of the 2012 step increase request of \$4.2 million.

---

Witness: John M. Felling  
Preparer: Jake W. Miller  
Title: Senior Accounting/Financial Analyst  
Department: Capital Asset Accounting  
Telephone: 612-330-1959  
Date: May 23, 2011

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-94

Date Received: April 28, 2011

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Question:

Reference: Asset Retirement Obligations (ARO)

Are any ARO's or Nuclear Decommissioning funds overfunded as of December 31, 2010? If so please provide the following:

- a) The name of the Plant that is overfunded.
- b) The amount of the overfunding.
- c) Will the company return to the rate payer the over funded ARO's and Decommissioning funds? If not why not and if so how and when will that be done?

Response:

- a-c) At this time, the Nuclear Decommissioning Trust Fund is not overfunded for any of the three nuclear units.

Previously, when the Monticello nuclear plant received approval for license extension, we conducted a full decommissioning review and concluded that the decommissioning trust fund was overfunded for the foreseeable future, and that amounts paid into escrow were appropriately eligible for refund.

As we near the triggering event of Nuclear Regulatory Commission ("NRC") approval, in regard to the Prairie Island escrow and the possibility for amounts in escrow to be refunded, we are evaluating key component assumptions. Our stress test of Monticello focused primarily on the risk of a depletion of the decommissioning fund from the potential of a disruptive market loss. Based on today's circumstances, we are now evaluating how certain other key

components, such as the potential of a lower real growth rate and a lengthened period for full removal from the site, may impact the fund. We are in the very early stages of preparing this additional information; thus it would be premature to draw conclusions regarding a potential refund at this time. We are continuing to refine our analysis in preparation for our full triennial nuclear decommissioning review, which will be filed with the Minnesota Public Utilities Commission ("MPUC") and the North Dakota Public Service Commission ("NDPSC") in October of 2011.

All Asset Retirement Obligations recorded for Northern States Power Company-Minnesota are income-statement and balance-sheet neutral and do not require funding. By their nature, they cannot be overfunded or underfunded. The remaining lives of production plant are evaluated and filed annually with the MPUC and the NDPSC to avoid over funding or underfunding.

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Preparer:        Brandon Kirschner  
Title:            Senior Accounting Analyst  
Department:    Capital Asset Accounting  
Telephone:      612-215-5361  
Date:            May 20, 2011

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-280

Date Received: May 27, 2011

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Question:

Subject: Depreciation

Reference company response to Data Request AS-2-RR-92 a-c. The company indicates that they are near the triggering event for NRC approval regarding the Prairie Island escrow and the possibility for amounts in escrow to be refunded and are evaluating key component assumptions. The company states they are in the very early stages of the evaluation.

- a. Would the company agree that based on the overfunding of the Monticello Decommissioning Trust fund that it is likely that Prairie Island will also be overfunded even though the amount is now as yet known?
- b. Assuming that the Prairie Island Nuclear Plant license extension is approved by all the regulatory bodies in 2011, when will the company know what the amount of any potential over funding will be?
- c. If the potential refund is known in 2011, prior to implementation of new rates, how will the company return the refund to the ratepayer?

Response:

A – C.

We cannot at this time speculate as to whether the Prairie Island Decommissioning Trust Fund (also referred to as “escrow fund”) will be overfunded. However, the NRC license approval does not in and of itself mean that the escrow fund will be over funded

In order to make that determination, it will first be necessary to submit a triennial review of nuclear decommissioning, the primary objective of which is to arrive at a reasonable estimate of the cost to decontaminate and remove nuclear facilities at the end of the operating lives of nuclear plants including the operation of the dry cask storage, and to attempt to calculate the proper amount of expense to accrue annually to accumulate a fund sufficient to pay the decommissioning costs when incurred. The triennial filing was required by the Minnesota Public Utilities Commission ("MPUC"). Since 1979, the MPUC has examined the costs of decommissioning the Company's three nuclear power plants and established decommissioning cost recovery procedures, from which the triennial plan filing requirements resulted.

The next triennial filing is due to the MPUC in October 2011 with likely resolution in 2012. If it is determined that the escrow fund for Prairie Island is over funded and the refund is approved, then the next step will be to propose a refund process for each jurisdiction. Until the MPUC makes its decision whether there will be any refund, assuming an overfunded status is determined to exist, it is too early to know how any potential refund to ratepayers will be provided.

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Preparer: Lisa H. Perkett  
Title: Director  
Department: Capital Asset Accounting  
Telephone: (612) 330-6950  
Date: June 14, 2011

**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**  
Washington, D.C. 20549  
**FORM 10-K**

(Mark One)

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**  
For the fiscal year ended December 31, 2010

or  
 **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**  
Commission File Number: 1-3034

**Xcel Energy Inc.**

(Exact name of registrant as specified in its charter)

**Minnesota**  
(State or other jurisdiction of incorporation or organization)

**41-0448030**  
(I.R.S. Employer Identification No.)

**414 Nicollet Mall**  
**Minneapolis, MN 55401**  
(Address of principal executive offices)

Registrant's telephone number, including area code: **612-330-5500**

Securities registered pursuant to Section 12(b) of the Act:

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
Common Stock, \$2.50 par value per share	New York
Rights to Purchase Common Stock, \$2.50 par value per share	New York
Cumulative Preferred Stock, \$100 par value:	
Preferred Stock \$3.60 Cumulative	New York
Preferred Stock \$4.08 Cumulative	New York
Preferred Stock \$4.10 Cumulative	New York
Preferred Stock \$4.11 Cumulative	New York
Preferred Stock \$4.16 Cumulative	New York
Preferred Stock \$4.56 Cumulative	New York
\$7.60 Junior Subordinated Notes, Series due 2068	New York

Securities registered pursuant to section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.  Yes  No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.  Yes  No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.  Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).  Yes  No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.  Large accelerated filer  Accelerated filer  Non-accelerated filer (Do not check if a smaller reporting company)  Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).  Yes  No

As of June 30, 2010, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was \$9,472,921,126 and there were 459,627,420 shares of common stock outstanding.

As of Feb. 17, 2011, there were 482,686,603 shares of common stock outstanding, \$2.50 par value.

**DOCUMENTS INCORPORATED BY REFERENCE**

The Registrant's Definitive Proxy Statement for its 2011 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

Consistent with cost-recovery in utility customer rates, NSP-Minnesota previously recorded annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. The most recent study, which resulted in an authorization of no funding, presumes that costs will escalate in the future at a rate of 2.89 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by the external decommissioning trust fund, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 6.30 percent, net of tax, for external funding. The net unrealized loss on nuclear decommissioning investments is deferred as a regulatory liability based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The external funds are held in trust and in escrow. The portion in escrow is subject to refund if approved by the various commissions. The MPUC authorized the return of \$23.5 million of funds associated with the Monticello plant for the Minnesota retail jurisdictions. This amount was withdrawn in December 2009 and was refunded on customers' bills in February 2010. An amount of approximately \$5.9 million was also withdrawn from the Monticello plant portion of the escrow fund in March of 2010 in preparation for a refund to Wisconsin and Michigan retail customers. The funds have not yet been refunded as of Dec. 31, 2010, and the timing of the refunds will be determined in future rate cases in each jurisdiction.

At Dec. 31, 2010, NSP-Minnesota recorded and recovered in rates cumulative decommissioning expense of \$1.4 billion. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters from the most recently approved decommissioning study. Xcel Energy believes future decommissioning cost expense, if necessary, will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO.

(Thousands of Dollars)	2010	2009
Estimated decommissioning cost obligation (2008 dollars) .....	\$ 2,308,196	\$ 2,308,196
Effect of escalating costs (to 2010 and 2009 dollars, respectively, at 2.89 percent per year) .....	135,342	66,707
Estimated decommissioning cost obligation (in current dollars) .....	2,443,538	2,374,903
Effect of escalating costs to payment date (2.89 percent per year) .....	2,672,825	2,741,460
Estimated future decommissioning costs (undiscounted) .....	5,116,363	5,116,363
Effect of discounting obligation (using risk-free interest rate) .....	(3,856,516)	(3,973,493)
Discounted decommissioning cost obligation .....	1,259,847	1,142,870
Assets held in external decommissioning trust .....	1,350,630	1,248,739
Excess assets in external trust compared to discounted decommissioning obligation .....	<u>\$ (90,783)</u>	<u>\$ (105,869)</u>

Decommissioning expenses recognized include the following components:

(Thousands of Dollars)	2010	2009	2008
Annual decommissioning cost expense reported as depreciation expense:			
Externally funded .....	\$ 934	\$ 2,849	\$ 43,239
Internally funded (including interest costs) .....	(777)	(884)	(819)
Net decommissioning expense recorded .....	<u>\$ 157</u>	<u>\$ 1,965</u>	<u>\$ 42,420</u>

Reductions to expense for internally-funded portions in 2010, 2009 and 2008 are a direct result of the 2008 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the remaining operating life of the unit. The 2008 nuclear decommissioning filing approved in 2009 has been used for the regulatory presentation. The change in estimated decommissioning obligations was calculated using a cost estimate for Monticello assuming a 60-year operating life.

**Nuclear Decommissioning Fund** — The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities, and other funds - all classified as available-for-sale securities under the applicable accounting guidance. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

**BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION  
STATE OF NORTH DAKOTA**

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 Nos. PU-10-657 and PU-11-55

**WORKPAPERS SUPPORTING THE REVENUE REQUIREMENTS  
CALCULATIONS INCLUDED  
IN THE DIRECT TESTIMONY AND EXHIBITS OF**

**MICHAEL J. MCGARRY, SR.**

Xcel Energy  
 Annual Revenue Requirement  
 Mercury Removal  
 2011 Test Year North Dakota Electric Rate Case - Interim  
 (000's)

Rate Analysis

	Total Company	ND Jurisdiction
Plant Investment	(5,691)	(331)
Depreciation Reserve	(400)	(23)
CWIP	-	-
Accumulated Deferred Taxes	(846)	(55)
	(4,345)	(253)
Average Rate Base	(4,345)	(253)
Debt Return	(123)	(7)
Equity Return	(257)	(15)
Current Income Tax Requirement	(180)	(10)
Book Depreciation	(249)	(14)
Annual Deferred Tax	10	1
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	(217)	(13)
AFUDC Expenditure	-	-
Avolded Tax Interest	-	-
O&M Production Expense	(4,493)	(261)
<b>Total Revenue Requirements</b>	<b>(5,292)</b>	<b>(306)</b>

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.2500%	52.5600%	5.9100%
Required Rate of Return			8.7400%
Tax Rate (ND)	39.2300%		

Staff Adj. 1-1

Docket No PU-10-657 & PU-11-55  
 Exhibit (MJM-47)  
 Page 2 of 65  
 A38-3

Northern States Power, a Minnesota corporation  
 2011 Test-Year Budget  
 Mercury Interim Rate Adjustment

Case No. PU-10-\_\_\_\_\_

Demand Prod ND Jur % 5.8107%  
 Demand MN Co % (1) 83.8766%  
 Demand After Interchange % 4.8738%

CWIP

	Total Company		Total Company after IA		ND Jurisdiction		(1) Adjustment Included in Interchange Calculation
	BOY	EOY	BOY	EOY	BOY	EOY	
Production	11,199.61	0.00	9,393.74	0.00	545.84	0.00	
COSS Adj (000's)	11	-	9	-	1	-	1 Excluded for ND Ratemaking

Plant

	Total Company		Total Company after IA		ND Jurisdiction		
	BOY	EOY	BOY	EOY	BOY	EOY	
Production	6,731,785.01	6,839,022.03	5,646,325.07	5,736,270.76	328,091.01	333,317.49	
COSS Adj (000's)	6,732	6,839	5,646	5,736	328	333	331

Reserve

	Total Company		Total Company after IA		ND Jurisdiction		
	BOY	EOY	BOY	EOY	BOY	EOY	
Production	328,601.34	625,224.33	275,616.34	524,410.66	16,015.24	30,471.93	
COSS Adj (000's)	329	625	276	524	16	30	23

Accumulated Deferred

	Total Company		Total Company after IA		ND Jurisdiction		
	BOY	EOY	BOY	EOY	BOY	EOY	
Production	1,134,282.61	1,121,961.19	951,394.73	941,051.68	55,282.69	54,661.69	
COSS Adj (000's)	1,134	1,122	951	941	55	55	55

5,180.50

Book Depreciation

	Total Company		Total Company after IA		ND Jurisdiction	
	Annual	Annual	Annual	Annual	Annual	Annual
Production	296,622.99		248,794.31		14,456.69	
COSS Adj (000's)	-	297	-	249	-	14

Annual Deferred

	Total Company		Total Company after IA		ND Jurisdiction	
	Annual	Annual	Annual	Annual	Annual	Annual
Production	(12,331.42)		(10,343.05)		(601.00)	
COSS Adj (000's)	-	(12)	-	(10)	-	(1)

Tax Depreciation

	Total Company		Total Company after IA		ND Jurisdiction	
	Annual	Annual	Annual	Annual	Annual	Annual
Production	258,290.89		216,643.03		12,588.48	
COSS Adj (000's)	-	258	-	217	-	13

Staff Adj. 1-2

Docket No PU-10-657 & PU-11-55  
 Exhibit (MJM-47)  
 Page 3 of 65

A38-4

Northern States Power, a Minnesota corporation  
 2011 Test-Year Budget  
 Mercury Interim Rate Adjustment

Case No. PU-10-\_\_\_\_\_

Demand Prod ND Jur % 5.8107%  
 Demand MN Co % (1) 83.8758%  
 Demand After Interchange % 4.8738%

AFUDC

	Total Company Annual	Total Company after IA Annual	ND Jurisdiction Annual	
Production	37.41	31.38	1.82	
COSS Adj (000's)	-	-	-	Excluded for ND Ratemaking
Avoided Tax				
	Total Company Annual	Total Company after IA Annual	ND Jurisdiction Annual	
Production	12.88	10.80	0.63	
COSS Adj (000's)	-	-	-	
O&M Production Expense				
	Total Company Annual	Total Company after IA Annual	ND Jurisdiction Annual	
Production	5,356,486.29	4,492,785.02	261,062.28	
COSS Adj (000's)	5,356	4,493	261	

Staff Adj. 1-3

Docket No PU-10-657 & PU-11-55  
 Exhibit (MJM-47)  
 Page 4 of 65

A38-5

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Bluc Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-22

Date Received: April 28, 2011

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Question:

Reference: Plant Investment

Reference Company witness Benson Exhibit IRB-1, schedule 4 page 1 of 3.

The expected in-service date of the Pleasant Valley – Byron project has changed from 2011 to 2012. Has this project been excluded from ratebase in 2011? If not why not?

Response:

No, this project was not excluded from rate base in the 2011 test year. Including the project in the test year rate base was an oversight and the Company proposes to remove the project in its Rebuttal Testimony.

Excluding the Pleasant Valley – Byron project from the test year reduces test year revenue requirements by \$28,000. Please see Attachment A to this response for the revenue requirement calculation of excluding the project from the test year.

---

Witness: John M. Felling  
Preparer: John M. Felling  
Title: Consultant  
Department: Revenue Requirements North  
Telephone: 612-330-6539  
Date: May 26, 2011

Staff Adj. 2-1

Northern States Power Company, a Minnesota corporation  
 Annual Revenue Requirement  
 Remove Transmission - Pleasant Valley-Byron  
 2011 Test Year North Dakota Electric Rate Case  
 (000's)

Case No. PU-10-657 & 11-55  
 Data Request No. AS-2-RR-22  
 Attachment A  
 Page 1 of 1

Rate Analysis

	Total Company	ND Jurisdiction
Plant Investment	(4,004)	(195)
Depreciation Reserve	(17)	(1)
CWIP	-	-
Accumulated Deferred Taxes	(1,616)	(79)
	<u>(2,372)</u>	<u>(116)</u>
 Average Rate Base	 (2,372)	 (116)
 Debt Return	 (67)	 (3)
Equity Return	(140)	(7)
Current Income Tax Requirement	2,901	141

Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.2500%	52.5600%	5.9100%
Required Rate of Return			<u>8.7400%</u>
 Tax Rate (ND)	 39.2300%		

Book Depreciation	(33)	(2)
Annual Deferred Tax	(3,231)	(157)
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	(7,969)	(388)
AFUDC Expenditure	-	-
Avoided Tax Interest	(71)	(3)
Property Taxes	-	-
<b>Total Revenue Requirements</b>	<b>(570)</b>	<b>(28)</b>

Staff Adj. 2-2

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-13

Date Received: April 28, 2011

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Question:

Reference: Plant Investment

Please provide a breakdown of all properties sold or transferred from the company books in 2011. For each transaction provide the following:

- a) Date property was sold or transferred
- b) the Sales price
- c) the book value at the time of sale
- d) the gain/loss recorded on the company books
- e) whether the property sold was included in a rate case filing
- f) whether the sale or transfer was made to an affiliated company. If sold to an affiliate please provide the fair market value at the time of sale or transfer and provide the workpapers in support of the calculation of the fair market value.

Response:

In 2011, there was one transaction involving a property that was sold or transferred from the Company books, the sale of the Lakefield Junction-Fox Lake transmission line. Details of the transaction are as follows:

- a) Sold on January 7, 2011
- b) Sales Price: \$17,308,946.93
- c) Net Book Value: \$17,308,946.93
- d) No gain or loss recognized
- e) Fox Lake was included in the rate case filing as the sale was not final at the time we filed the case. Please see AS-2-RR-013 Attachment A for the

Staff Adj. 3-1

revenue requirement impact of removing the data that was in the test year which is slightly different at the time of the sale. This will reduce revenue requirements by approximately \$122,000.

- f) The sale was not made to an affiliate.

---

Witness: John Felling  
Preparer: Amber Zobeck / John Stinson/Shari Cardille  
Title: Accounting Analyst/Senior Accounting Analyst/Principal Rate  
Department: Capital Asset Accounting/Capital Asset Accounting/Revenue Requirements  
Telephone: 612-330-5758 / 806-378-2476 / 612-330-1974  
Date: May 19, 2011

Northern States Power Company, a Minnesota corporation  
 Lakefield Junction - Fox Lake 161 kV Transmission Line

(\$) (\$)

<u>Rate Analysis</u>	<u>Total Company ND Jurisdiction</u>	
<u>Average Rate Base</u>		
Plus Plant Investment	19,646,089	957,503
Less Depreciation Reserve	2,627,505	128,058
Net Plant	17,018,584	829,445
Plus CWIP	-	-
Less Accumulated Deferred Taxes	2,474,827	120,617
	14,543,757	708,828
Average 2011 Rate Base	14,543,757	708,828

<u>Revenue Requirements</u>		
Debt Return	411,600	20,100
Equity Return	859,500	41,900
Current Income Tax Requirement	333,900	16,300
Book Depreciation	476,078	23,203
Annual Deferred Tax	230,401	11,229
ITC Flow Thru	-	-
Tax Depreciation & Removal Expense	1,048,725	51,112
AFUDC Expenditure	-	-
Book Depreciation Cleared to Operating	-	-
Avoided Tax Interest	-	-
Property Tax	195,126	9,510
<b>Total Revenue Requirements</b>	<b>2,506,605</b>	<b>122,242</b>

<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.2500%	52.5600%	5.9100%
Required Rate of Return			8.7400%
Tax Rate (ND)	39.2300%		

<u>2011</u>	
Demand ND Jur %	5.8107%
IA Demand MN Co %	83.8756%
Composite ND Jur Allocation	4.8738%

Staff Adj. 3-3



414 Nicollet Mall  
Minneapolis, Minnesota 55401

April 10, 2009

—VIA ELECTRONIC FILING—

Burl W. Haar  
Executive Secretary  
Minnesota Public Utilities Commission  
121 7<sup>th</sup> Place East, Suite 350  
St. Paul, Minnesota 55101

RE: IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, REGARDING THE ELIGIBILITY OF THE WIND2BATTERY PROJECT FOR RECOVERY UNDER THE RENEWABLE ENERGY STANDARD RIDER AND APPROVAL AS AN AFFILIATED INTEREST ARRANGEMENT  
DOCKET No. E002/M-09-\_\_\_\_/E002/AI-09-\_\_\_\_

Dear Dr. Haar:

Attached for filing, please find Northern States Power Company's, a Minnesota corporation ("Xcel Energy" or the "Company"), petition for approval of our Wind2Battery project as eligible for recovery in our Renewable Energy Standard ("RES") Rider and as an affiliated interest arrangement.

The Wind2Battery project is a 1 MW sodium sulfur battery storage facility that is operating in conjunction with the 11 MW Minwind wind project in Luverne, Minnesota. By storing energy for Minwind, we are able to manage some of the variable production associated with wind power from this project to the benefit of our customers. In addition, the Wind2Battery project will give us valuable experience and information that will allow us to assess and improve the viability of scaling up battery storage on our system as more and more wind power is added to meet the renewable policies in the states we serve.

While the battery itself is proven technology, the application of the battery as support for wind energy has not been tested on a large scale. The integration equipment and

Staff Adj. 4-1

**Xcel Energy  
 Renewable Energy Standard Rider  
 Revenue Requirement - 5 Year Summary**

**Schedule 3  
 Page 1 of 1**

	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>
<b>Wind To Battery</b>					
<b>Rate Base</b>					
Plus CWIP Ending Balance	4,572,979	(1,000,000)	(1,000,000)	(1,000,000)	(1,000,000)
Plus Plant In-Service	(537,554)	4,785,157	4,785,157	4,785,157	4,785,157
Less Book Depreciation Reserve	0	12,184	364,239	716,295	1,068,350
Less Accum Deferred Taxes	(39,548)	246,447	761,351	1,015,572	1,112,318
End Of Month Rate Base	4,074,973	3,526,526	2,659,566	2,053,290	1,604,488
Average Rate Base (BOM/EOM)	1,850,058	3,901,501	3,093,052	2,356,428	1,828,889
<b>Calculation of Return</b>					
Plus Debt Return	62,162	131,090	103,927	79,176	61,451
Plus Equity Return	100,828	212,632	168,571	128,425	99,674
Total Return	162,990	343,722	272,498	207,601	161,125
<b>Income Statement Items</b>					
Plus Operating Expense	51,390	52,356	53,340	54,343	55,365
Plus Accrued Costs / Benefits	0	0	0	0	0
Plus Avoided Property Taxes	0	0	0	0	0
Plus Property Taxes	0	(6,080)	54,120	54,120	54,120
Plus Book Depreciation	0	12,184	352,055	352,055	352,055
Plus Deferred Taxes	(30,468)	285,994	514,904	254,221	96,746
Plus Gross Up for Income Tax	152,791	(142,270)	(400,441)	(162,102)	(21,298)
Less AFUDC	188,936	0	0	0	0
Less AFUDC Gross Up for Income Tax	133,315	0	0	0	0
Less Wind Production Tax Credit	0	0	0	0	0
Less Wind PTC Gross up for Income Tax (Fed only)	0	0	0	0	0
Total Income Statement Expense	(148,538)	202,185	573,979	552,638	536,988
<b>Total Revenue Requirements</b>	<b>14,452</b>	<b>545,907</b>	<b>846,477</b>	<b>760,240</b>	<b>698,113</b>
<b>MN Jurisdictional Revenue Requirement</b>	<b>0</b>	<b>399,904</b>	<b>620,087</b>	<b>556,913</b>	<b>511,403</b>

Staff Adj. 4-2

B2

**Xcel Energy  
 Electric Demand & Energy Allocations  
 D-10 & E-10 Allocator  
 2011 Budget**

		2011 Bud	Juris
		Retail	Split
Demand (1)			
D10-12 CP	MN	62,587,113	88.4924%
after TLM	ND	4,109,688	5.8107%
Includes Contract	SD	3,945,062	5.5779%
	Wholesale	84,164	0.1190%
		<u>70,726,027</u>	<u>100.0000%</u>

		Demand
		Allocator
MN		88.4924%
ND		5.8107%
SD		5.5779%
WHI		0.1190%
		<u>100.0000%</u>

Total 70,726,027

		2011 Bud	Juris
		Retail	Split
Demand			
W/o Contract Services			
	MN	62,587,113	88.4924%
	ND	4,109,688	5.8107%
	SD	3,945,062	5.5779%
	Wholesale	84,164	0.1190%
		<u>70,726,027</u>	<u>100.0000%</u>

		2011 Bud	Juris
		Retail	Split
Energy (2)			
E10-Sales			
	MN	32,597,728	87.9087%
	ND	2,322,121	6.2622%
	SD	2,119,188	5.7150%
	WHSL	42,302	0.1141%
		<u>37,081,339</u>	<u>100.0000%</u>

		Energy
		Allocator
MN		87.9087%
ND		6.2622%
SD		5.7150%
WHI		0.1141%
		<u>100.0000%</u>

Total 37,081,339

**Source**

- 1) Load Research - F. Brown
- 2) Rate Design - L. Pavlovic

Staff Adj. 4-3

Northern States Power, a Minnesota corporation  
 2011 Test-Year Budget  
 Wind to Battery ITC

Demand Prod ND Jur % 5.8107%  
 Demand MN Co % 83.8756%  
 4.8738%

**CWIP**

	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	-	-	-	-
COSS Adj (000's)	-	-	-	-
<b>Plant</b>				
	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	-	-	-	-
COSS Adj (000's)	-	-	-	-
<b>Reserve</b>				
	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	-	-	-	-
COSS Adj (000's)	-	-	-	-
<b>Accumulated Deferred</b>				
	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	(133,781.62)	(169,993.37)	(6,520.19)	(8,285.07)
COSS Adj (000's)	(134)	(170)	(7)	(8)

Staff Adj. 4-4

AS-1

Northern States Power, a Minnesota corporation  
 2011 Test-Year Budget  
 Wind to Battery ITC

Demand Prod ND Jur % 5.8107%  
 Demand MN Co % 83.8756%  
 4.8738%

Book Depreciation

	Total Company Annual	ND Jurisdiction Annual
Production	-	-
COSS Adj (000's)	-	-

Annual Deferred

	Total Company Annual	ND Jurisdiction Annual
Production	(140,273.75)	(6,836.61)
COSS Adj (000's)	(140)	(7)

Tax Depreciation

	Total Company Annual	ND Jurisdiction Annual
Production	(140,691.46)	(6,856.96)
COSS Adj (000's)	(141)	(7)

AFUDC

	Total Company Annual	ND Jurisdiction Annual
Production	-	-
COSS Adj (000's)	-	-

Avoided Tax

	Total Company Annual	ND Jurisdiction Annual
Production	-	-
COSS Adj (000's)	-	-

Staff Adj. 4-5

Docket No PU-10-657 & PU-11-55  
 Exhibit (MJM-47)  
 Page 14 of 65  
 AS-2



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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-231

Date Received: April 29, 2011

---

Question: Subject: Prepayments & Other Working Capital

Reference Company witness Felling direct testimony, page 38, line 4-6. Please provide the actual 13 month balances for the period December 2009 through December 2010 related to Prepayments, customer advances, deposits and any other components included in Other Working Capital.

Response:

Please see Attachment A for the actual 13-month balances for the period December 2009 through December 2010 related to prepayments, customer advances, and customer deposits.

---

Preparer: Shari Cardille

Title: Principal Rate Analyst

Department: Revenue Requirements North

Telephone: 612-330-1974

Date: May 31, 2011

STAFF Adj. 5-2

10 Cust Deposits FERC 235 All detail Year End

Company Desc	Bus Unit Cd	Bus Unit Desc	Obj Acct	Subsidiary Acct	Posting Acct Desc	AC20 Util Ovr- Rd Cd	AC20 Util Ovr- Rd	AC21 FERC Cd	AC21 FERC Desc	Beg Bal Act	Jan Act LTD	Feb Act LTD	Mar Act LTD	Apr Act LTD	May Act LTD	Jun Act LTD
Northern States Power - MN	10	Northern States Power - MN	371450		Cust Deposits-Peaco Energy			23500	Customer Deposits Sum:	(2,280,611)	(2,253,231)	(2,206,622)	(2,224,274)	(3,872,952)	(4,021,364)	(3,887,169)
										(2,280,611)	(2,253,231)	(2,206,622)	(2,224,274)	(3,872,952)	(4,021,364)	(3,887,169)

Staff Adv. 5-3

Jul Act	Aug Act	Sep Act	Oct Act	Nov Act	Dec Act	13 Month Avg
LTD	LTD	LTD	LTD	LTD	LTD	
(3,820,383)	(4,062,164)	(4,194,641)	(4,102,841)	(4,340,804)	(4,473,789)	
(3,820,383)	(4,062,164)	(4,194,641)	(4,102,841)	(4,340,804)	(4,473,789)	(3,518,527)

STATE Adj. 5-4

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-331

Date Received: June 24, 2011

---

Question:

Subject: Wages & Salaries

Follow up to Data Request AS-RR-130: The Company stated that it will make a downward adjustment to reflect the 2.5% increase in base salary in 2011 (instead of the 3.0% estimate used) for bargaining employees based upon the new labor agreement. Please provide the workpapers for this adjustment and the impact the adjustment will have on the ND electric jurisdiction.

Response:

Please see Attachment A to this response for the workpapers showing the North Dakota electric jurisdiction first-year annual base pay savings of an estimated \$38,311 from a 2.5% bargaining base salary increase instead of a 3.0% bargaining base salary increase.

---

Preparer: Todd M. Degrugillier

Title: Manager, Employee Tax and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: July 7, 2011

Staff Adj. 6-1

Xcel Energy and NSPM Company Labor allocated to NSPM Electric Utility      Union Labor

Line No.	Description	NSPM	State of North Dakota Electric Average Allocation Factor (1)	Estimated State of North Dakota Electric Jur.
1	<b>2011 Budget Base Pay</b>	<b>\$122,490,198</b>	<b>6.06%</b>	<b>\$7,425,250</b>
2				
3	less: 2011 Budget Merit @ 3.0%	<u>(3,567,676)</u>	6.06%	(216,269)
4				
5	Estimated Base Pay Before 2011 Budget Merit Increase	118,922,522	6.06%	7,208,981
6				
7	2011 Actual % Merit Increase	<u>2.50%</u>		
8				
9	Estimated 2011 Actual Merit Increase	2,973,063	6.06%	180,225
10				
11	<b>Estimated 2011 Actual Base Pay</b>	<b>\$121,895,585</b>	<b>6.06%</b>	<b>\$7,389,206</b>
12				
13	Estimated total Income Statement Adjustment	(594,613)	6.06%	(36,045)
14				
15	Estimated O&M % of Labor Cost	70.30%		
16				
17	Estimated Incremental Capital Merit Spend	(251,209)	6.06%	(15,228)
18				
19	Rate Base Impact Assuming 1/2 year in service	(125,605)	6.06%	(7,614)
20	x Rate Base Revenue Requirement Factor (2)	14.88%		
21				
22	Estimated Total Rate Base Adjustment	(37,380)	6.06%	(2,266)
23				
24	<b>Estimated Total Revenue Requirement Adjustment</b>	<b>(\$631,993)</b>	<b>6.06%</b>	<b>(\$38,311)</b>

STAFF Adj. 6-2

(1) Average Allocation Factor is determined by taking ND O&M labor as a percent of total Company O&M Labor

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction

Case No. PU-10-657 & 11-55  
 Data Request AS-RR-331  
 Attachment A - Page 2 of 2

<u>Cost of Capital</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>
Long Term Debt	6.0700%	46.3000%	2.8100%
Short Term Debt	2.0600%	1.1400%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	11.2500%	52.5600%	5.9100%
<b>Required Rate of Return</b>			<b>8.7400%</b>
		Tax Rate	39.2300%
		Equity GrossUp	3.8200%
		PreTax Return	<del>12.56%</del>

<b>Composite Book Life (\$000s)</b>	
Average Gross Plant	\$763,216
Annual Book Depr	\$17,697
Average Composite Depr Rate	2.3%

Total Revenue Requirement Factor **14.88%**

staff Adj. 6-3

		Transmission				Transmission				Transmission				Transmission			
Period		MN	ND	SD	WVs	MN	ND	SD	WVs	MN	ND	SD	WVs	MN	ND	SD	WVs
<b>Statement of Income</b>																	
<b>Operating Expenses</b>																	
Fuel & Purchased Energy	Annual	1,309,223	1,309,223	1,309,223	1,309,223									1,151,713	81,382	74,633	1,484
Power Production	Annual	732,518	732,518	732,518	732,518									847,980	43,082	41,819	966
Transmission	Annual					195,974	195,974	195,974	195,974					173,422	11,387	10,831	233
Distribution	Annual									104,853	104,853	104,853	104,853	92,604	8,278	9,473	0
Customer Accounting	Annual									85,472	85,472	85,472	85,472	85,853	4,385	4,307	0
Customer Service & Information	Annual									85,472	85,472	85,472	85,472	85,811	4,341	4,278	0
Sales, Econ Dvlp & Other	Annual									86,284	86,284	86,284	86,284	86,177	4,113	4,113	0
Administrative & General	Annual	128,879	128,879	128,879	128,879	19,215	19,215	19,215	19,215					18,177	1,038	1,136	0
<b>Total Operating Expenses</b>	<b>Annual</b>	<b>2,170,620</b>	<b>2,170,620</b>	<b>2,170,620</b>	<b>2,170,620</b>	<b>215,189</b>	<b>215,189</b>	<b>215,189</b>	<b>215,189</b>	<b>318,729</b>	<b>318,729</b>	<b>318,729</b>	<b>318,729</b>	<b>2,550,542</b>	<b>160,640</b>	<b>150,240</b>	<b>1,750</b>
Depreciation	Annual																
Amortization	Annual																
<b>Taxes</b>																	
Property	Annual																
Gross Earnings Tax	Annual																
Deferred Income Tax & ITC	Annual																
Payroll & Other	Annual					1,713	1,713	1,713	1,713								
<b>Total Taxes</b>	<b>Annual</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>1,713</b>	<b>1,713</b>	<b>1,713</b>	<b>1,713</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Jurisdiction Cash Working Capital</b>																	
<b>Fuel Expenses</b>																	
Coal & Rail Transport	Annual																
Gas for Generation	Annual																
Oil	Annual																
Nuclear & EOL	Annual																
Nuclear Disposal	Annual																
<b>Total Fuel Expenses</b>	<b>Annual</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Purchased Power</b>																	
Purchases	Annual	788,126	788,126	788,126	788,126	96,028	96,028	96,028	96,028								
Interchange	Annual					53,367	53,367	53,367	53,367								
<b>Total Purchased Power</b>	<b>Annual</b>	<b>788,126</b>	<b>788,126</b>	<b>788,126</b>	<b>788,126</b>	<b>149,395</b>	<b>149,395</b>	<b>149,395</b>	<b>149,395</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Labor Related</b>																	
Regular Payroll	Annual					19,487	19,487	19,487	19,487								
Income Compensation	Annual					3,543	3,543	3,543	3,543								
Pension & Benefits	Annual					4,819	4,819	4,819	4,819								
<b>Total Labor &amp; Related</b>	<b>Annual</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>28,849</b>	<b>28,849</b>	<b>28,849</b>	<b>28,849</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>
<b>Taxes</b>																	
State Sales Tax Customer Billings	Annual																
Employer's Payroll Taxes	Annual																
All Other Operating Expenses	Annual																
Property Tax	Annual																
Gross Earnings Tax	Annual																
Federal Income Tax	Annual																
State Income Tax	Annual																
<b>Total Taxes</b>	<b>Annual</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>

Staff Adj. 6-4

01-1

Northern States Power Co (MN)  
Elec O&M Bridge Report - NORTH DAKOTA  
BUDGET YEAR ENDED 12/31/2011

	Minnesota	N. Dakota	S. Dakota	Wholesale	Total Company
Fuel & Purchased Energy	1,151,713,079	81,391,857	74,633,477	1,484,088	1,309,222,501
Power Production Expense	644,356,785	42,844,022	40,804,819	862,017	728,867,643
Transmission Expense	173,901,901	11,418,966	10,961,477	233,855	196,516,199
Distribution Expense	93,345,651	6,292,509	5,491,580	133,071	105,262,812
Customer Accounting Expense	52,768,058	4,338,714	4,264,900	40,749	61,412,422
Cust Service & Info Expense	85,371,333	547,719	1,275,077	82,988	87,277,118
Sales Expense	151,202	65,640	51,546	33	268,421
Administrative & General	179,809,413	13,321,419	11,930,843	209,109	205,270,784
<b>Total Elec O&amp;M</b>	<b>2,381,417,422</b>	<b>160,220,846</b>	<b>149,413,720</b>	<b>3,045,911</b>	<b>2,694,097,900</b>
Payroll Taxes	26,495,709	1,814,591	1,696,130	26,810	30,033,241
<b>Total Elec O&amp;M without COGS</b>	<b>1,229,704,343</b>	<b>78,828,990</b>	<b>74,780,243</b>	<b>1,561,823</b>	<b>1,384,875,399</b>

	PRODUCTION	TRANSMISSION	DISTRIBUTION	TOTAL COMPANY
NOTE: A&G Total Company PTD	123,671,467	18,141,169	63,458,148	205,270,784

	Production	Tranmission	Distribution	Total Company
Payroll Taxes NOTE: Entry for Total Company PTD	20,992,093	1,713,438	7,323,152	30,028,683

As of: 12/9/2010 14:12

Staff Adj. 6-5

01-2

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Xcel Energy  
Docket No.: PU-10-657 & PU-11-55  
Response To: Blue Ridge Consulting Information Request No.  
Requestor: Michael McGarry AS-2-RR-147  
Date Received: April 28, 2011

---

Question:

Reference: Employee Health and Welfare Benefit Program  
Reference: Reed Direct, page 18, lines 5-6

Please provide the total ND electric jurisdiction health care costs for 2006, 2007, 2008, 2009, 2010, and the 2011 budget. Explain any significant variance from one year to the next.

Response:

*2006 and 2007 were not included in our response as per the Data Request modification notice received by the Company on May 20, 2011.*

The O&M costs for active health care from 2008 to 2010 and the 2011 test year for the NSPM North Dakota electric jurisdiction are shown below. In addition, a column has been added to show the 2011 budget test year amount updated to reflect the cost saving initiatives discussed in Data Request responses AS-2-RR-148 and AS-2-RR-149.

2008 Actual	2009 Actual	2010 Actual	2011 Test Year Estimate *	2011 Estimate as of 05/10/11 *
\$2,132,856	\$2,732,624	\$2,500,593	\$2,516,761	\$2,339,010

\* The 2011 percent to North Dakota jurisdiction is net of the Interchange Agreement. The 2008 to 2010 percents to the North Dakota jurisdiction do not factor in the Interchange Agreement.

The primary reasons for the increase in 2009 active health care costs from 2008 was normal health care cost inflation, an unusually high amount of catastrophic claims and higher headcount. The decrease in 2010 active health care costs from 2009 was primarily the result of cost savings initiatives that were implemented in 2010.

---

Witness: Jill H. Reed  
Preparer: Todd Degrugillier  
Title: Manager, Employee Tax and Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: June 8, 2011

staff Adj. 7-1

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Information Request No.

Requestor: Michael McGarry

AS-2-RR-148

Date Received: April 28, 2011

---

Question:

Reference: Employee Health and Welfare Benefit Program

Reference: Reed Direct, page 15, lines 20-24

Was the 2011 budget test year adjusted to recognize the savings associated with the reductions in the High Deductible Health Plan (HDHP) plan for non-bargaining and certain bargaining employees to be implemented in 2011?

Response:

The savings associated with the reductions in the HDHP plan were not reflected in the 2011 test year due to the timing of finalizing these plans and ongoing labor negotiations with our NSP unions. However, these HDHP design changes have since been implemented for 2011 for all non-bargaining and bargaining NSP employees. The impact to the 2011 test year for the ND electric jurisdiction resulting from this initiative is approximately a savings of \$174,000. Offsetting this HDHP decrease is a cost increase of approximately \$8,000 resulting from the NSPM bargaining dental cost share change of 60 percent employer and 40 percent employee to a cost share of 75 percent employer and 25 percent employee.

Please see Attachment A of this response for the derivation of these amounts.

---

Witness: Jill H. Reed

Preparer: Todd Degrugillier

Title: Manager, Employee Taxes and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: May 31, 2011

staff Adj. 7-2

**AS-2-RR-148 Attachment A  
 HDHP Savings**

NSPM Bargaining Plan Changes	
HDHP changes: 10% coinsurance after deductible with new out of pocket maximums	HSA elimination on original contribution amounts of \$670/\$1,340
(1,183,234)	(2,328,108)
64.7%	64.7%
(766,129)	(1,507,421)
5.42%	5.42%
(41,532)	(81,717)

**MN**  
 Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to NSPM electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Nonbarg 10% coinsurance, new out of pocket maximums
(727,120)
64.7%
(470,801)
(1,526,951)
31.00%
(473,355)
(944,156)
5.42%
(51,183)

**MN**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

**XS**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

Total amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Grand Total



**Dental Cost Increase**

Dental cost share change from 60/40 to 75/25
241,175
64.7%
156,158
5.42%
(41,532)

**MN**  
 Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Staff Adj. 7.3

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-2-RR-149

Date Received: April 28, 2011

---

Question:

Reference: Employee Health and Welfare Benefit Program

Reference: Reed Direct, page 15, lines 24-27

Was the 2011 budget test year adjusted to recognize the savings associated with the mandatory drug programs that will be added in 2011 that will reduce costs for prescription drug coverage.

Response:

The savings associated with the two mandatory drug programs were not reflected in the 2011 test year due to the timing of finalizing these program changes and ongoing labor negotiations with our NSP unions. However, these prescription drug plan design changes have since been implemented in 2011 for all non-bargaining and bargaining NSP employees. The impact to the 2011 test year for the ND electric jurisdiction resulting from this initiative is approximately a savings of \$12,000. Please see Attachment A to this response for the derivation of this amount.

---

Witness: Jill H. Reed

Preparer: Todd Degrugillier

Title: Manager, Employee Taxes and Accounting

Department: Payroll and Benefits Accounting

Telephone: 612-330-6557

Date: May 27, 2011

Staff Adj. 7-4

**Pharmacy Savings**

<b>NSPM Bargaining Plan Changes</b>		
Mandatory mail order for pharmacy	Member Pay the Difference for pharmacy	Selected prescription drug elimination
(120,776)	(15,299)	(15,724)
64.7%	64.7%	64.7%
(78,201)	(9,906)	(10,181)
5.42%	5.42%	5.42%
(4,239)	(537)	(552)

**MN**  
 Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

Member Pay the Difference & mandatory mail order for nonbargs
(91,717)
64.7%
(59,386)
(192,606)
31.00%
(59,708)
(119,093)
5.42%
(6,456)

**MN**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

**XS**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

Total amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

(11,784)

Staff Adj. 7-5

**Pharmacy Savings**

	Mandatory mail order for pharmacy	Member Pay the Difference for pharmacy	Selected prescription drug elimination
<b>MN</b>			
Total Cost Amount	(120,776)	(15,299)	(15,724)
Percent to NSPM electric O&M	64.7%	64.7%	64.7%
Amount to MN electric O&M	(78,201)	(9,906)	(10,181)
Percent to North Dakota Jurisdiction	5.42%	5.42%	5.42%
Total NSPM Electric O&M for North Dakota Jurisdiction	(4,239)	(537)	(552)

**MN**  
 Total Cost Amount  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

	Member Pay the Difference & mandatory mail order for nonbargs
<b>MN</b>	
Total Cost - Medical and Pharmacy	(91,717)
Percent to NSPM electric O&M	64.7%
Amount to MN electric O&M	(59,386)
<b>XS</b>	
Total Cost - Medical and Pharmacy	(192,606)
Percent to NSPM electric O&M	31.00%
Amount to MN electric O&M	(59,708)
Total amount to MN electric O&M	(119,093)
Percent to North Dakota Jurisdiction	5.42%
Total NSPM Electric O&M for North Dakota Jurisdiction	(6,456)

**MN**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

**XS**  
 Total Cost - Medical and Pharmacy  
 Percent to NSPM electric O&M  
 Amount to MN electric O&M

Total amount to MN electric O&M  
 Percent to North Dakota Jurisdiction  
 Total NSPM Electric O&M for North Dakota Jurisdiction

(11,784)

Staff Adj. 7-4

02-5d  
 Case No. PU-10-XXX  
 Page 1 of 1

2011 Pension Adjustment  
 Accounting Summary Report

2011 Budget Adjustment to Pension & Benefits

Data Year	2011
Utility	Elec
Company	10

FERC	Sum of Amount		IA Alloc to WS Co	Total After IA Allocation	MN	ND	SD	Whls
	Description	Total						
926	FAS 106 Retiree Medical	(34,799)	(4,141)	(30,658)	(27,032)	(1,869)	(1,730)	(27)
926	FAS 112 LTD	264,151	31,436	232,715	205,193	14,188	13,132	202
926	FAS 112 Work Comp	269,250	29,470	238,780	210,639	14,337	13,611	149
926	Nonqualified Pension	52,533	6,231	46,352	40,862	2,830	2,620	140
926	NO Pension SFRP Remov	(924,927)	(109,599)	(815,327)	(718,764)	(49,786)	(46,080)	(698)
926	Qualified Pension	1,655,970	196,217	1,459,693	1,286,814	69,132	62,497	1,250
	<b>Grand Total</b>	<b>1,281,168</b>	<b>149,613</b>	<b>1,131,555</b>	<b>997,713</b>	<b>68,833</b>	<b>64,050</b>	<b>960</b>

Staff Adj. 8-1

- Non Public Document – Contains Trade Secret Data  
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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-328

Date Received: June 24, 2011

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Question:

Subject: Pensions

Follow up to Data Request AS-2-RR-151: The Company's adjustment for pension and benefits of \$68,833 [which includes qualified pension, non-qualified pension (less the SERP portion), postretirement benefits (FAS 106), FAS 112 long-term disability, and FAS 112 workers compensation] is based upon the difference between the original 2011 budget and the 2011 test year amount from the 2011 Towers Watson estimated expenses. Please update this adjustment for the ND electric jurisdiction using the format in AS-2-RR-151 Attachment B based on the update to the actual 2011 actuarial costs from Towers Watson dated May 10, 2011.

Response:

Please see Attachment A to this response for the North Dakota electric jurisdiction benefit adjustment based on a comparison of the original 2011 budget and the update to the 2011 actuarial costs received from Towers Watson on May 10, 2011.

Using the revised costs provided on May 10, 2011, the Company has calculated an adjustment from the original budget of -\$12,005. In our filed case, we made an adjustment of \$68,833 using the Towers Watson estimates from October 1, 2010. We would therefore recommend a reduction in expense from our filed case of -  
\$80,838.

---

Preparer: Todd M. Degrugillier  
Title: Manager, Employee Tax and Accounting  
Department: Payroll and Benefits Accounting  
Telephone: 612-330-6557  
Date: July 13, 2011

staff Adj. 8.2

Updated Response to AS-RR-151-B

	FAS 87 Qualified Pension			FAS 108 Expense			FAS 87 Nonqualified Pension			FAS 112 LTD			FAS 112 WC			Total		
	Final 5/10/11	Budget 5/13/2010	Increase (decrease)	Final 5/10/11	Budget 5/13/2010	Increase (decrease)	Final 5/10/11	Budget 5/13/2010	Increase (decrease)	Final 5/10/11	Budget 5/13/2010	Increase (decrease)	Final 5/10/11	Budget 5/13/2010	Increase (decrease)	Final 5/10/11	Budget 5/13/2010	Increase (decrease)
Legal Entity	11,650,000	10,127,000	1,523,000	10,526,000	11,633,000	(1,107,000)	411,000	504,000	(83,000)	2,095,000	1,128,000	967,000	543,000	578,000	(35,000)	25,455,000	23,970,000	1,485,000
NSPM Nuclear	878,000	1,126,000	(247,000)	(86,000)	(84,000)	28,000	74,000	118,000	(44,000)	(74,000)	57,000	(131,000)	-	-	-	866,000	1,149,000	(283,000)
XES	19,515,000	19,998,000	(483,000)	981,000	793,000	(172,000)	4,113,000	3,254,000	759,000	(74,000)	57,000	(131,000)	-	-	-	24,235,000	24,202,000	33,000
Total Cost from Towers Watson	32,243,000	31,250,000	993,000	11,741,000	12,332,000	(1,191,000)	4,822,000	3,978,000	832,000	2,021,000	1,185,000	838,000	543,000	578,000	(35,000)	50,576,000	49,321,000	1,255,000
Amount to NSPM O&M Electric																		651,563
Remove SERP																		(978,016)
Total NSPM O&M Electric Excluding SERP																		(326,453)
Total After Interchange Agreement																		(187,066)
Total Adjustment to NSPM O&M Electric ND																		(112,695)

Updated Adjustment

Previous Response to AS-RR-151-B

	FAS 87 Qualified Pension			FAS 108 Expense			FAS 87 Nonqualified Pension			FAS 112 LTD			FAS 112 WC			Total		
	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)	Estimate 10/1/10	Budget 5/13/2010	Increase (decrease)
Legal Entity	12,394,000	10,127,000	2,267,000	11,561,000	11,633,000	(72,000)	504,000	504,000	-	1,378,000	1,128,000	250,000	1,048,000	578,000	470,000	27,325,000	23,970,000	3,355,000
NSPM Nuclear	977,000	1,126,000	(149,000)	(86,000)	(84,000)	28,000	122,000	118,000	4,000	(74,000)	57,000	(131,000)	-	-	-	1,001,000	1,149,000	(148,000)
XES	21,632,000	19,998,000	1,634,000	824,000	793,000	31,000	3,512,000	3,354,000	158,000	87,000	57,000	30,000	-	-	-	26,055,000	24,202,000	1,853,000
Total Cost from Towers Watson	35,003,000	31,250,000	3,753,000	12,287,000	12,332,000	(45,000)	4,138,000	3,978,000	162,000	1,663,000	1,185,000	480,000	1,038,000	578,000	510,000	54,181,000	49,321,000	4,860,000
Amount to NSPM O&M Electric																		2,706,094
Remove SERP																		(924,977)
Total NSPM O&M Electric Excluding SERP																		1,781,117
Total After Interchange Agreement																		1,131,555
Total Adjustment to NSPM O&M Electric ND																		(83,833)

Previous Adjustment

Change to Adjustment

Staff Adj. 8-3

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-342

Date Received: June 29, 2011

REVISED

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Question:

Subject: Mercury Sorbent

Please provide the total NSPM company and ND jurisdictional costs for mercury sorbent by power plant for 2009, 2010, and included in the 2011 test year budget.

Response:

Please see Attachment A to this response for the mercury sorbent cost detail for Northern States Power Company-Minnesota and the North Dakota jurisdiction, electric utility, by plant, by year, including the 2011 budget adjustment discussed in the Direct Testimony of Mr. John Felling.

Variations in year-to-year comparison of mercury sorbent usage reflect the testing and evaluation of the activated carbon injection systems at Sherco Unit 3 and the King plant discussed in Ms. Pamela Graika's Direct Testimony. Standards established by state and federal regulators will require usage of greater amounts of mercury sorbent than used during the testing/evaluation period.

**REVISED:**

We reviewed our response to this data request upon receiving Data Request No. AS-RR-355. As a result, we have modified Attachment A to this response and also included the modified version in our response to AS-RR-355.

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Preparer: Mary Dupre

Title: Senior Rate Analyst

Department: Revenue Requirements North

Telephone: 612-330-5862

Date: July 8, 2011

REVISED: July 15, 2011

Staff Adj. 9-1



FERC	Reg Bus Area	Business Unit Hierarchy	IS/BS Rpt Desc	FERC Description	2011 Incremental Cost Estimate	Allocators	MN	ND	SD	WhISI	CK
593	Utilities Group	MN Utility President	Distribution	Dist Mtc of Overhead Lines	625,000		587,500	18,125	19,375		-
				Total Incremental Estimate	<u>625,000</u>		<u>587,500</u>	<u>18,125</u>	<u>19,375</u>		-

94.00%    2.90%    3.10%  
 Estimated split based upon poles in state to total Qwest poles.  
 Per Joe Mansur e-mail

Staff Adj. 10-1

11-2

A11-4

From: Murray, Joseph P  
To: Murray, Thomas E  
Cc: [Redacted]  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, We have always done a "best" amount of pole transfers for Quest in prior years, but this has been done on the level of approximately 75 poles per year. Starting this year, we are now looking up to 700 pole transfer requests per year based on a new formal inspection program that Quest has recently undertaken. We did not account for this significant uptick in either this year's budget nor in the 2011/2012 Budgets.

Joe

From: Murray, Thomas E  
Sent: Wednesday, September 29, 2010 1:49 PM  
To: Murray, Joseph P  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Thanks for the update. In talking with Pat Silerud this morning she was wondering why this is considered an incremental cost for the rate case? Is it a new cost beginning in 2011 or did Quest notify us that the annual number of poles being replaced was increasing over prior years normal levels and therefore the current level in the 2011 and 2012 budgets was too low?

Thanks

Tom

From: Murray, Joseph P  
Sent: Wednesday, September 29, 2010 1:35 PM  
To: Murray, Thomas E  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom - I need to verify the estimated percent split between MW, ND, and SD

Total NSP Pole Quest pole attachments = 47,200

MW Attachments = 63 (0.13%)  
ND Attachments = 1,900 (4.0%)  
SD Attachments = 2,100 (4.5%)

From: Murray, Joseph P  
To: Murray, Thomas E  
Cc: Poon, Stephen R; Gurne-Gossamer, Elizabeth M  
Subject: RE: 2010 MW Elec Case: Information to do Quest pole budget adjustment -2011 and beyond

Hi Tom, please see my responses to your questions in red below

From: Murray, Thomas E  
Sent: Monday, September 27, 2010 1:38 PM  
To: Murray, Joseph P  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Good afternoon Joe,

... putting the rate case adjustment together for this item and have a couple questions or clarification points.

1<sup>st</sup> Is this incremental cost estimate 100% assignable to the distribution operations group in MW or are there some cost for ND and SD as well? If they are split do you have a breakdown by state? - No, this is the number for NSPMA Company, included of any transfer requests we may get from Quest for our service territory in ND and/or SD. According to our records, we are attaching a spreadsheet of 64,328 Quest poles in NSPMA/SDP at which approximately 63,000 of those attachments are within the State of Minnesota. SD, going strictly by number of attachments in each state, approximately 87% of the attachments (53,100) would be assigned to MW.

2<sup>nd</sup> Do you have a breakdown for this estimate by object account or at least type of costs (i.e. internal labor, material, contractor, etc.) - Since this is incremental to the 2011 Budget class, we do not have the labor item specifically within the budget page 1. Also, at this point in time, we have not decided on whether the bulk of these pole transfers will be done by our crew, contractors, or a combination of both. Historically, the "heavy" transfers have been done by local crews and break down as follows: Labor = 67.3%, Materials = 11.6%, Contractor = 2.1%, Transportation = 19.0%.

3<sup>rd</sup> Is this the cost to NSP to transfer from Quest poles to NSP poles or to re-aging our equipment on new Quest poles? I am still a little fuzzy on what activity is actually happening. - Cost is to transfer our facilities attached to existing Quest poles to new Quest poles replacing the existing ones.

Thanks

Tom Krueger

From: Murray, Joseph P  
To: Murray, Thomas E; Poon, Stephen R; Gurne-Gossamer, Elizabeth M; Silerud, Patricia G; Pelling, John M; Corbett, Sharon L  
Cc: Corbett, Larry R; Poon, Stephen R; Silerud, Patricia G; Gurne-Gossamer, Elizabeth M; Silerud, Patricia G; Pelling, John M; Corbett, Sharon L  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, the items for this estimate in their entirety will vary from pole to pole. Could be as simple as transferring a necessary service to as complex as decommissioning a SD degree three-phase primary structure (busbar) structure. The SDMA facility transfer would include any one or a combination of the following:

- Single-phase primary conductor transfer (including neutral wire, risers, pin, conductor (w/ associated hardware)
- Two-phase primary conductor transfer (including neutral wire, crossarm, risers, pin, conductor (w/ associated hardware)
- Three-phase primary conductor transfer (including neutral wire, crossarm, risers, pin, conductor (w/ associated hardware)
- Secondary bus conductor transfer (single-phase, two-phase, or three-phase)
- Service conductors (single-phase, two-phase, or three-phase)
- Wood cross-arms
- Arms
- Insulators
- Various other electrical equipment

From: Murray, Joseph P  
Sent: Tuesday, September 28, 2010 4:40 PM  
To: Murray, Thomas E  
Cc: Corbett, Larry R; Poon, Stephen R; Silerud, Patricia G; Gurne-Gossamer, Elizabeth M; Silerud, Patricia G; Pelling, John M; Corbett, Sharon L  
Subject: RE: 2010 MW Elec Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Also, the unanticipated increase in Distribution O&M associated with Quest pole transfers we would like to include in your testimony at \$625,000 for 2011 and then escalated 3% for each successive year to a \$730 in 2012. This increase in O&M is based on NSPMA Distribution transferring our electric facilities attached to Quest owned poles assuming an estimated 700 Quest pole replacements annually. The potential Distribution O&M would be budgeted under P&MC account 101 - Other Misc of Overhead Lines.

Let me know if you need any further information or have any questions. Thanks,

Joe Murray

Staff Adv. 10-2

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-167

Date Received: April 29, 2011

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Question: Subject: Qwest Pole Replacements

Please respond to the following questions/requests concerning the calculation of the adjustment cost for the Qwest Pole Adjustment:

- a. Is the total adjustment of \$625,000 for NSP(MN) based on 700 replacements per year?
- b. Please provide the basis for the \$892.86 per pole line reattachment (\$625,000 adjustment divided by 700 pole replacements).
- c. Please provide both the number of pole replacements and total cost of line reattachments actually realized for NSP(MN) total company in years 2007 through 2010.
- d. Please provide both the number of pole replacements and total cost of line reattachments actually realized for the ND jurisdiction in years 2007 through 2010.
- e. Please provide the amount in the 2011 budget that had been included for line reattachments based on Qwest pole replacements (prior to the adjustment).
- f. Is the adjustment based on total pole replacements anticipated or the increase of pole replacements over the base norm?

Response:

- a. The \$625,000 O&M adjustment is for the overall NSPM Company level, but is to be applied to the incremental number of pole transfers driven by Qwest's formal inspection program over and above the average annual "base" transfers the Company experienced prior to 2009 when our average number of Qwest transfers first started increasing. We have determined the "base" amount for Qwest transfers to be approximately \$109,000 annually. So, it is the total "base"

Staff Adj. 10-3

plus “incremental”, or \$734,000, that is the basis for the 700 annual replacements (transfers), equating to approximately \$1,049 O&M per pole transfer.

- b. As indicated in a. above, the Company has determined the average O&M cost per Qwest pole transfer to be \$1,049. The basis for this amount is our actual average O&M cost per transfer experienced (as conducted by Xcel Energy internal line resources) for the years 2006 through 2009.
- c. Please note that we did not set-up a mechanism to specifically track the volume and spend associated with Qwest “pole transfers” prior to 2010. As a result, our method for capturing this information for the years prior to 2010 have had to rely on work orders “titles” and may not necessarily be comprehensive. The following table provides the total O&M spend and quantity of Qwest transfers for NSPM Company from 2007 through 2010:

**NSPM Company Qwest Transfer Actuals**

	2007	2008	2009	2010
O&M	\$106,127	\$107,937	\$189,970	\$875,178
Poles	111	111	163	0

- d. The following table provides the total O&M spend and quantity of Qwest transfers for the North Dakota Jurisdiction from 2007 through 2010:

**North Dakota Qwest Transfer Actuals**

	2007	2008	2009	2010
O&M	\$983	\$161	\$1,786	\$0
Poles	1	1	2	0

- e. Per our answer in part a. above, the original “base” budget (prior to adjustment) for Qwest pole transfers included in the 2011 test year for NSPM Company level is approximately \$109,000.
- f. Yes. The adjustment of \$625,000 for the NSPM Company level is based on the increase of pole replacements (transfers) over the base norm number of transfers.

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Preparer: Joseph P. Mansur  
Title: Manager, Planning & Operational Performance  
Department: Construction Ops Maintenance  
Telephone: (612) 229-2286  
Date: June 6, 2011

Revised Billed Commodity Revenue

NSP Minnesota Co Consolidated		Updated 2011	3,709,386
Grand total			<u>3,709,386</u>

Write-Offs/Revenue Percentages	%s		
NSP Minnesota Co Consolidated	0.479%		17,777.77
Grand total			17,777.77
			0.48%

NSP Minnesota Co Consolidated		17,777,768
Grand total		<u>17,777,768</u>

NSP Minnesota Co Consolidated	JDE Acct #		Original Budget		
			Level	Difference	
MN Elect	0.70121	432813.723055	12,465,875	13,199,994	(734,119)
ND Elect	0.04375	432815.723055	777,721	823,521	(45,800)
SD Elect	0.04001	435816.723055	711,351	753,242	(41,892)
ND Gas	0.02343	432817.723055	416,504	441,032	(24,528)
MN Gas	0.19161	432819.723055	3,406,318	3,606,917	(200,599)
Grand total			<u>17,777,768</u>	<u>18,824,707</u>	<u>(1,046,939)</u>

(821,811) Elec Distribution Total PTD
(225,127) Gas Total

Staff Adj. 11-1

Docket No PU-10-657 & PU-11-55  
 Exhibit (MJM-47)  
 Page 40 of 65  
 AIG-3

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-352

Date Received: July 12, 2011

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Question:

Reference: AS-RR-155 - Based on information provided in Northern States Power Company (Minnesota)'s FERC Form 1 for 2010, Uncollectibles (Acct 904) for Company total – Electric is \$11,575,400, while the Budget Amount for 2010 is \$17,221,258 (see AS-RR-155 Att A to D.xls, spreadsheet tab "O&M Bud"). Please explain the cause(s) for this significant variance.

Response:

FERC 904 reflects actuals, while the 2010 Budget was based primarily on actual revenues and write-off expense. This approach was consistent with the Company's methodology, which used historic results in order to budget future bad debt expense. Based on that information, bad debt expense was budgeted at 0.54%. The reasonableness of that forecast was initially confirmed by the 2009 actuals, which were at 0.54 percent.

However, the 2010 year-end bad debt results were better than the historic period that was used to develop the budget. The lower actual bad debt expense in 2010 of \$5.6 million in FERC 904 is primarily due to three factors. These factors were less billed commodity revenues than budgeted, a favorable change to the bad debt reserve during the year, and less in write-offs than anticipated. For NSPM, the three factors primarily reflect: a) lower commodity prices as compared to recent prior periods, b) favorable changes in economic conditions, c) greater attention on collection related activities by Customer Care, and d) increased customer assistance payments.

The information in Table 1 below reflects that \$5.3 million of the variance in FERC 904 is related to the activities of the Customer Care Business Organization for commodity and non-commodity bad debt expense.

Staff Adj. 11 - 2

Table 1

Total Bad Debt Expense <sup>1</sup>	2010 Actual	2010 Budget	Difference
NSP MN Electric Commodity Bad Debt Expense (1)	\$ 11,067,263	\$ 16,280,016	\$ (5,212,753)
NSP MN Electric Non Commodity Bad Debt Expense (1)	44,328	122,232	(77,904)
NSP MN Electric Bad Debt Expense (2)	463,809	819,009	(355,200)
Total NSP MN Bad Debt Expense FERC 904	\$ 11,575,400	\$ 17,221,257	\$ (5,645,857)
Billed Electric Commodity Revenue	\$ 2,956,377,920	\$ 3,271,036,161	\$ (314,658,242)
Variance Due to Revenue			\$ (1,566,061)
Variance Due to Less Write Offs and Favorable Reserve Change			(3,646,692)
Total Commodity Bad Debt Expense variance supported by Customer Care			\$ (5,212,753)

(1) NSP MN electric bad debt expense relating to customer accounts supported by Customer Care.  
 (2) Made up of bad debt expenses managed outside the Customer Care organization (example: damage claim third party billings).

Preparer: Charles E. Anderson  
 Title: Director, TTC Business Area Finance  
 Department: TTC Finance  
 Telephone: (303) 294-2360  
 Date: July 26, 2011

**NSP Mn Economic Development  
Rate Case Adjustment  
Budget Year 2011**

<b>Recap of Adjustment</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	
O&M Reduction	(9,615)	(9,615)	-	-	Removal of non allowed ED program costs included in O&M
ED Donation Inclusion	151,986	37,957	64,029	50,000	Inclusion of allowable ED donations
<b>Net Adjustment to Econ Dev</b>	<b>142,371</b>	<b>28,342</b>	<b>64,029</b>	<b>50,000</b>	

**Recap of Economic Development Costs in Test Year**

Total Budgeted ED O&M (Bu 811203)	129,705
Less: Non Allowed Program Costs	(9,615)
<b>Subtotal O&amp;M</b>	<b>120,091</b>
Plus: Allowable Program Donations	37,957
<b>Total ED Costs in Test Year</b>	<b>158,047</b>

STAFF Adj. 12-1

**NORTHERN STATES POWER CO d/b/a XCEL ENERGY**  
**Charitable Contributions / Donations**  
**YEAR ENDED 12-31-11**  
**FERC 426.1**

A/B-2

<b>ELECTRIC</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>	<b>SD</b>	<b>WHLSL</b>
<i>Corporate Contributions</i>					
Total Corporate Contributions	\$267,476	\$234,519	\$16,902	\$16,055	\$1
<i>Focus Area Grants</i>					
Total Focus Area Grants	\$ 1,980,752	\$ 1,736,693	\$ 125,162	\$ 118,893	\$ 4
<i>Matching Gifts Program</i>					
Total Matching Grants	\$ 224,673	\$ 196,990	\$ 14,197	\$ 13,486	\$ 0
<i>United Way</i>					
Total United Way	\$ 862,745	\$ 756,442	\$ 54,516	\$ 51,785	\$ 2
<i>Other Donations</i>					
Total Other Donations	\$ 910,095	\$ 832,619	\$ 52,440	\$ 25,035	\$ 1
<b>Total Electric</b>	<b>\$ 4,021,067</b>	<b>\$ 3,757,263</b>	<b>\$ 263,216</b>	<b>\$ 225,253</b>	<b>\$ 8</b>
<b>MN &amp; ND - 50% Electric Inclusion</b>	<b>\$2,010,244</b>	<b>\$1,878,632</b>	<b>\$131,608</b>	<b>\$0</b>	<b>\$4</b>

<b>GAS</b>	<b>Total Co</b>	<b>MN</b>	<b>ND</b>
<i>Corporate Contributions</i>			
Total Corporate Contributions	\$24,943	\$22,509	\$2,434
<i>Focus Area Grants</i>			
Total Focus Area Grants	\$184,714	\$ 166,688	\$ 18,026
<i>Matching Gifts Program</i>			
Total Matching Grants	\$211,187	\$ 196,990	\$ 14,197
<i>United Way</i>			
Total United Way	\$80,455	\$ 72,603	\$ 7,852
<i>SEE Other Donations</i>			
Total SEE Other Donations	\$84,117	\$ 77,889	\$ 6,228
<b>Total Gas</b>	<b>\$ 374,230</b>	<b>\$ 339,690</b>	<b>\$ 34,540</b>
<b>MN &amp; ND 50% Gas Inclusion</b>	<b>\$187,115</b>	<b>\$169,845</b>	<b>\$17,270</b>

Staff Adj. 13 - 1

<b>Electric - PTD Adjustment</b>	<b>Production</b>	<b>Transmission</b>	<b>Distribution</b>	<b>check</b>
Allocated	1,149,457	237,008	623,779	
	\$ 1,149,457	\$ 237,008	\$ 623,779	\$ 2,010,244
PTD Allocator	57.1800%	11.7900%	31.0300%	

Northern States Power Co (MN)  
Elec O&M Bridge Report - NORTH DAKOTA  
BUDGET YEAR ENDED 12/31/2011

	Minnesota	N. Dakota	S. Dakota	Wholesale	Total Company
Fuel & Purchased Energy	1,151,713,079	81,391,857	74,633,477	1,484,088	1,309,222,501
Power Production Expense	644,356,785	42,844,022	40,804,819	862,017	728,867,643
Transmission Expense	173,901,901	11,418,966	10,961,477	233,855	196,516,199
Distribution Expense	93,345,651	6,292,509	5,491,580	133,071	105,262,812
Customer Accounting Expense	52,768,058	4,338,714	4,264,900	40,749	61,412,422
Cust Service & Info Expense	85,371,333	547,719	1,275,077	82,988	87,277,118
Sales Expense	151,202	65,640	51,546	33	268,421
Administrative & General	179,809,413	13,321,419	11,930,843	209,109	205,270,784
<b>Total Elec O&amp;M</b>	<b>2,381,417,422</b>	<b>160,220,846</b>	<b>149,413,720</b>	<b>3,045,911</b>	<b>2,694,097,900</b>
Payroll Taxes	26,495,709	1,814,591	1,696,130	26,810	30,033,241
<b>Total Elec O&amp;M without COGS</b>	<b>1,229,704,343</b>	<b>78,828,990</b>	<b>74,780,243</b>	<b>1,561,823</b>	<b>1,384,875,399</b>

	PRODUCTION	TRANSMISSION	DISTRIBUTION	TOTAL COMPANY
NOTE: A&G Total Company PTD	123,671,467	18,141,169	63,458,148	205,270,784

	Production	Transmission	Distribution	Total Company
Payroll Taxes NOTE: Entry for Total Company PTD	20,992,093	1,713,438	7,323,152	30,028,683

staff Adj. 14-1

As of: 12/9/2010 14:12

01-2

Docket No PU-10-657 & PU-11-55  
Exhibit (MJM-47)  
Page 45 of 65

**2011 Budget of Base Incentive budgeted at 85% of Target  
Adjustment Worksheet for Electric Utility**

	2011 Budget Amounts for NSP Company	NSP Company Electric	Minnesota Electric Jurisdiction	North Dakota Electric Jurisdiction	South Dakota Electric Jurisdiction	Wholesale Electric Jurisdiction
Total Identified in Base Data as Incentive	31,830,433	30,097,720	26,497,656	1,843,402	1,738,362	18,300
Less Non-regulated Amount (FERC 417.1)	(418)					
Less Lobbying Amount not includable (FERC 426)	(47,667)	(43,601)	(40,829)	(1,407)	(1,346)	(19)
<b>Incentive Pay at 85% of Target</b>	<b>31,382,766</b>	<b>29,654,119</b>	<b>26,456,827</b>	<b>1,842,005</b>	<b>1,737,016</b>	<b>18,281</b>
Less Long Term Plan	(1,689,043)	(1,546,833)	(1,356,418)	(97,632)	(92,754)	(29)
Less Restricted Stock	(4,583,817)	(4,302,403)	(3,782,845)	(265,269)	(252,738)	(1,550)
Less Cash Retention	(3,812)	(3,812)	(3,373)	(222)	(213)	(5)
Less Other Bonuses/Incentives	(907,655)	(907,655)	(798,667)	(56,252)	(51,694)	(1,042)
Less Over 15% Amount	(1,679,371)	(1,561,467)	(1,377,837)	(93,195)	(89,154)	(1,282)
<b>Adjusted Amount of Base Incentive at 85% of Target</b>	<b>22,918,650</b>	<b>21,731,949</b>	<b>19,137,687</b>	<b>1,329,426</b>	<b>1,250,463</b>	<b>14,373</b>
Adjust total to 85% of Target Level	-	-	-	-	-	-
<b>Net Incentive Pay included in test year</b>	<b>22,918,650</b>	<b>21,731,949</b>	<b>19,137,687</b>	<b>1,329,426</b>	<b>1,250,463</b>	<b>14,373</b>
<b>Total Incentive Pay at 85% of Target</b>	<b>22,918,650</b>	<b>21,731,949</b>	<b>19,137,687</b>	<b>1,329,426</b>	<b>1,250,463</b>	<b>14,373</b>

P 57.18% (4,758,617)  
T 11.79% (981,184)  
D 31.03% (2,582,369)

STAFF ADJ. 14-2

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 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-350

Date Received: July 12, 2011

---

Question:

Subject: Payroll Taxes

Follow up to AS-RR-192

- a. Did the Company include payroll taxes for the 2011 budget?
- b. Are payroll taxes included in the test year for incentive compensation?
- c. How much are the payroll taxes for the \$1,329,426 included in the test year for incentive compensation?
- d. Have the payroll taxes for the amount excluded for incentive compensation (\$512,569) been removed from the test year?
- e. How much are the payroll taxes for the \$512,569 excluded incentive compensation in the test year?
- f. Please provide the workpaper calculating the payroll taxes for both the included and excluded amounts for incentive compensation.

Response:

- a. Yes, estimated payroll taxes are included in the 2011 budget. The total amount of payroll taxes assigned to North Dakota is identified on 2011 Budget Workpaper O1-2.
- b. Incentive pay is one of the labor components included in the development of the payroll tax labor additive rate used to develop the payroll tax budgeted cost for the period. Payroll taxes are calculated as a labor additive percentage on budgeted productive labor and not on the individual labor components.
- c. There is not a specific calculation of payroll taxes directly associated with incentive pay amount. Therefore no specific calculation is made on the \$1,329,426 incentive amount. An estimate of the Medicare payroll taxes associated with the \$1,329,426 incentive would be \$19,277 ( $\$1,329,426 \times .0145$  [Medicare Tax Rate]). Regarding Social Security payroll taxes, an estimate of the maximum associated with the incentive amount would be \$82,424 ( $\$1,329,426 \times .062$  [Social Security Tax Rate]). This calculation assumes no Social Security maximum has occurred and does not include any state

Staff Adj. 14-3

- unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with incentive pay would be between zero and \$82,424.
- d. The incentive adjustment did not include any adjustment for estimated payroll taxes.
  - e. As discussed in the response to section d. above, no calculation was made in the adjustment calculation. An estimate of the Medicare payroll taxes associated with the \$512,569 excluded incentive would be \$7,432 ( $\$512,569 \times .0145$  [Medicare Tax Rate]). Regarding Social Security payroll taxes, an estimate of the maximum associated with the excluded incentive amount would be \$31,779 ( $\$512,569 \times .062$  [Social Security Tax Rate]). This calculation assumes no Social Security maximum has occurred and does not include any state unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with excluded incentive would be between zero and \$31,779.
  - f. The calculation of the estimated stand alone payroll taxes for the amounts included in the test year and the amounts excluded from the test year are identified in the answers to subparts c and e to this Response.

---

Preparer: Thomas E Kramer  
Title: Principal Rate Analyst  
Department: Revenue Requirements - North  
Telephone: 612-330-5866  
Date: July 13, 2011

**2011 Budget of Base Incentive budgeted at 85% of Target  
Adjustment Worksheet for Electric Utility**

**Budgeted at 85% of target**

	2011 Budget Amounts for NSP Company	NSP Company Electric	Minnesota Electric Jurisdiction	North Dakota Electric Jurisdiction	South Dakota Electric Jurisdiction	Wholesale Electric Jurisdiction
Total Identified in Base Data as Incentive	31,830,433	30,097,720	26,497,656	1,843,402	1,738,362	18,300
Less Non-regulated Amount (FERC 417.1)	(418)					
Less Lobbying Amount not includable (FERC 426)	(47,667)	(43,601)	(40,829)	(1,407)	(1,346)	(19)
<b>Incentive Net of Allowance Items</b>	<b>31,782,348</b>	<b>30,054,119</b>	<b>26,456,827</b>	<b>1,841,995</b>	<b>1,737,016</b>	<b>18,281</b>
Less Long Term Plan	(1,689,043)	(1,546,833)	(1,356,418)	(97,632)	(92,754)	(29)
Less Restricted Stock	(4,583,817)	(4,302,403)	(3,782,845)	(265,269)	(252,738)	(1,550)
Less Cash Retention	(3,812)	(3,812)	(3,373)	(222)	(213)	(5)
Less Other Bonuses/Incentives	(907,655)	(907,655)	(798,667)	(56,252)	(51,694)	(1,042)
Less Over 15% Amount	(1,679,371)	(1,561,467)	(1,377,837)	(93,195)	(89,154)	(1,282)
<b>Adjusted Amount of Base Incentive at 85% of Target</b>	<b>22,918,650</b>	<b>21,731,949</b>	<b>19,137,687</b>	<b>1,329,426</b>	<b>1,250,463</b>	<b>14,373</b>
Adjust total to 85% of Target Level	-	-	-	-	-	-
<b>Net Incentive Pay included in test year</b>	<b>22,918,650</b>	<b>21,731,949</b>	<b>19,137,687</b>	<b>1,329,426</b>	<b>1,250,463</b>	<b>14,373</b>
<b>Total Adjustment to Incentive Amount in Budget</b>	<b>(8,861,698)</b>	<b>(8,322,170)</b>	<b>(7,319,140)</b>	<b>(512,569)</b>	<b>(486,553)</b>	<b>(3,908)</b>

P 57.18% (4,758,617)  
T 11.79% (981,184)  
D 31.03% (2,582,369)

Staff Adj. 15-1

11/23/2010

2011 Incentive Comp Adjustment No Dak.xls/Elec Summary at 85% ND Rules

Docket No PU-10-657 & PU-11-55  
Exhibit (MJM-47)  
Page 49 of 65  
A36-7

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Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-350

Date Received: July 12, 2011

---

Question:

Subject: Payroll Taxes

Follow up to AS-RR-192

- a. Did the Company include payroll taxes for the 2011 budget?
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Response:

- a. Yes, estimated payroll taxes are included in the 2011 budget. The total amount of payroll taxes assigned to North Dakota is identified on 2011 Budget Workpaper O1-2.
- b. Incentive pay is one of the labor components included in the development of the payroll tax labor additive rate used to develop the payroll tax budgeted cost for the period. Payroll taxes are calculated as a labor additive percentage on budgeted productive labor and not on the individual labor components.
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staff Adj. 15-2

unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with incentive pay would be between zero and \$82,424.

- d. The incentive adjustment did not include any adjustment for estimated payroll taxes.
- e. As discussed in the response to section d. above, no calculation was made in the adjustment calculation. An estimate of the Medicare payroll taxes associated with the \$512,569 excluded incentive would be \$7,432 ( $\$512,569 \times .0145$  [Medicare Tax Rate]). Regarding Social Security payroll taxes, an estimate of the maximum associated with the excluded incentive amount would be \$31,779 ( $\$512,569 \times .062$  [Social Security Tax Rate]). This calculation assumes no Social Security maximum has occurred and does not include any state unemployment rates. Due to employees potentially reaching Social Security maximums, the actual Social Security payroll tax associated with excluded incentive would be between zero and \$31,779.
- f. The calculation of the estimated stand alone payroll taxes for the amounts included in the test year and the amounts excluded from the test year are identified in the answers to subparts c and e to this Response.

---

Preparer: Thomas E Kramer  
Title: Principal Rate Analyst  
Department: Revenue Requirements - North  
Telephone: 612-330-5866  
Date: July 13, 2011

**2011 Corporate Aviation Adjustment**  
**Adjustment To A&G - Includes Payroll Taxes**  
 Adjustment to remove 50% of Budgeted Amount

Allocated to Jurisdiction Using 2Factor Allocator

Electric	Total	MN	ND	SD	Whisl
Amount Budgeted *	1,654,923	1,460,302	98,772	94,489	1,359
Adjustment Amount at 50%	(827,462)	(730,151)	(49,386)	(47,245)	(680)
P 57.18%	(473,142)	(417,500)	(28,239)	(27,014)	(389)
T 11.79%	(97,558)	(86,085)	(5,823)	(5,570)	(80)
D 31.03%	(256,761)	(226,566)	(15,324)	(14,660)	(211)
	<u>(827,462)</u>	<u>(730,151)</u>	<u>(49,386)</u>	<u>(47,245)</u>	<u>(680)</u>

\* This adjustment does not include any of the payroll taxes associated with Aviation Costs

Staff Adj. 16-1

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Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-238

Date Received: May 3, 2011

**SUPPLEMENT**

---

Question: Subject: Nuclear Spent Fuel Storage

Reference company witness Koehl's direct testimony page 30, lines 20-24

- a. How much has been spent by the company to sue the DOE and either charged or allocated to ND Electric Jurisdiction? In which FERC accounts are the expenses recorded?
- b. Are any of those costs included in the 2011 test year or 2012 step-in adjustment? If so how much?

Response:

The first suit against the DOE is under appeal in the United States Circuit Court of Appeals for the Federal Circuit and the second suit is pending in the Court of Federal Claims. Total litigation expenditures related to a pending matter are highly confidential and subject to the attorney-client privilege. In addition, disclosing the exact amounts included for this matter in the 2011 test year could give other parties insight into our litigation strategy and are therefore also highly confidential and subject to the attorney-client privilege. Our anticipated costs for this matter are included in the total legal department budget. Once the matter is resolved, either through settlement or litigation, the Company will update this response.

**SUPPLEMENT:**

The Company is still compiling the total litigation costs. Based upon our review so far, the Company has, to date, spent \$6,876,000 on the DOE litigation starting in the year 2000. These costs are still being finalized and costs incurred from 1997-2000 are still being compiled. The Total Company budget for 2011 is \$225,000 in FERC Account 921 (Legal-Other), and \$275,000 in FERC Account 923 (Consulting-Professional Services-Legal). The amount of the total \$500,000 included in the North Dakota 2011 test year is \$29,000.

Staff Adj. 17-1

By letter dated July 8, 2011, provided as Attachment A, the Company advised the North Dakota Commission that a settlement has been reached with the Department of Energy that resolves the referenced litigation through 2013.

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Witness: Dennis L. Koehl  
Preparer: Deborah R. Meuwissen  
Title: Manager  
Department: Legal Administration  
Telephone: 612-215-4545  
Date: May 31, 2011      SUPPLEMENT: July 13, 2011

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 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-205

Date Received: May 3, 2011

---

Question:

Subject: Insurance and Security Costs

Please provide a list of insurance policies in which costs have been allocated to the ND Electric Jurisdiction in 2009 and 2010. Include type insurance, a brief description of the insurance, carrier, policy period, policy year premium, why the insurance is necessary, and the costs included within the test year.

Response:

Attachments A through D to this response provide the requested information pertaining to insurance that encompass the specified years.

Please see Attachments A, B and C for insurance policy information as of January 1, 2009, January 1, 2010 and December 31, 2010 respectively for Xcel Energy Inc. (Premium amounts are for total corporate coverage across all operating companies.)

See Attachment D, arranged by FERC object account number, for a summary of 2009 and 2010 actual insurance costs and 2011 budgeted amounts for Northern States Power Company-Minnesota ("NSPM") and for insurance costs included in the 2011 test year for the North Dakota jurisdiction.

---

Preparer: John T. Hernick  
Title: Administrator, Insurance  
Department: Hazard Insurance  
Telephone: 612-215-5349  
Date: July 8, 2011

Staff Adj. 18-1

Northern States Power Company, a Minnesota corporation  
 Electric Utility - State of North Dakota Jurisdiction

Case No. PU-10-657 and 11-55  
 Data Request AS-RR-205  
 Attachment D - Page 1 of 1

**924 A&G Property Insurance**

Object Account Allocated	2009 NSPM	2010 NSPM	2011 NSPM	2011 ND
	Total Company Actuals	Total Company Actuals	Total Company Budget	Test Year
723510 Property Insurance	\$ 3,478,760	\$ 3,624,105	\$ 3,995,569	\$ 238,472
723535 Auto Liab/Physical Damage	\$ 464,711	\$ 438,693	\$ 374,582	\$ 22,357
723572 Nuclear Property Insurance	\$ 3,084,484	\$ 3,238,090	\$ 3,378,375	\$ 196,307
723574 Nuclear Interupt Insurance	\$ 1,516,407	\$ 1,532,946	\$ 1,779,012	\$ 103,373
723576 Nuclear Liability Insurance	\$ 1,820,794	\$ 2,470,257	\$ 2,475,552	\$ 147,751
723577 Nuclear Liability ICRP	\$ (508,450)	\$ (438,009)	\$ (371,064)	\$ (22,147)
723578 NEIL Surplus Insurance	\$ 2,259	\$ (2,609,819)	\$ -	\$ -
	<b>\$ 9,858,965</b>	<b>\$ 8,256,262</b>	<b>\$ 11,632,026</b>	<b>\$ 686,113</b>

925 A&G Injuries & Damages	2009 NSPM	2010 NSPM	2011 NSPM	2011 ND
	Total Company Actuals	Total Company Actuals	Total Company Budget	Test Year
Workers Compensation	\$2,728,035	\$2,953,994	\$3,011,562	\$ 183,086
723520 General Liability Insurance	\$3,490,380	\$4,743,432	\$3,543,695	\$ 211,502
723530 Excess Liability Insurance	\$2,640,303	\$3,132,009	\$3,674,135	\$ 219,287
723540 Directors and Officers Insuran	\$1,425,203	\$1,527,819	\$1,527,752	\$ 91,182
723545 Fiduciary Insurance	\$485,020	\$473,196	\$494,566	\$ 29,518
723550 Other Insurance	\$59,064	\$51,332	\$171,316	\$ 10,225
	<b>\$10,828,005</b>	<b>\$12,881,782</b>	<b>\$12,423,026</b>	<b>\$744,800</b>

Staff Adj. 18-2

A31-2

NORTHERN STATES POWER COMPANY				
2011 Requested Expenses				
RATE CASE AMORTIZATION				
FERC	Business Unit Description		State of ND	
			Monthly	Annual
928	NSPM E Regulatory Expense-ND			
	Total Rate Case costs to amortize	561,400		
	24 month amortization		23,392	280,700

**Electric RATE CASE EXPENSES**  
 Year Ended 12/31/2011

**DESCRIPTION**

Consulting	130,000	
Itron & Christensen Assoc	5,000	Interruptible Rates Study
Robinson	35,000	Robinson
Concentric	90,000	Return On Equity
Towers Watson		Compensation Study
Outside Legal Fees	275,000	
Moss & Barnett		
State Agency Fees	125,000	
Administrative Costs	31,400	
Inserts/Notices	6,000	Ads and Inserts
Postage	600	Postage and Messenger Service
Rentals - Hearings	16,800	Employee Expenses
Copies	8,000	
	561,400	

staff Adj. 19-1

A32-3

**2011 Minnesota Electric Rate Case  
 ND EPA Emission Credit Auction Proceeds**

**JDE Acct  
 10,424,490**

Date	Amortize over 24 Months	Balance 12/31/2010	(260,197.29)
Jan 11		10,841.55	(249,355.74)
Feb 11		10,841.55	(238,514.18)
Mar 11		10,841.55	(227,672.63)
Apr 11		10,841.55	(216,831.08)
May 11		10,841.55	(205,989.52)
Jun 11	ND:Emission 130,098.65	10,841.55	(195,147.97)
Jul 11		10,841.55	(184,306.41)
Aug 11		10,841.55	(173,464.86)
Sep 11		10,841.55	(162,623.31)
Oct 11		10,841.55	(151,781.75)
Nov 11		10,841.55	(140,940.20)
Dec 11		10,841.55	(130,098.65)
Jan 12		10,841.55	(119,257.09)
Feb 12		10,841.55	(108,415.54)
Mar 12		10,841.55	(97,573.98)
Apr 12		10,841.55	(86,732.43)
May 12		10,841.55	(75,890.88)
Jun 12		10,841.55	(65,049.32)
Jul 12		10,841.55	(54,207.77)
Aug 12		10,841.55	(43,366.22)
Sep 12		10,841.55	(32,524.66)
Oct 12		10,841.55	(21,683.11)
Nov 12		10,841.55	(10,841.55)
Dec 12		10,841.55	(0.00)

staff Adj. 20-1

133 2

Summary of DSM Deferral for 2010

Balance as of 10-31-2010	339,060
No & Dec anticipated Spend	112,036
Anticipated 12-31-2010 balance for ND DSM	<u>451,096</u>
Proposed Amortizations over 2 Years	225,548

Originally filed as a rider request but the Company has asked the Commission to consider during as part of this rate filing

From: Hager, Michael R  
 To: Felling, John M  
 Cc: McLaughlin, Bridget; Rennings, Patrick  
 Subject: RE: ND DSM

Sent: Thu 11/18/2010

Hi John,

Per our conversation, you inquired about the anticipated ND-Elec Regulatory Asset balance as of 12/31/2010:

Our Reg. Asset balance as of 10.31.2010 =	\$339,060
Our Nov. and Dec. forecasted spend =	\$112,036
Anticipated balance as of 12/31/2010 =	\$451,096

This does not include ARRA funded projects. That "recovery mechanism" involves a quarterly application process that Budget facilitates, therefore, I don't believe we should factor in that balance for Rate making purposes.

The Nov. and Dec. forecast details:

96,973	15,063	112,036
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Month	State	Category	Project Name	Account	Nov	Dec
November 2010 Forecast	North Dakota	Electric	11072071 - ECPND Business Savers Switch	LM	4,411	1,430
November 2010 Forecast	North Dakota	Electric	11072086 - ECPND Electric Rate Savings	LM	129	135
November 2010 Forecast	North Dakota	Electric	11072306 - ECPND Res Home Energy Audits	RES	0	0
November 2010 Forecast	North Dakota	Electric	11072371 - ECPND Resident Savers Switch	LM	92,433	13,498

The following is from docket PU-08-171

Order

The Commission Orders:

- NSP's proposed cost recovery tariff rider is denied.
- NSP is authorized to record expenditures to further promote its existing Savers Switch and Peak & Energy Control Service load management programs in a deferred account for amortization in NSP's next general rate case. The amount deferred may not exceed \$266,904 per year.

Staff Adj. 21-1

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 & PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-304

Date Received: May 27, 2011

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Question:

Subject: DSM

Reference: Felling Direct Page 71 and associated workpaper Adjustment A33 2011 RC DSM Referring to the document hand labeled A33-2, please provide the back up documentation to show that the "Balance as of 10-31-2010 \$339,060" is related to Savers Switch and/or Peak & Energy Control as order by the Commission.

Response:

Please see Attachment A to this response for a spreadsheet supporting the \$339,060 in deferred account spend referenced in workpaper A33-2. In its November 5, 2008 Order, the North Dakota Public Service Commission approved a deferred account under Case No. PU-08-171 for up to \$266,904 per year for our Business Saver's Switch, Residential Saver's Switch and Peak and Energy Control programs. The accumulated balance of \$339,060 cited above spans 2008 thru October 31, 2010 and in no single year exceeds the approved load management amounts approved in Case No. PU-08-171.

Attachment A is from the JD Edward details universe and is broken down into the various account program types, including the "Consumer Education" and "Home Energy Audits" programs that are included in the \$339,060 total but are not directly related to the two Savers Switch or Peak and Energy Control programs. Of the \$339,060 in deferred charges, \$338,603 is for the Business and Residential Saver's Switch and Peak and Energy Control programs. The balance of \$457.26 is for Consumer Education and Home Energy Audit charges from 2008 - 2010.

The \$457.28 that was charged to Consumer Education and Home Energy Audits appear to be in error and are the result of a mistake being made in the subledgers charged for these costs. The impact of removing these costs from the 2011 Test Year cost of service is likely zero, as all costs are rounded to the nearest thousand for test year purposes.

Staff Adj. 21-2

Witness: John M. Felling  
Preparer: Michael R. Hager  
Title: Consultant  
Department: TTC Finance  
Telephone: 303-571-7472  
Date: July 5, 2011

1

2       **23) 2011 DSM**

3    **Q. PLEASE DESCRIBE THE 2011 DSM AMORTIZATION.**

4    **A. In Case No. PU-08-171, Demand Side Management & Cost Recovery Rider**  
5       **Tariff, the Commission order states**

6       *“NSP is authorized to record expenditures to further promote its existing Savers Switch*  
7       *and Peak & Energy Control Service load management programs in a deferred account for*  
8       *amortization in NSP’s next general rate case. The amount deferred may not exceed*  
9       *\$266,904 per year”.*

10       In the 2009 and 2010 calendar years, the Company has a projected deferred  
11       balance related to DSM of \$451,000. We are therefore proposing a two-year  
12       amortization of \$226,000 per year.

13

14       The detailed jurisdictional operating income impacts of the adjustment are  
15       reflected on Exhibit \_\_\_(JMF-1), Schedule 5b, page 4, column 34. As shown  
16       on Schedule 5b, page 4, column 34, row 31, this adjustment increases test-year  
17       revenue requirements by \$226,000.

18

19       In addition to the amortization of the past years balance, the Company has  
20       included \$266,904 in its 2011 test-year O&M budget related to DSM. This  
21       represents the anticipated ongoing annual expense for DSM.

22

23       **F. Other Ratemaking Adjustments**

24       **24) Change in the Cost of Capital**

25       The revenue requirements associated with the above adjustments described in  
26       sections X and XII of my testimony are calculated using the approved cost of  
27       capital in Case No. PU-07-776. We calculate the revenue requirement impact

- Non Public Document – Contains Trade Secret Data  
 Public Document – Trade Secret Data Excised  
 Public Document

Xcel Energy

Docket No.: PU-10-657 and PU-11-55

Response To: Blue Ridge Consulting

Data Request No.

Requestor: Michael McGarry

AS-RR-303

Date Received: May 27, 2011

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Question:

Subject: Updated Filing Removing Merricourt

Reference: Updated application dated May 10, 2011 removing the Merricourt Wind Project. Please supply electronic files in their native format with all formulas and links intact for the updated Exhibits JMF-1, Schedule 5A, 5b, 7, 8A, and 8B.

Response:

Attachments A through F to this response are provided in live Excel spreadsheet format. These attachments are the above-noted schedules, respectively, that were included in pdf format with the Company's May 10, 2011 report to the North Dakota Public Service Commission updating the impact of the termination of the Merricourt Wind Project on Xcel Energy's pending electric rate case. (Case Nos. PU-10-657 and PU-11-55.)

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Preparer: John M. Felling  
Title: Rate Consultant  
Department: Revenue Requirements  
Telephone: 612-330-6539  
Date: July 5, 2011

Staff Adj. 22-1

**Rate Base Detail - Cash Working Capital**

Expense	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Investible Expenses</b>							
<b>Fuel Expenses</b>							
1 Coal & Rail Transport	21.08	353,157	7,444,550	22,115	466,184	331,042	6,978,365
2 Gas for Generation	38.45	180,864	6,954,990	11,327	435,523	169,557	6,519,467
3 Oil	22.51	883	15,374	43	968	640	14,408
4 Nuclear & EOL	0.00	111,489	0	6,982	0	104,517	0
5 Nuclear Disposal	78.00	11,164	849,464	649	49,324	10,515	799,140
		657,397	15,263,378	41,116	951,999	616,271	14,311,378
<b>Purchased Power</b>							
7 Purchases	28.12	894,154	25,143,610	54,286	1,526,522	839,868	23,617,088
8 Interchange	38.21	119,793	4,577,281	7,047	269,266	112,746	4,309,025
		1,013,947	29,720,901	61,333	1,795,788	952,614	27,926,113
<b>Labor &amp; Related Costs</b>							
9 Regular Payroll	12.31	367,828	4,527,963	22,236	273,725	345,592	4,254,238
10 Incentive Compensation	255.05	21,732	5,542,747	1,329	339,961	20,403	5,203,765
11 Pension & Benefits	19.20	78,160	1,519,872	4,828	92,688	74,332	1,427,174
12 Subtotal Labor & Related		466,720	11,590,581	28,393	706,384	440,327	10,885,197
14 All Other Operating Expenses	35.01	552,802	19,353,595	29,308	1,029,073	523,494	18,327,522
15 Property Tax	358.72	115,650	41,254,668	5,863	2,016,538	109,997	38,238,130
16 Employer's Payroll Taxes	26.56	30,033	797,676	1,815	48,206	28,218	749,470
17 Gross Earnings Tax	41.48	0	0	0	0	0	0
18 Federal Income Tax	37.75	(34,212)	(1,291,498)	(5,853)	(220,951)	(28,359)	(1,070,547)
19 State Income Tax	37.75	(4,589)	(172,484)	(924)	(34,894)	(13,570)	(517,570)
20 State Sales Tax Customer Billings	35.73	136,595	4,951,999	0	0	138,686	4,951,999
21 Total Expenses	41.34	2,838,353	121,669,837	160,841	6,288,144	2,777,513	115,180,683
22 Net Annual Expense Amount			332,791		17,228		315,564
<b>Revenues</b>							
23 Computer Billing	100.00%	3,094,653	137,942,263	184,504	7,477,151	2,870,349	130,465,112
24 Hand Billed	46.45	0	0	0	0	0	0
25 Retail Revenue Adjustments	0.00%	0	0	0	0	0	0
26 Interdepartmental	0.00	607	0	0	0	607	0
27 Late Payment	0.00	5,490	0	355	0	5,135	0
28 Connect and Trouble Charges	42.85	2,281	98,989	243	10,413	2,018	86,475
29 C/P Incentive	0.00	0	0	0	0	0	0
30 Rentals	114.17	4,032	460,333	255	29,113	3,777	431,220
31 Interchange Revenues	38.21	446,657	17,066,764	26,889	1,027,429	419,768	16,039,335
32 Sales for Resale	37.10	148,783	5,519,849	9,166	340,059	139,617	5,179,791
33 Production Associated Revenues	37.10	6,436	238,776	403	14,951	6,033	223,824
34 MISD	14.00	13,342	186,788	775	10,850	12,567	175,938
35 Point to Point Firm	37.10	59,651	2,213,052	3,466	128,589	56,185	2,084,464
36 Services & Facilities	37.10	8,828	327,519	507	18,810	8,321	308,709
37 Ancillary	37.10	23,148	859,791	1,345	49,900	21,803	806,991
38 Distribution Associated Revenues	42.85	1,872	80,219	0	0	1,872	80,219
39 Other	42.85	2,356	100,958	(652)	(27,940)	3,008	128,899
40 JOA - Rev Into PSC	37.10	(4,896)	(181,642)	(307)	(11,390)	(4,589)	(170,252)
41 (blank)	0.00	0	0	0	0	0	0
42 (blank)	0.00	0	0	0	0	0	0
43 (blank)	0.00	0	0	0	0	0	0
44 Total Revenues	43.94	3,763,420	164,910,560	206,949	9,087,935	3,546,471	155,842,625
45 Net Annual Amount			451,810		24,844		426,966
46 Expense / Revenue Factor			0.7628		0.7772		
47 Allocated Revenue Amount			353,696		19,308		
48 Net Cash Working Capital			20,807		2,061		18,828

Due to rounding, may not be exactly to rate base number

Staff Adj. 22-2

**Rate Base Detail - Cash Working Capital**

Business	Total Company Electric		ND Retail Electric		All Other	
	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<b>Includable Expenses</b>						
<b>Fuel Expenses</b>						
1 Coal & Rail Transport	353,157	7,444,650	22,115	466,184	331,042	6,978,366
2 Gas for Generation	180,884	6,954,990	11,327	435,523	169,557	6,519,487
3 Oil	693	15,374	43	968	640	14,406
4 Nuclear & EOL	111,499	0	6,982	0	104,517	0
5 Nuclear Disposal	11,164	648,464	649	49,324	10,515	798,140
6	657,387	15,263,378	41,116	951,999	616,271	14,311,378
<b>Purchased Power</b>						
7 Purchases	894,154	25,143,610	54,296	1,526,522	839,859	23,617,088
8 Interchange	119,293	4,577,231	7,047	269,266	112,246	4,308,025
	1,013,947	29,720,901	61,333	1,795,788	952,614	27,925,113
<b>Labor &amp; Related Costs</b>						
9 Regular Payroll	367,828	4,527,963	22,236	273,725	345,592	4,254,238
10 Incentive Compensation	21,732	5,542,747	1,329	338,961	20,403	5,203,785
11 Pension & Benefits	79,180	1,318,872	4,828	92,898	74,332	1,427,174
12 Subtotal Labor & Related	468,720	11,590,581	28,393	705,384	440,327	10,685,197
13 All Other Operating Expenses	552,802	19,343,595	29,579	1,035,561	523,223	18,318,034
14 Property Tax	117,651	41,968,465	5,911	2,106,572	111,740	39,859,893
15 Employer's Payroll Taxes	30,033	787,678	1,815	48,206	28,218	749,470
16 Gross Earnings Tax	0	0	0	0	0	0
17 Federal Income Tax	(51,211)	(1,933,219)	(5,778)	(218,136)	(45,433)	(1,715,083)
18 State Income Tax	(9,387)	(364,374)	(910)	(34,335)	(8,478)	(320,039)
19 State Sales Tax Customer Billings	139,595	4,951,999	0	0	139,595	4,951,999
20 Total Expenses	2,918,636	121,359,002	181,459	6,393,039	2,737,077	114,965,963
21			41,70			
22 Net Annual Expense Amount		332,490		17,515		314,975
<b>Revenues</b>						
23 Computer Billing	3,034,853	137,942,263	184,504	7,477,151	2,850,349	130,465,112
24 Hand Billed	0	0	0	0	0	0
25 Retail Revenue Adjustments	0	0	0	0	0	0
26 Interdepartmental	607	0	355	0	607	0
27 Late Payment	5,490	0	243	10,413	5,135	0
28 Connect and Trouble Charges	2,261	96,898	0	0	2,018	86,475
29 CIP Incentive	0	0	0	0	0	0
30 Rentals	114,17	4,032	255	29,113	3,777	431,220
31 Interchange Revenues	38,21	17,066,764	26,869	1,027,429	419,768	16,038,335
32 Sales for Retail	148,783	5,519,849	9,166	340,059	139,617	5,179,791
33 Production Associated Revenues	6,436	238,776	483	14,951	6,033	223,824
34 MISO	13,342	166,788	775	10,850	12,567	175,936
35 Point to Point Firm	59,651	2,213,052	3,466	128,589	56,185	2,064,464
36 Services & Facilities	6,828	327,519	507	18,810	6,321	308,709
37 Ancillary	23,148	858,791	1,345	49,900	21,803	808,891
38 Distribution Associated Revenues	1,872	80,219	0	0	1,872	80,219
39 Other	2,356	100,959	(852)	(27,940)	3,008	128,899
40 JOA - Rev into PSC	(4,896)	(181,642)	(307)	(11,390)	(4,589)	(170,252)
41 (blank)	0	0	0	0	0	0
42 (blank)	0	0	0	0	0	0
43 (blank)	0	0	0	0	0	0
44 Total Revenues	3,753,420	164,810,560	206,949	9,067,935	3,546,471	155,942,825
45		451,810		24,844		426,966
46 Net Annual Amount		0,776		0,7802		0
47 Expense / Revenue Factor		351,312		19,383		16,955
48 Allocated Revenue Amount		18,822		1,868		16,955
49 Net Cash Working Capital						

Due to rounding, may not be exactly to rate base number:

Staff Adj. 22 - 3