

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

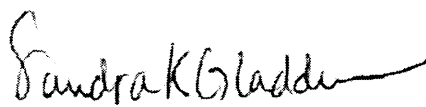
In the matter of the Application of Northern)
States Power Company, a Minnesota Corporation)
For Authority to Increase Rates for Electric Service) Case No. PU - 10-657
In North Dakota) Case No. PU - 11-55

**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

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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

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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

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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

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- 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?**

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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.¹

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.

¹ 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.

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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 \$17,990,000² should be
13 reduced by \$6,545,000 resulting in a rate increase of \$11,446,000.³ The
14 Company's 2012 Step revised proposed rate increase of \$20,365,000⁴ should be
15 adjusted by (\$6,691,000) resulting in a revenue requirement for 2012 of
16 \$13,674,000.⁵ 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.

² Exhibit ____ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission.

³ Exhibit ____ (MJM-2) Schedule 1, Comparison of Company's 2011 Revenue Requirements and Staff's Proposal.

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

⁵ Exhibit ____ (MJM-2) Schedule 5, Comparison of Company's 2012 Revenue Requirements and Staff's Proposal.

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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**

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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.⁶

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 2011.⁷ 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.⁸

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

⁶ Exhibit ____ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission.

⁷ Direct Testimony of John M. Felling page 1, lines 16-17.

⁸ Direct Testimony of John M. Felling page 3, lines 4-12.

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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 \$317,494,000,⁹ 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.¹⁰ For the 2012 step, the Company's revised proposed an average
12 rate base of \$327,429,000.¹¹

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 \$27,749,000¹²
17 which is based on the revised adjusted rate base of \$317,494,000¹³ and a proposed
18 rate of return of 8.74%.¹⁴ The Company calculated an adjusted pro forma income

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

¹⁰ Direct Testimony of John M. Felling, page 34, lines 7-18.

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

¹² Ibid., Revised Schedule 7.

¹³ Ibid., Revised Schedule 7.

¹⁴ Ibid., Revised Schedule 7.

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1 deficiency of \$10,934,000.¹⁵ When considering income taxes, the resulting
2 revenue requirement requested by the Company is \$17,991,000.¹⁶ For the 2012
3 step, the Company is requesting a revenue requirement of \$20,365,000¹⁷ 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

¹⁵ Ibid., Revised Schedule 7.

¹⁶ Ibid., Revised Schedule 7.

¹⁷ Ibid., Revised Schedule 7.

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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.

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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.¹⁸

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, 2011.¹⁹ However, these are proposed regulations that are only
20 being considered by the EPA and for which comments are being received.

¹⁸ Direct Testimony of John M. Felling, page 27, lines 23-24.

¹⁹ Exhibit ____ (MJM-4) Data Request and Response AS-RR-302.

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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.**

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1 A. The Company included this project in the 2011 test year even though the
2 scheduled in-service date was 2012.²⁰ 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 2012.²¹

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/Byron 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 2011.²²

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

²⁰ Exhibit ____ (MJM-5) IRB-1, Schedule 4, page 1 of 3.

²¹ Exhibit ____ (MJM-6) Data Request and Response AS-2-RR-22.

²² Exhibit ____ (MJM-7) Data Request and Response AS-2-RR-13.

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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.²³ 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 \$122,242.²⁴

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 (MNPSC) in MNPSC 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

²³ Exhibit ____ (MJM-7) Data Request and Response AS-2-RR-13.

²⁴ Exhibit ____ (MJM-7) Data Request and Response AS-2-RR-13, Attachment A, page 1 of 1.

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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.²⁵

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.”²⁶
25

²⁵ Exhibit __ (MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission.

²⁶ Exhibit __ (MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission, page 4.

Direct Testimony and Exhibits of
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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.²⁷

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.²⁸

²⁷ Exhibit___(MJM-8) April 10, 2009 Filing Xcel Energy to Minnesota Public Service Commission, page 8.

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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.

²⁸ Exhibit ____ (MJM-9) September 14, 2009 Order approving OES recommendation on Wind2battery.

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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 \$8,000.²⁹ 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.

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

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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 \$131,000³⁰ and increased interest expense by \$1,000.³¹

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 request³² 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

³⁰ Exhibit___ (JMF-1) Schedule 5a, Page 3 of 3, line 29, Column 13.

³¹ Exhibit___ (JMF-1) Schedule 5b, Page 2 of 5, line 14, Column 20.

³² Exhibit___ (MJM-10) Data Request and Response AS-RR-231.

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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?**

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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, 2010.³³

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.³⁴

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.³⁵

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

³³ Exhibit ____ (MJM-11) Data Request and Response AS-RR-130.

³⁴ Exhibit ____ (MJM-11) Data Request and Response AS-RR-130.

³⁵ Exhibit ____ (MJM-11) Data Request and Response AS-RR-130.

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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.³⁶ 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.³⁷

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

³⁶ Direct Testimony of Jill H. Reed, p. 15, lines 20-21.

³⁷ Exhibit ____ (MJM-12) Data Request and Response AS-RR-148.

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

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 \$12,000.³⁹

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?**

³⁸ Exhibit ____ (MJM-12) Data Request and Response AS-RR-148.

³⁹ Exhibit ____ (MJM-13) Data Request and Response AS-RR-149.

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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 2010.⁴⁰

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 2011.⁴¹

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 \$80,838.⁴²

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.

⁴⁰ Exhibit ____ (MJM-14) Data Request and Response AS-RR-151.

⁴¹ Exhibit ____ (MJM-15) Data Request and Response AS-RR-196.

⁴² Exhibit ____ (MJM-16) Data Request and Response AS-RR-328.

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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.⁴³ The Company also eliminated a post
4 retirement medical benefit⁴⁴ 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**

⁴³ Direct testimony of Jill H. Reed, page 19, lines 3-6.

⁴⁴ Direct testimony of Jill H. Reed, page 19, lines 13-14.

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1 Unit 3, resulting in a North Dakota jurisdictional downward adjustment to
2 mercury sorbent costs of \$52,061.⁴⁵

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, 2011.⁴⁶ 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.

⁴⁵ Exhibit ____ (MJM-17) Company Workpaper A14-2.

⁴⁶ Exhibit ____ (MJM-4) Data Request and Response AS-RR-302.

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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.⁴⁷ 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

⁴⁷ Exhibit ____ (MJM-18) Data Request and Response AS-RR-342 Revised.

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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.⁴⁸ 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.⁴⁹ This total
7 increase—an additional 596 poles at \$1,049 per pole—is about \$625,000 for
8 NSPM company-wide.⁵⁰

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 \$18,125.⁵¹ 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.⁵²

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

⁴⁸ Exhibit ____ (MJM-19) Data Request and Response AS-RR-167.

⁴⁹ Exhibit ____ (MJM-20) Company Workpaper A11-4 and Exhibit ____ (MJM-21) Data Request and Response AS-RR-166.

⁵⁰ Exhibit ____ (MJM-22) Company Workpaper A11-2.

⁵¹ Exhibit ____ (MJM-22) Company Workpaper A11-2.

⁵² Exhibit ____ (MJM-20) Company Workpaper A11-4.

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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.⁵³ 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-

⁵³ Exhibit ____ (MJM-19) Data Request and Response AS-RR-167.

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1 energy related bad debt expense of \$8,000.⁵⁴ 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 \$46,000.⁵⁵

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's⁵⁶ 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.

⁵⁴ Direct Testimony of John M. Felling, page 59, lines 19-22.

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

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

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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%
Test year	\$13,954,946	21%

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 2010.⁵⁷ 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.⁵⁸

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

⁵⁷ Exhibit ____ (MJM-23) Data Request and Response AS-RR-353.

⁵⁸ Exhibit ____ (MJM-23) Data Request and Response AS-RR-353.

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activities by Customer Care, and d) increased customer assistance payments.”⁵⁹

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

Q. WHAT DO YOU RECOMMEND?

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

Adjustment 12-Economic Development Costs

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

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

⁵⁹ Exhibit ____ (MJM-24) Data Request and Response AS-RR-352.

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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.⁶⁰ 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 426.1.⁶¹

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 1st
14 \$100,000 (or up to \$50,000).

15 **Q. WHAT DO YOU 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

⁶⁰ Direct Testimony of John M. Felling page 62, Lines 13-20.

⁶¹ Exhibit ____ (MJM-25) Company Workpaper A15-3.

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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.⁶² The Company
16 included 50%, or \$131,608, as an adjustment increasing operating expenses.⁶³
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.⁶⁴

⁶² Direct Testimony of John M. Felling, page 63, line 26 – page 64, line 25 and Exhibit ____ (MJM-26) Company Workpaper A18-2.

⁶³ Direct Testimony of John M. Felling, page 63, lines 24-25 and Exhibit ____ (MJM-26) Company Workpaper A18-2).

⁶⁴ Exhibit ____ (MJM-27) December 22, 2008, Settlement Agreement – Charitable Contributions, PU-07-776, page 14, paragraph J.

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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).

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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 \$1,329,426.⁶⁵ 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.⁶⁶

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

⁶⁵ Direct Testimony of Jill H. Reed, page 5, line 20-21.

⁶⁶ Direct Testimony of John M. Felling, page 66, lines 14-16.

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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 \$31,779.⁶⁷

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%.⁶⁸

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

⁶⁷ Exhibit ____ (MJM-28) Data Request and Response AS-RR-350, parts d and e.

⁶⁸ Exhibit ____ (MJM-29) Exhibit ____ (JHR-1), Schedule 2.

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

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.⁷⁰

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.

⁶⁹ Exhibit ____ (MJM-30) Data Request and Response AS-RR-140.

⁷⁰ Exhibit ____ (MJM-31) Data Request and Response AS-RR-351.

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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.⁷¹ 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))."⁷² 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

⁷¹ Exhibit ____ (MJM-31) Data Request and Response AS-RR-351, Attachment A, page 1 of 17.

⁷² Exhibit ____ (MJM-31) Data Request and Response AS-RR-351, Attachment A, page 2 of 17.

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1 \$98,772 of NSPM's \$1,654,923 allocation.⁷³ 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.⁷⁴

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."⁷⁵

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).

⁷³ Exhibit ____ (MJM-32) Company Workpaper A28-2.

⁷⁴ Direct Testimony of John M. Felling, page 67, lines 22-24.

⁷⁵ Exhibit ____ (MJM-33) Data Request and Response AS-RR-299.

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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.^{76 77}

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 2011.⁷⁸

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

⁷⁶ Direct Testimony Dennis L. Koehl, page 30, lines 22-26.

⁷⁷ Exhibit ____ (MJM-34) 2010 Form 10-K page 45, legal contingencies.

⁷⁸ Direct Testimony of Dennis L. Koehl, page 31, lines 1-8.

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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."⁷⁹

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.⁸⁰

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.⁸¹ 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.**

⁷⁹ Exhibit ____ (MJM-35) Data Request and Response AS-RR-238 supplemental Xcel Letter on DOE Settlement dated July 8, 2011

⁸⁰ Exhibit ____ (MJM-36) Data Request and Response AS-RR-238.

⁸¹ Exhibit ____ (MJM-35) Data Request and Response AS-RR-238 supplemental.

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1 A. The Company has included \$91,182 in the test year for Directors' and Officers'
2 (D&O) insurance.⁸² 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.**

⁸² Exhibit ___ (MJM-37) Data Request and Response AS-RR-205, Attachment D.

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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 2012.⁸³ Listed below are the Company's total
4 request and amortization amounts for the test year.⁸⁴

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

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."⁸⁵ 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

⁸³ Direct Testimony of John M. Felling, pages 70 and 71.

⁸⁴ 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.

⁸⁵ Direct Testimony of John M. Felling, page 69, lines 5-7.

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1 increase in 2008,⁸⁶ 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.⁸⁷

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?**

⁸⁶ Exhibit___ (MJM-38) Case No. PU-07-776 December 31, 2008 Order Adopting Settlement.

⁸⁷ Direct Testimony of John M. Felling, page 69, line 5-6.

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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 V. **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 \$20,365,000⁸⁸ 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.

⁸⁸ Exhibit___ (MJM-3) May 10, 2011 Letter: David H. Sederquist to Darrell Nitschke, Executive Secretary, North Dakota Public Service Commission, Revised Schedule 7.

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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*

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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.”⁸⁹*

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

⁸⁹ Exhibit ____ (MJM-39) Email from Mr. Larry Gauper to Mr. Michael Diller, dated June 28, 2011.

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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.

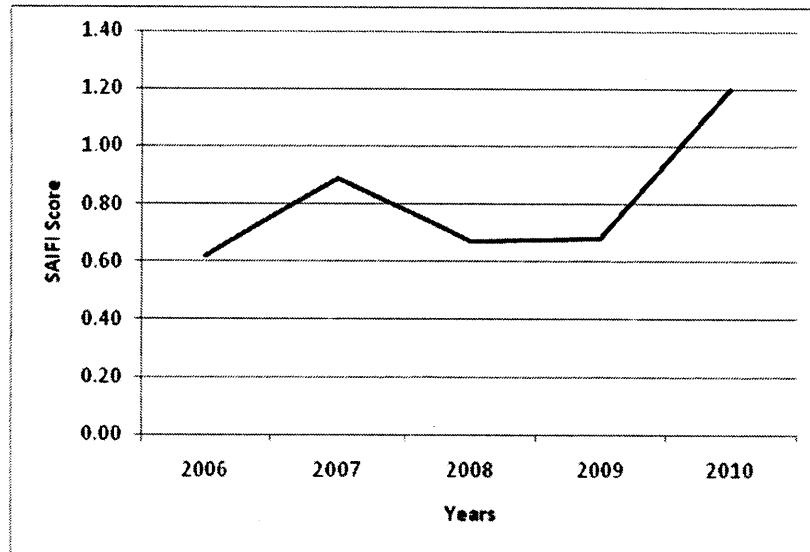
17 **Q. HAS THE 2010 SAIFI SCORE INCREASED OR DECREASED FROM**
18 **PREVIOUS YEARS?**

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.⁹⁰

⁹⁰ Exhibit ____ (MJM-40) Data Request and Response AS-RR-333.

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Figure 1: SAIFI Score by Year



Q. WAS THE INCREASE IN 2010 CONSISTENT ACROSS ALL REGIONS?

A. No. Of the five major substations, two (Cass County and Souris) actually improved. Of the other three (Red River, Gateway, and Nordic), Gateway and Nordic experienced the most significant increases: Gateway rose from 0.19 in 2009 to 0.68 in 2010 while Nordic rose from 0.55 in 2009 to 2.27 in 2010.

Q. HOW DOES THE COMPANY EXPLAIN THE INCREASE?

A. The Company provided information that shows that most of the causes were related to vegetation encroachment and feeder cable failures.⁹¹ NSP also provided a list of major outage events at the major substation areas that caused significant SAIFI increases.

Q. WHAT IS CAIDI?

⁹¹ Exhibit ____ (MJM-41) Data Request and Response AS-RR-343, Attachment B.

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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

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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,⁹² 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?**

⁹² Exhibit ____ (MJM-42) Data Request and Response AS-RR-334.

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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 Year⁹³**

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
Total	\$ 319,893	\$ 1,040,246	\$ 376,312	\$ 1,233,958	\$ 982,438
New to 2011					
Tap Improvement Program				\$ 9,000	
Install Remote Fault Indicators				\$ 63,000	
Total 2011				\$ 1,054,438	

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.

⁹³ Exhibit ____ (MJM-42) Data Request and Response AS-RR-334.

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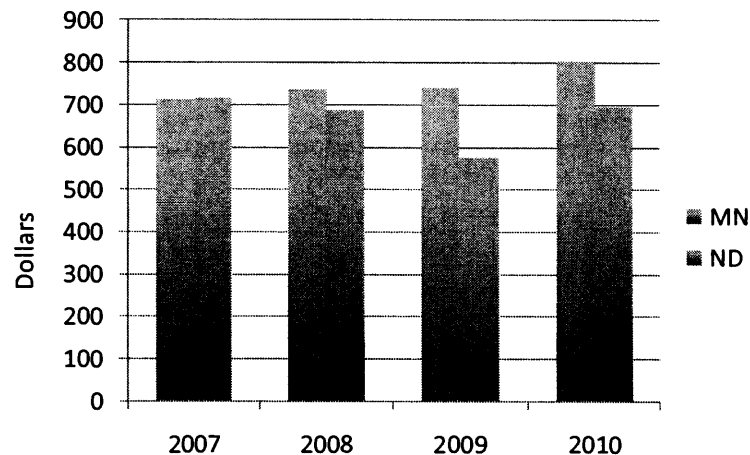
1 **Q. IS THERE ANY OTHER INDICATOR THAT WOULD SUPPORT A**
2 **MORE FOCUSED REVIEW OF THE COMPANY'S RELIABILITY?**

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.

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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.)

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- 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.⁹⁴

22 **Q. HOW DOES EXTENDING THE REMAINING LIFE OF PRAIRIE**
23 **ISLAND BECOME AN ISSUE?**

⁹⁴ Exhibit ____ (MJM-43) Data Request and Response AS-2-RR-53

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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.⁹⁵ 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

⁹⁵ Exhibit ____ (MJM-44) Data Request and Response AS-2-RR-94.

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1 October 2011.⁹⁶ 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.⁹⁷

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 2010.⁹⁸

17 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

18 A. Yes.

⁹⁶ Exhibit ____ (MJM-45) Data Request and Response AS-RR-280.

⁹⁷ Exhibit ____ (MJM-44) Data Request and Response AS-2-RR-94.

⁹⁸ Exhibit ____ (MJM-46) Xcel Energy Form 10-K Year Ended December 31, 2010, page 145 para 2.

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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,

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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 prudence 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

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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 intervenor'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*

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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 unbundle 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 unbundle 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.

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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 (MDPU)

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.

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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.

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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

Line #	Schedule #	Description
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 ¹ (B)	Proposed Adjustment (C)	Staff's Position (D)	Adjustment Reference (E)
1	Rate Base				
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	Operating Revenues				
17	Retail	\$ 164,504	\$ -	\$ 164,504	
18	Other Operating	42,445		42,445	
19	Total Operating Revenues	\$ 206,949	\$ -	\$ 206,950	
20	Operating Expenses				
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	Total Expenses	\$ 190,134		\$ 189,079	
40	AFUDC	-		-	
41	Total Operating Income	\$ 16,815	\$ -	\$ 17,871	
42	Income Deficiency	\$ 10,934		\$ 6,955	
43	Revenue Conversion Factor	1.64541	-	1.64541	
44	Revenue Deficiency	\$ 17,991	\$ (6,545)	\$ 11,446	
45	Revenue Deficiency Percent Change	17.991	36.38%	63.62%	

¹ Exhibit (JMF-1), Schedule 7 and Schedule 8a, Revised 5/9/11

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric
 Twelve Months Ending December 31, 2011
 Rate of Return Calculation

Docket No. PU-10-657 & PU-11-55
 Exhibit (MJM-2), Schedule 2
 Page 1 of 1

Line	Description (A)	Capital Structure (B)	Ratio (C)	Cost % (D)	Weighted Cost % (E)	Reference (F)
<u>Company Rate of Return</u>						
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

<u>Staff Rate of Return</u>						
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

Northern States Power Company - Electric

Twelve Months Ending December 31, 2011

Impact of Staff's Rate of Return on Company's Proposed Revenue Requirements

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 2.1
Page 1 of 1

(in thousands)

Line	Description (A)	Company 2011 Test Year (B)	Proposed Adjustment (C)	Staff's Position (D)	Adjustment Reference (E)
1	Total Rate Base	\$ 317,494		\$ 317,494	
2	Rate of Return	8.74%	-0.89%	7.85%	Schedule 2
3	Return Requirement	\$ 27,749		\$ 24,934	
4	Operating Revenues				
5	Retail	\$ 164,504		\$ 164,504	
6	Other Revenues	42,445		42,445	
7	Total Operating Revenues	\$ 206,949		\$ 206,950	
8	Operating Expenses				
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	\$ 190,134		\$ 190,134	
13	Net Operating Income Before Taxes	\$ 16,815		\$ 16,816	
14	AFUDC	-		-	
15	Operating Income for ROR Calculation	\$ 16,815		\$ 16,816	
16	Income Deficiency	\$ 10,934		\$ 8,118	
17	Revenue Conversion Factor	1.64541		1.64541	
18	Revenue Deficiency	\$ 17,991	\$ (4,633)	\$ 13,358	
19	Revenue Deficiency Percent Change		-25.75%		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Twelve Months Ending December 31, 2011

Summary of Adjustments to Company's Proposed Rate Base

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 3.1
Page 1 of 1

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	<u>Electric Plant in Service</u>				
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	<u>Accumulated Depreciation</u>				
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	<u>Accumulated Deferred Income Taxes</u>				
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	<u>Cash Working Capital</u>				
21	Adjustment 22 Cash Working Capital	Schedule 4.22	<u>\$ (18)</u>	<u>\$ (1)</u>	<u>\$ (2)</u>
22	<u>Prepays & Other</u>				
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
Col E: Computed using Revenue Conversion Factor

7.85%

1.64541

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Twelve Months Ending December 31, 2011

Summary of Staff's Adjustments to Company's Proposed Operating Income

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 3.2
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Line	(A) Description	Reference (B)	O&M Adjustment (C)	Other Taxes & ITC	State Income Tax (D)	Federal Income Tax (E)	NOI Adjustment (F)	Estimated Revenue Requirement Impact (G)
1	<u>Revenue</u>							
2								
3	Total Revenue		\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4	<u>Expenses</u>							
5	<u>Operating Expense: Labor Related</u>							
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	(30)
9	Total Operating Expense: Labor Related		\$ (295)	\$ (3)	\$ 18	\$ 97	\$ 181	\$ (110)
10	<u>Operating Expense: Power Production</u>							
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	<u>Operating Expense: Distribution</u>							
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	<u>Operating Expense: Customer Accounting</u>							
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	<u>Operating Expense: Econ Dvlp & Other</u>							
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	<u>Operating Expense: Administrative & General</u>							
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. A26)	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	<u>Depreciation and Amortization</u>							
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)	(26)	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	<u>Tax totals</u>			\$ (49)	\$ 116	\$ 588		
42	State and Federal Income Tax Total		\$ (940)			\$ 704		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Twelve Months Ending December 31, 2011

Summary of Staff's Adjustments to Company's Proposed Operating Income

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Exhibit (MJM-2), Schedule 3.2

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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

**Northern States Power Company - Electric
Adjustment 1
Mercury Emissions (Co. Adj. A38)**

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.1
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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	Impact to Rate Base	\$ 252,479	\$ (252,479)	\$ -		
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	\$ 13,856	\$ (13,856)	\$ -		
10	State Income Tax Rate	6.5%		6.5%		
11	Effect on State income tax expense	\$ (901)	\$ 901	\$ -		
12	Federal Taxable	\$ 12,955		\$ -		
13	Federal Income Tax Rate	35%		35%		
14	Effect on Federal income tax expense	\$ (4,534)	\$ 4,534	\$ -		
15	Total Expense	\$ 8,421		\$ -		
16	Impact to Operating Income	\$ (8,421)	\$ 8,421	\$ -		
17	Rate Base: Mercury Emissions	BOY	EOY	Average		
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

Northern States Power Company - Electric

Adjustment 2

Remove Transmission-Pleasant Valley/Bryon Not in Service

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.2
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
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	Impact to Rate Base	\$ 115,000	\$ (115,000)	\$ -		
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	\$ (10,335)	\$ 10,335	\$ -		
12	Federal Taxable	\$ 148,665		\$ -		
13	Federal Income Tax Rate	35%		35%		
14	Effect on Federal income tax expense	\$ (52,033)	\$ 52,033	\$ -		
15	Total Expense	\$ 96,632		\$ -		
16	Impact to Operating Income	\$ (96,632)	\$ 96,632	\$ -		

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

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
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	Impact to Rate Base	\$ 708,828	\$ (708,828)	\$ -		
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	Impact to Operating Income	\$ (26,706)	\$ 26,706	\$ -		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 4

Remove Wind2Battery Project and ITC (Co. Adj. A5)

Docket No. PU-10-657 & PU-11-55
Exhibit___(MJM-2), Schedule 4.4
Page 1 of 2

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
1	<u>Rate Base:</u>					
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	Total Accumulated Deferred Taxes	\$ (37,565)	\$ 37,565	\$ -		
7	Impact to Rate Base	<u>\$ 229,550</u>	<u>\$ (229,550)</u>	<u>\$ -</u>		
8	<u>Expense:</u>					
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	Total Depreciation and Amortization	\$ 50,376	\$ (50,376)	\$ -		
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	Total Expenses	\$ 49,764	\$ (53,521)	\$ -		
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	Total Expense	<u>\$ 30,244</u>		<u>\$ -</u>		
22	Impact to Operating Income	<u>\$ (30,244)</u>	<u>\$ 30,244</u>	<u>\$ -</u>		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 4

Remove Wind2Battery Project and ITC

Docket No. PU-10-657 & PU-11-55
Exhibit____(MJM-2), Schedule 4.4
Page 2 of 2

Line	Description	(A)	(B)	(C)	(D)	Adjustment Reference (E)
1	<u>Rate Base</u>	2010¹	2011¹	Average		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>		
7	Plus CWIP Ending Balance	Average \$ (1,000,000)	Allocator² 5.8107%	ND Jurisdiction \$ (58,107)		See footnote for reference
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	<u>Expenses</u>	2011¹	Allocator²	ND Jurisdiction		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>		

¹ Xcel MNPUC Petition Dated 4/1/09, Schedule 3, page 1 of 1

² Allocator-Company Workpaper B2

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric
Adjustment 5
 Customer Deposits (Co. Adj. A19)

Docket No. PU-10-657 & PU-11-55
 Exhibit____(MJM-2), Schedule 4.5
 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	Rate Base Prepaids & Other:					
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

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

Exhibit _____ Schedule 4.6

Page 2 of 2

1	Calculations of Impact to Bargaining Unit Wage Difference:				
2	NSPM Estimated 2011 Actual Base Pay		\$	121,895,585	Response AS-RR-331
3	NSPM 2011 Budget Base Pay	\$	122,490,198	122,490,198	Response AS-RR-331
4	NSPM Difference between Budget and Actual			<u>\$ (594,613)</u>	
5	<u>O&M Impact</u>				
6	NSPM Difference between Budget and Actual		\$	(594,613)	Response AS-RR-331
7	ND Electric Average Allocation Factor	6.06%		6.06%	Response AS-RR-331
8	ND Electric Wage Adjustment to Actual	\$	7,425,250	<u>\$ (36,045)</u>	
9	<u>O&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		\$	(36,045)	
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			(594,613)	Response AS-RR-331
24	Estimated Incremental Capital Merit Spend		\$	(251,209)	
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		\$	(7,614)	
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

Northern States Power Company - Electric
Adjustment 7
Employee Benefits

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.7
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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	\$ 2,516,761	<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	\$ (163,589)	\$ 11,553	\$ (152,036)		
17	Federal Taxable	\$ 2,353,172		\$ 2,186,974		
18	Federal Income Tax Rate	35%		35%		
19	Effect on Federal income tax expense	\$ (823,610)	\$ 58,169	\$ (765,441)		
20	Total Expense	\$ 1,529,562		\$ 1,421,533		
21	Impact to Operating Income	\$ (1,529,562)	\$ 108,029	\$ (1,421,533)		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 8

Employee Retirement Programs (Co. Adj. 02)

Docket No. PU-10-657 & PU-11-55
Exhibit___(MJM-2), Schedule 4.8
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	Pension and Benefits	68,833	(80,838)	(12,005)	Workpaper 02-5d	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	Impact to Operating Income	\$ (41,833)	\$ 49,129	\$ 7,296		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 9

Mercury Sorbent Reduction (Co. Adj. A14)

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.9
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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	252,668	(252,668)	-		
5	State Income Tax Rate	6.5%		6.5%		
6	Effect on State income tax expense	\$ (16,423)	\$ 16,423	\$ -		
7	Federal Taxable	\$ 236,245		\$ -		
8	Federal Income Tax Rate	35%		35%		
9	Effect on Federal income tax expense	\$ (82,686)	\$ 82,686	\$ -		
10	Total Expense	\$ 153,559		\$ -		
11	Impact to Operating Income	\$ (153,559)	\$ 153,559	\$ -		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

**Northern States Power Company - Electric
Adjustment 10
Qwest Pole Replacements (Co. Adj. A11)**

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.10

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

Northern States Power Company - Electric

Adjustment 11

Bad Debt (Co. Adj. A10)

Docket No. PU-10-657 & PU-11-55
Exhibit____(MJM-2), Schedule 4.11
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
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	Impact to Operating Income	\$ (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

Northern States Power Company - Electric
Adjustment 12
 Economic Development Costs (Co. Adj. A15)

Docket No. PU-10-657 & PU-11-55
 Exhibit (MJM-2), Schedule 4.12
 Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
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	Impact to Operating Income	\$ (38,914)	\$ 38,914	\$ -		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 13

Charitable Contributions (Co. Adj. A18)

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.13
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	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

Northern States Power Company - Electric

Adjustment 14

Payroll Taxes-Excluded Incentive Comp (Co. Adj. A26)

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.14
Page 1 of 1

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

Northern States Power Company - Electric
Adjustment 15
 Incentive Compensation (Co. Adj. A26)

Docket No. PU-10-657 & PU-11-55
 Exhibit (MJM-2), Schedule 4.15
 Page 1 of 1

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	Line 15 / .15
16	Gross up to 100%	(621,300)				Line 16 x .17
17	Incentive Comp Over 17%	(105,621)	(105,621)			Line 17 - Line 15
18	Difference		(12,426)			
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

Northern States Power Company - Electric

Adjustment 16

Aviation Expense (Co. Adj. A28)

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.16
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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

Northern States Power Company - Electric
Adjustment 17
Nuclear Waste Disposal Litigation Costs

Docket No. PU-10-657 & PU-11-55
 Exhibit (MJM-2), Schedule 4.17
 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	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

Northern States Power Company - Electric
Adjustment 18
 Directors' and Officers' Insurance

Docket No. PU-10-657 & PU-11-55
 Exhibit____(MJM-2), Schedule 4.18
 Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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	<u>\$ (5,927)</u>	<u>\$ 5,927</u>	<u>\$ -</u>		
5	Federal Taxable	\$ 85,255		\$ -		
6	Federal Income Tax Rate	35%		35%		
7	Effect on Federal income tax expense	<u>\$ (29,839)</u>	<u>\$ 29,839</u>	<u>\$ -</u>		
8	Total Expense	<u>\$ 55,416</u>		<u>\$ -</u>		
9	Impact to Operating Income	<u>\$ (55,416)</u>	<u>\$ 55,416</u>	<u>\$ -</u>		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 19

2011 Rate Case Expenses (Co. Adj. A31)

Docket No. PU-10-657 & PU-11-55
Exhibit____(MJM-2), Schedule 4.19
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	Total Rate Case Costs to Amortize	\$ 561,400	-	561,400	Company Workpaper A31-2	3-Year Amortization
2	Amortization Period (Years)	2	1	3		
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

Northern States Power Company - Electric

Adjustment 20

ND EPA Emission Credit Auction Proceeds (Co. Adj. A32)

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

Exhibit (MJM-2), Schedule 4.20

Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (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

Northern States Power Company - Electric
Adjustment 21

2011 Demand Side Management (Co. Adj. A33)

Docket No. PU-10-657 & PU-11-55
Exhibit____(MJM-2), Schedule 4.21
Page 1 of 1

Line	Description	Company Actual (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
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	<u>\$ 2,081</u>	<u>\$ (18,280)</u>	<u>\$ (16,199)</u>		

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric
Adjustment 22
Cash Working Capital

Docket No. PU-10-657 & PU-11-65
Exhibit (MJM-2), Schedule 4.22
Page 2 of 2

Includable Expenses	ND Electric As Provided by Company			Adjustments	Reference	Adjusted		
	Lead Days	Dollars	Dollar x Days			Lead Days	Dollars	Dollar x Days
Fuel Expenses					Schedule 3.2			
1 Coal & Rail Transport	21.08	22,115	466,184			21.08	22,115	466,184
2 Gas for Generation	38.45	11,327	435,523			38.45	11,327	435,523
3 Oil	22.51	43	968			22.51	43	968
4 Nuclear & EOL	0.00	6,982	0			0.00	6,982	0
5 Nuclear Disposal	76.00	649	49,324			76.00	649	49,324
6		41,116	951,999				41,116	951,999
Purchased Power								
7 Purchases	28.12	54,286	1,526,522			28.12	54,286	1,526,522
8 Interchange	38.21	7,047	269,266			38.21	7,047	269,266
		61,333	1,795,788				61,333	1,795,788
Labor & Related Costs								
9 Regular Payroll	12.31	22,236	273,725	(36,045) Adj. 6		12.31	(13,809)	(169,988)
10 Incentive Compensation	255.05	1,329	338,961			255.05	1,329	338,961
11 Pension & Benefits	19.20	4,828	92,698	(258,589) Adj. 7 & 8		19.20	(253,761)	(4,872,211)
12 Subtotal Labor & Related		28,393	705,384				(266,241)	(4,703,238)
13								
14 All Other Operating Expenses	35.01	29,308	1,026,073	(645,030) Adj. 4, 9, 10, 12, 13, 14, 15, 16, 17, 18		35.01	(615,722)	(21,556,424)
15 Property Tax	356.72	5,653	2,016,538	(9,510) Adj. 3		356.72	(3,857)	(1,375,869)
16 Employer's Payroll Taxes	26.56	1,815	48,206	(42,727) Adj. 6, 14, 15		26.56	(40,912)	(1,086,621)
17 Gross Earnings Tax	41.48	0	0			41.48	0	0
18 Federal Income Tax	37.75	(5,853)	(220,951)	587,756		37.75	581,903	21,966,838
19 State Income Tax	37.75	(924)	(34,894)	116,358		37.75	115,434	4,357,620
20 State Sales Tax Customer Billings	35.73	0	0			35.73	0	0
21 Total Expenses		39.10	160,841	6,288,144 (287,787)		-2.76	(126,946)	350,093
22 Net Annual Expense Amount			17,228					959
Revenues	Lag Days	Dollars	Dollar x Days			Lag Days	Dollars	Dollar x Days
23 Computer Billing 100.00%	45.45	164,504	7,477,151			45.45	164,504	7,477,151
24 Hand Billed 0.00%	43.07	0	0			43.07	0	0
25 Retail Revenue Adjustments	0.00	0	0			0.00	0	0
26 Interdepartmental	0.00	0	0			0.00	0	0
27 Late Payment	0.00	355	0			0.00	355	0
28 Connect and Trouble Charges	42.85	243	10,413			42.85	243	10,413
29 CIP Incentive	0.00	0	0			0.00	0	0
30 Rentals	114.17	255	29,113			114.17	255	29,113
31 Interchange Revenues	38.21	26,889	1,027,429			38.21	26,889	1,027,429
32 Sales for Resale	37.10	9,166	340,059			37.10	9,166	340,059
33 Production Associated Revenues	37.10	403	14,951			37.10	403	14,951
34 MISO	14.00	775	10,850			14.00	775	10,850
35 Point to Point Firm	37.10	3,466	128,589			37.10	3,466	128,589
36 Services & Facilities	37.10	507	18,810			37.10	507	18,810
37 Ancillary	37.10	1,345	49,900			37.10	1,345	49,900
38 Distribution Associated Revenues	42.85	0	0			42.85	0	0
39 Other	42.85	(652)	(27,940)			42.85	(652)	(27,940)
40 JOA - Rev fr/to PSC	37.10	(307)	(11,390)			37.10	(307)	(11,390)
41 (blank)	0.00	0	0			0.00	0	0
42 (blank)	0.00	0	0			0.00	0	0
43 (blank)	0.00	0	0			0.00	0	0
44 Total Revenues	43.82	206,949	9,067,935			43.82	206,949	9,067,935
45 Net Annual Amount			24,844					24,844
46 Expense / Revenue Factor			0.7772					-0.6134
47 Allocated Revenue Amount			19,308					(15,240)
48 Net Cash Working Capital			2,081					(16,199)

Due to rounding, may not be exactly to rate base number

Source: Response to AS-RR-303

NORTH DAKOTA PUBLIC SERVICE COMMISSION

Northern States Power Company - Electric

Adjustment 23

Interest Synchronization

Docket No. PU-10-657 & PU-11-55
Exhibit (MJM-2), Schedule 4.23
Page 1 of 1

(in thousands)

Line	Description	Company Amount (A)	Adjustment (B)	Adjusted Amount (C)	Company Reference (D)	Adjustment Reference (E)
1	Rate Base	\$ 327,428	(1,367)	326,061		Rate Base Impact
2	Interest Component of Rate of Return	2.83%		2.83%		per Schedule 3.1
3	Interest Attributable to Rate Base	9,266		9,228		Line 14 \$ (1,367)
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	Impact to Operating Income	\$ (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

(in thousands)

Line	Description (A)	Company 2011 Test Year ¹ (B)	Company with 2012 Step ² (C)	2011 Proposed Adjustment (D)	2012 Step Up with 2011 Adjustments (E)	Adjustment Reference (F)
1	Rate Base					
2	Electric Plant in Service	\$ 752,278	\$ 763,458	\$ (1,769)	\$ 761,689	Schedule 3.1
3	Less: Accumulated Depreciation and Amortization	(370,100)	(370,105)	163	(369,942)	Schedule 3.1
4	Net Plant in Service	\$ 382,178	\$ 393,353	\$ (1,606)	\$ 391,746	
5	Construction Work in Progress	\$ 2,100	\$ 2,100		\$ 2,100	
6	Accumulated Deferred Income Taxes	(78,577)	(80,259)	292	(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	
10	Fuel Inventory	5,674	5,674		5,674	
11	Non-Plant Assets & Liabilities	(6,173)	(6,173)		(6,173)	
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	
14	Rate of Return	8.74%	8.74%		7.85%	Schedule 2
15	Return Requirement	\$ 27,749	\$ 28,617	\$ (3,010)	\$ 25,607	
16	Operating Revenues					
17	Retail	\$ 164,504	\$ 164,504		\$ 164,504	
18	Other Operating	42,445	42,445		42,445	
19	Total Operating Revenues	\$ 206,949	\$ 206,949	\$ -	\$ 206,950	
20	Operating Expenses					
21	Fuel & Purchased Energy	\$ 81,392	\$ 81,392		\$ 81,392	
22	Labor Related	n/a	n/a	\$ (295)	(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	
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	Customer Service & Information	548	548		548	
28	Sales, Econ Dvlp & Other	66	66	(64)	2	Schedule 3.2
29	Administrative & General	13,322	13,322	(314)	13,008	Schedule 3.2
30	Total Operating Expenses	\$ 160,150	\$ 160,421	\$ (1,211)	\$ 159,210	
31	Depreciation and Amortization	\$ 18,153	\$ 18,943	\$ (500)	\$ 18,443	Schedule 3.2
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	
36	State & Federal Income Tax	(6,777)	(6,688)	704	(5,984)	Schedule 3.2
38	Total Taxes	\$ 11,831	\$ 11,344	\$ 656	\$ 12,000	
39	Total Expenses	\$ 190,134	\$ 190,708	\$ (1,055)	\$ 189,653	
40	AFUDC	-	-		-	
41	Total Operating Income	\$ 16,815	\$ 16,240	\$ 1,055	\$ 17,297	
42	Income Deficiency	\$ 10,934	\$ 12,377	\$ (4,066)	\$ 8,310	
43	Revenue Conversion Factor	1.64541	1.64541	-	1.64541	
44	Revenue Deficiency	\$ 17,991	\$ 20,365	\$ (6,691)	\$ 13,674	
45	Revenue Deficiency Percent Change	17.991	20.365	32.85%		

¹ Exhibit (JMF-1), Schedule 7 and Schedule 8a, Revised 5/9/11² 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)

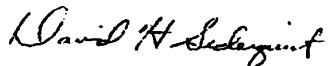
Enclosed with this letter are the following supporting schedules from the Direct Testimony of Mr. John M. Felling, revised to reflect updates related to the termination of the Merricourt Project:

- 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 3a
Revised May 9, 2011
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Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE ADJUSTMENT SCHEDULES
2011 Unaudited Test Year versus Final Adjusted Test Year
(\$000s)

Line No.	Description	Data		Budget Adjustments					
		Unaudited	Transmissions	Wind to Battery	Nuclear	Nuclear	Nuclear	Transmission	Transmission
		(1)	CAPEX (2)	ETC (4)	Production (5)	Production (6)	Production (7)	Interconnect (8)	Interconnect (9)
1	Electric Plant as Booked	\$478,047							
2	Production	\$112,810	(\$1,140)	\$0	\$200	\$200	\$209		(\$89)
3	Transmission	\$125,117							
4	Distribution	\$20,607							
5	General	\$27,990							
6	Common	\$763,976	(\$1,140)	\$0	\$280	\$280	\$209		(\$89)
7	TOTAL Utility Plant in Service								
8	Reserve for Depreciation	\$251,791			\$4	\$4	\$12		(\$1)
9	Production	\$34,060	(\$1)						
10	Transmission	\$57,662							
11	Distribution	\$4,418							
12	General	\$17,300	(\$1)	\$0	\$4	\$4	\$12		(\$1)
13	TOTAL Reserve for Depreciation								
14	Net Utility Plant in Service	\$226,296							
15	Production	\$77,724	(\$1,139)		\$256	\$256	\$197		(\$48)
16	Transmission	\$67,465							
17	Distribution	\$12,186							
18	General	\$10,205							
19	Common	\$393,038	(\$1,139)	\$0	\$256	\$256	\$197		(\$48)
20	Net Utility Plant in Service								
21	Utility Plant Held for Future Use	\$0							
22	Construction Work in Progress	\$2,100							
23	Less: Accumulated Deferred Income Taxes	\$72,101	(\$24)	\$7.23	\$2	\$2	\$64		(\$19)
24	Cash Working Capital	\$1,772							
25	Other Rate Base Items:								
26	Materials and Supplies	\$6,186							
27	Fuel Inventory	\$5,674							
28	Non-Plant Assets & Liabilities	(\$6,173)							
29	Prepayments	\$1,018							
30	Nuclear Outage Amortization	\$2,712							
31	Customer Advances	(\$1)							
32	Customer Deposits	(\$131)							
33	Other Working Capital	\$428							
34	Total Other Rate Base Items	\$6,711	\$0	\$0	\$0	\$0	\$0	\$0	\$3
35	TOTAL Average Rate Base	\$335,320	(\$1,115)	(\$7.23)	\$8	\$8	\$133		(\$70)

Case No. PU-10-657 & PU-11-55
Exhibit (MJM-3) Schedule 66
Revised May 9, 2011
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Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE ADJUSTMENT SCHEDULES
2011 Unadjusted Test Year versus Final Adjusted Test Year
(\$000's)

Line No.	Description	Rate Base Adjustments						Proposed 2011 Test Year (14)
		Steam Production Black Ops 3 & 4 (8)	Prairie Island Life Extension (9)	Steam Production Net Salvage (10)	Other Production Net Salvage (11)	Remove Handover (12)	Income Statement CIMS (13)	
1	Electric Plant as Booked							\$469,014
2	Production							\$110,945
3	Transmission							\$125,117
4	Distribution							\$20,607
5	General							\$27,598
6	Common							\$752,278
	TOTAL Utility Plant in Service	\$0	\$0	\$0	\$0	(\$10,938)	\$0	
7	Reserve for Depreciation							\$251,746
8	Production	(\$294)	(\$26)	\$263	\$33	(\$57)		\$34,883
9	Transmission					(\$2)		\$57,662
10	Distribution							\$6,416
11	General							\$17,390
12	Common							\$770,100
	TOTAL Reserve for Depreciation	(\$294)	(\$26)	\$263	\$33	(\$59)	\$0	
13	Net Utility Plant in Service							\$218,248
14	Production	\$294	\$26	(\$263)	(\$33)	(\$10,444)		\$75,062
15	Transmission					(\$435)		\$67,465
16	Distribution							\$12,188
17	General							\$10,208
18	Common							\$382,176
	Net Utility Plant in Service	\$294	\$26	(\$263)	(\$33)	(\$10,879)	\$0	
19	Utility Plant Held for Future Use							\$0
20	Construction Work in Progress							\$2,100
21	Less: Accumulated Deferred Income Taxes	\$108	\$10	(\$101)	(\$13)	(\$775)		\$78,577
22	Cash Working Capital							\$2,282
23	Other Rate Base Items:							
24	Materials and Supplies							\$6,186
25	Fuel Inventory							\$5,874
26	Non-Plant Assets & Liabilities							(\$6,173)
27	Prepayments							\$1,018
28	Nuclear Outage Amortization							\$2,712
29	Customer Advances							(\$1)
30	Customer Deposits							(\$131)
	Other Working Capital							\$428
31	Total Other Rate Base Items	\$0	\$0	\$0	\$0	\$0	\$0	\$9,711
32	Total Average Rate Base	\$158	\$16	(\$153)	(\$20)	(\$10,104)	\$310	\$317,494

Case No. PU-10-657 & PU-11-55
Exhibit (MJM-3) Schedule 4a
Revised May 9, 2011
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Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
RATE BASE SCHEDULE
2011 Unadjusted Test Year versus Final Adjusted Test Year
(\$100's)

Line No.	Description	Known and Measurable Adjustments						Final Proposed With 2011 Base (20)
		Proposed 2011 Test Year (14)	Manufacturing (15)	Nuclear Production (16)	Transmission Plant Accumulation (17)	Nuclear Outage Amortization (18)	Income Statement CYC (19)	
1	Electric Plant as Booked							
2	Production	\$468,014	\$0	\$6,971	\$4,208			\$474,985
3	Transmission	\$110,945						\$110,945
4	Distribution	\$125,117						\$125,117
5	General	\$20,807						\$20,807
6	Common	\$27,596						\$27,596
	TOTAL Utility Plant in Service	\$752,278	\$0	\$6,971	\$4,208	\$0	\$0	\$763,458
7	Reserve for Depreciation							
8	Production	\$251,746	\$0	(\$364)	\$669			\$250,852
9	Transmission	\$34,883						\$34,883
10	Distribution	\$67,662						\$67,662
11	General	\$6,419						\$6,419
12	Common	\$17,260						\$17,260
	TOTAL Reserve for Depreciation	\$378,100	\$0	(\$364)	\$669	\$0	\$0	\$378,100
13	Net Utility Plant in Service							
14	Production	\$216,268	\$0	\$7,635	\$3,340			\$224,100
15	Transmission	\$76,062						\$76,062
16	Distribution	\$67,455						\$67,455
17	General	\$12,188						\$12,188
18	Common	\$10,206						\$10,206
	Net Utility Plant in Service	\$382,178	\$0	\$7,635	\$3,340	\$0	\$0	\$393,353
19	Utility Plant Held for Future Use	\$0						\$0
20	Construction Work in Progress	\$2,100						\$2,100
21	Less Accumulated Deferred Income Taxes	\$78,577	\$0	\$738	\$677	\$268		\$80,259
22	Cash Working Capital	\$2,062					(\$214)	\$1,848
23	Other Rate Base Items:							
24	Materials and Supplies	\$6,186						\$6,186
25	Fuel Inventory	\$5,674						\$5,674
26	Non-Plant Assets & Liabilities	(\$6,173)						(\$6,173)
27	Prepayments	\$1,018						\$1,018
28	Nuclear Outage Amortization	\$2,712				\$657		\$3,369
29	Customer Advances	(\$1)						(\$1)
30	Customer Deposits	(\$131)						(\$131)
	Other Working Capital	\$426						\$426
31	Total Other Rate Base Items	\$8,711	\$0	\$0	\$0	\$657	\$0	\$10,367
32	Total Average Rate Base	\$317,484	\$0	\$7,097	\$3,963	\$389	(\$214)	\$327,429

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)

Case No. PU-10-657 & PU-11-55
Exhibit (MJM-3) Schedule 5b
Revised May 9, 2011
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Line No.	Description	Data Corrections										Budget Adjustments Plant related			
		Unadjusted (1)	SAWPA Billing (2)	Transmission Charges to Proper Subscribers (3)	Transmission CAPX2020 (4)	Bonus Tax Depreciation (5)	Wind to Battery ITC (6)	Nuclear Production Monies (7)	Nuclear Production MLUR PI (8)	Transmission Interconnect Agreement (9)					
1	Operating Revenues														
2	Retail	\$164,504	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
3	Asset & Non Asset Margin Sharing														
4	Interdepartmental														
5	Other Operating	43,423	0	0	0	0	0	0	0	0	0				
6	Gross Earnings Tax														
7	Total Operating Revenues	\$207,927	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
8	Operating Expenses:														
9	Fuel & Purchased Energy	\$81,382	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
10	Power Production	\$43,002	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
11	Transmission	\$11,387	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
12	Distribution	\$6,275	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
13	Customer Accounting	\$4,365	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
14	Customer Service & Information	\$548	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
15	Sales, Econ Dpt & Other	\$2	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
16	Administrative & General	\$14,014	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
17	Total Operating Expenses	\$161,065	\$7	\$12	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
18	Depreciation	\$17,665	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
19	Amortization	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
20	Taxes:														
21	Property	\$5,653	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
22	Gross Earnings	\$12,369	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
23	Deferred Income Tax & ITC	\$17,816	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
24	Federal & State Income Tax	\$1,615	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
25	Payroll & Other	\$12,021	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
26	Total Taxes	\$46,463	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
27	Allowance for Funds Used During Construction	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
28	Total Operating Income	\$17,969	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
29	Calculation of Revenue Requirements														
30	Rate Base	\$335,320	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
31	Required Operating Income	\$29,307	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
32	Operating Income	\$17,665	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
33	Revenue Deficiency	\$12,138	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
34	Revenue Requirements	\$18,872	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
35	Calculation of Income Taxes														
36	Operating Revenue	\$207,927	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
37	- Operating Exp	\$161,065	\$7	\$12	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
38	- Amortization	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
39	- Taxes on then Inc	\$38,387	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
40	Operating Income before Adjs	\$12,572	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
41	Additions to Income	\$58,708	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
42	Deduct from Income	\$16,490	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
43	State Income Tax before Credits	\$11,056	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
44	State Tax Credits	\$41	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
45	Federal Taxable Income	\$11,142	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
46	Fed Income Tax before Credits	\$15,309	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
47	Federal Tax Credits	\$1,420	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				
48	Income Tax	\$17,816	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0				

2011 Unadjusted Test Year versus 2011 Adjusted Test Year
(000's)

2011 Unadjusted Test Year versus 2011 Adjusted Test Year (6000's)												
Line No.	Description	Budget Adjustments Non Plant Related					Traditional Adjustments					
		Transmission Tree Trimming (LIDAR) (10)	Bad Debt (11)	Qwest Pole Replacement (12)	Joint Zonal Rate Update (13)	Nuclear Fees (14)	Borbon Reduction at Sherco-3 (15)	Economic Development (16)	Advertising (17)	Association Dues (18)	Donations (19)	Interest on Customer Deposits (20)
Operating Revenues												
1	Total	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2	Asset & Non Asset Margin Sharing											
3	Interdepartmental											
4	Other Operating	0	0	0	(3)	0	0	0	0	0	0	0
5	Gross Earnings Tax											
6	Total Operating Revenues	\$0	\$0	\$0	(3)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Expenses												
Operating Expenses:												
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	(810)	\$0	\$0	(446)	\$0	(352)	\$0	\$0	\$0	\$0	\$0
10	Distribution	\$0	\$0	\$18	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
11	Customer Accounting	\$0	\$0	\$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 Dvp & Other	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
14	Administrative & General	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
15	Total Operating Expenses	(810)	(446)	\$18	(446)	(843)	(352)	\$0	(3214)	(53)	\$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
Taxes												
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	(97)	\$17	\$33	\$20	(425)	\$64	\$1	(952)	(80)
22	Payroll & Other	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
23	Total Taxes	\$4	\$18	(97)	\$17	\$33	\$20	(425)	\$64	\$1	(952)	(80)
24	Total Expenses	(88)	(428)	\$11	(329)	(850)	(322)	\$39	(1120)	(52)	580	\$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	(511)	\$28	\$50	\$32	(339)	\$120	\$2	(380)	(31)
Calculation of Revenue Requirements												
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	(511)	\$28	\$50	\$32	(339)	\$120	\$2	(380)	(31)
30	Revenue Deficiency	(86)	(328)	\$11	(329)	(850)	(322)	\$39	(1120)	(52)	580	\$1
31	Revenue Requirements	(810)	(446)	\$18	(446)	(843)	(352)	\$0	(3214)	(53)	\$132	\$1
Calculation of Income Taxes												
32	Operating Revenue	\$0	\$0	\$0	(3)	\$0	\$0	\$0	\$0	\$0	\$0	\$0
33	- Operating Exp	(810)	(446)	\$18	(446)	(843)	(352)	\$0	(3214)	(53)	\$132	\$1
34	- Amortizations	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
35	- Taxes on Inc	\$10	\$46	(318)	\$43	\$83	\$32	(344)	\$214	\$3	(8132)	(31)
36	Operating Income before Ads	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
37	Additions to 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	Debt Amortization	\$10	\$46	(318)	\$43	\$83	\$32	(344)	\$214	\$3	(8132)	(31)
40	State Taxable Income	\$1	\$3	(81)	\$3	\$5	\$3	(14)	\$14	\$0	(59)	(60)
41	State Income Tax before Credits	\$1	\$3	(81)	\$3	\$5	\$3	(14)	\$14	\$0	(59)	(60)
42	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
43	Federal Taxable Income	\$0	\$0	(81)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
44	Fed Income Tax before Credits	\$3	\$15	(166)	\$14	\$27	\$17	(321)	\$200	\$3	(8123)	(31)
45	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
46	Income Tax	\$3	\$15	(166)	\$14	\$27	\$17	(321)	\$200	\$3	(8123)	(31)

[illegible]

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
INCOME STATEMENT SCHEDULES
INCOME STATEMENT ADJUSTMENT SCHEDULES

Case No. PU-10-657 & PU-11-55
Exhibit (MJM-3) Schedule 5b
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2011 Unadjusted Test Year versus 2011 Adjusted Test Year
(\$000's)

Line No.	Description	Amortizations					Income Statement CWC	Proposed 2011 Test Year
		2008 Private Fuel Storage (31)	2011 Rate Case (32)	2011 Emissions Credit (33)	2011 DSA (34)	Remove Morticount (35)	Chg in Cost of Capital (36)	
1	Operating Expenses:							
2	Retail	\$0	\$0	\$0	\$0	\$0		\$184,504
3	Asset & Non Asset Margin Sharing							\$0
4	Interdepartmental							\$0
5	Other Operating	0	0	0	0	0		\$42,445
6	Gross Earnings Tax							\$0
7	Total Operating Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$206,949
8	Operating Expenses:							
9	Fuel & Purchased Energy	\$0	\$0	\$0	\$0	\$0		\$91,282
10	Power Production	\$0	\$0	\$0	\$0	\$0		\$42,844
11	Transmission	\$0	\$0	\$0	\$0	\$0		\$11,347
12	Distribution	\$0	\$0	\$0	\$0	\$0		\$6,282
13	Customer Accounting	\$0	\$0	\$0	\$0	\$0		\$4,339
14	Customer Service & Information	\$0	\$0	\$0	\$0	\$0		\$549
15	Sales, Econ Dlg & Other	\$0	\$0	\$0	\$0	\$0		\$86
16	Administrative & General	\$0	\$0	\$0	\$0	\$0		\$13,222
17	Total Operating Expenses	\$0	\$0	\$0	\$0	\$0	\$0	\$180,180
18	Depreciation	\$0	\$0	\$0	\$0	\$0		\$17,578
19	Amortization	\$190	\$281	(\$130)	\$228	\$0		\$574
20	Taxes:							
21	Property	\$0	\$0	\$0	\$0	\$0		\$5,653
22	Gross Earnings	\$0	\$0	\$0	\$0	\$0		\$11,140
23	Federal Income Tax & ITC	(\$75)	(\$110)	\$51	(\$88)	\$1,578	(\$28)	(\$6,777)
24	Federal & State Income Tax	\$0	\$0	\$0	\$0	\$0		\$1,815
25	Payroll & Other	(\$75)	(\$110)	\$51	(\$88)	\$4	(\$26)	\$11,831
26	Total Taxes	\$115	\$171	(\$78)	\$137	(\$186)	(\$28)	\$180,134
27	Total Expenses	\$0	\$0	\$0	\$0	\$0		\$0
28	Allowance for Funds Used During Construction	(\$115)	(\$171)	\$78	(\$137)	\$186	\$28	\$18,815
29	Total Operating Income	\$0	\$0	\$0	\$0	\$0	\$4	\$18,815
30	Rate Base	\$0	\$0	\$0	\$0	(\$10,104)	\$0	\$317,494
31	Required Operating Income	\$0	\$0	\$0	\$0	(\$668)	\$11	\$27,749
32	Operating Income	(\$115)	(\$171)	\$78	(\$137)	\$186	\$28	\$16,815
33	Revenue Deficiency	\$115	\$171	(\$78)	\$137	(\$175)	(\$17)	\$10,934
34	Revenue Requirements	\$190	\$281	(\$130)	\$228	(\$1,769)	(\$28)	\$17,950
35	Calculation of Revenue Requirements							
36	Operating Revenue	\$0	\$0	\$0	\$0	\$0	\$0	\$206,949
37	Operating Exp	\$190	\$281	(\$130)	\$228	\$0	\$0	\$180,180
38	Amortizations	\$0	\$0	\$0	\$0	\$0	\$0	\$574
39	Taxes on Other Inc	\$0	\$0	\$0	\$0	\$0	\$0	\$7,485
40	Operating Income before Apts	(\$190)	(\$281)	\$130	(\$228)	\$72	\$0	\$38,767
41	Additions to Income	\$0	\$0	\$0	\$0	(\$545)	\$0	\$12,033
42	Deduct from Income	\$0	\$0	\$0	\$0	(\$4,164)	\$0	\$35,395
43	Debt Synchronization	\$0	\$0	\$0	\$0	(\$326)	\$71	\$10
44	State Taxable Income	(\$190)	(\$281)	\$130	(\$228)	\$4,017	(\$71)	(\$13,580)
45	State Income Tax before Credits	(\$12)	(\$18)	\$8	(\$15)	\$281	(\$6)	(\$885)
46	State Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$41
47	Federal Taxable Income	(\$178)	(\$293)	\$122	(\$211)	\$3,736	(\$67)	(\$12,866)
48	Federal Income Tax before Credits	(\$82)	(\$122)	\$43	(\$74)	\$23	(\$23)	(\$4,433)
49	Federal Tax Credits	\$0	\$0	\$0	\$0	\$0	\$0	\$1,450
50	Income Tax	(\$82)	(\$122)	\$43	(\$74)	\$23	(\$23)	(\$6,777)

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____(MJM-1) Schedule 7
Revised May 9, 2011
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<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	\$28,617
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

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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

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost Revised May 9, 2011
2011 Test Year Adj for Merricourt
(Dollars in Thousands)

Case No. PU-10-657 & PU-11-55
Exhibit (JMF-1) Schedule 8a
Revised May 9, 2011
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Rate Base Summary

	Total Company Electric			ND Retail Electric			All Other		
	<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 Prepaids & Other	62,822	69,020	65,921	3,849	4,198	4,024	58,973	64,822	61,897
11 Total Rate Base	5,434,655	6,258,815	5,846,734	293,583	341,403	317,494	5,141,072	5,917,412	5,529,240

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost Revised May 9, 2011
2011 Test Year Adj for Merricourt
(Dollars in Thousands)

Case No. PU-10-657 & PU-11-55
Exhibit (JMF-1) Schedule 8a
Revised May 9, 2011
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Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Operating Revenues</u>			
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 Total Operating Revenues	3,753,420	206,949	3,546,471
<u>Expenses</u>			
Operating Expenses:			
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 Total Operating Expenses	2,692,856	160,150	2,532,706
16 Depreciation	343,491	17,579	325,912
17 Amortization	15,949	574	15,375
Taxes:			
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 Total Taxes	288,075	11,831	276,244
24 Total Expenses	3,340,370	190,134	3,150,237
25 AFUDC	0	-	0
26 Total Operating Income	413,050	16,815	396,234

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)	(160,150)	(2,532,706)
3 Book Depreciation & Amortization	(359,440)	(18,153)	(341,287)
4 Taxes (Other Than Current Income)	(326,855)	(18,608)	(308,247)
5 Total Before Tax Book Income	374,269	10,038	364,231
<u>Tax Additions</u>			
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
<u>Tax Deductions</u>			
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	1,141,976	64,380	1,077,595
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	(4,569)	(924)	(3,644)
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	(34,212)	(5,853)	(28,359)
37 Total Federal & State Income Taxes	(38,780)	(6,777)	(32,003)

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
Cost Revised May 9, 2011
2011 Test Year Adj for Merricourt

Case No. PU-10-657 & PU-11-55
Exhibit (JMF-1) Schedule 8a
Revised May 9, 2011
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Revenue Requirement & Return Summary

(Dollars in Thousands)

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted</u>	<u>Composite Income Tax Rates</u>	
				<u>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%

Rate Base Detail - Cash Working Capital

		<u>Total Company Electric</u>		<u>ND Retail Electric</u>		<u>All Other</u>	
<u>Expenses</u>		<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>
<u>Includable Expenses</u>	<u>Lead Days</u>						
<u>Fuel Expenses</u>							
1 Coal & Rail Transport	21.08	353,157	7,444,550	22,115	468,184	331,042	6,978,365
2 Gas for Generation	38.45	180,884	8,954,990	11,327	435,523	169,557	6,519,467
3 Oil	22.51	683	15,374	43	968	640	14,406
4 Nuclear & EOL	0.00	111,499	0	6,982	0	104,517	0
5 Nuclear Disposal	76.00	11,164	848,464	649	49,324	10,515	799,140
6		657,387	15,263,378	41,116	951,999	616,271	14,311,378
<u>Purchased Power</u>							
7 Purchases	28.12	894,164	25,143,610	54,286	1,526,522	839,858	23,617,088
8 Interchange	38.21	118,783	4,577,291	7,047	269,266	112,746	4,308,026
		1,013,947	29,720,901	61,333	1,795,788	952,614	27,925,113
<u>Labor & Related Costs</u>							
9 Regular Payroll	12.31	387,828	4,527,863	22,236	273,725	345,592	4,254,238
10 Incentive Compensation	255.05	21,732	5,542,747	1,329	338,961	20,403	5,203,785
11 Pension & Benefits	19.20	79,180	1,519,872	4,828	82,968	74,332	1,427,174
12 Subtotal Labor & Related		468,720	11,590,581	28,393	705,384	440,327	10,885,197
13							
14 All Other Operating Expenses	35.01	552,802	19,353,595	29,308	1,026,073	523,494	18,327,522
15 Property Tax	356.72	115,650	41,254,858	5,663	2,018,538	108,997	39,238,130
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	(4,569)	(172,464)	(924)	(34,894)	(3,644)	(137,570)
20 State Sales Tax Customer Billings	35.73	138,595	4,951,999	0	0	138,595	4,951,999
21 Total Expenses	41.34	2,938,363	121,468,537	160,841	6,288,144	41.47	2,777,513
22 Net Annual Expense Amount			332,791		17,229		315,564
<u>Revenues</u>	<u>Lead Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>
23 Computer Billing	100.00%	3,034,853	137,942,263	164,504	7,477,151	2,870,349	130,465,112
24 Hand Billed	0.00%	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	2,261	95,888	243	10,413	2,018	86,475
29 CIP Incentive	0.00	0	0	0	0	0	0
30 Rentals	114.17	4,032	480,333	255	29,113	3,777	431,220
31 Interchange Revenues	38.21	446,657	17,088,784	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	223,624
34 MISO	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	858,791	1,345	49,900	21,803	808,891
38 Distribution Associated Revenues	42.85	1,672	80,219	0	0	1,672	80,219
39 Other	42.85	2,356	100,959	(652)	(27,940)	3,008	128,899
40 JOA - Rev 1/10 PSC	37.10	(4,866)	(181,642)	(307)	(11,390)	(4,589)	(170,262)
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	3,753,420	164,910,560	206,949	9,067,935	43.94	3,546,471
45 Net Annual Amount			451,810		24,844		426,966
46 Expense / Revenue Factor			0.7828		0.7772		
47 Allocated Revenue Amount			353,698		19,338		
48 Net Cash Working Capital	Page 1 - Line 8		20,907		2,081		18,826

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

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Northern States Power Company, a Minnesota Corporation
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Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
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Rate Base Summary

	Total Company Electric			ND Retail Electric			All Other		
	<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	(6,377,573)	(6,796,485)	(6,587,029)	(358,804)	(381,406)	(370,105)	(6,018,769)	(6,415,079)	(6,216,924)
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
11 Total Rate Base	5,698,259	6,240,656	5,969,458	311,488	343,368	327,429	5,386,771	5,897,288	5,642,029

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
(Dollars in Thousands)

Case No. PU-10-657 & PU-11-55
Exhibit (JMF-1) Schedule 8b
Revised May 9, 2011
Page 3 of 6

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Operating Revenues</u>			
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 Total Operating Revenues	3,753,420	206,949	3,546,471
<u>Expenses</u>			
Operating Expenses:			
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 Total Operating Expenses	2,692,856	160,421	2,532,435
16 Depreciation	356,330	18,369	337,961
17 Amortization	15,949	574	15,375
Taxes:			
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 Total Taxes	280,607	11,344	269,263
24 Total Expenses	3,345,742	190,708	3,155,034
25 AFUDC	0	-	0
26 Total Operating Income	407,678	16,241	391,437

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
Income Before Taxes			
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)	(341,206)	(18,032)	(323,174)
5 Total Before Tax Book Income	347,079	9,553	337,526
Tax Additions			
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
Tax Deductions			
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	1,184,973	63,441	1,121,531
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	(9,387)	(910)	(8,478)
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	(51,211)	(5,778)	(45,433)
37 Total Federal & State Income Taxes	(60,599)	(6,688)	(53,911)

Northern States Power Company, a Minnesota Corporation
Electric Utility - North Dakota Retail Jurisdiction
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Case No. PU-10-657 & PU-11-55
Exhibit (JMF-1) Schedule 8b
Revised May 9, 2011
Page 5 of 6

Revenue Requirement & Return Summary

				<u>Composite Income Tax Rates</u>	
<u>Capital Structure</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	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%

<u>Return on Equity (ROE)</u>			
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%

<u>Revenue Deficiency</u>			
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

<u>Total Retail Revenue Requirements</u>			
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 <u>Percentage Increase (Decrease)</u>	6.35%	12.38%	6.01%

Rate Base Detail - Cash Working Capital

			<u>Total Company Electric</u>		<u>ND Retail Electric</u>		<u>All Other</u>	
<u>Expense</u>		<u>Lead Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>
<u>Includable Expense</u>								
<u>Fuel Expenses</u>								
1 Coal & Rail Transport	21.08		353,157	7,444,550	22,115	466,184	331,042	8,976,365
2 Gas for Generation	38.45		180,884	6,954,990	11,327	435,523	169,557	6,519,467
3 Oil	22.51		683	15,374	43	968	640	14,406
4 Nuclear & EOL	0.00		111,489	0	6,982	0	104,517	0
5 Nuclear Disposal	76.00		11,164	848,464	648	49,324	10,515	799,140
6			657,367	15,263,378	41,116	951,699	616,271	14,311,378
<u>Purchased Power</u>								
7 Purchases	28.12		894,154	25,143,610	54,286	1,526,522	839,868	23,617,068
8 Interchange	38.21		119,793	4,577,281	7,047	269,286	112,748	4,308,025
9			1,013,947	29,720,901	61,333	1,795,788	952,614	27,925,113
<u>Labor & Related Costs</u>								
10 Regular Payroll	12.31		367,828	4,527,963	22,236	273,725	345,592	4,254,238
11 Incentive Compensation	255.05		21,732	5,542,747	1,329	338,961	20,403	5,203,785
12 Pension & Benefits	19.20		79,160	1,519,872	4,628	92,998	74,832	1,427,174
13 Subtotal Labor & Related			468,720	11,590,581	28,393	705,384	440,327	10,885,197
<u>All Other Operating Expenses</u>								
14 Property Tax	35.01		562,802	19,353,595	29,579	1,035,561	523,223	18,318,034
15 Employer's Payroll Taxes	25.56		117,651	41,988,485	5,911	2,108,572	111,740	39,859,893
16 Gross Earnings Tax	41.48		30,033	797,676	1,816	48,208	28,218	749,470
17 Federal Income Tax	37.75		0	0	0	0	0	0
18 State Income Tax	37.75		(51,211)	(1,933,219)	(5,778)	(218,136)	(45,433)	(1,715,083)
19 State Sales Tax Customer Billings	35.73		(9,387)	(354,374)	(910)	(34,335)	(8,478)	(320,039)
20 State Sales Tax Customer Billings	35.73		138,585	4,951,999	0	0	138,585	4,951,999
21 Total Expenses	41.58		2,918,536	121,359,002	161,459	6,393,039	2,767,077	114,965,963
22 Net Annual Expense Amount				332,490		17,515		314,975
<u>Revenues</u>								
23 Computer Billing	100.00%	45.45	3,034,853	137,942,283	184,504	7,477,151	2,870,349	130,465,112
24 Hand Billed	0.00%	43.07	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		2,261	98,888	243	10,413	2,018	86,475
29 CIP 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		448,657	17,066,764	26,889	1,027,429	419,768	16,038,335
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 MISO	14.00		13,342	186,788	775	10,850	12,567	175,938
35 Port to Point Firm	37.10		59,651	2,213,052	3,466	128,589	58,185	2,084,464
36 Services & Facilities	37.10		8,828	327,519	507	18,610	8,321	308,709
37 Ancillary	37.10		23,148	868,791	1,345	49,900	21,803	808,691
38 Distribution Associated Revenues	42.85		1,872	80,219	0	0	1,872	80,219
39 Other	42.85		2,356	100,999	(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	9,067,935	3,546,471	155,642,625
45 Net Annual Amount				451,810		24,844		426,656
46 Expense / Revenue Factor				0.7778		0.7802		
47 Allocated Revenue Amount				351,312		19,383		
48 Net Cash Working Capital				18,822		1,868		16,955

Page 1 - Line 5

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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-302

Date Received: May 27, 2011

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.

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 th 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

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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-22

Date Received: April 28, 2011

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

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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

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.

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

(\$) (\$)

Rate Analysis

Total Company ND Jurisdiction

Average Rate Base

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

Revenue Requirements

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

Total Revenue Requirements	2,506,605	122,242

<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%		

2011

Demand ND Jur %	5.8107%
IA Demand MN Co %	83.8756%
Composite ND Jur Allocation	4.8738%



414 Nicollet Mall
Minneapolis, Minnesota 55401

April 10, 2009

—VIA ELECTRONIC FILING—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th 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, 5th 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, 7th 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.

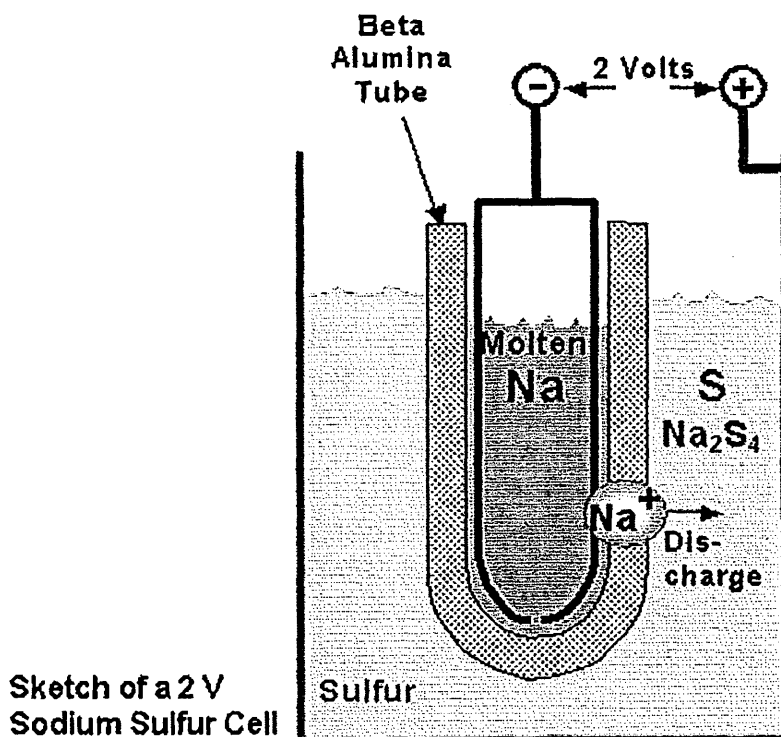
- The potential for battery-storage technology to more effectively integrate wind into transmission system operations. We believe batteries will help to maintain and maximize the integrity of the grid by providing frequency, voltage and reliability support.

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
Specifications & Contract Negotiations		
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
Engineering & Design		
Detailed system and process design; Engineering	Full set of drawings – electrical, mechanical and civil drawings	COMPLETE
Construction & Installation		
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
Research Plan		
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	
Data Collection & Analysis		
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
Reporting		
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, 5th Floor
Minneapolis, Minnesota 55401

SaGonna Thompson
Records Specialist
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, Minnesota 55401

CONCLUSION

Xcel Energy respectfully requests that the Commission find our Wind2Battery project eligible for recovery through our RES Rider and approve the arrangement as an affiliated interest. The Company plans to continue to pursue investments in renewable energy generation projects and appreciates the interest and efforts of state policy makers in supporting this effort.

Dated: April 10, 2009

Northern States Power Company,
a Minnesota corporation

By: /S/
AL KRUG
MANAGING DIRECTOR, GOVERNMENT AND REGULATORY AFFAIRS

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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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

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

Xcel Energy Capital		2007	2008	2009	2010	Grand Total
	Total Capital	\$ 73,377	\$ 1,868,155	\$ 2,375,756	\$ 9,704	\$ 4,326,992
Xcel Energy O&M		2007	2008	2009	2010	Grand Total
	Total O&M	\$ -	\$ 4,425	\$ 51,390	\$ 52,356	\$ 108,171
Partners in Research		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
PROJECT GRAND TOTAL		\$ 73,377	\$ 2,021,637	\$ 2,848,883	\$ 62,060	\$ 5,005,958

RDF Funding Distribution		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

Partner Contributions to Research		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

Xcel Energy Net Project Capital Costs		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)	
Xcel Energy Capital Project Total		\$	73,377	\$ 1,853,610	\$ 1,852,747	\$ (250,269)	\$ 3,529,465

**Xcel Energy Renewable Energy Standard Rider
Revenue Requirements**

**Schedule 2
Page 1 of 4**

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
Rate Base													
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	(286)	(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	1,403,858	1,690,642	1,967,431	785,649
Calculation of Return													
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
Income Statement Items													
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)	(989)	(1,306)	(1,364)	(1,624)	(1,792)	(8,858)
Plus Gross Up for Income Tax	462	485	476	585	1,800	3,620	4,328	6,214	8,085	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	(483)	(504)	(598)	(680)	(2,084)	(4,121)	(4,881)	(7,005)	(8,871)	(9,500)	(11,434)	(8,826)	(58,947)
Total Revenue Requirements	104	89	24	78	214	314	420	805	1,018	807	978	5,618	10,268
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0

**Xcel Energy Renewable Energy Standard Rider
Revenue Requirements**

**Schedule 2
Page 2 of 4**

Wind To Battery	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
Rate Base													
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	1,567,360	1,663,044	1,757,586	1,781,130	1,804,831	1,848,866	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	1,826,849	1,860,955	1,885,215	1,909,638	2,998,432	1,850,058
Calculation of Return													
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
Total Return	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
Income Statement Items													
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)	(2,248)	(2,277)	(2,330)	(2,425)	(2,480)	(2,497)	(2,524)	(2,551)	(2,587)	(2,584)	(3,770)	(30,488)
Plus Gross Up for Income Tax	11,449	10,880	11,085	11,411	11,975	12,320	12,449	12,640	12,832	12,964	13,097	19,690	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
Total Income Statement Expense	(9,585)	(10,588)	(10,779)	(11,120)	(11,715)	(12,075)	(12,204)	(12,400)	(12,597)	(12,730)	(12,864)	(19,902)	(148,538)
Total Revenue Requirements	3,257	616	668	738	842	915	959	1,012	1,066	1,111	1,156	2,112	14,452
MN Jurisdictional Revenue Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0

**Xcel Energy Renewable Energy Standard Rider
Revenue Requirements**

**Schedule 2
Page 3 of 4**

Wind To Battery	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
Rate Base													
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)	3,899,945	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
Calculation of Return													
Plus Debt Return	11,200	11,012	11,048	10,939	10,830	10,861	10,893	10,921	10,950	10,979	11,009	10,449	131,090
Plus Equity Return	16,166	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
Income Statement Items													
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
Total Revenue Requirements	46,269	45,561	45,698	45,289	44,880	45,000	45,119	45,229	45,339	45,450	45,562	46,509	545,907
MIN Jurisdictional Revenue Requirement	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

**Xcel Energy Renewable Energy Standard Rider
Revenue Requirements**

**Schedule 2
Page 4 of 4**

Wind To Battery	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
Rate Base													
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	129,538	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	3,418,188	3,345,920	3,273,872	3,201,425	3,129,177	3,056,929	2,984,681	2,912,434	2,840,188	2,767,938	2,695,690	3,093,052
Calculation of Return													
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	168,571
Total Return	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
Income Statement Items													
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
Total Income Statement Expense	49,105	48,873	48,642	48,410	48,179	47,947	47,718	47,484	47,253	47,021	46,790	46,558	573,979
Total Revenue Requirements	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
MN Jurisdictional Revenue Requirement	54,744	54,188	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

Schedule 3
Page 1 of 1

	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>
Wind To Battery					
<u>Rate Base</u>					
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
<u>Calculation of Return</u>					
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
<u>Income Statement Items</u>					
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
Total Revenue Requirements	14,452	545,907	846,477	760,240	698,113
MN Jurisdictional Revenue Requirement	0	399,904	620,087	556,913	511,403

Xcel Energy - Electric (State of Minnesota)
Renewable Energy Standards Rider

Schedule 4
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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
Total Expense (3)	\$ -	\$ 399,904	\$ 630,198	\$ 565,154	\$ 519,643
Revenues	-	389,792	621,958	560,314	519,643
Balance (4)	-	10,112	8,241	4,840	-

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

Schedule 5
Page 1 of 2

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

Schedule 5
Page 2 of 2

RES Projected Tracker Activity for 2011													
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	2011 Total
Wind to Battery (1)	-	-	-	-	-	-	-	-	-	-	-	-	\$ -
Balance Forward (2)	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
	10,112	-	-	-	-	-	-	-	-	-	-	-	\$ 10,112
Total Expense (3)	\$ 64,856	\$ 54,186	\$ 53,627	\$ 53,069	\$ 52,511	\$ 51,953	\$ 51,395	\$ 50,837	\$ 50,278	\$ 49,720	\$ 49,162	\$ 48,604	\$ 630,198
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
Balance (4)	13,117	19,069	22,423	28,855	32,880	31,068	21,951	14,427	13,771	11,551	11,727	8,241	\$ 8,241

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
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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:

- (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.

Schedule 6
Page 2 of 2

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:

- (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 10th day of April 2009

_____/s/_____
Carole Wallace
Regulatory Coordinator

Northern States Power Company,
a Minnesota corporation ("Xcel Energy")
Miscellaneous Electric Service List

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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

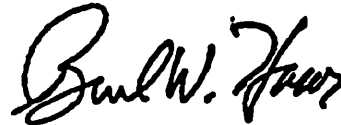
The above entitled matter has been considered by the Commission and the following disposition made:

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

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:

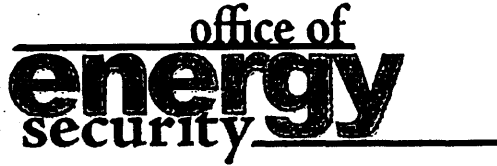
Al Krug
Managing Director, Government and Regulatory Affairs
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

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.¹

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).²

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.

¹ See Attachment 1 for background information on the RDF grant: OES's May 8, 2009 letter in Docket No. E002/M-07-675.

² 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.³

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-07-675.⁴
- 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.⁵

³ See Attachments 3, 4, 5 and 6 to these comments.

⁴ Source: pp. 11-12 of the instant filing.

⁵ 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;⁶ (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;⁷ 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.⁸
- 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-04-1752.⁹
- 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

⁶ Source: p. 9 of the instant filing and pp. 5-7 of Xcel's response to OES's Information Request No. 4.

⁷ Source: Xcel's response to OES's Information Request No. 6, Attachment 8 to these comments.

⁸ Source: page 2 of Xcel's response to OES's Information Request No. 4, Attachment 7 to these comments.

⁹ 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 Ouane
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:¹⁰

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.

¹⁰ 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)).¹¹ 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.

¹¹ 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:¹²

- 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.

¹² 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.¹³ 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.¹⁴

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:

¹³ See Attachment 11.

¹⁴ 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)
COUNTY OF RAMSEY)SS
)

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

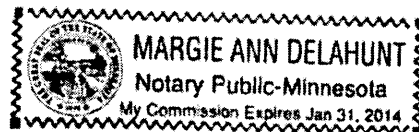
Robin Benson

Subscribed and sworn to before me,

a notary public, this 14th day of

September, 2009

Margie Ann DeLaHunt
Notary Public



Service List Name	First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
OFF_SL_9-379_1	Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No
OFF_SL_9-379_1	Burt W.	Haar	burt.haar@state.mn.us	MN Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No
OFF_SL_9-379_1	John	Lindell	agorud.ecf@state.mn.us	OAG-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No
OFF_SL_9-379_1	Julia	Anderson	Julia.Anderson@state.mn.us	MN Office Of The Attorney General	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No
OFF_SL_9-379_1	Priti R.	Patel	priti.r.patel@xcelenergy.com	Xcel Energy	5th Floor 414 Nicollet Mall, 5th Flr Minneapolis, MN 554011993	Paper Service	No
OFF_SL_9-379_1	SaGonna	Thompson	sagonna.thompson@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Paper Service	No
OFF_SL_9-379_1	Sharon	Ferguson	sharon.ferguson@state.mn.us	MN Department Of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No

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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

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Xcel Energy

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

Response To: Blue Ridge Consulting

Requestor: Michael McGarry

Date Received: April 28, 2011

Information Request No.

AS-2-RR-130

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

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 Heath 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

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

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 - Medical and Pharmacy

Percent to NSPM electric O&M

Amount to MN electric O&M

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)

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

(1,244,392)

Dental Cost Increase

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

Dental cost share change from 60/40 to 75/25
241,175
64.7%
156,158
5.42%

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☒ 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-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

Case No: PU-10-657 11-55
 Data Request No. AS-2-RR-149
 Attachment A
 Page 1 of 1

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 O&M		
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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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

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.

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]

(S's)	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																		
NSPM	12,394,000	10,127,000	2,267,000	11,561,000	11,633,000	(72,000)	504,000	504,000	-	1,578,000	1,128,000	450,000	1,066,000	578,000	510,000	27,125,000	23,970,000	3,155,000
NSPM Nuclear	977,000	1,125,000	(148,000)	(96,000)	(94,000)	(4,000)	122,000	118,000	4,000	-	-	-	-	-	-	1,001,000	1,149,000	(148,000)
XES	21,632,000	19,898,000	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	12,289,000	12,332,000	(45,000)	4,138,000	3,976,000	162,000	1,665,000	1,185,000	480,000	1,066,000	578,000	510,000	54,181,000	49,321,000	4,860,000
Amount to NSPM O&M Electric																		2,206,004
Remove SERP																		(624,827)
Total NSPM O&M Electric Excluding SERP																		1,581,167
Total After Interchange Agreement																		1,131,555
Total Adjustment to NSPM O&M Electric ND																		68,633

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

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

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Xcel Energy

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

Response To: Blue Ridge Consulting

Requestor: Michael McGarry

Date Received: June 24, 2011

Data Request No.

AS-RR-328

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

Attachment A - Page 1 of 1

[illegible]

**Backup Summary for Correction to Mercury Sorbent Expenses for Sherco 3
Reflecting the Credit for SMMPA Sharing and Interchange Agreement Impact
For 2011**

Change to FERC 502	Account	Starting Totals
Currently in Budget	230934.714080	4,180,000
SMMPA Credit in Budget	230934.714081.90	(1,671,568)
Net		2,508,432
New Budget Amount	230934.714080	2,400,000
New SMMPA Credit	230934.714081.90	(959,752)
Net		1,440,248
Adjustment with Interchange Agreement Impact		(895,946)

36 mth Interchange Demand Allocator			83.8756%	
Jurisdictional Allocators	MN	ND	SD	Whlsl
Demand	88.4924%	5.8107%	5.5779%	0.1190%
Net Correction To Production O&M	(792,844)	(52,061)	(49,975)	(1,066)

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

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

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

11-4

From: Marner, Joseph P
To: Marner, Thomas E
Cc: Marner, Joseph P
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

More the later. We have already done a "large" amount of pole transfers for Qwest in prior years, but this has been more on the basis of approximately 75 poles per year. Starting this year, we are now looking to do 700 pole transfers per year. Based on a new normal replacement program that Qwest has recently undertaken. We do not account for this significant spike in poles this year's budget nor in the 2011/2012 budgets.

From: Marner, Thomas E
Sent: Wednesday, September 29, 2010 1:49 PM
To: Marner, Joseph P
Subject: RE: 2010 NW 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: Marner, Joseph P
Sent: Wednesday, September 29, 2010 1:36 PM
To: Marner, Thomas E
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

Hi Tom - I need to review the estimated percent split between NW, SD, and SO.

Total NSP/Qwest pole attachments = 67,200

NW Attachments = 51,000 (76%)
SD Attachments = 1,300 (2%)
SO Attachments = 14,900 (22%)

From: Marner, Joseph P
To: Marner, Thomas E
Cc: Pat, Stephen R; Garza-Gonzalez, Elizabeth M
Subject: RE: 2010 NW 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: Marner, Thomas E
Sent: Wednesday, September 29, 2010 1:58 PM
To: Marner, Joseph P
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

Hi afternoon Joe,

... putting the rate case adjustment together for this firm and have a couple questions or clarification points.

1st Is this incremental cost estimate 100% assignable to the distribution operations group in NW or are there some costs for SD and SO as well? If they are split do you have a breakdown by state? - NW is the number for NSP/Qwest Company. We have of any transfer requests we may get from Qwest for our service territory in SD and SO. According to our records, we are affected by approximately \$4,900 Qwest poles in MINNESOTA in which approximately 62,200 of these attachments are within the State of Minnesota. So, going forward, it would be of attachments in each state, approximately 77% of the incremental costs would be assigned to NW.

2nd Do you have a breakdown for this estimate by object account or at least type of costs (i.e. material, labor, contractor, etc.) Since this is incremental to the 2011 budget base, we do not have this broken down specifically within the budget process. Also, at this point in time, we have not decided on whether the bulk of these incremental amounts will be paid by NW or SD and SO, or a combination of both. However, the "total" numbers have been done by NW at least or it broke down as follows: Labor = 67.7%, Materials = 12.6%, Contract = 2.0%, Transportation = 16.2%.

3rd Is this the cost to NSP to transfer from Qwest poles to NSP poles or to re-hung our equipment on new Qwest poles? I am still a little fuzzy on what activity is actually happening. - NW is the cost to transfer from Qwest poles to new Qwest poles (re-hung on existing poles).

Thanks

Tom Marner

From: Marner, Joseph P
To: Marner, Thomas E; Pat, Stephen R; Garza-Gonzalez, Elizabeth M; Silbert, Patricia S; Pelling, John M; Carls, Shari H
Cc: Marner, Joseph P
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

From: Marner, Joseph P
Sent: Tuesday, September 21, 2010 4:48 PM
To: Marner, Thomas E
Cc: Carls, Shari H; Pat, Stephen R; Garza-Gonzalez, Elizabeth M; Silbert, Patricia S; Pelling, John M; Carls, Shari H
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

If it, our pricing facilities makes it these transfers will cost from pole to pole. Could be as simple as transferring a secondary service to an existing or new building a 50 degree three-phase primary voltage (backbone) structure. Possible local transfers would include any one or a combination of the following:

- Single phase primary conductor transfer (including neutral wire, conductors, pin, conductor box, associated hardware)
- Two-phase primary conductor transfer (including neutral wire, crossarm, insulators, pins, conductor box, associated hardware)
- Three-phase primary conductor transfer (including neutral wire, crossarm, insulators, pins, conductor box, associated hardware)
- Secondary bus conductor transfer (single-phase, two-phase, or three-phase)
- Service conductors (single-phase, two-phase, or three-phase)
- Tapped conductors
- Accessories
- Transformers
- Various other pricing of equipment

From: Marner, Joseph P
Sent: Tuesday, September 21, 2010 4:20 PM
To: Marner, Thomas E
Cc: Carls, Shari H; Pat, Stephen R; Garza-Gonzalez, Elizabeth M; Silbert, Patricia S; Pelling, John M; Carls, Shari H
Subject: RE: 2010 NW Elec Case - Info needed to do Qwest pole budget adjustment - 2011 and beyond

Also, the unbudgeted incremental Distribution O&M associated with Qwest pole transfers we would like to include in your testimony as \$625,000 for 2011 and then escalated 3% for each successive year to \$1,275,000 in 2012. This incremental O&M is based on NSP/Qwest Distribution transferring one electric facility's attachment to Qwest owned poles assuming an estimated 700 Qwest pole replacements annually. The amount of Distribution O&M would be budgeted under FERC account 581 - Cost of Operation & Maintenance.

Let me know if you need any further information or have any questions. Thanks,

Joe Marner

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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

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 read "John Cesare", is written over the word "Sincerely,". The signature is fluid and cursive.

John Cesare

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>		<u>-</u>

94.00% 2.90% 3.10%
Estimated split based upon poles in state to total Qwest poles.
Per Joe Mansur e-mail

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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

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

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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

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).

Preparer: Charles E. Anderson
Title: Director, TTC Business Area Finance
Department: TTC Finance
Telephone: (303) 294-2360
Date: July 26, 2011

911 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 Desc	FERC	Alleg Rollup 24	Functional Class	RL Account Description	Location	Labor	2011 Budget	MN	ND	SD	Wh/Sl	Object Account	Financial Business Unit
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	2,287.00	2,287.00				723833 - Charitable Contributions	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	494.00	494.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	915.00	915.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	3,886.00	3,886.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	1,372.00	1,372.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	65,127.00	65,127.00				723837 Economic Development-Contribut	811203 Econ Develop-Common MN SA9122
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	North Dakota	Non-Labor	64,029.00		64,029.00			723837 Economic Development-Contribut	804103 Com Gov & Reg Rel ND AG921
Electric	426.1	MN Utility President	NSPM Regulatory	Donations NL E	South Dakota	Non-Labor	97,873.00			97,873.00		723837 Economic Development-Contribut	805002 Com Gov Reg Relation SD AG921
Reclass	426.1	MN Utility President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	9,127.00			9,127.00		723837 Economic Development-Contribut	805002 Com Gov Reg Relation SD AG921
Total Electric							246,942.00	75,913.00	64,029.00	107,000.00	-		
Cost Sharing Calculation:													
50% of Below The Line Donations Qualifying For Recovery State of Mn							37,956.50	37,956.50					
100% of Below The Line Donations Qualifying For Recovery State of ND							64,029.00		64,029.00				
50% of first \$100k 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	-		

Utility Desc	FERC	Alleg Rollup 24	Functional Class	RL Account Description	Location	Labor	2011 Budget	MN	ND	SD	Wh/Sl	Object Account	Financial Business Unit
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	213.00	213.00				723833 - Charitable Contributions	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	85.00	85.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	85.00	85.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	46.00	46.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	85.00	85.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	362.00	362.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL E	Minnesota	Non-Labor	128.00	128.00				723834 Community Sponsorships	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL G	Minnesota	Non-Labor	6,073.00	6,073.00				723837 Economic Development-Contribut	811203 Econ Develop-Common MN SA9122
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL G	North Dakota	Non-Labor	5,971.00		5,971.00			723837 Economic Development-Contribut	804103 Com Gov & Reg Rel ND AG921
Gas	426.1	MN Utility President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	8,127.00					723837 Economic Development-Contribut	805002 Com Gov Reg Relation SD AG921
Reclass	426.1	MN Utility President	NSPM Regulatory	Donations NL G	South Dakota	Non-Labor	(9,127.00)					723837 Economic Development-Contribut	805002 Com Gov Reg Relation SD AG921
Total Gas							12,844.00	7,077.00	5,971.00	-	-		
Cost Sharing Calculation:													
50% of Below The Line Donations Qualifying For Recovery State of Mn							3,036.50	3,036.50					
100% of Below The Line Donations Qualifying For Recovery State of ND							5,971.00		5,971.00				
Total Gas Adjustment							8,007.50	3,036.50	5,971.00	-	-		

NORTHERN STATES POWER CO d/b/a XCEL ENERGY
Charitable Contributions / Donations
YEAR ENDED 12-31-11
FERC 426.1

4/8-2

ELECTRIC	Total Co	MN	ND	SD	WHL
<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
Total Electric	\$ 4,021,067	\$ 3,757,263	\$ 263,216	\$ 225,253	\$ 8
MN & ND - 50% Electric Inclusion	\$2,010,244	\$1,878,632	\$131,608	\$0	\$4

GAS	Total Co	MN	ND
<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
Total Gas	\$ 374,230	\$ 339,690	\$ 34,540
MN & ND 50% Gas Inclusion	\$187,115	\$169,845	\$17,270

Electric - PTD Adjustment	Production	Transmission	Distribution	check
<i>Allocated</i>	1,149,457	237,008	623,779	
	\$ 1,149,457	\$ 237,008	623,779	\$ 2,010,244
<i>PTD Allocator</i>	57.1800%	11.7900%	31.0300%	



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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 17th 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.

110 PU-07-776 Filed: 12/29/2008 Pages: 29
Fully Executed Settlement Agreement

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

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

Year	Amt. Paid	100% of Target	% Paid to Target
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%
4 Year Average Payout (2009 through 2006)			89%
4 Year Average Payout (2008 through 2005)			70%

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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

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

Year	Amt. Paid	100% of Target	% Paid to Target
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%
4 Year Average Payout (2010 through 2007)			83%
4 Year Average Payout (2009 through 2006)			89%
4 Year Average Payout (2008 through 2005)			70%

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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

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				Weight	Definition
	Threshold 50% Level	Target 100% Level	Maximum 150% Level	Range Calculation	Empl	
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	Whlsl
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)
	(827,462)	(730,151)	(49,386)	(47,245)	(680)

* This adjustment does not include any of the payroll taxes associated with Aviation Costs

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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

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.

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

☐ **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.

2010	High	Low	Dividends
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
2009	High	Low	Dividends
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

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.

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) 330-6723

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, 1998.¹ 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

¹ See 10 C.F.R. § 961.11 (1983) for a description of the Standard Contracts' provisions.

Mr. Darrell Nitschke
July 8, 2011
Page 2

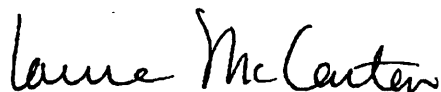
and 2014 respectively (assuming the claim amounts are resolved without the need for binding arbitration and the attendant delay). The settlement does not address potential claims beyond 2013.

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

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

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

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 Total Company Actuals	2010 NSPM Total Company Actuals	2011 NSPM Total Company Budget	2011 ND 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)	\$ -	\$ -
	\$ 9,858,965	\$ 8,256,262	\$ 11,632,026	\$ 686,113

925 A&G Injuries & Damages	2009 NSPM Total Company Actuals	2010 NSPM Total Company Actuals	2011 NSPM Total Company Budget	2011 ND 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
	\$10,828,005	\$12,881,782	\$12,423,026	\$744,800

**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 17th. 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

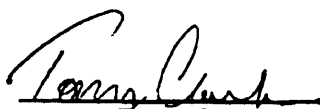
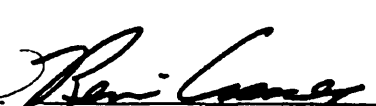
(d) accounting treatment for Midwest ISO Day-2 Energy Market costs.

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. Wehald 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

No virus found in this message.

Checked by AVG - www.avg.com

Version: 10.0.1388 / Virus Database: 1516/3731 - Release Date: 06/28/11

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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

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

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 24th 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 30th outage event was due to a cable splice failure and the August 30th 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 6th 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 7th and January 30th outages events was replaced with the project complete on May 19th, 2008. The cable involved with the July 29th and September 25th 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.

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

PUBLIC DOCUMENT: NON-PUBLIC 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 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
			[NON- PUBLIC BEGINS						
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
			NON- PUBLIC ENDS]	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]									

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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 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							
		2010 SAIFI: 2.27							
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
[NON-PUBLIC BEGINS]									
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
[NON-PUBLIC ENDS]									

TABLE 4									
Substation: Cass County		2008 SAIFI: 0.34							
		2009 SAIFI: 0.72							
Date	Cause	Level	Feeder	Dur	SCI	CMO	SAIFI Impact	SAIDI Impact	YE Cust Served
[NON-PUBLIC BEGINS]									
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
[NON-PUBLIC ENDS]									

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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
[NON-PUBLIC BEGINS]									
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	
[NON-PUBLIC 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-334

Date Received: June 27, 2011

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
TOTAL	\$ 78,885	\$ 610,534	\$ 151,246	\$ 182,262

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
TOTAL	\$ 143,674	\$ 266,252	\$ 122,819	\$ 768,255

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
TOTAL	\$ 97,334	\$ 163,459	\$ 102,246	\$ 283,440

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
TOTAL	\$ 319,893	\$ 1,040,246	\$ 376,312	\$ 1,233,957

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
TOTAL	\$ 1,054,438

*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.

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

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

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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-2-RR-94

Date Received: April 28, 2011

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.

Preparer: Brandon Kirschner
Title: Senior Accounting Analyst
Department: Capital Asset Accounting
Telephone: 612-215-5361
Date: May 20, 2011

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☐ Public Document – Trade Secret Data Excised
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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-280

Date Received: May 27, 2011

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.

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:

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.

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	\$ (90,783)	\$ (105,869)

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	\$ 157	\$ 1,965	\$ 42,420

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)

Case No. PU-10-_____
Page 1 of 1

Rate Analysis

	Total Company	ND Jurisdiction
Plant Investment	(5,691)	(331)
Depreciation Reserve	(400)	(23)
CWIP	-	-
Accumulated Deferred Taxes	(946)	(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	-	-
Avoided Tax Interest	-	-
O&M Production Expense	(4,493)	(261)
Total Revenue Requirements	(5,292)	(306)

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

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) 83.8756%
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	275,618.34	524,410.66	16,015.24	30,471.93

COSS Adj (000's)	329	625	276	624	16	30	23

Accumulated Deferred

	Total Company		Total Company after IA		ND Jurisdiction	
	BOY	EOY	BOY	EOY	BOY	EOY
Production	1,134,292.61	1,121,961.19	951,394.73	941,051.68	55,282.69	54,681.69

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

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	5,358,486.29	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 (MUM-47)
Page 4 of 65

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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-22

Date Received: April 28, 2011

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

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	-	-
Total Revenue Requirements	(570)	(28)

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%		

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

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

(\$) (\$)

Rate Analysis

Total Company ND Jurisdiction

Average Rate Base

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

Revenue Requirements

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

Total Revenue Requirements	2,506,605	122,242

Capital Structure

	<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%

2011

Demand ND Jur %	5.8107%
IA Demand MN Co %	83.8756%
Composite ND Jur Allocatio	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 7th 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/A1-09-____

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>
Wind To Battery					
<u>Rate Base</u>					
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
<u>Calculation of Return</u>					
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
<u>Income Statement Items</u>					
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
Total Revenue Requirements	14,452	545,907	846,477	760,240	698,113
MN Jurisdictional Revenue Requirement	0	399,904	620,087	556,913	511,403

Staff Adj. 4-2

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Xcel Energy
Electric Demand & Energy Allocations
D-10 & E-10 Allocator
2011 Budget

		2011 Bud	Juris
Demand (1)		Retail	Split
D10-12 CP	MN	62,587,113	88.4924%
after TLM	ND	4,109,688	5.8107%
Includes Contrac	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
Demand		Retail	Split
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%
Total		<u>70,726,027</u>	<u>100.0000%</u>

Energy	
Allocator	
MN	87.9087%
ND	6.2622%
SD	5.7150%
WHI	0.1141%
<u>100.0000%</u>	

		2011 Bud	Juris
Energy (2)		Retail	Split
E10-Sales	MN	32,597,728	87.9087%
	ND	2,322,121	6.2622%
	SD	2,119,188	5.7150%
	WHSI	42,302	0.1141%
		<u>37,081,339</u>	<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)	-	-	-	-
Plant				
	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	-	-	-	-
COSS Adj (000's)	-	-	-	-
Reserve				
	Total Company		ND Jurisdiction	
	BOY	EOY	BOY	EOY
Production	-	-	-	-
COSS Adj (000's)	-	-	-	-
Accumulated Deferred				
	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

AS-2

Updated 9-2010

12 Month July 2009 through June 2010

(1) JDE Object Account 371450 (FERC 235)
(2) 2011 Budget Year Master Allocators

Docket No PU-10-657 & PU-11-55
Exhibit ___ (MJM-47)
Page 15 of 65
A19-1

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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-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. S-2

10 Cust Deposits FERC 235 All detail Year End

Company Desc	Bus Unit Cd	Bus Unit Desc	Obj Acct	Subs d 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-Peace Energy			23500	Customer Deposits	(2,280,611)	(2,253,231)	(2,206,622)	(2,224,274)	(3,872,952)	(4,021,364)	(3,887,169)
									Sum:	(2,280,611)	(2,253,231)	(2,206,622)	(2,224,274)	(3,872,952)	(4,021,364)	(3,887,169)

staff Adj. 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)	(3,518,527)
(3,820,383)	(4,062,164)	(4,194,641)	(4,102,841)	(4,340,804)	(4,473,789)	

State Adj. 5-1

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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-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	2011 Budget Base Pay	\$122,490,198	6.06%	\$7,425,250
2				
3	less: 2011 Budget Merit @ 3.0%	(3,567,676)	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	2.50%		
8				
9	Estimated 2011 Actual Merit Increase	2,973,063	6.06%	180,225
10				
11	Estimated 2011 Actual Base Pay	\$121,895,585	6.06%	\$7,389,206
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	Estimated Total Revenue Requirement Adjustment	(\$631,993)	6.06%	(\$38,311)

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

Cost of Capital		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	39.2300%
			Equity GrossUp	3.8200%
			PreTax Return	5.5000%

Composite Book Life (\$000s)	
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

Docket No PU-10-657 & PU-11-55
Exhibit___(MJM-47)
Page 22 of 65

1-10

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
Total Elec O&M	2,381,417,422	160,220,846	149,413,720	3,045,911	2,694,097,900
 Payroll Taxes	 26,495,709	 1,814,591	 1,696,130	 26,810	 30,033,241
 Total Elec O&M without COGS	 1,229,704,343	 78,828,990	 74,780,243	 1,561,823	 1,384,875,399

	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	20,992,093	1,713,438	7,323,152	30,028,683
NOTE: Entry for Total Company PTD				

As of: 12/9/2010 14:12

01-2

Staff Adj. 6-5

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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 NID 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**

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

NSPM Bargaining Unit 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 - Medical and Pharmacy
Percent to NSPM electric O&M
Amount to MN electric O&M

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)

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

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

Dental cost share change from 60/40 to 75/25
241,175
64.7%
156,158
5.42%
(41,532)

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

Case No: PU-10-657 11-55
Data Request No. AS-2-RR-149
Attachment A
Page 1 of 1

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

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)

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**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

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)

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. 7-6

2011 Pension Adjustment
 Accounting Summary Report

02-5d
 Case No. PU-10-XXX
 Page 1 of 1

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
925	FAS 112 Work Comp	268,250	29,470	238,780	210,688	14,837	13,611	192
926	Nonqualified Pension	15,583	6,231	46,352	40,862	2,830	2,620	140
926	NQ Pension SEBP Remo	(921,927)	(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	89,132	82,497	1,250
	Grand Total	1,281,168	149,613	1,131,555	997,713	68,833	64,050	960

Staff Adj. 8-1

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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

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-2-RR-151-B

Legal Entity	FAS 87 Qualified Pension			FAS 106 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)
NSPM	11,850,000	10,127,000	1,723,000	10,526,000	11,633,000	(1,107,000)	441,000	504,000	(63,000)	2,095,000	1,128,000	967,000	543,000	578,000	(35,000)	23,455,000	23,970,000	1,485,000
NSPM Nuclear	878,000	1,125,000	(247,000)	(86,000)	(94,000)	28,000	74,000	118,000	(44,000)	-	-	-	-	-	-	886,000	1,149,000	(263,000)
XES	19,515,000	19,998,000	(483,000)	681,000	793,000	(112,000)	4,113,000	3,354,000	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	11,141,000	12,332,000	(1,191,000)	4,828,000	3,978,000	852,000	2,021,000	1,185,000	836,000	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																		(878,916)
Total NSPM O&M Electric Excluding SERP																		(227,353)
Total After Interchange Agreement																		(197,988)
Total Adjustment to NSPM O&M Electric ND																		Updated Adjustment (12,005)

Previous Response to AS-2-RR-151-B

Legal Entity	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)
NSPM	12,394,000	10,127,000	2,267,000	11,561,000	11,633,000	(72,000)	504,000	504,000	-	1,578,000	1,128,000	450,000	1,068,000	578,000	510,000	27,125,000	23,970,000	3,155,000
NSPM Nuclear	977,000	1,125,000	(148,000)	(98,000)	(94,000)	(4,000)	122,000	118,000	4,000	-	-	-	-	-	-	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	1,665,000	1,185,000	480,000	1,068,000	578,000	510,000	54,181,000	49,321,000	4,860,000
Amount to NSPM O&M Electric																		2,206,094
Remove SERP																		(824,927)
Total NSPM O&M Electric Excluding SERP																		1,281,167
Total After Interchange Agreement																		1,131,555
Total Adjustment to NSPM O&M Electric ND																		Previous Adjustment 88,933
Change to Adjustment																		(80,838)

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

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

Staff Adj. 9-1

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

Staff Adj. 9-2

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>		<u>-</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

A11-4

From: Thomas E. [mailto:thomas@questpole.com]
To: [mailto:thomas@questpole.com]
Cc: [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, We have always done a "base" amount of pole replacements 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 working up to 700 pole replacement 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: Thomas E. [mailto:thomas@questpole.com]
Sent: Wednesday, September 29, 2010 1:49 PM
To: Thomas E. [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Thanks Joe for the update. In talking with Pat Silernd 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: Thomas E. [mailto:thomas@questpole.com]
Sent: Wednesday, September 29, 2010 1:36 PM
To: Thomas E. [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, I need to revise the estimated project split between MN, ND, and SD.

Total NSP Quest pole attachments = 67,888

MN Attachments = 67,888 (94.0%)
ND Attachments = 1,900 (2.8%)
SD Attachments = 2,100 (3.1%)

From: Thomas E. [mailto:thomas@questpole.com]
To: [mailto:thomas@questpole.com]
Cc: [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, please see my responses to your questions (in red) below.

From: Thomas E. [mailto:thomas@questpole.com]
Sent: Wednesday, September 29, 2010 1:36 PM
To: Thomas E. [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Good afternoon Joe,

... am putting the rate case adjustment together for this item and have a couple questions or clarification points.

1st Is this incremental cost estimate 100% assignable to the distribution operations group in MN 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 NSP Company, inclusive of any transfer requests we may get from Quest for our service territory in ND and SD. According to our records, we are allocated to approximately 64,000 Quest poles in ND and SD or which approximately 67,000 if these attachments are within the State of Minnesota. If, going strictly by number of attachments in each state, approximately 85% of the incremental costs would be assigned to MN.

2nd Do you have a breakdown for this estimate by object account or at least type of cost (i.e. internal labor, materials, contractor, etc.) Since this is incremental to the 2011 Budget case, we do not have this broken down specifically within the budget case. Also, at this point in time, we have not decided on whether the bulk of these incremental attachments will be done by local crews, contractors, or a combination of both. Historically, the "base" attachments have been done by local crews and break down as follows: Labor = 67.3%, Materials = 11.6%, Contractor = 2.1%, Transportation = 9.0%.

3rd Is the cost to NSP to transfer from Quest poles to NSP poles or to re-lease our equipment on new Quest poles? I am still a little fuzzy on what activity is actually happening. - Cost is to transfer the facilities attached to existing Quest poles to new Quest poles (replacing the existing ones).

Thanks

Tom Krause

From: Thomas E. [mailto:thomas@questpole.com]
To: [mailto:thomas@questpole.com]
Cc: [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

From: Thomas E. [mailto:thomas@questpole.com]
Sent: Tuesday, September 28, 2010 4:40 PM
To: Thomas E. [mailto:thomas@questpole.com]
Cc: [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Hi Tom, we are working on these questions and will reply to you as quickly as we can. We are currently working on a 50 degree two-phase primary voltage (Three-Phase) structure. Possible facility transfers would include any one or a combination of the following:

- Single-phase primary conductor transfer (including neutral wire, insulators, pole, conductor line, associated hardware)
- Two-phase primary conductor transfer (including neutral wire, cross-arm, insulators, pole, conductor line, associated hardware)
- Three-phase primary conductor transfer (including neutral wire, cross-arm, insulators, pole, conductor line, associated hardware)
- Secondary line conductor transfers (single-phase, two-phase, or three-phase)
- Service conductors (single-phase, two-phase, or three-phase)
- Fused cutouts
- Arresters
- Transformers
- Various other electrical equipment

From: Thomas E. [mailto:thomas@questpole.com]
Sent: Tuesday, September 28, 2010 4:30 PM
To: Thomas E. [mailto:thomas@questpole.com]
Cc: [mailto:thomas@questpole.com]
Subject: RE: 2010 Pole Case: Info needed to do Quest pole budget adjustment -2011 and beyond

Also, the unanticipated incremental Distribution O&M associated with Quest pole transfers we would like to include in your testimony at \$425,000 for 2011 and then escalated 3% for each successive year (to \$437,875 in 2012). This incremental O&M is based on NSP Distribution transferring our electric facilities attached to Quest owned poles assuming an estimated 700 Quest pole replacements annually. The incremental Distribution O&M would be budgeted under PERC account 303 - Other Misc of Overhead Lines.

Let me know if you need any further information or have any questions. Thanks,

Joe Krause

Staff Adj. 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

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"

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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

Revised Billed Commodity Revenue

NSP Minnesota Co Consolidated

Grand total

Updated
2011

3,709,386

3,709,386

Write-Offs/Revenue Percentages

NSP Minnesota Co Consolidated

Grand total

%s

0.479%

17,777.77

17,777.77

0.48%

NSP Minnesota Co Consolidated

Grand total

17,777,768

17,777,768

NSP Minnesota Co Consolidated

MN Elect

0.70121

JDE Acct #

432813.723055

12,465,875

ND Elect

0.04375

432815.723055

777,721

SD Elect

0.04001

435816.723055

711,351

ND Gas

0.02343

432817.723055

416,504

MN Gas

0.19161

432819.723055

3,406,318

Original Budget

Level

Difference

13,199,994

(734,119)

823,521

(45,800)

753,242

(41,892)

441,032

(24,528)

3,606,917

(200,599)

Grand total

17,777,768

18,824,707

(1,046,939)

(821,811) Elec Distribution Total
PTD

(225,127) Gas Total

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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

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.

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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 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**

Recap of Adjustment	Total Co	MN	ND	SD	
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
Net Adjustment to Econ Dev	<u>142,371</u>	<u>28,342</u>	<u>64,029</u>	<u>50,000</u>	

Recap of Economic Development Costs in Test Year

Total Budgeted ED O&M (Bu 811203)	129,705
Less: Non Allowed Program Costs	(9,615)
Subtotal O&M	<u>120,091</u>
Plus: Allowable Program Donations	37,957
Total ED Costs in Test Year	<u><u>158,047</u></u>

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NORTHERN STATES POWER CO d/b/a XCEL ENERGY
Charitable Contributions / Donations
YEAR ENDED 12-31-11
FERC 426.1

A18-2

ELECTRIC	Total Co	MN	ND	SD	WHL	SL
<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>						
	\$ 910,095	\$ 832,619	\$ 52,440	\$ 25,035	\$ 1	
Total Electric	\$ 4,021,067	\$ 3,757,263	\$ 263,216	\$ 225,253	\$ 8	
MN & ND - 50% Electric Inclusion	\$2,010,244	\$1,878,632	\$131,608	\$0	\$4	

GAS	Total Co	MN	ND
<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>			
	\$84,117	\$ 77,889	\$ 6,228
Total Gas	\$ 374,230	\$ 339,690	\$ 34,540
MN & ND 50% Gas Inclusion	\$187,115	\$169,845	\$17,270

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Electric - PTD Adjustment	Production	Transmission	Distribution	check
<i>Allocated</i>	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
Total Elec O&M	2,381,417,422	160,220,846	149,413,720	3,045,911	2,694,097,900
 Payroll Taxes	 26,495,709	 1,014,591	 1,096,130	 26,810	 30,033,241
 Total Elec O&M without COGS	 1,229,704,343	 78,828,990	 74,780,243	 1,561,823	 1,384,875,399

	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	20,992,093	1,713,438	7,323,152	30,028,683
NOTE: Entry for Total Company PTD				

As of: 12/9/2010 14:12

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01-2

**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)
Incentive Pay at 85% of Target	31,830,433	30,097,720	26,497,656	1,843,402	1,738,362	18,300
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)
Adjusted Amount of Base Incentive at 85% of Target	22,918,650	21,731,949	19,137,687	1,329,426	1,250,463	14,373

Adjust total to 85% of Target Level

Net Incentive Pay included in test year	22,918,650	21,731,949	19,137,687	1,329,426	1,250,463	14,373

For () Distribution of Incentive Pay at 85% of Target	22,918,650	21,731,949	19,137,687	1,329,426	1,250,463	14,373

P	T	D
57.18%	11.79%	31.03%
(4,758,617)	(981,184)	(2,582,369)

Staff Adj. 14-2

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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-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 worksheet 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

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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)
Incentive Not Priced in Items	30,782,348	30,054,119	26,456,827	1,841,995	1,737,016	18,281
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)
Adjusted Amount of Base Incentive at 85% of Target	22,918,650	21,731,949	19,137,687	1,329,426	1,250,463	14,373
Adjust total to 85% of Target Level	-	-	-	-	-	-
Net Incentive Pay included in test year	22,918,650	21,731,949	19,137,687	1,329,426	1,250,463	14,373
Total Adjustment to Incentive Amount in Budget	(8,860,698)	(8,322,170)	(7,319,140)	(512,569)	(486,553)	(3,908)

P	T	D
57.18%	11.79%	31.03%
(4,758,617)	(981,184)	(2,582,369)

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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?
- 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

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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)
		(827,462)	(730,151)	(49,386)	(47,245)	(680)

* This adjustment does not include any of the payroll taxes associated with Aviation Costs

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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.

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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.

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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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 Total Company Actuals	2010 NSPM Total Company Actuals	2011 NSPM Total Company Budget	2011 ND 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 Interrupt 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 Injuries & Damages

	2009 NSPM Total Company Actuals	2010 NSPM Total Company Actuals	2011 NSPM Total Company Budget	2011 ND 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>

Staff Adj. 18-2

A31-2

NORTHERN STATES POWER COMPANY
2011 Requested Expenses
RATE CASE AMORTIZATION

FERC	Business Unit Description	Monthly	State of ND 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
10.424490

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

Balance as of 10-31-2010	339,060
No & Dec anticipated Spend	112,036
Anticipated 12-31-2010 balance for ND DSM	451,096
Proposed Amortizations over 2 Years	225,548

From: Hager, Michael R
To: Felling, John M
Cc: McLaughlin, Bridget; Rarrings, Patrick
Subject: RE: MD DSM

Sent: Thu 12/10/2014

Our Reg. Asset balance as of 10.31.2010 =	<u>\$339,060</u>
Our Nov. and Dec. forecasted spend =	<u>\$112,036</u>
Anticipated balance as of 12.31.2010 =	<u>\$451,096</u>

The Nov. and Dec. forecast details:

										95,973	15,063	117,036
Version: 10/27/2010	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.	Electric Dept.
November 2010 Forecast	North Dakota	Electric	11072071 - ECPND Business Savers Switch	LM	Def. Debt Details	4,411	1,430					
November 2010 Forecast	North Dakota	Electric	11072086 - ECPND Electric Rate Savings	LM	Def. Debt Details	129	135					
November 2010 Forecast	North Dakota	Electric	11072305 - ECPND Res Home Energy Audits	RES	Def. Debt Details	0	0					
November 2010 Forecast	North Dakota	Electric	11072371 - ECPND Resident Savers Switch	LM	Def. Debt Details	92,433	13,496					

Order

1. NSP's proposed cost recovery tariff rider is denied.
2. 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

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

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 E 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.)

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

		<u>Total Company Electric</u>		<u>ND Retail Electric</u>		<u>All Other</u>	
<u>Expenses</u>							
<u>Includable Expenses</u>	<u>Lead Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>	<u>Dollars</u>	<u>Dollar x Days</u>
<u>Fuel Expenses</u>							
1 Coal & Rail Transport	21.08	353,157	7,444,550	22,115	466,184	331,042	8,978,365
2 Gas for Generation	38.45	180,884	8,954,990	11,327	435,523	169,557	8,519,467
3 Oil	22.51	683	15,374	43	968	640	14,408
4 Nuclear & EOL	0.00	111,499	0	8,982	0	104,517	0
5 Nuclear Disposal	78.00	<u>11,164</u>	<u>848,464</u>	<u>649</u>	<u>49,324</u>	<u>10,515</u>	<u>799,140</u>
6		657,387	15,263,378	41,116	951,999	616,271	14,311,378
<u>Purchased Power</u>							
7 Purchases	28.12	894,154	25,143,610	54,286	1,526,522	839,868	23,817,088
8 Interchange	38.21	<u>119,793</u>	<u>4,577,291</u>	<u>7,047</u>	<u>269,266</u>	<u>112,745</u>	<u>4,308,025</u>
		1,013,947	29,720,901	61,333	1,795,788	952,614	27,925,113
<u>Labor & Related Costs</u>							
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	338,961	20,403	5,203,785
11 Pension & Benefits	19.20	<u>79,160</u>	<u>1,519,872</u>	<u>4,628</u>	<u>92,688</u>	<u>74,332</u>	<u>1,427,174</u>
12 Subtotal Labor & Related		468,720	11,590,581	28,393	705,384	440,327	10,885,197
13							
14 All Other Operating Expenses	35.01	552,802	19,353,595	29,308	1,026,073	523,494	18,327,522
15 Property Tax	356.72	115,650	41,254,668	5,653	2,018,538	109,997	39,238,130
16 Employer's Payroll Taxes	28.56	30,033	797,876	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)	(1,281,498)	(5,853)	(220,951)	(28,358)	(1,070,547)
19 State Income Tax	37.75	(4,589)	(172,464)	(924)	(34,894)	(3,644)	(137,570)
20 State Sales Tax Customer Billings	35.73	138,595	4,951,999	0	0	138,595	4,951,999
21 Total Expenses	<u>41.34</u>	2,938,353	<u>121,468,637</u>	<u>39.10</u>	<u>160,841</u>	<u>6,288,144</u>	<u>115,180,693</u>
22 Net Annual Expense Amount			<u>332,791</u>			<u>17,228</u>	<u>315,504</u>
<u>Revenues</u>							
23 Computer Billing	100.00%	45.45	3,034,853	137,942,263	164,504	7,477,151	2,870,349
24 Hand Billed	0.00%	43.07	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	2,261	98,888	243	10,413	2,018	86,475
29 CIP 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	223,624
34 MISO	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	858,791	1,345	49,900	21,803	808,891
38 Distribution Associated Revenues	42.85	1,872	80,219	0	0	1,872	80,219
39 Other	42.85	2,356	100,959	(652)	(27,940)	3,008	128,899
40 JOA - Rev fr/to PSC	37.10	(4,898)	(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	<u>43.94</u>	3,753,420	<u>164,910,560</u>	<u>43.82</u>	<u>206,949</u>	<u>9,067,935</u>	<u>155,842,625</u>
45 Net Annual Amount			<u>451,810</u>			<u>24,844</u>	<u>426,966</u>
46 Expense / Revenue Factor			0.7828			0.7772	
47 Allocated Revenue Amount			<u>353,698</u>			<u>19,308</u>	
48 Net Cash Working Capital			<u>20,907</u>			<u>2,081</u>	<u>18,826</u>

Due to rounding, may not be exactly to rate base number

Staff Adj. 22-2

Rate Base Detail - Cash Working Capital

		Total Company Electric		ND Retail Electric		All Other	
Expenses							
Includeable Expenses	Lead Days	Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
Fuel Expenses							
1 Coal & Rail Transport	21.08	353,157	7,444,550	22,115	468,184	331,042	6,978,365
2 Gas for Generation	38.45	180,884	6,954,990	11,327	435,523	188,557	6,519,487
3 Oil	22.51	683	15,374	43	968	640	14,406
4 Nuclear & EOL	0.00	111,499	0	6,982	0	104,517	0
5 Nuclear Disposal	76.00	11,164	848,464	649	49,324	10,515	799,140
6		657,387	15,263,378	41,116	951,999	616,271	14,311,378
Purchased Power							
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	4,577,291	7,047	269,266	112,748	4,308,025
		1,013,947	29,720,901	61,333	1,795,788	952,614	27,925,113
Labor & Related Costs							
9 Regular Payroll	12.31	367,826	4,527,963	22,236	273,725	345,592	4,254,238
10 Incentive Compensation	255.05	21,732	5,542,747	1,329	338,961	20,403	5,203,785
11 Pension & Benefits	19.20	79,180	1,519,872	4,628	92,698	74,332	1,427,174
12 Subtotal Labor & Related		468,720	11,590,581	28,393	705,384	440,327	10,885,197
13							
14 All Other Operating Expenses	35.01	552,802	19,353,595	29,579	1,035,561	523,223	18,316,034
15 Property Tax	356.72	117,651	41,968,485	5,911	2,108,572	111,740	39,859,893
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	(51,211)	(1,933,219)	(5,778)	(218,136)	(45,433)	(1,715,083)
19 State Income Tax	37.75	(9,387)	(364,374)	(910)	(34,335)	(8,478)	(320,039)
20 State Sales Tax Customer Billings	35.73	138,595	4,951,999	0	0	138,595	4,951,999
21 Total Expenses	41.58	2,916,536	121,359,002	181,459	6,393,039	2,757,077	114,985,963
22 Net Annual Expense Amount			332,490		17,515		314,975
Revenues							
23 Computer Billing	100.00%	3,034,853	137,942,263	164,504	7,477,151	2,870,349	130,465,112
24 Hand Billed	0.00%	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	2,261	96,888	243	10,413	2,018	86,475
29 CIP 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	448,657	17,068,764	26,889	1,027,429	419,768	18,039,335
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 MISO	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	858,791	1,345	49,900	21,803	808,891
38 Distribution Associated Revenues	42.85	1,872	80,219	0	0	1,872	80,219
39 Other	42.85	2,356	100,959	(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	3,753,420	164,910,560	206,949	9,067,935	3,546,471	155,842,625
45 Net Annual Amount			451,810		24,844		426,966
46 Expense / Revenue Factor			0.7776		0.7802		
47 Allocated Revenue Amount			351,312		19,363		
48 Net Cash Working Capital			18,822		1,868		16,955

Due to rounding, may not be exactly to rate base number

Staff Adj. 22-3