

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

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER
COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC
SERVICE IN NORTH DAKOTA

CASE NO. PU-12-813

EXHIBIT MJM-1

DIRECT TESTIMONY OF

MICHAEL J. MAJOROS, JR

ON BEHALF OF THE STAFF OF THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

1 **I. Introduction**

2 **Q. State your name, position, and business address.**

3 A. My name is Michael J. Majoros, Jr. I am President of Snavely King
4 Majoros & Associates, Inc. located at 8100 Professional Place, Landover
5 MD 20785.

6 **Q. Describe Snavely King Majoros & Associates, Inc.**

7 A. Snavely King Majoros & Associates, Inc. ("SKM") is an economic and
8 management consulting firm whose focus is the transparency,
9 accountability and effectiveness of economic regulation along regulated
10 and partially regulated supply chains. Its' clients include Main Street
11 individuals and organizations. The firm's consultants conduct economic,
12 accounting, and financial policy analysis, which they present in the form
13 of expert testimony and reports before courts and regulatory agencies. In
14 1970, Carl M. Snavely and Charles W. King founded Snavely King &
15 Associates, Inc. to conduct research on a consulting basis into the rates,
16 revenues, costs and economic performance of regulated firms in the
17 transportation, telecom and public utility industries. Since then, the firm
18 has participated in over 1000 proceedings before almost all of the state
19 commissions, and all Federal commissions that regulate the utility,
20 telecom and transportation industries.

21 **Q. Have you prepared a summary of your qualifications and experience?**

1 A. Yes, Appendix A is a summary of my qualifications and experience.
2 Appendix B contains a tabulation of my appearances as an expert witness
3 before state and Federal regulatory agencies.

4 **Q. For whom are you appearing in this proceeding?**

5 A. I am appearing on behalf of the North Dakota Public Service Commission
6 Staff.

7 **II. Subject of Testimony**

8 **Q. What is the subject of your testimony?**

9 A. My testimony addresses depreciation and nuclear decommissioning.

10 **Q. Do you have any specific experience in the field of public utility
11 depreciation?**

12 A. Yes, public utility depreciation is a field in which SKM specializes.
13 Members of the firm have appeared as expert witnesses on this subject
14 before the regulatory commissions of almost every state and several
15 Federal Commissions. I have testified on the subject of public utility
16 depreciation on multiple occasions, including appearances before the
17 North Dakota Public Service Commission (“PSC” or “Commission”). I
18 have also testified on the subject of nuclear decommissioning costs and
19 funds.

20 **III. Purpose of Testimony**

21 **Q. Explain the purpose of your testimony in this proceeding.**

22 A. My testimony reviews the Company’s depreciation proposals. It describes
23 expresses an opinion regarding the reasonableness of the Companies’

1 depreciation proposals. Finally, I make alternative recommendations.

2 **IV. Summary of Adjustments**

3 **Q. Do you have any alternative recommendations?**

4 A. Yes, I have two recommendations as a result of my analyses.

5 • I propose retention of the whole-life procedure with a separate
6 amortization of any significant reserve imbalances

7 • I propose to set fossil decommissioning cost to the present value of the
8 legal asset retirement obligations the company will incur when it
9 retires its plants.

10 • I propose to set net salvage cost estimates for the mass property
11 transmission, distribution and general functions to their present values
12 by direct reference to the legal asset retirement obligations the average
13 amounts of net salvage the company has incurred during the most
14 recent 5-year.

15 **VI. Structure of Testimony**

16 **Q. How have you structured your testimony?**

17 A. I begin by summarizing the Company's proposal. Next, I provide some
18 background regarding the genesis of the Companies' current depreciation
19 rates. Next, I discuss the Company's proposed rates and the differences
20 between the Company's proposals and the depreciation principles laid out
21 in Case No. PU-07-776. Finally, I discuss my analyses and
22 recommendation.

23

1 **Summary of Company Depreciation Proposals**

2 **Q. Summarize the Company's depreciation expense proposals.**

3 A. Lisa H. Perkett presents the Company's depreciation and nuclear
4 decommissioning expense testimony. Although Ms. Perkett sponsors the
5 depreciation study; it was prepared by Mr. Watson of Alliance Consulting.

6 **Q. Is Mr. Watson a witness in this proceeding?**

7 A. No.

8 **Q. What is the overall impact on depreciation of Ms. Perkett's**
9 **proposals?**

10 A. The overall impact to depreciation expense is shown below:

11 (\$millions)

12 <u>Functional Class</u>	Change	Change
	<u>Total Company</u> ¹	<u>North Dakota</u> ²
14 Nuclear Decommissioning	0.0	0
15 Electric Production	(\$4.9)	(\$.4)
16 Transmission, Dist. And General	(\$6.7)	1.5
17 Total	(\$11.7)	\$1.1

18 **Q. Can you explain why the North Dakota jurisdiction receives an**
19 **increase while total company expense decreases?**

20 A. According to Ms. Perkette: The overall reduction being referenced on
21 Page 3 [of her testimony] was shown at the total company level. The total

¹ Perkett, p.3.

² Workpapers A22 and A23.

1 reduction is primarily due to large decreases in depreciation for electric
2 transmission and electric software. When these amounts, along with
3 depreciation changes for electric general, common general and common
4 software, are jurisdictionalized down to the North Dakota level, the
5 decreases are smaller than the increase in depreciation related to [North
6 Dakota] electric distribution. Electric distribution assets are direct-
7 assigned to the State of North Dakota and do not need to be
8 jurisdictionalized. A side-by-side comparison of total company and North
9 Dakota jurisdictional depreciation changes can be seen in Table 4 of Lisa
10 Perkett's testimony.³

11 **Q. Is this a responsive answer?**

12 A. Yes, Ms. Perkett's answer is responsive, but it clearly demonstrates a need
13 to scrutinize the Company's North Dakota distribution depreciation rates.

14 **Q. Did you investigate the calculation of the Company's proposed
15 depreciation rates?**

16 A. Yes, Appendix C of Ms. Perkett's study compares the parameters
17 underlying the current and proposed depreciation rates. Any change to a
18 parameter will change the resulting depreciation rate.

19 **Q. What drives these changes?**

20 A. We asked the Company to provide a table showing the proposed change in
21 depreciation expense caused by: plant growth, life and curve changes,
22 gross salvage changes, cost of removal changes, procedure changes (e.g.

³ Response to NDPSC-8-87

1 Equal Life Group v. Average Life Group) and method changes (e.g.
2 Whole Life v Remaining Life), and other changes. We asked it to explain
3 the “other changes.”

4 **Q. How did the Company respond?**

5 A. The Company objected asserting that “this request is unduly burdensome
6 because the Company has not previously performed an analysis to
7 compute the requested information. As a result, the Company would have
8 to develop new analyses that are not presently available. The life and net
9 salvage changes by account are documented in Exhibit ____ (LHP-1),
10 Schedule 7, Appendix C. There is no procedure change; average life group
11 is still used with the exception of amortized depreciation groups. The
12 method change going from whole life and remaining life is documented in
13 Schedule 7 to the testimony of Lisa H. Perkett.”⁴

14 **Q. Did you make any other inquiries?**

15 A. Yes, we asked the Company to identify and explain all changes between
16 the current study and the most recent prior study. It directed us to the
17 workpapers filed as a part of our response to Data Request No. NDPSC-8-
18 1 or its’ depreciation study, filed as Schedule 7 with Lisa Perkett’s
19 testimony.⁵

⁴ Response to NDPSC-8-11

⁵ Response to NDPSC-8-45

1 **Q. Has there been any financial, operating, and maintenance change**
2 **since the Company’s last depreciation study that has affected**
3 **depreciation lives, retirement patterns or net salvage characteristics?**

4 A. Ms. Perkette responds “Please see Schedule 7 and associated electronic
5 workpapers provided in our response to Data Request NDPSC-8-001. No
6 other analysis has been performed.”⁶

7 **Q. Does the Company have any programs which might affect plant lives?**

8 A. Again, Ms. Perkette responds “Any Company programs that had an effect
9 on the plant lives being proposed would be discussed in our depreciation
10 study. The study has been submitted as Schedule 7 to Lisa Perkett’s Direct
11 Testimony.”⁷

12 **Q. What do you conclude?**

13 A. I conclude that the depreciation rates changes are not driven by changes
14 since the last study operational, maintenance or financial changes or
15 programs adopted since the last study.

16 **VII. Depreciation Principles**

17
18 **Q. What is genesis of the Companies’ present depreciation rates?**

19 A. MS. Perkette states that “The 2013 budget for depreciation expense was
20 based on the depreciation principles approved in Case No. PU-07-776, as
21 implemented in Case Nos. PU-10-657 and PU-11-55.” According to
22 Ms.Perkette “Those principles include:

⁶ Response to NDPSC-8-26

⁷ Response to NDPSC-8-64

- 1
- 2 • The nuclear decommissioning reserve remains at zero;
- 3 • The approved extended service lives for Sherco, Prairie Island, Angus
- 4 Anson, Granite City, High Bridge, Inver Hills, and Key City plants;
- 5 and
- 6 • The transmission and distribution removal cost estimates were
- 7 consistent with the ordered rates in Case No. PU-07-776.”⁸
- 8

9 **Q. Did you participate in Case Nos. PU-07-776, PU-10-657 and PU-11-**

10 **55?**

11 A. I participated in Case No. PU-07-776 but not the other two.

12 **Q. Does Ms. Perkett provide a fair representation of the depreciation**

13 **principles approved in Case No. PU-07-776?**

14 A. Ms. Perkette’s response is somewhat limited and avoids addressing a few

15 fundamental but major principles. I have attached the Order Adopting

16 Settlement in Case No. PU-07-776 as Exhibit___ (MJM-2). Below, I

17 discuss the principles she avoids and my responses concerning the

18 Company’s compliance therewith.

19 **Preamble:** The Company's proposed depreciation

20 expense in this case was based on a uniform

21 depreciation expense for use in all jurisdictions. In its

22 testimony and post-hearing briefs, Staff challenged the

23 reasonableness of the Company's methodologies in

24 several respects. In response, the Parties agree to the

25 following process for establishing depreciation

26 expenses.⁹

27

28 **Q. What is the first principle Ms. Perkett avoids?**

⁸ Perkett p.2.

⁹ Order Adopting Settlement Dated December 31, 2008 Case PU-07-776 Page 7.

1
2 A. The first principle is:
3

4 **Principle:** The Company will use the principles
5 adopted in this Settlement Agreement in establishing
6 depreciation rates for use in North Dakota. The
7 Company will reflect its North Dakota depreciation
8 rates in its annual North Dakota earnings reports and
9 will file depreciation rates consistent with these
10 principles as part of the Company's next electric rate
11 case.¹⁰
12

13 **Q. What is your response?**
14

15 A. The Company did not comply. Exhibit___ (MJM-3) is a copy of
16 the Company's 2011 and 2012 Earnings Reports to the NDPSC.
17 No depreciation rates are shown in the report; and the Company's
18 proposed depreciation rates in this case are not consistent with the
19 principles established in Case No. PU-07-776.

20 **Q. What do you recommend?**

21 A. I recommend the Company be ordered to report, in all future
22 earnings reports, the North Dakota-specific depreciation adopted in
23 this proceeding and the annual North Dakota depreciation expense
24 produced by those depreciation rates. The Company should also
25 be ordered to report in all future earnings reports, the North
26 Dakota-specific depreciation reserves approved in this proceeding
27 and maintain and update those reserves with North Dakota-specific
28 annual activity.

¹⁰ Order Adopting Settlement Dated December 31, 2008 Case PU-07-776 Page 7.

1 **Q. What is the next principle Ms. Perkett avoids?**

2 A. The next principle is:

3

4 **Principle:** Ninety days before filing its next electric rate
5 case, the Company will report to the Commission on
6 whether it intends to propose North Dakota specific
7 depreciable lives for distribution facilities, and the
8 reasons for its proposal.¹¹

9

10 **Q. What is your response?**

11

12 A. Regardless of the notification, Ms. Perkett did not propose
13 North Dakota-specific distribution lives or depreciation rates
14 in this case. My firm on behalf of the NDPSC has long
15 advocated North Dakota-specific depreciation studies and
16 rates.

17 **Q. What is the next principle Ms. Perkett avoids?**

18 A. The next principle actually contains two interrelated principles. It
19 is:

20

21 **Principle:** Both Parties agree that, unless directed
22 otherwise by the Commission, rate recovery -- past,
23 present, and future -- for the removal and retirement of
24 Company utility property [a]will be used solely for the
25 retirement of the Company's utility property and
26 [b] recognized as a regulatory liability.¹²

27

28 **Q. What is your response?**

29

30 A. The Company's depreciation filing does not comply with either
31 principle underlined above. First, the Company's proposed

¹¹ Order Adopting Settlement Dated December 31, 2008 Case PU-07-776 Page 8.

¹² Id., Page 8

1 removal costs for non-nuclear production and transmission,
2 distribution and general plant accounts overstate the costs of the
3 legal Asset Retirement Obligations (*legal*-AROs) it has in
4 conjunction with such retirements. Second, the Company has not
5 recognized its recovery of *non-legal* AROs as a regulatory liability
6 for regulatory accounting and ratemaking purposes.

7 **Legal AROs**

8
9 **Q. Please explain the legal ARO issue.**

10 A. The Company's 2012 Form 1 reports that:

11
12 [Legal] AROs have been reported for plant related
13 to nuclear production, stream production, wind
14 production, electric transmission and distribution,
15 natural gas transmission and office buildings. The
16 steam production obligation includes asbestos, ash
17 containment facilities, radiation sources and
18 decommissioning. The asbestos recognition
19 associated with the steam production includes
20 certain plants. NSP-Minnesota also recorded
21 asbestos recognition for its general office
22 buildings.¹³ ...
23

24 The Company's report goes on to state:

25 AROs have been recorded for NSP-Minnesota
26 steam production related to ash-containment
27 facilities such as bottom ash ponds, evaporation
28 ponds and solid waste landfills. Additional AROs
29 have been recorded for NSP-Minnesota steam
30 production plant related to radiation sources in
31 equipment used to monitor the flow of coal, lime
32 and other materials through feeders. NSP-
33 Minnesota has also recorded AROs for retirement

¹³ 2012 FERC Form 1, page 123.41

1 and removal of assets at certain wind production
2 facilities for which the land is leased and removal is
3 required by contract, with origination dates being
4 the in-service date of the various facilities. NSP-
5 Minnesota has recognized AROs for the retirement
6 costs of natural gas mains and for the removal of
7 electric transmission and distribution equipment,
8 which consists of many small potential obligations
9 associated with polychlorinated biphenyls, mineral
10 oil, storage tanks, treated poles, lithium batteries,
11 mercury and street lighting lamps. The electrical
12 and natural gas assets have numerous in-service
13 dates for which it is difficult to assign the obligation
14 to a particular year. Therefore, the obligation was
15 measured using an average service life.¹⁴
16

17 **Q. What is the significance of these quotes?**

18 A. The Company has booked the liability it has for the removal of all
19 functions of its plant. However, it has included estimates of vastly
20 more cost of removal in its depreciation rates. The Company's
21 production plant estimates assume complete demolition of its
22 production facilities, but it is not obligated to incur such costs. Its
23 future net salvage proposals for the transmission, distribution and
24 general facilities are inflated because they incorporate huge
25 amounts of front-loaded future inflation.

26 **Q. What do you conclude?**

27 A. I conclude that ratepayers should not be required to pay the
28 Company more money that it expects to spend upon removal of its
29 assets from service. Furthermore, in my opinion, the depreciation

¹⁴ Id., pages 123.41 to 123.42.

1 principles adopted in Case No. PU-07-776 demonstrate that the
2 Commission reached the same conclusion in that case.

3 **Q. What is the amount of the Company's actual legal AROs?**

4 A. Exhibit___ (MJM-4) consists of three pages from the Company's
5 2012 FERC Form 1. It shows the legal AROs by function at
6 December 31, 2012 by function. They are:

7
8 **Company's Legal AROs**

9

<u>Function:</u>	<u>Legal ARO</u>
	(\$000)
10 Steam production	\$60,760
11 Nuclear production	1,546,358
12 Wind production (other)	32,936
13 Electric transmission and distribution	13,838
14 Gas transmission and distribution	313
15 Common general plant	<u>1,197</u>
16 Total	\$1,655,402

17
18
19
20

21 **Q. What do you conclude?**

22 A. Setting aside the nuclear production function, the Company
23 estimates the present value cost of its legal AROs is about \$109
24 million:

25 **Legal AROs Excluding Nuclear**

26

<u>Function:</u>	<u>Legal ARO</u>
	(\$000)
27 Steam production	\$60,760
28 Wind production (other)	32,936
29 Electric transmission and distribution	13,838

30
31

**Direct Testimony of
Michael J. Majoros, Jr.
Exh. MJM-1**

1	Gas transmission and distribution	313
2	Common general plant	<u>1,197</u>
3	Total	\$109,044
4		

5 **Q. How much future decommissioning and negative net salvage**
6 **has the Company incorporated into its proposed depreciation**
7 **rates?**

8 A. I do not know the amount; however, I do know that it is more than
9 it would be if the legal AROs were used to calculate future net
10 salvage, instead of the company's approach.

11 **Q. What do you recommend?**

12
13 A. I recommend that the Company's Steam and Other production
14 plant depreciation rates reflect its actual legal AROs as the basis for
15 depreciation rates. I make the same recommendation for
16 transmission, distribution and general. The Commission should
17 order the company to provide the North Dakota-specific amounts
18 in all future earnings reports.

19 **Q. Is there another related principle that Ms. Perkett avoids?**

20 A. Yes, Ms. Perkett also avoids the following principle:

21
22 **Principle:** For purposes of determining the
23 overall revenue requirement, the Parties agree to:
24 recover removal costs in depreciation rates for
25 transmission and distribution based on a net
26 present value methodology rather than on a future
27 cost methodology (using Staffs alternative five
28 year historical average for the purposes of this

1 case).¹⁵

2
3 **Q. What is your response?**

4
5 A. Ms. Perkett's depreciation study does not comply. Mr. Watson used
6 the old inflated cost approach to estimate future removal costs for
7 the transmission, distribution and general functions rather than
8 Staffs alternative five year historical average approach. Net salvage
9 is the difference between gross salvage and cost of removal.¹⁶ Mass
10 property negative net salvage and the equivalent production
11 decommissioning costs are primary issues in this proceeding.

12 **Q. Can you confirm that Mr. Watson used the old inflated**
13 **cost approach?**

14 A. First by observation; Ms. Perkett's Exhibit___ (LHP-1), Schedule 7,
15 Appendix A., shows proposed negative net salvage ratios reaching
16 negative 100 percent for a certain North Dakota distribution
17 account. Based on my experience, I am certain that Mr. Watson
18 used the old inflated approach to rationalize a negative 100 percent
19 net salvage ratio.

20 **Q. Did you ask the Company about its net salvage ratios?**

21 A. Yes, NDPSC-8-49(c) asked "Do the net salvage estimates for mass
22 property accounts incorporate inflation expected to be incurred in the
23 future? Ms. Perkett responded: "Yes, but only to a small degree ... " In

¹⁵ Order Adopting Settlement Dated December 31, 2008 Case PU-07-776 Page 10.

¹⁶ Net salvage is the gross salvage for the property retired less its cost of removal. *See* NARUC at 322.

1 NDPSC-8-49(e) and (f) , we asked “Is it correct that Northern States
2 Power Company’s ’s mass property net salvage estimates incorporate
3 inflation that occurred in the past and project the past inflation into its
4 future net salvage estimate? If the answer to part (e) is “no,” please
5 explain why not.” Ms. Perkett responded “See response to part c and page
6 68 of Schedule 7 for a discussion of the computation of net salvage ratios.
7 The Company uses traditional net salvage, which is the precedent in most
8 jurisdictions across the United States.”¹⁷

9 **Q. Do you agree with that response?**

10 A. I agree that the Company used the old traditional net salvage approach. I
11 also agree with Ms. Perkett that the Company’s net salvage estimates for
12 mass property accounts incorporate inflation expected to be incurred in the
13 future. That is why the NDPSC established the present value principle. I
14 do not agree with Ms. Perkett’s assertion that the inflation is only
15 incorporated to a small degree. Inflation is incorporated in the Company’s
16 proposed net salvage ratios to a large degree. As prima facie evidence of
17 that fact, I merely point to the \$432 million regulatory liability for non-
18 legal AROs the Company reports in its 2012 form 10K.¹⁸

19 **Q. Did you ask the Company to provide the net present value of its**
20 **proposed net salvage ratios?**

¹⁷ Response to NDPSC-8-049(f).

¹⁸ Northern States Power Company December 31, 2012 SEC Form 10k page 39.

1 A. Yes, NDPSC-8-49(d) asked “If the answer to part (c) is “yes,” provide the
2 net present value of all of these ratios.” Ms. Perkett responded “The
3 Company has not performed such a calculation and the requested
4 information is not available.”¹⁹

5 **Q. What do you recommend?**

6 A. Since the Company chose not to use the 5-year average and did not
7 comply with other principles, and since the company’s legal AROs reflect
8 its own future cost estimates on a present value basis, the Commission
9 should order the company to use its legal AROs as the basis for all future
10 net salvage estimates.

11 **Q. Do you have any other recommendations concerning**
12 **depreciation rates?**

13 A. Yes, as explained above, I recommend the Company be ordered to
14 report the North Dakota-specific depreciation rates and annual
15 expense resulting there from in all future Earnings Reports to the
16 NDPSC. These reported expenses should be used in the annual
17 roll-forward of the North Dakota-specific depreciation reserves.

18 **Q. Is the Company able to cope with individual state depreciation**
19 **rates?**

20 A. Yes, the Company reported the following in its 2010 Remaining
21 Life Report:

¹⁹ Response to NDPSC-8-049 (d).

**Implementation of Jurisdictional Depreciation
for Financial Purposes**

In settlements to the 2007 North Dakota Electric Rate Case (NDPSC Case No. PUC 07-776) and the 2009 South Dakota Electric Rate Case (SDPUC Docket. No. EL09-009), the Company was ordered to establish remaining lives for some production plants that were materially different from what the Commission had approved in previous Minnesota Remaining Life filings. This went against the long time precedent of the North Dakota and South Dakota retail rate jurisdictions of keeping the remaining lives consistent with what is approved by the Commission. The primary result of this change is that the total Company depreciation calculation for financial purposes must account for different approved rates in the various retail jurisdictions. We do this by calculating a depreciation expense for each jurisdiction based on its approved remaining lives and then applying a jurisdictional allocator to each amount to blend the amounts together to get a total Company financial view. We use this blending of depreciation from each of the jurisdictions for financial purposes for the Company as a whole. When completing jurisdictional filings such as this 2010 Review of Remaining Life filing, we only use the lives as approved by the Commission. The result is that the decisions from the North Dakota and South Dakota Commissions do not affect filings we submit to the Commission. For regulatory purposes, the depreciation expense and the accumulated provision for depreciation are based solely on the remaining lives and net salvage rates approved by the Commission. However, numbers within this filing cannot be compared directly with total Company results that may be reported in filings before the Securities and Exchange Commission or other financial filings completed by the Company.

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Data Request 8-51
Attachment A, Page 17 of 136

1 **Non-legal AROs**

2 **Q. What are non-legal AROs??**

3 A. Non-legal AROs are the difference between the Company's legal
4 AROs and its proposed AROs as shown above. The Company's
5 collections of these excess amounts have led to the regulatory
6 liability discussed in Item [2] of the depreciation principle
7 discussed earlier. As I indicated, the Company has not complied
8 with the principle and has not recognized its recovery of non-legal
9 AROs as a regulatory liability for regulatory accounting and
10 ratemaking purposes.

11 **Q. What is the basis for your assertion that the Company has not
12 recognized the regulatory liability for regulatory accounting
13 and ratemaking purposes?**

14 A. The regulatory liability is not shown in North Dakota 2011 and
15 2012 earnings reports, thus it was not recognized. Also, the
16 Company's 2012 FERC Form 1 states "Removal costs for future
17 removal obligations are classified as accumulated depreciation
18 within the utility plant accounts in the FERC presentation and as
19 regulatory liabilities in the GAAP presentation."²⁰ Hence, even
20 though Case No. PU-07-776 principles required recognition, the
21 Company denies the regulatory liability in its FERC Form 1.
22 Although the Company recognizes the amount owed to ratepayers

²⁰ 2012 FERC Form 1, page 123.1

1 in its GAAP financial statements, it denies its existence in its
2 regulatory and ratemaking financial statements. This is in direct
3 contravention to the depreciation principle established in Case No.
4 PU-07-776.

5 **Q. Does Ms. Perkett confirm this contravention?**

6 A. Yes, Ms. Perkett confirms contravention when she responds to
7 NDPSC-8-68.

8 Question: Please refer to page 38 of the parent
9 Company's 2011 10-K filing to the SEC. If not
10 provided elsewhere, please provide the workpapers
11 supporting the calculation of the asset retirement
12 obligation of \$875 million as of December 31, 2010
13 and \$1.5 billion as of December 31, 2011. Please
14 provide these workpapers in electronic format
15 (Excel), with all formulae intact. Provide the
16 calculations on a plant account-by-plant account
17 basis. Also provide the workpapers in electronic
18 format (Excel), with all formulae intact that support
19 the calculation of the regulatory liability of \$463
20 million at 12/31/10 and \$439 million at 12/31/11.
21

22 Response: The Company respectfully objects that
23 this request [regarding the regulatory liability
24 reported in the 10K] is not reasonably calculated to
25 lead to the discovery of relevant evidence, because
26 the requested information is irrelevant to
27 determining the North Dakota depreciation expense
28 included in the test year revenue requirement. Asset
29 Retirement Obligations relate to the required
30 financial presentation necessary for every public
31 trading entity. However, this Commission
32 undertakes a regulatory review of removal in the
33 depreciation expense developed through the
34 depreciation study process. The creation of financial
35 reporting standards does not supplant the regulatory
36 process; in fact, the financial requirements
37 accounted for only a portion of what regulators

1 review. Subject to this objection and discussion, the
2 Company notes that the amounts related to the
3 regulatory liabilities are based on regulatory orders
4 and/or approved rates, and the detail underlying
5 these amounts can be seen on page 82 of our 2011
6 SEC Report 10-K.²¹
7

8 In 2011 the Company recognized a \$463 million regulatory
9 liability for non-ratemaking GAAP purposes, but not for
10 Commission Ordered regulatory ratemaking purposes.

11 **Q. What do you recommend?**

12 A. I recommend that the Company be ordered to report the total and
13 North Dakota's share of this regulatory liability in all future
14 Earnings reports to this Commission. I also recommend that the
15 Company be ordered to modify its FERC Form 1 language to state
16 that North Dakota's share of the non-legal ARO embedded in
17 accumulated depreciation has been recognized as a regulatory
18 liability.

19 **Nuclear Decommissioning**

20 **Q. What does the Company propose regarding Nuclear**
21 **Decommissioning?**

22 A. Ms. Perkett states:
23

24 Currently, the decommissioning fund accrual is set
25 to zero, and no funds are being collected from North
26 Dakota customers. Consistent with the recent
27 decision by the Minnesota Public Utilities
28 Commission (MPUC) in our Triennial Nuclear
29 Decommissioning proceeding (MPUC Docket No.

²¹ Response to NDPSC-08-068

1 E002/M-11-939), we propose using a 60-year
2 decommissioning period and propose to retain the
3 accrual at zero by placing all of the 2012 and 2013
4 DOE settlement payments into the external escrow
5 fund to cover the increase in accrual that would
6 otherwise need to be collected from North Dakota
7 customers beginning in 2013. Under our proposal,
8 there is no impact to the North Dakota jurisdiction
9 for the test year.²²

10
11 **Q. Was the North Dakota PSC invited to the Triennial Nuclear
12 Decommission proceeding?**

13
14 A. No. M's Perkett explains:

15
16
17 The Company files its Triennial Decommissioning
18 Fund Accrual with the Minnesota Public Utilities
19 Commission every three years. The most recent
20 filing was submitted on November 30, 2011. The
21 Minnesota Public Utilities Commission thereafter
22 issued a notice for comments. Any interested party
23 was allowed to file comments in the proceeding.
24

25
26 **Q. What was the outcome of the Minnesota Triennial Nuclear
27 Decommissioning proceeding?**

28 A. According to MS. Perkett:

29
30
31 In our Triennial Nuclear Decommissioning
32 proceeding in Minnesota, we proposed an annual
33 nuclear accrual amount greater than zero beginning
34 in 2013. Our submittal presented cost estimates
35 using 36-year, 60-year, 100-year, and 200-year
36 decommissioning periods. ... That filing also
37 proposed that the accrual be funded by the DOE
38 settlement payments for the next two years (using
39 the 2012 settlement payment for the 2013 accrual

²² Perkett Direct Testimony in Case PU-12-813 dated December 31, 2012 at lines 1-10.

1 and the expected 2013 settlement payment for the
2 2014 accrual). The MPUC chose the 60-year cost
3 estimate scenario with the DOE settlement
4 payments from October 2012 and 2013 being
5 placed in the external escrow fund to cover the
6 increase in accrual, resulting in no funds needing to
7 be collected from Minnesota customers in 2013.²³
8

9 **Q. Did the adoption of a 60-year decommissioning period produce**
10 **an excess within the Nuclear decommissioning Fund?**

11
12 **A.** Apparently not. Ms. Perkett explains:

13
14 There is not a decommissioning excess as a result of
15 the 60-year decommissioning period. Rather, the
16 accrual had been set to zero in prior proceedings. As
17 can be seen in Table 2 of Lisa Perkett's testimony,
18 however, the current cost estimates require an
19 annual accrual of \$276,513, beginning in 2013. An
20 accrual would not be required if an excess existed in
21 the nuclear decommissioning fund. The Company
22 proposes that all of the DOE settlement payments
23 received in 2012 and 2013 be used to fund the
24 accrual, which would result in deposits to the fund
25 in excess of the accrual amount. The excess
26 amounts from the DOE settlement payments would
27 be used to fund future accrual payments. Funds
28 would be applied first to the current accrual and
29 then the remaining DOE funds would be applied to
30 future accruals. This process would be used until
31 the excess funds have been exhausted and the
32 accrual exceeds DOE settlement funds remaining to
33 be applied. The use of the DOE settlement proceeds
34 would result in more funding in the short-term than
35 the current accrual, which serves to reduce future
36 accruals. Since the early funding of amounts over
37 the current accrual will not reduce future accruals to

²³ Perkett Direct Testimony in Case PU-12-813 dated December 31, 2012 at lines 24-27 page 4 and lines 1-9 page 5.

1 zero, this funding is not in excess of the total
2 needed.NDPSC-8-079²⁴
3

4 **Q. When was the accrual set to zero?**

5
6 A. Per the Company's response to NDPSC-8-80:
7

8 The nuclear decommissioning accrual was set to
9 zero as a part of the settlement in the Company's
10 2007 Electric Rate Case (Case No. PU-07-776). In
11 this settlement it was determined at that time, based
12 on market conditions and the decommissioning cost
13 estimate being used, that the decommissioning
14 accrual should be zero. The NDPSC approved the
15 settlement in its December 31, 2008 Order, included
16 here as Attachment A to this response.
17

18 **Q. Please explain the settlement payments to which Ms. Perkett
19 refers?**

20
21 A. The Company's response to NDPSC-8-82 explains:
22

23 Pursuant to the terms of the Standard Contracts
24 under the Nuclear Waste Policy Act, the DOE was
25 required to take title to, transport, and dispose of the
26 spent nuclear fuel beginning no later than January
27 31, 1998. The DOE has yet to accept any spent
28 nuclear fuel. In 1998, the Company filed suit
29 against the DOE seeking to recover damages
30 stemming from the DOE's partial breach of the
31 Standard Contracts. This first lawsuit sought
32 damages through 2004. The Company filed a
33 second lawsuit for damages through 2008. Xcel
34 Energy's lawsuits were among 74 filed by utilities
35 alleging a partial breach by the DOE.
36

37 The Company sought damages based on the costs
38 incurred for: an Independent Spent Fuel Storage
39 Installation (ISFSI); an Alternative Storage Facility
40 in Goodhue County; a Minnesota legislatively
41 created biomass mandate; a Minnesota legislatively

²⁴ Data Response ND PSC-8-079

1 created Renewable Development Fund (RDF); a
2 Minnesota legislatively mandated payments to the
3 Mdwakanton Dakota Tribal Community; and, cost
4 of capital. The United States Court of Federal
5 Claims generally allowed the Company's claims
6 except for the cost of capital (essentially interest on
7 the damages determined from the date the
8 recoverable costs were incurred). The DOE
9 appealed that decision, challenging the Company's
10 right to recover costs for the private ISFSI and any
11 costs that arose out of legislative mandates (i.e. the
12 biomass mandate, RDF, and payments to the
13 Mdwakanton Dakota Tribal Community). During
14 the appeal period, two new decisions were issued by
15 the U.S. Court of Appeals for the Federal Circuit
16 that raised issues concerning some of the factors in
17 the Company's case. We subsequently engaged in
18 further negotiations with the DOE, which resulted
19 in the Settlement.

20
21 Under the Settlement, the DOE agreed to reimburse
22 the following fuel storage costs paid by the
23 Company through December 31, 2013, as a result of
24 DOE's failure to remove the spent nuclear fuel and
25 high-level radioactive waste from Prairie Island and
26 Monticello beginning by January 31, 1998: a)
27 additional pool storage costs; b) additional dry
28 casks storage costs; c) costs for certain plant
29 modifications directly related to such storage costs;
30 d) certain related internal labor, overhead,
31 operations and maintenance, training, and security
32 costs related to such storage; and e) additional
33 property taxes resulting from the on-site dry cask
34 storage or other related plant modifications.
35 Accordingly, the settlement payments received from
36 the DOE are to address the additional costs incurred
37 in storing the spent nuclear fuel resulting from
38 DOE's partial contract breach. Because both the
39 settlement payments and decommissioning costs
40 address costs related to our nuclear generating
41 facilities, it is appropriate to offset one with the
42 other. In this way, current ratepayers do not receive
43 a credit for one cost and have to pay for another.
44

1 Please see Attachment A to this response which
2 shows the various accounting entries the Company
3 will complete related to nuclear decommissioning
4 and to fully account for the DOE settlement
5 payments.NDPSC-8-82
6
7

8 **Q. What is the interaction of the accrual and the settlement**
9 **payments for North Dakota?**

10
11 A. Ms. Perkett explains:

12
13 Table 2 below shows the 2013 and 2014 nuclear
14 decommissioning accrual for the North Dakota jurisdiction
15 based on the 60-year cost estimate, offset by the DOE
16 settlement payments received in 2012 and 2013. As shown,
17 we propose to offset the 2013 accrual with the two DOE
18 settlement payments received in March and October 2012,
19 and to use the expected October 2013 payment to offset the
20 decommissioning accrual for 2014. Using the DOE
21 settlement payments will place funds in the external escrow
22 fund in excess of the accrual requirement; however, this
23 process allows base rates to remain unchanged by the
24 current decommissioning accrual.

25
26 **Summary of Nuclear Decommissioning Accrual***

27 2013 Nuclear decommissioning accrual	\$276,513
28 March and October 2012 DOE Settlement Payment	\$1,875,897
29 Amount in excess of decommissioning accrual	\$1,599,384
30 2014 Nuclear decommissioning accrual	\$276,513
31 October 2013 DOE Settlement Payment (est.)	\$1,509,538
32 Amount in excess of decommissioning accrual	\$1,233,025
33 Total amount in excess at the end of 2014	\$2,832,409

34 *Exhibit____(LHP-1), Schedule 2
35
36
37

38 **Q. How does the Company propose to keep track of the excess**
39 **funding?**

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A. Ms. Perkett states:

Once a Commission order approving this funding mechanism is issued, and upon receipt of funds for the 2013 payment, the Company would deposit the 2012 DOE settlement payments into the external escrow fund. Funds would be applied first to the current accrual and then the remaining DOE funds would be applied to future accruals. This process would be used until the excess funds have been exhausted and the accrual exceeds DOE settlement funds remaining to be applied. Specifically, the amounts would be recognized in a regulatory liability account when the deposit occurs. On a monthly basis for 2013 and 2014, the Company would recognize one twelfth of the annual decommissioning accrual and would reduce the regulatory liability by the same expense amount. At any point in time, the regulatory liability account will show the total amount funded from the DOE settlement payments less any accrual recognized. In late 2014, the Company will file its next Triennial Nuclear Decommissioning filing in Minnesota for 2015 and beyond. Continued use of DOE settlement payments to fund decommissioning escrow fund accruals will be reviewed at that time.

Q. How was Nuclear Decommissioning handled in the Company's 2010 rate case?

A. Ms. Perkett states:

In our 2010 rate case settlement, the earlier DOE settlement payment was used to reduce the total rate increase. Using the 2012 and 2013 settlement payments to offset the accrual in 2013 and 2014 would have a similar effect: rather than providing a refund to customers and then raising rates, we propose to use the DOE settlement payments to reduce the requested increase in this case. In addition, we are proposing that the amount above what is necessary to offset the current

1 decommissioning accrual to zero also be placed in
2 the external escrow fund such that future accrual
3 requirements, beyond 2013 and 2014, will be
4 reduced.
5
6

7 **Q. What do you recommend?**

8

9 A. I recommend that the net excess be recorded in the regulatory liability as
10 requested by the company and that the Commission order the company to
11 report the related balances and activity in all future earnings reports.

12

13 **XV. Summary**

14 **Q. Does this conclude your testimony?**

15 A. Yes, it does.

Experience

Snavelly King Majoros & O'Connor, Inc.

President (2010 to present)

Vice President and Treasurer (1988 to 2010)

Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., Consultant (1978-1981)

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, Auditor (1973-1976)

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - (1971-1973)

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, (1969-1971)

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility Consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

"Asset Management – What is it ?" American Water Works Association, Pre-Conference Workshop, March 25, 2008.

"Main Street Gold Mine," with Dr. K. Pavlovic and J. Legieza, Public Utilities Fortnightly, October, 2010

Michael J. Majoros, Jr.

<u>Date</u>	<u>Jurisdiction / Agency</u>	<u>Docket</u>	<u>Utility</u>
<u>Federal Courts</u>			
2005	US District Court, Northern District of AL, Northwestern Division <u>55/56/57/</u>	CV 01-B-403-NW	Tennessee Valley Authority

<u>State Legislatures</u>			
2006	Maryland General Assembly <u>61/</u>	SB154	Maryland Healthy Air Act
2006	Maryland House of Delegates <u>62/</u>	HB189	Maryland Healthy Air Act

<u>Federal Regulatory Agencies</u>			
1979	FERC-US <u>19/</u>	RP79-12	El Paso Natural Gas Co.
1980	FERC-US <u>19/</u>	RM80-42	Generic Tax Normalization
1996	CRTC-Canada <u>30/</u>	97-9	All Canadian Telecoms
1997	CRTC-Canada <u>31/</u>	97-11	All Canadian Telecoms
1999	FCC <u>32/</u>	98-137 (Ex Parte)	All LECs
1999	FCC <u>32/</u>	98-91 (Ex Parte)	All LECs
1999	FCC <u>32/</u>	98-177 (Ex Parte)	All LECs
1999	FCC <u>32/</u>	98-45 (Ex Parte)	All LECs
2000	EPA <u>35/</u>	CAA-00-6	Tennessee Valley Authority
2003	FERC <u>48/</u>	RM02-7	All Utilities
2003	FCC <u>52/</u>	03-173	All LECs
2003	FERC <u>53/</u>	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.

<u>State Regulatory Agencies</u>			
1982	Massachusetts <u>17/</u>	DPU 557/558	Western Mass Elec. Co.
1982	Illinois <u>16/</u>	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland <u>8/</u>	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland <u>8/</u>	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut <u>15/</u>	810911	Woodlake Water Co.
1983	New Jersey <u>1/</u>	815-458	New Jersey Bell Tel. Co.
1983	New Jersey <u>14/</u>	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia <u>7/</u>	785	Potomac Electric Power Co.
1984	Maryland <u>8/</u>	7689	Washington Gas Light Co.
1984	Dist. Of Columbia <u>7/</u>	798	C&P Tel. Co.
1984	Pennsylvania <u>13/</u>	R-832316	Bell Telephone Co. of PA
1984	New Mexico <u>12/</u>	1032	Mt. States Tel. & Telegraph
1984	Idaho <u>18/</u>	U-1000-70	Mt. States Tel. & Telegraph

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1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.

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1993	New Jersey <u>1/</u>	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa <u>6/</u>	RPU-93-9	U.S. West – Iowa
1994	Iowa <u>6/</u>	RPU-94-3	Midwest Gas
1995	Delaware <u>24/</u>	94-149	Wilm. Suburban Water Corp.
1995	Connecticut <u>25/</u>	94-10-03	So. New England Telephone
1995	Connecticut <u>25/</u>	95-03-01	So. New England Telephone
1995	Pennsylvania <u>3/</u>	R-00953300	Citizens Utilities Company
1995	Georgia <u>23/</u>	5503-0	Southern Bell
1996	Maryland <u>8/</u>	8715	Bell Atlantic
1996	Arizona <u>26/</u>	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire <u>27/</u>	DE 96-252	New England Telephone
1997	Iowa <u>6/</u>	DPU-96-1	U S West – Iowa
1997	Ohio <u>28/</u>	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan <u>28/</u>	U-11280	Ameritech – Michigan
1997	Michigan <u>28/</u>	U-112 81	GTE North
1997	Wyoming <u>27/</u>	7000-ztr-96-323	US West – Wyoming
1997	Iowa <u>6/</u>	RPU-96-9	US West – Iowa
1997	Illinois <u>28/</u>	96-0486-0569	Ameritech – Illinois
1997	Indiana <u>28/</u>	40611	Ameritech – Indiana
1997	Indiana <u>27/</u>	40734	GTE North
1997	Utah <u>27/</u>	97-049-08	US West – Utah
1997	Georgia <u>28/</u>	7061-U	BellSouth – Georgia
1997	Connecticut <u>25/</u>	96-04-07	So. New England Telephone
1998	Florida <u>28/</u>	960833-TP et. al.	BellSouth – Florida
1998	Illinois <u>27/</u>	97-0355	GTE North/South
1998	Michigan <u>33/</u>	U-11726	Detroit Edison
1999	Maryland <u>8/</u>	8794	Baltimore Gas & Electric Co.
1999	Maryland <u>8/</u>	8795	Delmarva Power & Light Co.
1999	Maryland <u>8/</u>	8797	Potomac Edison Company
1999	West Virginia <u>2/</u>	98-0452-E-GI	Electric Restructuring
1999	Delaware <u>24/</u>	98-98	United Water Company
1999	Pennsylvania <u>3/</u>	R-00994638	Pennsylvania American Water
1999	West Virginia <u>2/</u>	98-0985-W-D	West Virginia American Water
1999	Michigan <u>33/</u>	U-11495	Detroit Edison
2000	Delaware <u>24/</u>	99-466	Tidewater Utilities
2000	New Mexico <u>34/</u>	3008	US WEST Communications, Inc.
2000	Florida <u>28/</u>	990649-TP	BellSouth -Florida
2000	New Jersey <u>1/</u>	WR30174	Consumer New Jersey Water
2000	Pennsylvania <u>3/</u>	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania <u>3/</u>	R-0005212	Pennsylvania American Sewerage
2000	Connecticut <u>25/</u>	00-07-17	Southern New England Telephone
2001	Kentucky <u>36/</u>	2000-373	Jackson Energy Cooperative
2001	Kansas <u>38/39/40/</u>	01-WSRE-436-RTS	Western Resources
2001	South Carolina <u>22/</u>	2001-93-E	Carolina Power & Light Co.
2001	North Dakota <u>37/</u>	PU-400-00-521	Northern States Power/Xcel Energy

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2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 40/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company

Michael J. Majoros, Jr.

2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company
2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.
2006	Colorado 60/	06S-234EG	Public Service Co. of Colorado
2006	Kentucky 36/	2006-00172	Union Light, Heat & Power
2006	Kansas 40/	06-KGSG-1209-RTS	Kansas Gas Service
2006	West Virginia 2/	06-0960-E-42T, 06-1426-E-D	Allegheny Power
2006	West Virginia 2/	05-1120-G-30C, 06-0441-G-PC, et al.	Hope Gas, Inc. and Equitable Resources, Inc.
2007	Delaware 24/	06-284	Delmarva Power & Light Company
2007	Kentucky 36/	2006-00464	Atmos Energy Corporation
2007	Colorado 60/	06S-656G	Public Service Co. of Colorado
2007	California 59/	A.06-12-009, A.06-12-010	San Diego Gas & Electric Co., and Southern California Gas Co.
2007	Kentucky 36/	2007-00143	Kentucky-American Water Co.
2007	Kentucky 36/	2007-00089	Delta Natural Gas Co.
2008	Kansas 40/	08-ATMG-280-RTS	Atmos Energy Corporation
2008	New Jersey 1/	GR07110889	New Jersey Natural Gas Co.
2008	North Dakota 37/	PU-07-776	Northern States Power/Xcel Energy
2008	Pennsylvania 3/	A-2008-2034045 et al	UGI Utilities, Inc. / PPL Gas Utilities Corp.
2008	Washington 63/	UE-072300, UG-072301	Puget Sound Energy
2008	Pennsylvania 3/	R-2008-2032689	Pennsylvania-American Water Co. - Coatesville
2008	New Jersey 1/	WR08010020	NJ American Water Co.
2008	Washington 63/ 64/	UE-080416, UG-080417	Avista Corporation
2008	Texas 65/	473-08-3681, 35717	Oncor Electric Delivery Co.
2008	Tennessee 66/	08-00039	Tennessee-American Water Co.
2008	Kansas	08-WSEE-1041-RTS	Westar Energy, Inc.
2009	Kentucky 36/	2008-00409	East Kentucky Power Coop.

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2009	Indiana 29/	43501	Duke Energy Indiana
2009	Indiana 29/	43526	Northern Indiana Public Service Co.
2009	Michigan 33/	U-15611	Consumers Energy Company
2009	Kentucky 36/	2009-00141	Columbia Gas of Kentucky
2009	New Jersey 1/	GR00903015	Elizabethtown Gas Company
2009	District of Columbia 7/	FC 1076	Potomac Electric Power
2009	New Jersey 1/	GR09050422	Public Service Gas & Electric Co.
2009	Kentucky 36/	2009-00202	Duke Energy Kentucky Co.
2010	Kentucky 36/	2009-00549	Louisville Gas and Electric Co.
2010	Kentucky 36/	2009-00548	Kentucky Utilities Co.
2010	New Jersey 1/	GR10010035	Southern New Jersey Gas Co.
2010	Hawaii 42/	2009-0286	Maui Electric Co.
2010	Hawaii 42/	2009-0321	Hawaii Electric Light Co.
2010	Hawaii 42/	2010-0053	Hawaiian Electric Co.
2010	Lancaster 3/	R-2010-2179103	Lancaster Water Fund
2011	Kansas 40/	11-KCPE-581-PRE	Kansas City Power and Light Co.
2011	Delaware 24/	11-207	Artesian

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**PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION
RATE REPRESRIPTION CONFERENCES**

<u>COMPANY</u>	<u>YEARS</u>	<u>CLIENT</u>
Diamond State Telephone Co. <u>24/</u>	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania <u>3/</u>	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. <u>8/</u>	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas <u>20/</u>	1986	Kansas Corp. Commission
Southern Bell – Florida <u>4/</u>	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. <u>2/</u>	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. <u>1/</u>	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina <u>22/</u>	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania <u>3/</u>	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

**PARTICIPATION IN PROCEEDINGS WHICH WERE
SETTLED BEFORE TESTIMONY WAS SUBMITTED**

<u>STATE</u>	<u>DOCKET NO.</u>	<u>UTILITY</u>
Maryland <u>8/</u>	7878	Potomac Edison
Nevada <u>21/</u>	88-728	Southwest Gas
New Jersey <u>1/</u>	WR90090950J	New Jersey American Water
New Jersey <u>1/</u>	WR900050497J	Elizabethtown Water
New Jersey <u>1/</u>	WR91091483	Garden State Water
West Virginia <u>2/</u>	91-1037-E	Appalachian Power Co.
Nevada <u>21/</u>	92-7002	Central Telephone - Nevada
Pennsylvania <u>3/</u>	R-00932873	Blue Mountain Water
West Virginia <u>2/</u>	93-1165-E-D	Potomac Edison
West Virginia <u>2/</u>	94-0013-E-D	Monongahela Power
New Jersey <u>1/</u>	WR94030059	New Jersey American Water
New Jersey <u>1/</u>	WR95080346	Elizabethtown Water
New Jersey <u>1/</u>	WR95050219	Toms River Water Co.
Maryland <u>8/</u>	8796	Potomac Electric Power Co.
South Carolina <u>22/</u>	1999-077-E	Carolina Power & Light Co.
South Carolina <u>22/</u>	1999-072-E	Carolina Power & Light Co.
Kentucky <u>36/</u>	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky <u>36/</u>	2002-485	Jackson Purchase Energy Corporation
Kentucky <u>36/</u>	2009-00202	Duke Energy Kentucky
New Jersey <u>1/</u>	ER09080664	Atlantic City Electric Co.
New Jersey <u>1/</u>	ER09080668	Rockland Electric Co.

Michael J. Majoros, Jr.

Clients

<u>1/</u> New Jersey Rate Counsel/Advocate	<u>34/</u> New Mexico Attorney General
<u>2/</u> West Virginia Consumer Advocate	<u>35/</u> Environmental Protection Agency Enforcement Staff
<u>3/</u> Pennsylvania OCA	<u>36/</u> Kentucky Attorney General
<u>4/</u> Florida Office of Public Advocate	<u>37/</u> North Dakota Public Service Commission
<u>5/</u> Toms River Fire Commissioner's	<u>38/</u> Kansas Industrial Group
<u>6/</u> Iowa Office of Consumer Advocate	<u>39/</u> City of Wichita
<u>7/</u> D.C. People's Counsel	<u>40/</u> Kansas Citizens' Utility Rate Board
<u>8/</u> Maryland's People's Counsel	<u>41/</u> NIPSCO Industrial Group
<u>9/</u> Idaho Public Service Commission	<u>42/</u> Hawaii Division of Consumer Advocacy
<u>10/</u> Western Burglar and Fire Alarm	<u>43/</u> Nevada Bureau of Consumer Protection
<u>11/</u> U.S. Dept. of Defense	<u>44/</u> GCI
<u>12/</u> N.M. State Corporation Comm.	<u>45/</u> Wisc. Citizens' Utility Rate Board
<u>13/</u> City of Philadelphia	<u>46/</u> Vermont Department of Public Service
<u>14/</u> Resorts International	<u>47/</u> Oklahoma Corporation Commission
<u>15/</u> Woodlake Condominium Association	<u>48/</u> National Assn. of State Utility Consumer Advocates
<u>16/</u> Illinois Attorney General	<u>49/</u> Nova Scotia Utility and Review Board
<u>17/</u> Mass Coalition of Municipalities	<u>50/</u> Florida Office of Public Counsel
<u>18/</u> U.S. Department of Energy	<u>51/</u> Maryland Public Service Commission
<u>19/</u> Arizona Electric Power Corp.	<u>52/</u> MCI
<u>20/</u> Kansas Corporation Commission	<u>53/</u> Transmission Agency of Northern California
<u>21/</u> Public Service Comm. – Nevada	<u>54/</u> Florida Industrial Power Users Group
<u>22/</u> SC Dept. of Consumer Affairs	<u>55/</u> Sierra Club
<u>23/</u> Georgia Public Service Comm.	<u>56/</u> Our Children's Earth Foundation
<u>24/</u> Delaware Public Service Comm.	<u>57/</u> National Parks Conservation Association, Inc.
<u>25/</u> Conn. Ofc. Of Consumer Counsel	<u>58/</u> Missouri Office of the Public Counsel
<u>26/</u> Arizona Corp. Commission	<u>59/</u> The Utility Reform Network
<u>27/</u> AT&T	<u>60/</u> Colorado Office of Consumer Counsel
<u>28/</u> AT&T/MCI	<u>61/</u> MD State Senator Paul G. Pinsky
<u>29/</u> IN Office of Utility Consumer Counselor	<u>62/</u> MD Speaker of the House Michael Busch
<u>30/</u> Unitel (AT&T – Canada)	<u>63/</u> Washington Office of Public Counsel
<u>31/</u> Public Interest Advocacy Centre	<u>64/</u> Industrial Customers of Northwestern Utilities
<u>32/</u> U.S. General Services Administration	<u>65/</u> Steering Committee of Cities
<u>33/</u> Michigan Attorney General	<u>66/</u> City of Chattanooga

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;

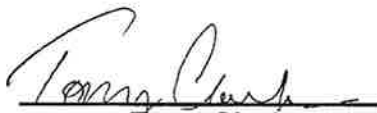
- (b) a moratorium prohibiting further electric rate increases from becoming effective prior to January 1, 2011;
- (c) an earnings sharing mechanism if net income exceeds 10.75% return on equity; and
- (d) accounting treatment for Midwest ISO Day-2 Energy Market costs.


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. Wefald
President


Kevin Cramer
Commissioner



RECEIVED

VIA ELECTRONIC FILING AND U.S. MAIL

DEC 29 2008

December 22, 2008

PUBLIC SERVICE COMMISSION

Darrell Nitschke
Executive Secretary and Director of Administration
North Dakota Public Service Commission
State Capital
600 East Boulevard
Bismarck, ND 58505-0480

Re: IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER
COMPANY, A MINNESOTA CORPORATION, FOR AUTHORITY TO INCREASE
RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA
Case No. PU-07-776

Dear Mr. Nitschke:

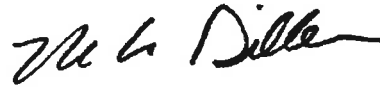
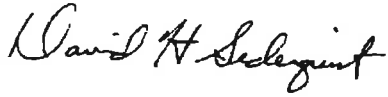
Attached is a Settlement Agreement dated December 22, 2008 between Northern States Power Company, a Minnesota corporation operating in North Dakota and the Advocacy Staff of the North Dakota Public Service Commission ("Commission") in the above referenced matter. It replaces entirely the Settlement Agreement 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.

Very truly yours,



David Sederquist	Michael Diller
Sr. Regulatory Consultant	Director, Economic Regulation

Encls.

cc: Service List

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Susan E. Wefald
Kevin Cramer
Tony Clark

President
Commissioner
Commissioner

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

SETTLEMENT AGREEMENT

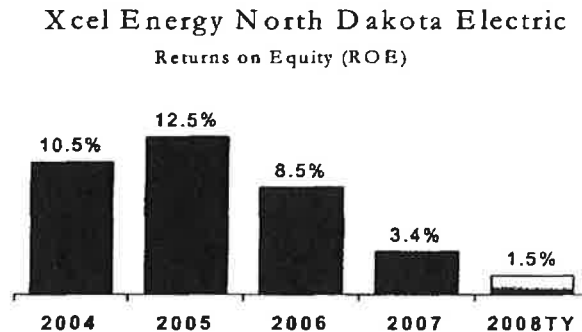
This Settlement Agreement is entered into this 22nd day of December 2008, by and between the North Dakota Public Service Commission Advocacy Staff (“Staff”) and Northern States Power Company (“Xcel Energy” or the “Company”), a Minnesota corporation operating in North Dakota (collectively, the “Parties”). 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. This Settlement Agreement resolves all outstanding issues in the above-captioned proceeding in a manner consistent with the public interest and will result in just and reasonable rates for the Company’s retail electric operations in North Dakota.

BACKGROUND

Xcel Energy’s electric operations in North Dakota were revenue deficient in 2006 and 2007, earning substantially below the authorized return on equity (“ROE”) of 11.5

percent, as shown in Figure 1 below. Projected ROE for the 2008 test year, absent rate relief, was 1.54 percent.

Figure 1



Prior to this rate application, the Company had not filed a general electric rate increase application since November 1992 (Case No. PU-400-92-399). During this period, Xcel Energy did implement two modest performance-based rate increases under the provisions of the “PLUS Plan.” authorized in Case No. PU -400-00-195. Those increases were triggered by above-target operating and rate performance, and below-authorized earnings.

In 2007, Xcel Energy’s average residential electric rate was ranked as the lowest among investor-owned utilities in the states of North Dakota, Iowa, Minnesota, Montana, South Dakota, Wisconsin and Wyoming. This was the fourth year since 2001 in which the Company’s North Dakota residential electric rates were the lowest in the region. With the increase contemplated in this Settlement Agreement, Xcel Energy’s North Dakota residential rates are expected to remain within the top six of the thirty service territories comprising this regional comparison group. Moreover, even with the agreed-to increase, the Company’s North Dakota rates will have

averaged an annual increase of less than one percent since 1993, well under half the rate of inflation over the same period.

See Attachment A for a summary of the procedural history of this case, leading to the Settlement Agreement.

TERMS

The Parties agree to the provisions as defined below and supported by Attachments B, C, D, and E to this Settlement Agreement.

ENERGY POLICY

In this case, the Company determined its revenue requirement in part based on the costs of operating a single, multistate, and integrated system of generation and transmission facilities, with a corresponding allocation of those costs to the North Dakota jurisdiction.

Staff challenged whether North Dakota customers should pay for a portion of the integrated system costs incurred by the Company to satisfy environmental and renewable requirements imposed or facilitated by Minnesota law. During this proceeding, this issue became central to this rate case.

To eliminate or minimize conflicts surrounding energy resource decisions and the associated costs in future general rate proceedings, the Parties agree to adhere to the following regulatory procedures to ensure appropriate Commission involvement and

oversight of the Company's future resource plans and selection of future generation and transmission projects to be added to the system serving North Dakota.

A. North Dakota Resource Planning Process

The Parties to this Agreement recognize that Xcel Energy, with its multi-state utility system, seeks to provide its customers the benefits of operating an integrated system while at the same time complying with the energy goals and policies of the states it serves. Currently, these states have different and/or conflicting energy priorities. The intent of the Energy Policy provisions of this Settlement Agreement is to provide a framework for identifying future plans and investments and, to the extent applicable, state-specific energy goals and policies and their implications for serving North Dakota customers. Using input provided by the Commission, the Company will be able to determine how best to proceed to both meet the needs of its North Dakota customers and recover its system-wide cost of providing service.

Xcel Energy agrees to provide to the Commission its Minnesota-filed Resource Plans ("RPs") for the integrated NSP System (Minnesota, Michigan, North Dakota, South Dakota and Wisconsin) as it has in the past. In addition to these overall RPs, the Company agrees to provide an alternative system-wide resource plan (the "North Dakota version") that strictly meets both Federal and North Dakota environmental and renewable requirements for the same time period addressed by the Minnesota Resource Plan.

While no formal action by the Commission on these RP scenarios would be required, the Parties envision that the Commission would consider the

submissions on an informal basis and provide input to the Company's planning process. The intent of this provision is to seek and obtain such input prior to Company investments in resources for which it intends to seek recovery from North Dakota customers.

The Company also agrees to file with its annual Ten Year Plan required by N.D.C.C. § 49-22-04 and N.D.A.R. § 69-06-02-01 a summary of the key generating and transmission investments or purchase agreements that it intends to construct or enter into within the next five years. This summary will provide an anticipated schedule of future applications for Advance Determination of Prudence ("ADP") pursuant to N.D.C.C. § 49-05-16 that the Company would commit to filing with the Commission (see Section B of this Settlement Agreement).

Finally, the Company agrees to meet with the Commission and Staff as necessary to conduct updates on its resource planning efforts and decisions, and discuss the Ten Year Plan filed in that year. Such updates would include, but not be limited to, details regarding the above described alternative planning analyses, the specific projects identified in the five-year horizon, key management decisions being considered or made regarding the generation fleet and transmission systems, issues or trends in the energy industry impacting generation and transmission, the status of energy policies or laws approved or under consideration across the integrated NSP-System, as well as other pertinent planning topics of interest to the Commission. The Company commits to keeping the Commission and its Staff informed on a timely basis of any major changes in its Resource Plan or significant legislative initiatives under consideration in another jurisdiction.

Xcel Energy will file its next Ten Year Plan report on or before July 1, 2009. In the report, the Company will provide the results of its North Dakota version of the Resource Plan (based on the current 2008-2022 RP) outlined in this Settlement Agreement. Thereafter, Xcel Energy agrees to file the complete RP and updated North Dakota version on a schedule that corresponds to its overall Resource Planning cycle. In this first and all future Ten Year Plans, the Company will include and describe the current five-year action plan for generation and transmission facilities and its anticipated schedule for filings under the ADP statute.

B. Advanced Determination of Prudence

In accordance with N.D.C.C. § 49-05-16 the Company agrees to file for an ADP finding from the Commission for all proposed new construction, rehabilitation, or acquisition of an energy conversion facility, renewable energy facility, transmission facility or proposed energy purchase in which:

1. The Company proposes to allocate all or part of the related costs to the North Dakota jurisdiction for recovery in electric rates; and
2. The capacity of the generation facility or purchase is at least 50 MW; and/or the length of the transmission facility is at least 50 miles long.

The Company will identify its proposed cost-allocation methodology in the ADP petition as an item for which a determination of prudence by the Commission is requested.

The Parties anticipate that RP and ADP processes will provide a sound basis for Commission decision-making and substantially reduce the likelihood that the disputes of this case will occur in future rate proceedings. To the extent that these new processes reveal continued concern with individual resource decisions or cost assignments to jurisdictions, the Parties agree to work together on alternative approaches that might be employed while still allowing the Company to recover its costs of service and earn a reasonable return. Such efforts will include advocacy by the Company for cost recovery statutes to directly assign costs and benefits of mandated expenditures to the jurisdiction imposing the mandate when appropriate.

C. North Dakota Depreciation Study

The Company's proposed depreciation expense in this case was based on a uniform depreciation expense for use in all jurisdictions. In its testimony and post-hearing briefs, Staff challenged the reasonableness of the Company's methodologies in several respects.

In response, the Parties agree to the following process for establishing depreciation expenses:

- The Company will use the principles adopted in this Settlement Agreement in establishing depreciation rates for use in North Dakota. The Company will reflect its North Dakota depreciation rates in its annual North Dakota earnings reports and will file depreciation rates consistent with these principles as part of the Company's next electric rate case.

- For informational purposes, the Company will submit to the Commission the various depreciation studies and related documents that are periodically filed with the Minnesota Public Utilities Commission. Such filings include: Annual Review of Remaining Lives, Average Service Life and Vintage Group Filing (every five years), Triennial Review of Nuclear Decommissioning
- Ninety days before filing its next electric rate case, the Company will report to the Commission on whether it intends to propose North Dakota specific depreciable lives for distribution facilities, and the reasons for its proposal.
- Both Parties agree that, unless directed otherwise by the Commission, rate recovery -- past, present, and future -- for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability.

REVENUE REQUIREMENTS

As a result of the adjustments agreed to herein and described below, the Parties agree to an increase in Xcel Energy's electric rates for retail customers in North Dakota to ultimately yield an annual retail sales and miscellaneous revenue increase of approximately \$10,855,000 or 7.4 percent. As shown in Table 1 below and on Attachment B, the rates implemented on March 1, 2009 will reflect an increase in base rates of \$12,785,000 offset by projected fuel clause reductions as a result of customer credits from wholesale margins of \$1,930,000.

Table 1

Implementation	Base Rates	Fuel Rates	Overall Revenue
March 1, 2009	\$12,785,000	(\$1,930,000)	\$10,855,000

An interim rate refund will be issued to customers for the difference between the interim rate increase placed into effect on February 5, 2008 and the Settlement Agreement amount. The interim rate refund will reflect the fact that wholesale margins were credited to the interim revenue requirement. However, such margins will be credited to the fuel clause adjustment on a prospective basis, coinciding with final rates. See Attachment C for the calculation of the annualized interim rate refund.

Following is a description of the specific test year adjustments agreed to in this Settlement Agreement. (See also Attachment B):

D. Return on Equity

The Parties agree to a return on equity of 10.75 percent as outlined in the previous settlement with Staff. The adjustment reduces the original revenue request by \$1,562,000 and agrees to share any earnings above 10.75% with customers (see other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that a 10.75% ROE will be used for purposes of determining interim rates in the Company's next electric rate case.

E. Generating Plant Service Lives

For purposes of determining the overall revenue requirement, the Parties agree to:

- Extend the service lives of the Sherco Generating Station, and five other combustion plants (Angus C. Anson, Granite City, High Bridge, Inver Hills, and Key City) as proposed by Staff. The Company will reflect the longer service lives in final rates implemented in this docket. The adjustment reduces the revenue requirement by \$1,362,000.
- Reduce the depreciation rates for its transmission and distribution assets to effect an adjustment in the reserve balance, thereby recalibrating the balance to be more in line with theoretically calculated levels. This adjustment reduces the revenue requirement by \$1,180,000.
- Recover removal costs in depreciation rates for transmission and distribution based on a net present value methodology rather than on a future cost methodology (using Staff's alternative five year historical average for the purposes of this case). This adjustment reduces the revenue requirement by \$437,000.
- The Parties recognize that the life extension has already been approved for the Monticello nuclear generating plant and that this fact eliminates the need for continued accruals to the existing escrow account, as reflected in the revenue requirement in this rate case. The Parties also agree to return, effective beginning March 1, 2009 and completed by the end of 2010, the amounts that North Dakota customers contributed to the decommissioning escrow account for the Monticello plant. This provision reduces the revenue deficiency for final rates by \$212,000. Because this provision applies only to final rates (effective after March 1,

2009), it results in no change to the interim rate refund in this proceeding.

In addition, the Parties agree to determine final rates using a remaining life for the Prairie Island nuclear generating plant that assumes approval of the requested life extension for this facility. This adjustment results in a \$2,162,000 decrease to the test year revenue requirement.

The Company has sought the necessary approvals for life extension and spent fuel storage from the Nuclear Regulatory Commission (NRC) and the Minnesota Public Utilities Commission (MPUC) for the Prairie Island nuclear generating plant, but those petitions are pending.¹ Final approvals from the NRC and MPUC are not expected prior to 2010. In recognition of the possibility that life extension and fuel storage may not be obtained, the Parties further agree that the Company will track the rate benefit provided by this provision. The rate benefit being tracked is the revenue requirement difference due to depreciation recognized using the longer remaining life versus the depreciation calculated using the current license life. In the event the needed regulatory approvals for life extension and fuel storage are not received, the amount in the tracker account shall become a regulatory asset, with an appropriate offset to accumulated depreciation, that will be recoverable from customers in a manner to be determined by the Commission in the Company's next electric rate case. In addition, within 60 days of the determination that life extension or the necessary additional fuel storage has been denied, the Company shall file a petition with the Commission to adjust North Dakota rates to recover the remaining investment in the Prairie Island

¹ The Prairie Island life extension requires approval of a new operating license from the Nuclear Regulatory Commission and a Certificate of Need ("CON") from the Minnesota Public Utilities Commission. Pursuant to Minn. Stat. § 216B.242, the Minnesota Public Utilities Commission's approval of a CON for additional nuclear storage will take effect after the close of the next legislative session after approval of the CON.

nuclear generating plant over the remaining life as determined by the operating license.

The Parties also agree that in no event is this provision intended to limit or deny the Company the opportunity to recover all prudent costs associated with the Prairie Island nuclear generating plant. Instead, this provision is intended to respond to the Commission's expectation that life extension for this plant will be approved and its expressed desire to provide the benefits of such extension at this time.

In all other respects, the Parties recommend that the Commission approve the methodologies used by the Company in this proceeding.

The service life extensions and other depreciation-related and escrow fund refunds reduce the revenue increase request by \$6,335,000.

F. Generation and Transmission Investments

The Parties agree to allow recovery of the Company's proposed costs of its investments in the King and High Bridge power plants and the Grand Meadows wind farm and associated transmission investments. The Parties recognize that these investments were primary issues of dispute in this proceeding. The Parties reached agreement on this issue as a whole, and believe that the RP, ADP, earnings sharing, and rate moratorium provisions all facilitate the resolution of this issue and result in reasonable rates. Further, the Parties agree that the Company's refurbishment and repowering of two of its aging coal-fired power plants were prudent and economic investments, especially considering the strategic location of these plants. Moreover, Staff acknowledges that the Grand Meadow Wind Farm is able to take advantage of

existing production tax credits to produce low and stable-priced energy that will contribute to Xcel Energy's efforts to meet North Dakota's renewable energy objective of supplying 10 percent of its retail energy needs with renewable resources. For these reasons, this Settlement Agreement provides for recovery of Company's costs associated with the King, High Bridge, and Grand Meadow generating facilities.

G. Wholesale Margins

For purposes of determining the overall revenue requirement, the Parties agree to provide to ratepayers 85 percent of all asset-based and 50 percent of non-asset-based margins achieved by the Company through the fuel clause. Passing these credits directly to customers through the fuel clause as they are realized ensures that neither customers nor the Company are disadvantaged by a non-representative margin forecast in the test year. By sharing the gains on asset-based sales, the Parties recognize that the Company is incented to maximize the benefit from these sales. Further, the non-asset sharing at 50 percent is more than adequate to assure that any costs imposed on customers as a result of this activity is fully credited.

H. Amortization of Nuclear Refueling Expenses

For purposes of determining the overall revenue requirement, the Parties agree to an annual amortization expense level of \$2,492,407, which approximates the levelized annual amortization after refueling outages have occurred for all three of the nuclear units at the Prairie Island and Monticello nuclear generating plants. This provision results in no change to the revenue requirement initially filed in the rate case. Given that other provisions of this Settlement Agreement provide for the accelerated life extension for Prairie Island, earnings sharing and a rate moratorium, the Parties

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.

L. Mercury Emissions Control

For purposes of determining the overall revenue requirement, the Parties agree to a reduction in costs related to monitoring mercury emissions reduction efforts at its King and Sherco generating plants to meet Minnesota mercury emissions requirements. The adjustment reduces the revenue increase request by \$12,335.

M. MISO Schedule 16 and 17 Costs

For purposes of determining the overall revenue requirement, the Parties agree to recovery of Midwest Independent Systems Operator (“MISO”) Schedule 16 and 17 costs in the fuel clause. Fuel clause treatment is appropriate given that, like all other MISO Day 2 charge types which are also recovered through the fuel clause, they are non-discretionary charges billed out by the MISO, and they have been recovered through the fuel clause in North Dakota for the past three years. Fuel clause treatment is also consistent with the present treatment of these costs in South Dakota. This adjustment does not impact the overall revenue increase, since the recovery of these costs is just being shifted from base rates to fuel clause rates. This adjustment does, however, reduce the base rate revenue requirement by \$532,000.

N. Private Fuel Storage

The Parties clarify that the rate increase contained in this Settlement Agreement provides for recovery of the Company’s costs associated with Private Fuel Storage. The Parties agree that the Company’s effort in securing such a facility was prudent and appropriate in light of delays in the development of a Federal repository for spent

nuclear fuel. This provision results in no change in the Company's proposed test year revenue requirement.

RATE DESIGN

The Parties agree to the following revenue requirement apportionment among customer classes for the March 1, 2009 rate increase:

1. Residential service: \$5,157,000 or 8.9 percent;
2. Commercial (non-demand metered) service: \$972,000 or 9.3 percent; and
3. Commercial (demand metered) service: \$6,656,000 or 8.6 percent.

These changes are further shown on Attachment E to the Settlement Agreement. This apportionment reflects base rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on the attachment.

The Parties agree to the filed tariff changes proposed in the Company's initial filing, as amended to reflect the change in revenue requirement contained in this Settlement Agreement. In amending the tariffs, the Parties agree to using the Company's proposed rate design principles in the development of final rates to implement the approved revenue requirement contained in this Settlement Agreement.

The Company shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

INTERIM RATES

The Parties agree the interim rates will remain in effect for all customer classes until February 28, 2009. Refunds will be issued to customers within ninety (90) days of the implementation of final rates for the difference between the interim revenue level and the March 1, 2009 revenue level agreed to in this Settlement. Based on current information, the Parties estimate that customers will receive \$6,328,000 in base rate refunds (see Attachment C).

OTHER TERMS AND CONDITIONS

O. Customer Refunds for Earnings Above Authorized ROE

The Parties agree to an earnings-sharing mechanism that will result in customer refunds if the Company's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If the Company earns in excess of 10.75 percent ROE during the 2009 or 2010 calendar years, the Company will refund to customers revenues corresponding to earnings as shown below:

- 50% of earnings above 10.75% up to and including 11.25%; and
- 75% of earnings above 11.25%.

Earnings sharing refunds would be applied to customer accounts as a one-time bill credit as soon as practical on or after July 1st of the following calendar year.

P. Rate Moratorium

The Parties agree to a moratorium on an electric rate increases until 2011 for Xcel Energy's North Dakota operations. This moratorium does not preclude the Company from submitting a rate application for electric rates prior to 2011, but no change in customer rates would be implemented before January 1, 2011.

Q. Basis of Settlement Agreement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates and depreciation expenses in the Company's next electric rate case, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

R. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

S. Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

T. Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff agreed to by this Settlement Agreement shall be effective on the dates specified in the Revenue Requirements Section of this Settlement Agreement.

V. Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such party.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve the contested issues in the electric rate case proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates. For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

Dated this 22nd day of December 2008.

Northern States Power Company,
A Minnesota corporation



By: _____
Judy M. Pofert
Regional Vice President

Dated this 23rd day of Dec. 2008.

Northern Dakota Public Service Commission Staff

By:  _____
Doug Bahr
Counsel to the Commission

PROCEDURAL HISTORY

Case No. PU-07-776

On December 7, 2007, Xcel Energy filed a Notice of Change in Rates for Electric Service (“Notice”) with the North Dakota Public Service Commission (the “Commission”), based on a 2008 test year, with interim rates to become effective February 5, 2008. The Notice proposed an increase in electric retail and miscellaneous base rates of \$20,535,000 and a decrease in fuel clause rates of \$2,371,000, or about a 12.3 percent overall increase in revenues. The Company filed testimony by eleven witnesses in support of the Notice.

Xcel Energy proposed to increase residential base rates by \$8,228,000 or 14.3 percent and commercial service revenues by \$12,056,000 or 13.9 percent. Filed with the Notice were revised tariffs, direct testimony, exhibits, and supporting statements.

Concurrent with the Notice, Xcel Energy submitted an Alternate Petition for Interim Rates. The proposed interim increase, which impacted only base rates, was for \$17,183,000 or 11.5 percent, to be effective February 5, 2007 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C 49-05-06.

On December 31, 2007, the Commission issued an order suspending Xcel Energy’s general rate increase application and set the matter for investigation and hearing.

On January 16, 2008, the Commission issued a Notice of Public Input Session and Intervention Deadline announcing a Public Input Session to be held via interactive television on March 14, 2008, at 11:30 a.m. central time at various locations in Fargo, Grand Forks, Minot, and Bismarck. Members of the public

were invited to appear and participate in the informal discussion. The notice also set forth a deadline of March 28, 2008 for parties to indicate their interest in participating in the case. No parties intervened.

On March 26, 2008, the Commission issued a Notice of Hearing that set forth the following issues to be considered in this case:

What is the value of NSP's property, used and useful, for the service and convenience of the public in North Dakota?

What is NSP's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?

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?

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?

Are NSP's 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?

Other relevant information or proposals concerning the proceeding.

On January 30, 2008, the Commission issued an order allowing an interim base rate increase of \$17,183,000, to be placed into effect February 5, 2008, subject to refund.

On March 14, 2008, the Commission conducted a public input session. The session utilized interactive video-conferencing capabilities to include participants in Fargo, Grand Forks, Minot, and Bismarck.

On May 16, 2008, Advisory Staff filed Direct Testimony prepared by two consultants from Snavely King & Majoros.

On June 13, 2008, Xcel Energy filed Rebuttal Testimony prepared by seven witnesses.

On June 23 and 24, evidentiary hearings were held in the Commission Hearing Room at the state capitol building in Bismarck, North Dakota. Fourteen Xcel Energy witnesses provided testimony on the Company's need for rate relief. Two consultants from Snavely King & Majoros provided testimony on behalf of Commission Advocacy Staff.

On August 22, post-hearing briefs were filed by both Xcel Energy and the Commission Advocacy Staff.

From November 9th through December 12th of 2008 the Commission held three working sessions with its Advisory Staff during which the issues raised by Advocacy Staff and the Company were considered and discussed.

On December 22nd this Settlement Agreement was entered into by Advocacy Staff and the Company, and filed with the Commission.

The administrative record in this proceeding supports the Settlement Agreement. Accordingly, the Parties jointly recommend the Commission issue an Order approving this Settlement Agreement, and the earlier settlement on ROR, without further conditions or modifications.

Northern States Power Company, a Minnesota corporation
Electric Utility- State of North Dakota
2008 Summary of Settlement Agreement Impacts

	<u>Base Rates</u>	<u>Fuel Rates</u>	<u>Total Revenue</u>
1 12/7/07 Rate Application	\$20,535	(\$2,371) [1]	\$18,164
2 Stipulate to ROE of 10.75%	(\$1,562)	\$0	(\$1,562)
3 Depr - life adj. - Prairie Island*	(\$2,162)	\$0	(\$2,162)
4 Depr - life adj. - Steam & Other Production	(\$1,362)	\$0	(\$1,362)
5 Depr - T&D reserve recalibration	(\$1,180)	\$0	(\$1,180)
6 Depr - Net PV method for removal in T&D	(\$437)	\$0	(\$437)
5 King, High Bridge, Gr Meadow Generation	\$0	\$0	\$0
7 Monti Decommissioning escrow refund amort	(\$212)	\$0	(\$212)
5 Levelized nuclear fuel reload amortization	\$0	\$0	\$0
5 Amortization of private nuclear fuel storage	\$0	\$0	\$0
8 Disallow Renewable Development Fund	(\$170)	\$0	(\$170)
9 Add'l 35% of non-asset margins to cust (50/50 shar	\$0	(\$91)	(\$91)
10 Disallow all charitable contributions	(\$86)	\$0	(\$86)
11 Decrease Incentive comp cap from 25% to 15%	(\$35)	\$0	(\$35)
12 Disallow mercury emissions costs	(\$12)	\$0	(\$12)
13 Recover MISO 16/17 costs in fuel rates	<u>(\$532)</u>	<u>\$532</u>	<u>\$0</u>
14 Settlement Outcome (implemented 3/1/09)	\$12,785	(\$1,930)	\$10,855 7.4%

Notes:[1] Fuel Clause Impact of 12/7/07 Application

Pass 85% Asset-Based margins to customers	(\$1,800)
Pass 15% Non-Asset Based margins to cust.	(\$39)
Move MISO 16/17 costs to Base Rates	<u>(\$532)</u>
	(\$2,371)

Northern States Power Company, a Minnesota corporation
Electric Utility- State of North Dakota
Calculation of 2008 Test Year Annualized Refund
Dollars in 000's

	<u>Amount</u>
Interim Revenue Increase (annual)	\$17,183
Amended Settlement Agreement Increase	<u>\$10,855</u>
Estimated refund [1]	\$6,328

Notes:

- [1] This refund amount is an estimate based on a 12 month interim rate period. Assuming final rates are implemented on March 1, 2009, the refund will include a 13 month period and will include interest.

**Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Amortization of Nuclear Fuel Outage Costs**

	<u>NSPM Co.</u>	<u>North Dakota Jurisdiction</u>
2008 Actual Outage Expense	\$50,759,000	\$2,492,407 *
2008 Amortization	\$16,535,421	\$811,935
2009 Actual Outage Expense	\$58,821,000	\$2,888,274
2009 Amortization	\$44,282,980	\$2,174,417
2010 Actual Outage Expense	\$35,000,000	\$1,718,597
2010 Amortization	\$52,307,202	\$2,568,428

* Test year and amended settlement level

Notes:

2008 amortization reflects 10 months of PI 1 and 3 months of PI 2.

2010 amortization reflects 12 months at all three units.

There are 2 fuel reloading outages (PI1 and PI2) scheduled to occur in 2008; 2 reloading outages (Monti and PI1) are scheduled in 2009, and 1 outage (PI2) is scheduled in 2010.

Northern States Power Company, a Minnesota corporation
Electric Utility - State of North Dakota
Settlement Base Rate Revenue Apportionment
Dollars in 000's

<u>Original Application</u>	<u>Residential</u>	<u>Non-Dem</u>	<u>Demand</u>	<u>Street Ltg</u>	<u>Total</u>
Present revenues	\$57,723	\$10,436	\$77,139	\$1,881	\$147,179
Proposed revenues	<u>\$66,006</u>	<u>\$11,997</u>	<u>\$87,830</u>	<u>\$1,881</u>	<u>\$167,714</u>
Base rate deficiency	\$8,283	\$1,561	\$10,691	\$0	\$20,535
Percent change	14.3%	15.0%	13.9%	0.0%	14.0%
 <u>March 1, 2009 Increase</u>					
Base rate increase	\$5,157	\$972	\$6,656	\$0	\$12,785 [1]
Percent change	8.9%	9.3%	8.6%	0.0%	8.7%

Notes:

- [1] Revenue impacts do not include credits for wholesale margins, which will be passed directly to customers through the Fuel Clause.

ANNUAL REPORT

OF

**NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION**

TO THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

FOR THE YEAR ENDING

DECEMBER 31, 2011

North Dakota Jurisdiction
Electric Utility



Filed May 9, 2012

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Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

I. RETURN ON EQUITY (ROE)

<u>Actual Return on Equity (ROE)¹</u>	<u>2011</u>	<u>2010</u>
1 Operating Income from Electric Operations (E-2):	\$24,952	\$11,664
2 Average Regulated Rate Base (E-3):	\$322,995	\$282,316
3 Rate of Return on Rate Base (ROR) (line 1 / line 2):	7.73%	4.13%
4 Weighted Cost of Debt (E-4):	2.88%	2.99%
5 Weighted Cost of Preferred Stock (E-4):	0.00%	0.00%
6 % of Equity in Capital Structure (E-4):	52.67%	51.99%
7 Return on Equity (ROE):	9.20%	2.20%

<u>ROE, Normalized for Weather Impact on Sales¹</u>	<u>2011</u>	<u>2010</u>
8 Operating Income from Electric Operations:	\$24,952	\$11,664
9 Impact of weather on Mwh Sales:	9,730	(2,517)
10 Impact of weather on Electric Operating Income :	\$254	\$2
11 Weather-Normalized Operating Income:	\$24,698	\$11,662
12 Average Regulated Rate Base:	\$322,995	\$282,316
13 Weather-Normal Rate of Return on Rate Base (ROR):	7.65%	4.13%
14 Weather-Normalized Return on Equity (ROE):	9.05%	2.19%

Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

II. OPERATING INCOME

<u>Line</u>	<u>Item</u>	2011 <u>Total NSP</u>	2011 <u>N.D. Juris.</u>	<u>N. D. %</u>	2010 <u>N.D. Juris.</u>	<u>Annual</u> <u>Change</u>
<u>Operating Revenues:</u>						
1	Residential	1,142,370	68,744	5.4%	61,131	12.5%
2	Small Comm. & Ind.	1,273,405	83,167	5.7%	72,918	14.1%
3	Large Comm. & Ind.	661,865	21,516	2.9%	19,074	12.8%
4	Public Street & Highway Ltg	25,590	1,616	5.7%	1,452	11.3%
5	Other Sales to Publ Auth	8,665	1,246	12.7%	1,097	13.6%
	Total Retail	3,111,896	176,290	5.0%	155,671	13.2%
6	Interdepartmental	548	0	0.0%	0	*
7	Sales for Resale	74,745	4,497	15.1%	11,295	-60.2%
8	Interchange Agreement	440,519	26,283	5.5%	24,210	8.6%
9	Other	118,333	6,814	4.8%	5,644	20.7%
10	Total Revenues:	3,746,042	213,884	5.7%	196,820	8.7%
<u>Operating Expenses:</u>						
11	Fuel & Purchased Energy	1,228,707	76,040	6.2%	86,548	-12.1%
12	Production	740,713	43,220	5.8%	40,558	6.6%
13	Transmission	195,079	11,219	5.8%	9,725	15.4%
14	Distribution	112,987	6,737	6.0%	5,779	16.6%
15	Customer Billing	59,289	4,411	7.4%	4,394	0.4%
16	Customer Service	115,749	489	0.4%	262	86.6%
17	Sales & Marketing	254	135	53.1%	151	-10.6%
18	Admin. & General	189,822	11,770	6.2%	12,374	-4.9%
19	Depreciation & Amortization	346,369	17,885	5.2%	15,981	11.9%
20	Property Taxes	123,651	5,881	4.8%	5,585	5.3%
21	Payroll & Other Taxes	30,956	1,820	5.9%	1,731	5.1%
22	Income Taxes	(189)	(1,111)	587.8%	0	*
23	Deferred Income Taxes & ITC	156,485	10,436	6.7%	2,068	404.6%
24	Total Expenses:	3,299,872	188,932	5.7%	185,156	2.0%
25	Regulated Operating Income	446,170	24,952	5.6%	11,664	113.9%

Northern States Power Company
Electric Utility - North Dakota

(Dollars In Thousands)

III. AVERAGE RATE BASE

<u>Line</u>	<u>Item</u>	2011 <u>Total NSP</u>	2011 <u>N.D. Juris.</u>	<u>N. D. %</u>	2010 <u>N.D. Juris.</u>	<u>Annual</u> <u>Change</u>
1	Plant in Service	13,666,833	742,545	5.4%	673,626	10.2%
2	Accumulated Depreciation	6,539,914	364,662	5.6%	339,921	7.3%
3	Net Plant in Service	7,126,919	377,883	5.3%	333,705	13.2%
4	Plant Held for Future Use	0	0	*	0	*
5	Construct Work in Progress	10,012	657	6.6%	900	-27.0%
6	Materials and Supplies	124,370	7,213	5.8%	6,283	14.8%
7	Fuel Stocks	87,684	5,454	6.2%	5,234	4.2%
8	Prepayments & Other Rate Base	59,821	3,833	6.4%	4,379	-12.5%
9	Customer Deposits	(1,974)	(15)	0.8%	(166)	-91.0%
10	Cash Working Capital	0	0	*	0	*
11	Other Rate Base ¹	(65,643)	(3,903)	5.9%	(6,232)	-37.4%
12	Accum. Deferred Taxes	(1,380,354)	(68,127)	4.9%	(61,787)	10.3%
13	Total Other Rate Base	(1,166,084)	(54,888)	4.7%	(51,389)	6.8%
14	Total Average Rate Base	5,960,835	322,995	5.4%	282,316	14.4%

¹ Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, environmental cleanup, severance accrual, etc.

Northern States Power Company Electric Utility - North Dakota

(Dollars In Thousands)

IV. COST OF CAPITAL

2011 Actual

<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
1	Long-Term Debt	\$3,286,351	46.90%	6.12%	2.87%
2	Short-Term Debt	\$30,167	0.43%	3.06%	0.01%
3	Total Debt	\$3,316,518	47.33%	6.09%	2.88%
4	Preferred Stock	\$0	0.00%	0.00%	0.00%
5	Common Equity	\$3,690,284	52.67%	9.20%	4.85%
6	Total Equity	\$3,690,284	52.67%		
7	Total Capital	\$7,006,802	100.00%		7.73%

2010 Normalized

<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
8	Long-Term Debt	\$3,286,351	46.90%	6.12%	2.87%
9	Short-Term Debt	\$30,167	0.43%	3.06%	0.01%
10	Total Debt	3,316,518	47.33%	6.09%	2.88%
11	Preferred Stock	\$0	0.00%		0.00%
12	Common Equity	\$3,690,284	52.67%	9.05%	4.76%
13	Total Equity	\$3,690,284	52.67%		
14	Total Capital	\$7,006,802	100.00%		7.65%

Xcel Energy
Electric Utility - State of North Dakota
Reliability Performance - Overall ND System
2007 - 2011 Results - Normalized

System Average Interruption Frequency Index (SAIFI)

(Average # of interruptions per customer)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011 YTD	0.05	0.28	0.31	0.44	0.48	0.77	0.83	0.90	1.01	1.07	1.11	1.13
2010 YTD	0.03	0.05	0.11	0.27	0.40	0.52	0.66	0.85	0.91	1.17	1.18	1.20
2009 YTD	0.01	0.02	0.08	0.08	0.22	0.29	0.41	0.50	0.56	0.59	0.61	0.68
2008 YTD	0.07	0.08	0.12	0.13	0.20	0.42	0.51	0.57	0.60	0.63	0.65	0.67
2007 YTD	0.01	0.12	0.20	0.24	0.30	0.39	0.46	0.57	0.60	0.70	0.83	0.89
5 year average:												0.91

Customer Average Interruption Duration Index (CAIDI)

(Average # of minutes per interruption per customer)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011 YTD	109.0	320.6	295.0	230.1	217.7	157.9	156.0	155.3	148.5	143.0	141.0	140.6
2010 YTD	62.3	75.4	76.6	65.6	75.5	68.3	70.3	64.0	65.3	59.4	59.6	62.8
2009 YTD	141.4	108.1	92.6	98.6	74.1	78.0	81.0	90.8	87.1	89.6	90.4	91.5
2008 YTD	87.7	86.7	74.5	78.0	75.7	85.7	88.1	92.2	94.4	95.4	94.6	95.6
2007 YTD	79.2	110.9	106.5	102.8	94.1	97.6	93.8	91.9	93.1	85.4	77.6	77.6
5 year average:												93.6

Xcel Energy
Electric Utility - State of North Dakota
Reliability Performance - 5 Largest Substations
2007 - 2011 Results - Normalized

System Average Interruption Frequency Index (SAIFI)

(Average # of interruptions per customer)

	Cass County Sub (Fgo)	Red River Sub (Fgo)	Gateway Sub (GF)	Nordic Sub (GF)	Souris Sub (Minot)
2011	1.80	1.13	0.81	0.69	1.00
2010	0.46	1.68	0.68	2.27	0.29
2009	0.72	0.96	0.19	0.55	0.49
2008	0.34	0.88	0.67	0.57	0.58
2007	0.29	1.12	2.36	0.25	0.72
5 year average:	0.72	1.15	0.94	0.86	0.62

Customer Average Interruption Duration Index (CAIDI)

(Average # of minutes per interruption per customer)

	Cass County Sub (Fgo)	Red River Sub (Fgo)	Gateway Sub (GF)	Nordic Sub (GF)	Souris Sub (Minot)
2011	342.0	86.3	100.7	83.7	69.4
2010	127.1	58.2	44.3	61.9	76.5
2009	87.6	87.8	96.0	86.9	58.0
2008	143.2	96.7	100.6	85.4	62.8
2007	126.3	78.0	76.2	96.5	63.4
5 year average:	165.23	81.39	83.54	82.88	66.04

Xcel Energy
Electric Utility – State of North Dakota
2012 Reliability Plan Summary

Overhead Line Upgrades - \$324,000

Xcel Energy's 2012 capital budget includes about \$324,000 to upgrade its electric overhead system in North Dakota. These improvements include replacing failed devices, installing upgrades necessary to the backbone system to serve new customers, and installing upgrades necessary to solve reliability issues. Included in this effort is funding for our Reliability Exception Monitoring System ("REMS") program. Generally, this computer-based system initiates an investigation by flagging any device that has tripped more than twice in a rolling 12 month period. Following an engineering review, corrective actions are identified and implemented where appropriate.

Distribution Pole Testing - \$251,000

Xcel Energy's 2012 pole replacement plan includes an operating and maintenance expense budget of \$251,000 for testing wood distribution poles in North Dakota. The testing methodology conforms to a scientific procedure that is utilized throughout the industry. It includes a visual check and test of remaining pole strength. If a pole is identified as having strength characteristics below acceptable standards, the pole is scheduled for replacement or reinforcement. The expense budget for this program is subject to ongoing adjustments based on the Company's overall financial situation throughout the plan year.

Underground Cable Upgrade - \$211,000

In 2012, Xcel Energy plans to spend about \$211,000 in capital funds to upgrade its underground cable system in North Dakota. A little over half of these expenditures will include replacing cables that have failed but are not fit to be repaired and returned to service. They also include cables that may have experienced multiple failures in the past but for which repairs still present a viable remedy. Projects will involve the installation of additional backbone system capacity to serve new load or relieve load on existing facilities.

In addition, beginning in 2012, Xcel Energy will embark on a 3 year effort to proactively locate and remove non-standard 500 MCM cable remaining on our system. This project reflects one of several Settlement commitments in our most recent electric rate case (PU-10-657 and PU-11-55). The company plans to spend about \$102,000 in 2012 on this project.

Northern States Power Company Supporting Information - North Dakota

I. Sales and Customer Data

Electric Utility (N. D. Jurisdiction)

<u>Line</u>	<u>Customers (@ Dec)</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
1	Residential	76,126	76,319	75,608	75,036	74,094
2	Small C & I	12,033	12,078	11,989	11,895	11,821
3	Large C & I	20	20	19	22	21
4	PSHL/OSPA	<u>280</u>	<u>284</u>	<u>283</u>	<u>280</u>	<u>273</u>
5	Total Retail	88,459	88,701	87,899	87,233	86,209
<u>Line</u>	<u>Mwh Sales</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>	<u>2007</u>
6	Residential	776,125	769,024	794,420	761,934	761,356
7	Small C & I	1,085,821	1,057,747	1,116,612	1,093,952	1,067,116
8	Large C & I	350,764	349,581	310,239	328,203	358,129
9	PSHL/OSPA	<u>29,790</u>	<u>29,528</u>	<u>25,354</u>	<u>26,057</u>	<u>26,858</u>
10	Total Retail	2,242,500	2,205,880	2,246,625	2,210,146	2,213,459
11	Ave. ϕ /Kwh	7.86	7.06	7.10	7.33	6.59
12	Ave. Res. Monthly Usage (kwh)	850	840	876	846	856
13	Ave. Res. Monthly Bill	\$75.25	\$66.75	\$69.96	\$69.19	\$62.40

Xcel Energy
Supporting Information - North Dakota
II. AFFILIATED TRANSACTIONS Summary

Line #	Affiliate Name	General Description of Services Rendered &/or Supplied	Portion Allocated to North Dakota Jurisdiction Electric and Gas Totals (1)	
			Expense (2)	Revenue (3)
1	Northern States Power Company (Wis.)	Electric and Gas Utility	7,276,846	26,320,435
2	Public Service of Colorado	Electric and Gas Utility	2,849	16,814
3	Southwestern Public Service	Electric Utility	1,714	4,427
4	United Power and Land	Real estate holdings	-	-
5	Eloigne Company	Affordable housing investment program	-	-
6	Xcel Energy Services	Xcel Energy Inc. service company	16,420,741	-
7	e'Prime	Engineering services	-	-

Notes:

- (1) The amounts allocated to North Dakota electric and gas jurisdictions represent an estimate based on an overall allocation factor applied to all of the revenues and expenses for each affiliate. To derive the actual amounts by jurisdiction would require an allocation by transaction by account number and would require significant analysis and expense to perform.
- (2) Expense to North Dakota electric and gas jurisdictions. Revenue to affiliate for services provided to NSP (Mn).
- (3) Revenue to North Dakota electric and gas jurisdictions. Expense to the affiliate for services provided to the affiliate by NSP (MN).

Xcel Energy
Supporting Information - North Dakota
III. Affiliated Transactions Summary

	<u>Total Expense</u>	<u>Total Revenue</u>	<u>Elec %</u>	<u>Gas %</u>	<u>(Customers) ND Elec%</u>	<u>(Customers) ND Gas%</u>	<u>Allocation Used (1)</u>
NSP Wis.	538,857	1,374,186	92.8654%	7.1346%	6.2805%	9.8133%	Common
PSCo	45,368	267,718	100.0%	0.0%	6.2805%	0.0%	Electric
SPS	27,288	70,492	100.0%	0.0%	6.2805%	0.0%	Electric
UP&L	-	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
Eloigne	-	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
XES	251,367,962	-	92.8654%	7.1346%	6.2805%	9.8133%	Common
e'Prime	-	-	100.0%	0.0%	6.2805%	0.0%	Electric
	251,979,475	1,712,396					

(1) Allocation of Revenues & Expenses between NSP Minnesota and Affiliates

Common Allocation Methodology is Labor	<u>Electric</u>	<u>Gas</u>	<u>Load Dispatch</u>	
Utility Labor Allocator	92.8654%	7.1346%	<u>Design Day</u>	10.5613%
Customers North Dakota Jurisdictional	6.2805%	9.8133%		
Factor Formula: ((Util Elec)*ND Jur Ele)+((Util Gas)*ND Jur Gas) =				6.5326%

(2) Affiliated Transactions between Minnesota and Wisconsin

	<u>Total</u>	<u>ND Alloc.</u>		<u>Total</u>	<u>ND Alloc.</u>	<u>Alloc. Method</u>	<u>ND Alloc %</u>
Electric Inter change Agreement dollars							
Revenues							
	195,939,717	11,268,689	Fixed	48,949,521	2,815,136	Demand	5.751%
	202,288,680	12,582,154	Variable	19,429,562	1,208,499	Energy	6.220%
	41,200,349	2,369,473	Transmission	55,954,687	3,218,010	Demand	5.751%
Electric Total	439,428,745	26,220,316		124,333,770	7,241,645		
Gas SCADA Agreement							
SCADA	98,031	10,350					



ANNUAL REPORT

OF

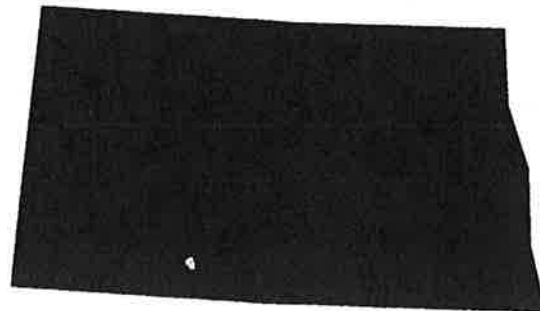
NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

TO THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

FOR THE YEAR ENDING
DECEMBER 31, 2012

North Dakota Jurisdiction
Electric Utility



2012

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Electric Utility

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Supporting Information

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Northern States Power Company
Electric Utility - North Dakota
(Dollars In Thousands)

I. RETURN ON EQUITY (ROE)

<u>Actual Return on Equity (ROE)</u>	<u>2012</u>	<u>2011</u>
1 Operating Income from Electric Operations (E-2):	\$24,371	\$24,952
2 Average Regulated Rate Base (E-3):	\$338,666	\$322,995
3 Rate of Return on Rate Base (ROR) (line 1 / line 2):	7.20%	7.73%
4 Weighted Cost of Debt (E-4):	2.61%	2.88%
5 Weighted Cost of Preferred Stock (E-4):	0.00%	0.00%
6 % of Equity in Capital Structure (E-4):	52.78%	52.67%
7 Return on Equity (ROE):	8.69%	9.20%

<u>ROE, Normalized for Weather Impact on Sales</u>	<u>2012</u>	<u>2011</u>
8 Operating Income from Electric Operations:	\$24,371	\$24,952
9 Impact of weather on Mwh Sales:	(24,994)	9,730
10 Impact of weather on Electric Operating Income: ¹	(\$407)	\$254
11 Weather-Normalized Operating Income:	\$24,778	\$24,698
12 Average Regulated Rate Base:	\$338,666	\$322,995
13 Weather-Normal Rate of Return on Rate Base (ROR):	7.32%	7.65%
14 Weather-Normalized Return on Equity (ROE):	8.92%	9.05%

¹ Beginning in 2012 the weather impact estimate includes a demand component in addition to sales.

Northern States Power Company
Electric Utility - North Dakota

(Dollars In Thousands)

II. OPERATING INCOME

<u>Line Item</u>	<u>2012 Total NSP</u>	<u>2012 N.D. Juris.</u>	<u>N. D. %</u>	<u>2011 N.D. Juris.</u>	<u>Annual Change</u>
<u>Operating Revenues:</u>					
1 Residential	1,166,495	69,329	5.9%	68,744	0.8%
2 Small Comm. & Ind.	1,326,542	85,328	6.3%	83,167	2.6%
3 Large Comm. & Ind.	633,557	22,301	3.4%	21,516	3.6%
4 Public Street & Highway Ltg	26,142	1,540	6.2%	1,616	-4.7%
5 Other Sales to Publ Auth	<u>8,330</u>	<u>1,159</u>	<u>15.0%</u>	<u>1,246</u>	<u>-7.0%</u>
Total Retail	3,161,066	179,657	5.6%	176,290	1.9%
6 Interdepartmental	532	0	0.0%	0	*
7 Sales for Resale	74,264	4,511	6.1%	4,497	0.3%
8 Interchange Agreement	449,958	26,898	5.8%	26,283	2.3%
9 Other	<u>112,083</u>	<u>8,540</u>	<u>6.1%</u>	<u>6,814</u>	<u>25.3%</u>
10 Total Revenues:	<u>3,797,903</u>	<u>219,606</u>	<u>5.8%</u>	<u>213,884</u>	<u>2.7%</u>
<u>Operating Expenses:</u>					
11 Fuel & Purchased Energy	1,242,746	77,805	6.3%	76,040	2.3%
12 Production	727,894	42,550	5.8%	43,220	-1.6%
13 Transmission	210,577	12,309	5.8%	11,219	9.7%
14 Distribution	111,134	6,387	5.7%	6,737	-5.2%
15 Customer Billing	53,705	4,128	7.7%	4,411	-6.4%
16 Customer Service	103,566	370	0.4%	489	-24.3%
17 Sales & Marketing	68	2	2.9%	135	-98.5%
18 Admin. & General	222,349	12,969	5.8%	11,770	10.2%
19 Depreciation & Amortization	384,321	20,400	5.3%	17,885	14.1%
20 Property Taxes	151,204	6,690	4.4%	5,881	13.8%
21 Payroll & Other Taxes	31,462	1,866	5.9%	1,820	2.5%
22 Income Taxes	0	0	*	(1,111)	-100.0%
23 Deferred Income Taxes & ITC	<u>156,513</u>	<u>9,759</u>	<u>6.2%</u>	<u>10,436</u>	<u>-6.5%</u>
24 Total Expenses:	<u>3,395,539</u>	<u>195,235</u>	<u>5.7%</u>	<u>188,932</u>	<u>3.3%</u>
25 Regulated Operating Income	<u>402,364</u>	<u>24,371</u>	<u>6.1%</u>	<u>24,952</u>	<u>-2.3%</u>

Northern States Power Company
Electric Utility - North Dakota

(Dollars In Thousands)

III. AVERAGE RATE BASE

<u>Line Item</u>	<u>2012 Total NSP</u>	<u>2012 N.D. Juris.</u>	<u>N. D. %</u>	<u>2011 N.D. Juris.</u>	<u>Annual Change</u>
1 Plant in Service	14,347,235	780,660	5.4%	742,545	5.1%
2 Accumulated Depreciation	<u>6,821,974</u>	<u>379,380</u>	<u>5.6%</u>	<u>364,662</u>	<u>4.0%</u>
3 Net Plant in Service	7,525,261	401,280	5.3%	377,883	6.2%
4 Plant Held for Future Use	0	0	*	0	*
5 Construct Work in Progress	51,931	2,936	5.7%	657	346.9%
6 Materials and Supplies	128,683	7,471	5.8%	7,213	3.6%
7 Fuel Stocks	90,424	5,634	6.2%	5,454	3.3%
8 Prepayments & Other Rate Base	82,396	4,830	5.9%	3,833	26.0%
9 Customer Deposits	(3,188)	(29)	0.9%	(15)	93.3%
10 Cash Working Capital	0	0	*	0	*
11 Other Rate Base ¹	(63,118)	(3,776)	6.0%	(3,903)	-3.3%
12 Accum. Deferred Taxes	<u>(1,679,223)</u>	<u>(79,680)</u>	<u>4.7%</u>	<u>(68,127)</u>	<u>17.0%</u>
13 Total Other Rate Base	(1,392,095)	(62,614)	4.5%	(54,888)	14.1%
14 Total Average Rate Base	6,133,166	338,666	5.5%	322,995	4.9%

¹ Includes deferred assets and liabilities such as accrued vacations, post-retirement medical benefits (FASB 106), post employment benefits (FASB 112), unfunded pension liability, environmental cleanup, severance accrual, etc.

Northern States Power Company
Electric Utility - North Dakota

(Dollars In Thousands)

IV. COST OF CAPITAL

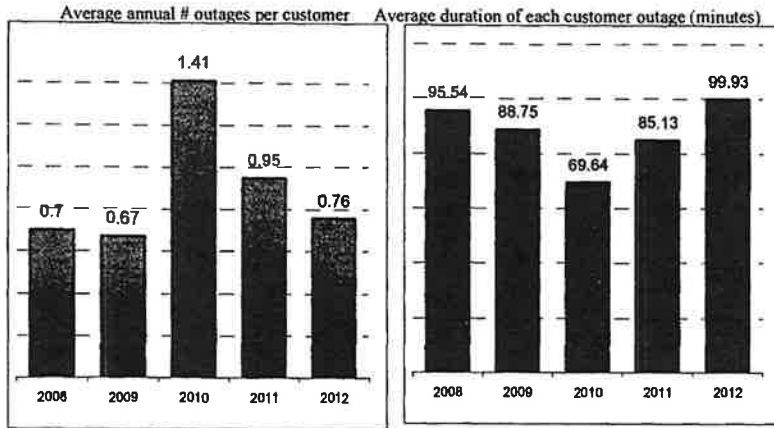
<u>2012 Actual</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
1	Long-Term Debt	\$3,360,934	45.38%	5.71%	2.59%
2	Short-Term Debt	\$136,000	1.84%	0.98%	0.02%
3	Total Debt	\$3,496,934	47.22%	5.52%	2.61%
4	Preferred Stock	\$0	0.00%	0.00%	0.00%
5	Common Equity	\$3,908,649	52.78%	8.69%	4.59%
6	Total Equity	\$3,908,649	52.78%		
7	Total Capital	\$7,405,583	100.00%		7.20%

<u>2012 Normalized</u>					
<u>Line</u>	<u>Item</u>	<u>Amount</u>	<u>% of Total</u>	<u>Cost</u>	<u>Weighted Cost</u>
8	Long-Term Debt	\$3,360,934	45.38%	5.71%	2.59%
9	Short-Term Debt	\$136,000	1.84%	0.98%	0.02%
10	Total Debt	3,496,934	47.22%	5.52%	2.61%
11	Preferred Stock	\$0	0.00%		0.00%
12	Common Equity	\$3,908,649	52.78%	8.92%	4.71%
13	Total Equity	\$3,908,649	52.78%		
14	Total Capital	\$7,405,583	100.00%		7.32%

Xcel Energy
Annual Reliability Report
Outage Frequency and Duration Indices

System Avg Interruption Frequency Index (SAIFI)

Customer Avg Interruption Duration Index (CAIDI)



Input Section	Normalized SAIFI	Normalized CAIDI
2008	0.70	95.5
2009	0.67	88.8
2010	1.41	69.6
2011	0.95	85.1
2012	0.76	99.9

SAIFI - Largest Five Substations

	2008	2009	2010	2011	2012	5 Yr. Avg
Souris (Mnt)	0.58	0.48	0.29	0.68	0.36	0.52
Gateway (GF)	0.61	0.18	0.68	0.78	0.59	0.57
Cass County (Fgo)	0.44	0.58	0.67	0.82	0.71	0.64
Nordic (GF)	0.58	0.57	2.52	0.88	1.01	1.11
Red River (Fgo)	0.97	1.03	1.96	1.02	0.70	1.14

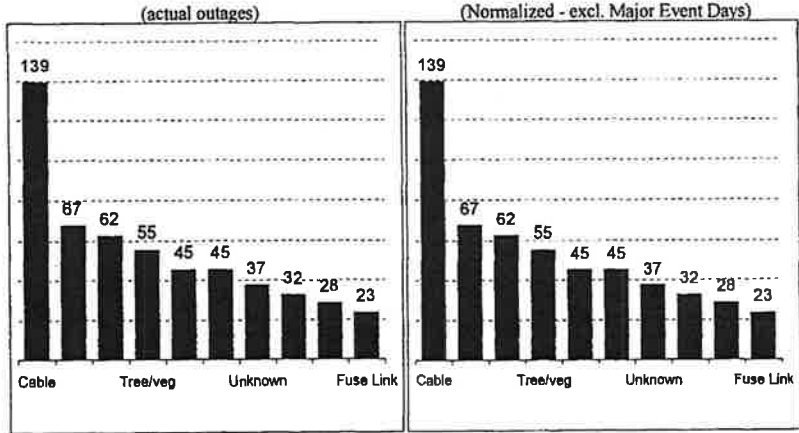
CAIDI - Largest Five Substations

	2008	2009	2010	2011	2012	5 Yr. Avg
Souris (Mnt)	66.7	61.0	82.7	71.2	105.8	77.5
Red River (Fgo)	94.0	81.4	70.3	73.8	110.1	85.9
Nordic (GF)	102.2	97.0	61.8	95.7	74.1	86.2
Gateway (GF)	113.7	122.1	47.9	109.1	89.1	96.4
Cass County (Fgo)	101.6	90.8	115.2	103.3	78.6	97.9

Data reflects outages lasting 5 minutes or longer. There were no Major Event Days in 2012 to normalize.

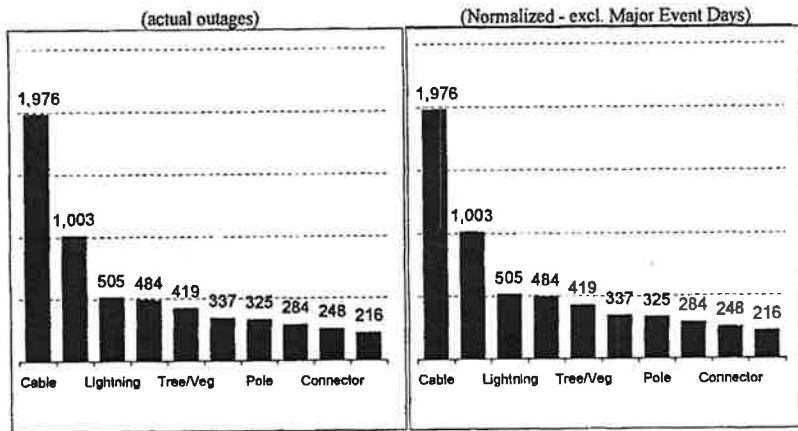
Xcel Energy
Annual Reliability Report
Most Common Outage Causes

Top 10 Outage Causes



Input Section	Actual Events	Excl MEDs
1 Cable	139 Cable	139
2 Intentional	67 Intentional	67
3 Animal	62 Animal	62
4 Tree/veg	55 Tree/veg	55
5 Connector	45 Connector	45
6 Public Dar	45 Public Dar	45
7 Unknown	37 Unknown	37
8 Overload	32 Overload	32
9 Transform	28 Transform	28
10 Fuse Link	23 Fuse Link	23

Top 10 Causes of Lengthy or Wide-spread Interruptions
(measured in customer-minutes without power - 000's)



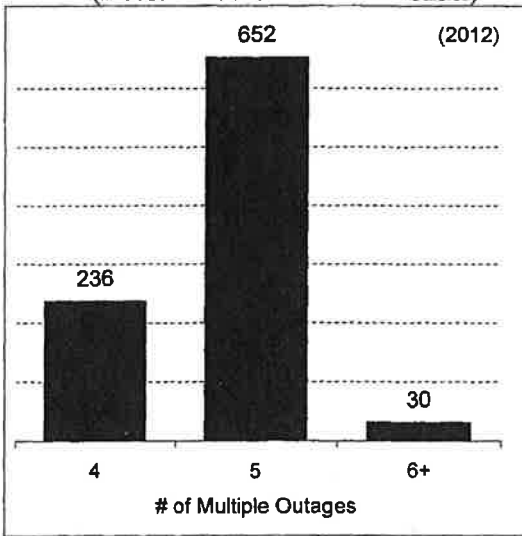
Input Section	Actual CMO	Excl MEDs
1 Cable	1,976 Cable	1,976
2 Intentional	1,003 Intentional	1,003
3 Lightning	505 Lightning	505
4 Relay	484 Relay	484
5 Tree/Veg	419 Tree/Veg	419
6 Public Dar	337 Public Dar	337
7 Pole	325 Pole	325
8 Insulator	284 Insulator	284
9 Connector	248 Connector	248
10 Conduct C	216 Conduct C	216

Note: Date reflects outages lasting 5 minutes or longer.

**Xcel Energy
Annual Reliability Report
CEMI, Feeder Outages, and Underground Cable Failures**

**Customers Experiencing Multiple Interruptions
(CEMI)**

(# Customers at Each Level of CEMI)

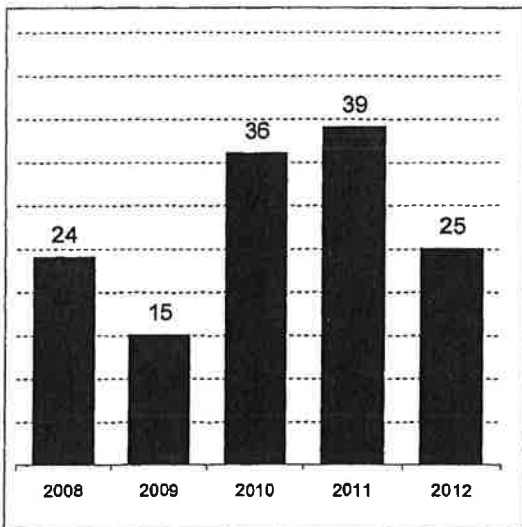


Annual CEMI Credit Results

Year w > 3 interr.	Customers	CEMI Credits
2012	918	none
2013		
2014		
2015		

Input Section	
CEMI Outages	CEMI Cust
4	236
5	652
6+	30

Feeder-Level Outages



Underground Cable Failures

Year	UG Cable Failures
2010	137
2011	149
2012	139
2013	
2014	
2015	

Input Section	
Fdr lvl outages	Fdrs
2008	24
2009	15
2010	36
2011	39
2012	25

(reflects primary, secondary cable failures)

Data reflects outages lasting 5 minutes or longer; Major Event Days and public damage events excluded.

Xcel Energy
Electric Utility – State of North Dakota
2013 Reliability Plan Summary

Overhead Line Upgrades - \$1,522,000

Xcel Energy's 2013 capital budget includes about \$1,522,000 to upgrade its electric overhead system in North Dakota. These improvements include replacing failed devices, installing upgrades necessary to the backbone system to serve new customers, and improvements to enhance reliability. Included in this effort is funding for our Reliability Exception Monitoring System ("REMS") program. This computer-based system initiates an engineering review of a part of our system by flagging any device that has tripped more than twice in a rolling 12 month period. Following such a review, corrective actions are identified and implemented where appropriate.

Underground Cable Upgrade - \$903,000

In 2013, Xcel Energy plans to spend about \$903,000 in capital funds to upgrade its underground cable system in North Dakota. A little over half of these expenditures will include replacing cables that have failed but are not fit to be repaired and returned to service. They also include cables that may have experienced multiple failures in the past but for which repairs still present a viable remedy. Projects will involve the installation of additional backbone system capacity to serve new load or relieve load on existing facilities.

In addition, these funds reflect Xcel Energy's continued efforts to proactively locate and remove non-jacketed 500 MCM cable remaining on our system. This project reflects one of several Settlement commitments from Case No.'s PU-10-657 and PU-11-55. The company plans to spend about \$450,000 in 2013 on this project. The total program has been extended from its initial 3 year term (2012 – 2014) to a 4 year project, and the expenditure budget increased from \$750,000 to \$1,700,000, using funds available from the Company's Intelliteam project.

Distribution Pole Testing - \$47,000

Xcel Energy's 2013 pole replacement plan includes an operating and maintenance expense budget of \$47,000 for testing wood distribution poles in North Dakota. The testing methodology conforms to a scientific procedure that is utilized throughout the industry. It includes a visual check and test of remaining pole strength. If a pole is identified as having strength characteristics below acceptable standards, the pole is scheduled for replacement or reinforcement. The expense budget for this program is subject to ongoing adjustments based on the Company's overall financial situation throughout the plan year.

Northern States Power Company Supporting Information - North Dakota

I. Sales and Customer Data

Electric Utility (N. D. Jurisdiction)

<u>Line</u>	<u>Customers (@ Dec)</u>	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
1	Residential	77,231	76,126	76,319	75,608	75,036
2	Small C & I	12,182	12,033	12,078	11,989	11,895
3	Large C & I	21	20	20	19	22
4	PSHL/OSPA	<u>322</u>	<u>280</u>	<u>284</u>	<u>283</u>	<u>280</u>
5	Total Retail	89,756	88,459	88,701	87,899	87,233
<u>Line</u>	<u>Mwh Sales</u>	<u>2012</u>	<u>2011</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
6	Residential	758,810	776,125	769,024	794,420	761,934
7	Small C & I	1,069,443	1,085,821	1,057,747	1,116,612	1,093,952
8	Large C & I	349,595	350,764	349,581	310,239	328,203
9	PSHL/OSPA	<u>29,553</u>	<u>29,790</u>	<u>29,528</u>	<u>25,354</u>	<u>26,057</u>
10	Total Retail	2,207,401	2,242,500	2,205,880	2,246,625	2,210,146
11	Ave. ¢/Kwh	8.10	7.85	7.24	7.10	7.33
12	Ave. Res. Monthly Usage (kwh)	819	850	840	876	846
13	Ave. Res. Monthly Bill	\$74.46	\$75.16	\$68.32	\$69.96	\$69.19

Xcel Energy
Supporting Information - North Dakota
II. AFFILIATED TRANSACTIONS Summary

Line #	Affiliate Name	General Description of Services Rendered &/or Supplied	Portion Allocated to North Dakota Jurisdiction Electric and Gas Totals (1)	
			Expense (2)	Revenue (3)
1	Northern States Power Company (Wis.)	Electric and Gas Utility	7,356,944	26,916,044
2	Public Service of Colorado	Electric and Gas Utility	5,460	7,179
3	Southwestern Public Service	Electric Utility	2,012	962
4	United Power and Land	Real estate holdings	-	54
5	Eloigne Company	Affordable housing investment program	-	1,220
6	Xcel Energy Services	Xcel Energy Inc. service company	15,886,741	-
7	e'Prime	Engineering services	-	-
			<u>23,251,156</u>	<u>26,925,459</u>

Notes:

- (1) The amounts allocated to North Dakota electric and gas jurisdictions represent an estimate based on an overall allocation factor applied to all of the revenues and expenses for each affiliate. To derive the actual amounts by jurisdiction would require an allocation by transaction by account number and would require significant analysis and expense to perform.
- (2) Expense to North Dakota electric and gas jurisdictions. Revenue to affiliate for services provided to NSP (Mn).
- (3) Revenue to North Dakota electric and gas jurisdictions. Expense to the affiliate for services provided to the affiliate by NSP (MN).

Xcel Energy
Supporting Information - North Dakota
III. Affiliated Transactions Summary

	<u>Total Expense</u>	<u>Total Revenue</u>	<u>Elec %</u>	<u>Gas %</u>	<u>(Customers) ND Elec%</u>	<u>(Customers) ND Gas%</u>	<u>Allocation Used (1)</u>
NSP Wis.	700,842	952,566	92.2092%	7.7908%	6.3320%	9.9502%	Common
PSCo	86,227	113,381	100.0%	0.0%	6.3320%	0.0%	Electric
SPS	31,778	15,191	100.0%	0.0%	6.3320%	0.0%	Electric
UP&L	-	819	92.2092%	7.7908%	6.3320%	9.9502%	Common
Eloigne	-	18,443	92.2092%	7.7908%	6.3320%	9.9502%	Common
XES	240,202,796	-	92.2092%	7.7908%	6.3320%	9.9502%	Common
ePrime	-	-	100.0%	0.0%	6.3320%	0.0%	Electric
	241,021,643	1,100,400					

(1) Allocation of Revenues & Expenses between NSP Minnesota and Affiliates

Common Allocation Methodology Is Labor	<u>Electric</u>	<u>Gas</u>	<u>Load Dispatch</u>	
Utility Labor Allocator	92.9310%	7.0690%	<u>Design Day</u>	10.2008%
Customers North Dakota Jurisdictional	6.3320%	9.9502%		10.6373%
Factor Formula: ((Util Elec)*ND Jur Ele)+((Util Gas)*ND Jur Gas) =				6.5878%

(2) Affiliated Transactions between Minnesota and Wisconsin

	<u>Total</u>	<u>ND Alloc.</u>		<u>Total</u>	<u>ND Alloc.</u>	<u>Alloc. Method</u>	<u>ND Alloc %</u>
Electric Inter change Agreement dollars			Expenses				
Revenues	195,624,441	11,259,947	Fixed	45,205,562	2,601,987	Demand	5.756%
	210,611,539	13,121,520	Variable	20,220,356	1,259,769	Energy	6.230%
	42,632,106	2,453,861	Transmission	59,918,260	3,448,835	Demand	5.756%
Electric Total	448,868,086	26,835,329		125,344,178	7,310,591		
Gas SCADA Agreement							
SCADA	98,213	17,714					

THIS FILING IS	
Item 1: <input checked="" type="checkbox"/> An Initial (Original) Submission	OR <input type="checkbox"/> Resubmission No. _____

Exhibit__ (MJM-4)
 Form 1 Approved
 OMB No.1902-0021
 (Expires 12/31/2014)
 Form 1-F Approved
 OMB No.1902-0029
 (Expires 12/31/2014)
 Form 3-Q Approved
 OMB No.1902-0205
 (Expires 05/31/2014)



FERC FINANCIAL REPORT

FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Northern States Power Company (Minnesota)	End of <u>2012/Q4</u>

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Northern States Power Company (Minnesota)	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/12/2013	2012/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

NSP-Minnesota records depreciation expense related to its plant using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.9 and 3.2 percent for the years ended Dec. 31, 2012 and 2011, respectively.

Leases — NSP-Minnesota evaluates a variety of contracts for lease classification at inception, including purchased power agreements (PPAs) and rental arrangements for office space, vehicles, and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 9 for further discussion of leases.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in NSP-Minnesota's rate base for establishing utility service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases, including certain wind and transmission projects, the Minnesota Public Utilities Commission (MPUC) has approved a more current recovery of the cost of capital associated with large capital projects, through various riders, resulting in a lower recognition of AFUDC.

Asset Retirement Obligations — NSP-Minnesota accounts for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the amounts through the establishment of a regulatory asset and recovery in rates. NSP-Minnesota also recovers through rates certain future plant removal costs in addition to AROs. See Note 9 for further discussion of AROs.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC and other state commissions for approval. NSP-Minnesota filed its most recent triennial nuclear decommissioning studies with the MPUC in December 2011 and received approval in December 2012. These studies reflect NSP-Minnesota's plans, under the current operating licenses, for prompt dismantlement of the Monticello and Prairie Island facilities. These studies assume that NSP-Minnesota will be storing spent fuel on site pending removal to a United States government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants, including operating costs associated with spent fuel, over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC. The studies consider estimated future costs of decommissioning and the market value of investments in trust funds, and recommend annual funding amounts. Amounts collected in rates are deposited in the trust funds. See Note 10 for further discussion of the approved nuclear decommissioning studies and funded amounts. For financial reporting purposes, NSP-Minnesota accounts for nuclear decommissioning as an ARO as described above.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the balance sheets. See Note 7 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC), as well as future disposal costs of spent nuclear fuel and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs NSP-Minnesota uses a deferral and amortization method for nuclear refueling operation and maintenance (O&M) costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4
Northern States Power Company (Minnesota)			
NOTES TO FINANCIAL STATEMENTS (Continued)			

NSP-Minnesota has recognized AROs for the retirement costs of natural gas mains and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with polychlorinated biphenyls, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have numerous in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the AROs associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originated with the in-service date of the facility. See Note 10 for further discussion of nuclear obligations.

A reconciliation of NSP-Minnesota's AROs is shown in the tables below for the years ended Dec. 31, 2012 and 2011, respectively:

(Thousands of Dollars)	Beginning	Accretion	Revisions	Ending
	Balance		to Prior	Balance
	Jan. 1, 2012		Estimates	Dec. 31, 2012 ^(a)
Electric plant				
Steamproduction asbestos	\$ 10,479	\$ 459	\$ 1,851	\$ 12,789
Steamproduction ash containment	30,989	1,065	15,872	47,926
Steamproduction radiation sources	42	3	-	45
Nuclear production decommissioning ..	1,482,741	75,301	(11,684)	1,546,358
Wind production	40,515	2,068	(9,647)	32,936
Electric transmission and distribution ..	15,700	570	(2,432)	13,838
Natural gas plant				
Gas transmission and distribution	295	18	-	313
Common and other property				
Common general plant asbestos	1,135	62	-	1,197
Total liability	<u>\$ 1,581,896</u>	<u>\$ 79,546</u>	<u>\$ (6,040)</u>	<u>\$ 1,655,402</u>

^(a) There were no new ARO liabilities recognized or settled during the 12 months ended Dec. 31, 2012.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.5 billion as of Dec. 31, 2012, consisting of external investment funds.

In 2012, NSP-Minnesota incurred revisions for nuclear decommissioning, asbestos, ash-containment facilities, wind facilities and electric transmission and distribution AROs due to revised estimated cash flows.