OAH 15-2500-21773-2
PUC No. E-002/GR-10-971

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota

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FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION

An evidentiary hearing was held before Administrative Law Judge Beverly Jones Heydinger on June 1-8, 2011, at the Public Utilities Commission, St. Paul, Minnesota. Public hearings were held in Brooklyn Center, Minneapolis, Mankato, St. Paul, Woodbury, Bloomington and St. Cloud, Minnesota between April 11 and April 20, 2011. Public Comments were received until the close of the evidentiary hearing.

The hearing was reconvened on November 4, 2011, for the limited purpose of considering the Supplemental Testimony of Dennis Koehl and Richard Ostberg concerning the Monticello Nuclear Power Plant life cycle management/extended power uprate (LCM/EPU) project.

Post-hearing briefs were filed on November 18, 2011, and responsive briefs were filed on December 16, 2011.

The hearing record closed upon receipt of the last post-hearing briefs on December 22, 2011.

Appearances:

Christopher B. Clark, Matthew P. Loftus, Kari L. Valley, James P. Johnson, James R. Denniston, Mara N. Koeller, all of Xcel Energy Services, Inc., Sam Hanson, Briggs and Morgan, P.A., and Richard J. Johnson and Michael J. Bradley, Moss and Barnett, on behalf of Northern States Power Company, the Company;[1]

James M. Strommen, Kennedy & Graven Chartered, on behalf of the Suburban Rate Authority;

Pam Marshall, Executive Director, on behalf of Energy CENTS Coalition.

[1] Also referred to in the record as the Applicant, NSP or Xcel Energy.

Alan R. Jenkins, Jenkins at Law, LLC, on behalf of an association of the Applicant's large commercial customers, including but not limited to Macy's Inc., Sam's West, Inc., and Wal-Mart Stores, Inc. (Commercial Group);

Lloyd W. Grooms and Tammy Diehm, Winthrop & Weinstine, P.A., on behalf of Verso Paper;

Richard J. Savelkoul, Felhaber, Larson, Fenlon & Vogt, P.A., on behalf of the Minnesota Chamber of Commerce;

Andrew P. Moratzka, Mackall, Crounse & Moore, PLC, on behalf of Flint Hills Resources LP, Gerdau Ameristeel Corporation, USG Interiors, Inc., and Northern Tier Energy, LLC (Xcel Large Industrials or XLI);

Paula Goodman Maccabee, Just Change Law Offices, on behalf of Minwind Energy, LLC (Minwind);

Ronald M. Giteck, Assistant Attorney General, on behalf of the Attorney General's Office, Antitrust and Utilities Division (OAG);[2]

Julia E. Anderson and Linda S. Jensen, Assistant Attorneys General, on behalf of the Department of Commerce, Division of Energy Resources (Department).[3]

Janet Gonzalez, Jerry Dasinger, Clark Kaml and Christopher Fittipaldi, Public Utilities Commission Staff, also attended the hearing.

STATEMENT OF THE ISSUES

1. On November 3, 2010, the Applicant filed a petition to increase its electric rates in Minnesota. It requested an annual rate increase of $150.1 million or approximately 5.62 percent, effective January 2, 2011, and an additional increase of $48.3 million or 1.81 percent, effective January 1, 2012, for a total requested increase of $198.5 million or 7.43 percent. On December 27, 2010, the PUC issued a Notice and Order for Hearing referring the matter to the Office of Administrative Hearings for contested case proceedings.

2. The Notice and Order for Hearing set forth the following issues to be addressed:

   a. Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings?

   b. Is the rate design proposed by the Company reasonable?

[2] Previously named Residential and Small Business Utilities Division (RUD) and appears as such in portions of the record.

[3] Previously named Office of Energy Security (OES) and appears as such in portions of the record.

c. Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

d. Issues identified in past Commission Orders for further analysis in the Company's next rate case and identified in Xcel's Filing Requirement Table.

e. Issues related to the proposed increase in Windsource rates, with consideration of the full record in Docket No. E-002/M-09-1177, including the Commission's Order dated June 21, 2010, staff briefing papers, OES comments and Xcel's filings.

f. Issues related to the Company's proposed 2012 "step-in" rates.

g. Issues arising from Docket No. E-002/M-09-1488, the Central Corridor docket.

h. Further explanation and schedule of the Company's salary and benefits history for the past three years.

3. Overall, are the requested rate increases just and reasonable?

Based on the evidence in the hearing record,[4] the Administrative Law Judge makes the following:

FINDINGS OF FACT

Summary of the Application

1. The Company's petition to increase electric rates in Minnesota requested an annual rate increase of $150.135 million, approximately 5.62 percent, effective January 2, 2011, based on an 11.25 percent rate of return on equity, and an additional increase of $48.327 million, approximately 1.81 percent effective January 1, 2012, for a total increase of $198.5 million, approximately 7.43 percent. This was based on the Minnesota jurisdiction electric operations overall retail revenue requirement of $2.822 billion.[5]

2. The 2012 step-in adjustment of $48.3 million had four components: Monticello Life Cycle Management and Extended Power Uprate (LCM/EPU), which made up $34.6 million of the total step-in adjustment; transmission plant investment ($4.3 million); distribution plant investment ($5.4 million); and nuclear outage amortization expense ($4.5 million), minus a small change in cash working capital ($0.5 million).[6]

[4] A Master Exhibit List, including links to all exhibits received into evidence, was efiled by the court reporter on Nov. 14, 2011, Edocket Doc. No. 201111-68300-01.
[5] Exhibit (Ex.) 70 at 14-15 (Heuer Direct); Ex. 15 at 2-3 (Poferl Rebuttal).
[6] Ex. 74 at 5-6 (Ostberg Direct).

3. In the course of this proceeding, many issues were resolved among the parties. The Company made many adjustments to the schedules in its Application, including an adjustment to its requested return on equity, which reduced the total revenue requirement to $122.941 million for 2011, a reduction of $27.194 million from its initial filing. The Company also requested a 2012 step increase of $47.992 million, for a combined total increase in the revenue requirement of $170.993 million for 2012.[7]

4. Following the close of the hearing, based on issues resolved during the proceeding and its position on the remaining issues, the Department recalculated Xcel's revenue requirement to be $81.793 million for 2011, and $14.779 million for the 2012 step-in adjustment for a total of $96.572 million.[8]

5. All issues that affect the revenue requirement and were fully resolved are listed in Attachment A.

The Parties

6. Xcel Energy Inc. is a public utility holding company with four utility subsidiaries that serve electric and natural gas customers in eight states, including Northern States Power Company, a Minnesota corporation that serves Minnesota customers.

7. Energy CENTS Coalition intervened in this proceeding to protect the financial interests of low-income Xcel customers; however, it did not participate in the proceeding and withdrew as a party on June 29, 2011.

8. Suburban Rate Authority is a joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, most served by Xcel Energy.

9. Commercial Group is an association of large commercial operators of retail facilities and distribution centers in Minnesota, many of which are served by Xcel. It was concerned with any rate increase to Xcel's commercial customers.

10. Verso Paper operates an industrial facility in Sartell, Minnesota. It is one of Xcel's largest customers. It played a limited role in the proceeding.

11. Minnesota Chamber of Commerce represents over 2,400 businesses throughout the State of Minnesota. Many of its members are within Xcel's service territory. The Chamber of Commerce is involved in policy issues that affect business, including energy policy, on behalf of its members.

12. XLI includes some of Xcel's large retail electric customers. Their costs of production could be significantly affected by a rate increase.

[7] Xcel Summary of Issues, Schedule (June 30, 2011), Edocket Doc. No. 20116-64364-01.
[8] Exs. 194, 195.

13. Minwind is a limited liability company formed to develop community wind projects so that local farmers and communities may benefit economically from the development of renewable energy in southwestern Minnesota. Its interest in the proceeding was related to negotiations with Xcel for a power purchase agreement for Community Wind South, a local wind project, and Xcel's costs for wind purchases and for the Nobles County Substation.

14. OAG represents the interests of residential and small business ratepayers. Its staff reviews the testimony and schedules filed by the applicant and other parties and files testimony and argument intended to protect those interests.

15. The Department of Commerce, Division of Energy Resources, represents the interests of the State's ratepayers in rate proceedings. Department staff reviews the testimony and schedules filed by the applicant and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

Procedural Background[9]

16. On November 3, 2010, the Applicant filed its petition to increase its electric rates in Minnesota.

17. The Public Utilities Commission (PUC or Commission) issued a Notice and Order for Hearing on December 27, 2010. On the same date, it issued three other orders, one finding the rate case filing was substantially complete,[10] one setting an interim rate schedule for the duration of this proceeding,[11] and one accepting Xcel's withdrawal of its request for deferred accounting treatment of Smart VAR Project costs, requiring various reporting and that the deferred amount to be determined in the rate case.[12]

18. The Commission issued its Notice and Order for Hearing on December 27, 2010. At the time of its Order, the parties to the proceeding were the Company, OAG and the Department.

19. A Prehearing Conference was held on January 14, 2011, at the Public Utilities Commission. A Prehearing Order was issued on January 19, 2011, setting forth the procedures for discovery and hearing preparation, as well as the dates of the evidentiary hearing.

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[9] All Documents referred to in this section are filed with the Department of Commerce eDocket system, Docket Number 10-971, and are listed at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&userType=public.
[10] Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing.
[11] Order Setting Interim Rates.
[12] Order Accepting Withdrawal, Granting Deferred Accounting, and Setting Filing Requirements.

20. On January 26 and February 10, 2011, the Company filed supplemental direct testimony and schedules in compliance with the Commission's December 27, 2010, Order Accepting Filing, Suspending Rates, and Requiring Supplemental Filing.

21. On February 15, 2011, the Commission issued its Order Requiring Change in General Allocator and Requiring Filings, directing Xcel to change the formula for allocating corporate expenses from Number of Employees to Allocated Labor Hours with Overtime, and to file supplementary testimony and financial adjustments in this case.

22. On April 1, 2011, the Company filed supplemental testimony and financial schedules in compliance with the Commission's February 15, 2011, order.

23. On April 5, 2011, the Intervenors filed Direct Testimony.

24. Public hearings were held according to the following schedule:

April 11, 2011, Brookdale Regional Library, Brooklyn Center and Sabathani Community Center, Minneapolis;

April 12, 2011, Intergovernment Center, Mankato;

April 13, 2011, West Minnehaha Recreation Center, St. Paul and Woodbury Central Park, Woodbury;

April 14, 2011, Bloomington Civic Plaza, Bloomington;

April 18, 2011, Lake George Municipal Center, St. Cloud[13]

25. On April 27, 2011, Minwind Energy LLC filed a Petition to Intervene. The Applicant opposed the Petition as untimely. Minwind requested intervention in order to address issues specific to its negotiations with Xcel for a power purchase agreement for its Community Wind South project and to assure that independent and community-based wind developers were not adversely affected by the proceeding. On May 4, 2011, Minwind was granted intervention, subject to certain limitations because of the timing of its petition.

26. On May 4, 2011, the parties filed Rebuttal Testimony.

27. On May 26, 2011, the parties filed Surrebuttal Testimony.

28. The evidentiary hearing was held on June 1-3 and 6-8, 2011, at the Public Utilities Commission. At the close of the evidentiary hearing, counsel for the Company stated that, in the event of a Minnesota State Government shut-down, the Company would agree to extend the deadline for decision in this matter to reflect that shut-down.[14]

[13] Administrative Law Judge Steve M. Mihalchick presided at the St. Cloud public hearing.
[14] Transcript Volume (Tr. Vol.) 6 at 208 (ALJ Summary).

29. By letter dated June 10, 2011, the parties were notified of the posthearing schedule.

30. On June 13, 2011, following the close of the Evidentiary Hearing, Notice and Order to Show Cause was issued to Verso Paper and Energy CENTS, noting that neither of them had participated in the proceeding to that point. Each of them was asked to file a Memorandum and Supporting Affidavit explaining why they should remain as a party.

31. On June 27, 2011, Verso Paper filed its response, explaining its participation to date and reasons to remain as a party. On June 28, 2011, Order Confirming Party Status – Verso Paper was issued.

32. On June 29, 2011, Energy Cents notified the Administrative Law Judge that it would like to withdraw from the proceeding. On that date, the Order Dismissing Energy CENTS Coalition was issued.

33. On June 30, 2011, at the request of the ALJ, the Company filed a Summary of Issues, identifying all issues raised in the course of the rate proceeding, specifying which issues had been resolved in the course of the proceeding, and which issues remained in dispute, with annotations to the hearing record.[15]

34. Many Minnesota State Government functions were shut down from July 1, 2011, through July 20, 2011, and the Public Utilities Commission, Office of Administrative Hearings and Department of Commerce were closed.

35. Following consultation with the parties, the posthearing schedule was revised. The date for parties to file objections to the Applicant's Summary of Issues was reset for August 19, 2011, and a briefing schedule was set.

36. The ALJ requested that the Company acknowledge that the proposed extension of deadlines would further delay the Commission's final order establishing rates. The Company made such an acknowledgement in a letter dated July 29, 2011.

37. On August 18, 2011, Minwind gave notice that all of its issues had been satisfactorily addressed through discovery, testimony at hearing, and successful negotiation of a power purchase agreement with Xcel Energy and that it did not intend to submit briefing.

38. On August 19, 2011, the parties responded to the Company's filing regarding the status of issues. The Commercial Group and the Chamber of Commerce filed corrected versions shortly thereafter.

[15] Summary of Issues, Edocket Doc. No. 20116-64364-01.

Motion to Admit Post-Hearing Supplemental Testimony

39. On August 25, 2011, the Company filed a Motion to Admit Post-Hearing Supplemental Testimony of Dennis Koehl and Richard Ostberg into the hearing record, to supplement the record with information concerning the Monticello LCM/EPU project. In its Motion, the Company stated that there would be delay in completing the project and obtaining the necessary license, which would have a significant effect on the 2011 Test Year revenue requirement and its requested 2012 step-in adjustment.

40. On September 12, 2011, an Order was issued, staying the briefing schedule, allowing discovery concerning the information set forth in the proposed Supplemental Testimony, and scheduling a hearing on the Company's Motion.

41. A hearing was held on October 10, 2011, to consider the Company's Motion and to address the schedule.

42. On October 12, 2011, an Order Granting Xcel's Motion to Supplement Record and Setting Schedule was issued, scheduling an evidentiary hearing for November 4, 2011, for the limited purpose of considering the Supplemental Testimony offered by Xcel. The Order also established a revised briefing schedule.

43. An additional evidentiary hearing was held on November 4, 2011, at the Public Utilities Commission.

Partial Settlement

44. On November 14, 2011, the Company filed a Stipulation and Settlement Agreement (Settlement) with the Chamber of Commerce, XLI, the Commercial Group and Verso Paper, addressing the revenue requirement and some other issues. The Company requested that the ALJ convene a settlement conference. Neither the Department nor the OAG were parties to the Settlement.

45. On November 18, 2011, the parties filed initial post-hearing briefs. On the same day, the parties were notified that a settlement conference would be held on December 5, 2011.

46. On December 2, 2011, the Department filed a letter setting forth its view of the proposed Settlement. Although the Department did not oppose the Settlement, it was not a signatory.

47. On December 5, 2011, the ALJ convened a settlement conference. At that time, the parties and Commission staff had the opportunity to raise questions and offer comments concerning the Settlement. In order to give the non-participating parties an opportunity to fully review the Settlement, the deadline for filing post-hearing reply briefs was extended six days. The OAG did not state an opinion concerning the Settlement on that date.

48. On December 12, 2011, at the request of the ALJ, the Company filed an Update to Summary of Issues, specifying which of the issues were resolved by the Settlement and a Revised Settlement Agreement, reflecting the issues addressed.

49. On December 21, 2011, Xcel Energy requested authorization from the Commission to defer approximately $28 million in property tax liabilities for potential recovery in its next electric and gas general rate case or, in the alternative, to approve a new Real and Personal Property Tax rider.[16]

50. On December 22, 2011, the parties filed post-hearing reply briefs.

Summary of Public Comments

51. A summary of the public comments is included as Attachment B to this report. There was general opposition to any rate increase, particularly during troubled economic times when few people are getting raises and many are unemployed or underemployed. There were specific objections to the Company's executive compensation and proposed increase in the Windsource charge. Some members of the public were concerned that they were conserving more energy, but their rates were still rising; others complained about the complexity of their bills and the number of riders. There were also complaints about power outages in certain cities or neighborhoods.

Legal Standards

52. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[17] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market. Minnesota law recognizes this principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[18]

53. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[19] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[20]

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[16] Petition for Approval of Deferred Accounting for Property Tax Costs, Docket No. E002/M-11-1263 (Dec. 21, 2011); Edocket Doc. No. 201112-69559-01.
[17] Minn. Stat. § 216B.03. Minnesota Statutes are cited to the 2010 Edition.
[18] Minn. Stat. § 216B.16.
[19] *In re Northern States Power,* 416 N.W.2d 719, 722 (Minn. 1987).
[20] Minn. Stat. § 216B.03.

54. The Commission acts in both a quasi-judicial and quasi-legislative capacity. It evaluates the facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[21]

55. There are several steps to developing a rate. In general, the utility will select a test year and look at its rate base, revenue, expenses and reasonable rate of return to determine if it will have a revenue deficiency. As part of this process, the utility may also propose to move funds collected through riders into its rates. It will conduct a study of costs by customer class, and allocate revenue by class to determine the portion of the deficiency each class should bear. Then, it designs rates to collect the appropriate portion from each class.[22] In constructing its rate proposal, the Company must follow standard accounting principles and comply with prior orders of the Commission.[23]

Terms of the Partial Settlement

56. On November 14, 2011, the Company filed a Stipulation and Settlement Agreement (Settlement) that it had reached with four of the parties: XLI, the Chamber of Commerce, Verso and the Commercial Group. They agreed on a revenue requirement that resolved all financial issues related to the 2011 test year and to the 2012 step-in adjustment. Some issues were specifically resolved; others were wrapped into a general agreement on a dollar figure, without resolution of the underlying issues. The parties to the Settlement also agreed to a resolution of some of the non-financial issues.[24] Other issues remain in dispute.

57. The Settlement noted that, following the close of the evidentiary hearing in June, there had been a delay of the second planned 2011 outage at the Monticello nuclear power plant and a state government shut-down that postponed the contested case schedule. As a result, the Company had filed post-hearing testimony reducing the revenue requirement due to the delay in completing the Monticello LCM/EPU project and the EPU license amendment from the Nuclear Regulatory Commission. The delays motivated the Company to attempt to reach a settlement of the issues in this proceeding in order to more quickly resolve a complex case and implement final rates.[25]

58. The Company's revenue requirement is its total cost of doing business, comprised of its operating expenses, depreciation expenses, taxes and a margin sufficient to meet its capital costs. The Company used the 2011 calendar year as its test year for this proceeding (2011 Test Year). It also requested a step-in adjustment

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[21] *Id.*
[22] For general discussion, *see* Ex. 70 (Heuer Direct).
[23] *See* Ex. 14 at JMP-1, Sched. 3 (Poferl Direct) (addressing the Company's compliance with prior Commission Orders).
[24] Edocket Doc. No. 201111-68338-01 (Settlement). A revised version, annotated but without substantive change, was filed on December 12, 2012, clarifying the issues that were resolved by the Settlement. Edocket Doc. No. 201112-69163-01 (Update to Summary of Issues).
[25] Settlement at 4.

for 2012 to recover costs that it asserts are known and measureable for that year, primarily related to the Company's extensive capital expansion.

59. The Settlement reduced the 2011 requested revenue increase from $122.941 million to $58.036 million, a reduction of approximately $65 million from the Applicant's position at the close of the evidentiary hearing. In the Settlement, the parties agreed to a 2012 step-in rate increase of $14.815 million, approximately $33.1 million less than the Company's position at the close of the evidentiary hearing. The combined increase for 2011 and 2012 is $72.851 million, a 2.73 percent increase over current rates.[26]

60. The parties that participated in the settlement did not attempt to resolve each issue that leads to the calculation of the revenue requirement. Rather, they agreed that the total amount agreed upon adequately reflects their positions on the combined issues.[27]

61. The Settlement Agreement can be summarized as follows:

Calculation of 2011 and 2012 Base Rate Increases ($,000s)

Revenue Requirement, Post-hearing	$122,941[28]
ROE at 10.37%	(23,820)
Monticello LCM/EPU	(1,152)
SEP Rider	(2,442)
Compensation	(7,500)
Resolution of All Revenue Issues	$88,027
Depreciation	(30,000)
Cash Working Capital	9
2011 Rate Increase	**$58,036**
2012 Step-in (including cash working capital)	$14,815
2012 Final Rate Increase	**$72,851**

62. The Department did not sign the Settlement but does not oppose it. The revenue requirement of $58.036 million in the Settlement is lower than the 2011 revenue requirement that the Department calculated to be just and reasonable ($81.793 million), and incorporates its proposed 10.37 percent ROE. The Department did not include a recalculation of depreciation. The Settlement amount for the 2012 step-in adjustment, $14.815 million, is close to the Department's recommended 2012 step-in adjustment, $14.779 million.

63. If the Settlement is not approved, the Department asserted that the Company has failed to meet its burden of proof and that the Department's calculations,

[26] Settlement at 3-4.
[27] Settlement at 4.
[28] This is the Company's revenue requirement calculated at the close of the June hearing, the starting point for the adjustments included in the Settlement.

as set forth in Exhibit 195, support the appropriate revenue requirement. This includes several cost items that were not addressed in the Settlement.

64. The OAG opposed the Settlement in its entirety. It asserted that the 2011 revenue requirement was too high, although it supported the depreciation mitigation, and it opposed the 2012 step-in adjustment.

65. The Settlement did not specifically address all of the disputed cost issues. If the Settlement is approved, the revenue requirement would be at the agreed upon levels for 2011 and 2012, fully resolving all issues related to the revenue requirement, including those that were not specifically addressed in the Settlement.

66. To evaluate whether the Settlement should be accepted, the findings of fact will address each term of the Settlement. Then, the disputed cost items that were not specifically addressed in the Settlement will be evaluated to determine the effect of excluding them from the Settlement.

67. The Settlement did not address most rate design issues, including the class cost of service study, revenue apportionment and customer charges. Those will be analyzed after the findings that address the Settlement.

Rate of Return

68. The concept of a fair rate of return (ROR) is, by definition, the rate which, when multiplied by the rate base, will give the utility a reasonable return on its total investment, including a return that is sufficient to enable the utility to attract capital to provide reasonable service to its customers.[29]

69. The ROR is based on a projected capital structure including debt and equity and, when applied to its rate base, is an amount that a utility can recover to meet the cost of interest on its debt, attract capital, maintain a desired equity position and pay a fair rate of return to its shareholders.

70. In the regulated utility industry, the regulatory agencies ensure that utilities provide an appropriate supply of satisfactory services at reasonable rates because, as a utility, its costs are not subject to a competitive environment. However, the utility must be able to compete in the capital markets and assure a sufficient return to investors to attract the capital required to provide services to its customers.[30]

71. A utility is not entitled to large profits but its return:

> should be reasonable, sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its

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[29] Minn. Stat. § 216.16, subd. 6; Ex. 143 at 3 (Amit Direct).
[30] *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 670 (1923).

credit and enable it to raise the money necessary for the proper discharge of its public duties.[31]

Return on Equity – 10.37 Percent[32]

72. The fair rate of return on equity is the utility's cost of equity capital. The following guidelines are commonly applied to determine the fair cost of common equity capital for a regulated electric utility:

- It is sufficient to enable the regulated company to maintain its credit rating and financial integrity;

- It is sufficient to enable the utility to attract capital;

- It is commensurate with returns earned on other investments having equivalent risks.[33]

73. The cost of equity capital to the Company is the rate of return that it must pay to investors to induce them to invest in its regulated operations.

74. The Company initially requested an ROE of 11.25 percent, but revised its request to 10.85 percent.[34]

75. The Department initially proposed an ROE of 10.53 percent, but updated its DCF analysis in Surrebuttal Testimony. With that revision, the Department recommended an ROE of 10.37 percent.[35] Based on its analysis, 10.37 percent was at the midpoint of a reasonable range of ROE, from 9.29 percent to 11.58 percent, and the Department recommended that the Commission adopt that midpoint.[36]

76. The Settlement adopts a 10.37 percent ROE. The Company's position is that the Settlement ROE of 10.37 percent is the "lowest reasonable" ROE based on the record in this case.

77. The OAG opposed the Settlement ROE because it included a factor for flotation costs, as discussed below. XLI proposed an ROE of 9.5 percent, but acceded to the Settlement.

78. One inducement for investors to invest in a company, including a utility, is the expectation of receiving a flow of future dividends. The Discounted Cash Flow (DCF) method, upon which both the Company and the Department based their ROE calculation, assumes that annual dividends grow at a constant rate over an infinite

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[31] *Id.*, at 693.
[32] Summary of Issues, No. 1; Settlement at C.1.
[33] *Bluefield Waterworks & Improvement Co., v. Public Serv. Comm'n of West Virginia, supra*, at 693; *Federal Power Comm'n v. Hope,* 320 U.S. 591, 603 (1944); *see also* Ex. 143 at 3 (Amit Direct).
[34] Ex. 41 at 34 (Reed Rebuttal).
[35] Ex. 145 at 2 (Amit Surrebuttal).
[36] Ex. 145 at 5 (Amit Surrebuttal).

period. Per this formula, the expected (required) rate of return on equity equals the expected dividend yield and the expected growth rate in dividends.[37]

79. The Company and the Department used two comparable groups of companies, one group of pure electric companies, and another group of combination gas and electric companies like the Company. Both the Company and the Department weighted the two comparable groups, assigning 60 percent weighting to the electric company comparables and 40 percent weighting to the combination company comparables.[38]

80. Generally, both the Company and Department used earnings projections and applied the constant growth DCF model (earnings per share growth),[39] although the Department made one modification, using a Two-Growth DCF model for one comparable company.[40]

81. The use of the Two-Growth DCF model for one comparable company reduced the Department's midpoint DCF results by 14 basis points from the Company's calculation.[41]

82. The Company and the Department calculated dividend yield differently. Since the Company used 30-day, 90-day and 180-day periods to calculate the dividend yields, and the Department used only a 30-day period, their calculated dividend yields differed. There were other differences in the application of the CAPM model and risk premium analysis.[42]

Flotation or Issuance Costs[43]

83. The Company and Department agreed that the DCF results should be adjusted to allow for the cost of issuing new shares of common stock (the issuance or flotation costs). Due to flotation costs, the price paid by an investor for a new share of common stock is higher than the price per share received by the company, and must be recognized by adjusting the required rate of return. To do so, the flotation costs are calculated and used to adjust the dividend yield of the comparable companies.[44]

84. The Company and the Department agreed that an adjustment is appropriate even if no new common stock issuances are planned in the near future because failure to allow the adjustment may deny the Company the opportunity to earn its required rate of return.[45] Although agreeing that a flotation adjustment was

[37] Ex. 143 at 4 (Amit Direct).
[38] Ex. 40 at 37 (Reed Direct); Ex. 145 at 5 (Amit Surrebuttal).
[39] Ex. 40 at 29-33 (Reed Direct).
[40] Ex. 143 at 26-29 (Amit Direct); Ex. 145 at 3-4 (Amit Surrebuttal).
[41] Ex. 143 at 26-30 (Amit Direct).
[42] Initial Post Hearing Brief of the Department of Commerce (Department's Initial Brief) at 15-39.
[43] Summary of Issues, No. 53.
[44] Ex. 143 at 30 (Amit Direct).
[45] Ex. 143 at 30 (Amit Direct).

appropriate, the Company and the Department took different approaches to determining it.

85. The Company recommended a flotation adjustment of 26 basis points, based on 5.281 percent cost of its public issuances.[46] It contended that it has very high capital needs relative to comparable companies that public issuances will be essential, and that non-public issuances will not provide sufficient equity.[47]

86. The Company also asserted that the ROE, including the flotation costs, takes on added importance at a time of heavy investment and affects the Company's ability to fund capital investment with internally generated funds, a substantial portion of the Company's investment funding.[48]

87. The Department's recommended flotation adjustment of 15 basis points was based on the 3.9133 percent blended cost of the Company's public issuances and non-public issuances.[49] The Company received common equity from non-public common equity issuances such as dividend reinvestment, employee stock ownership, other employee benefits, etc.[50] The costs of the non-publicly issued common stock are administrative costs which are expensed, not capitalized, by the Company. Therefore, the Department asserted that the non-public issuances of common equity must be included in the calculation of flotation costs for the Company, at zero costs. Based on its review of flotation costs for the period from 1949 through 2010, including both public issuances and non-public issuances, with the capitalized costs of those issuances, the Department determined that the flotation cost percentage was more accurately 3.1933 percent.[51]

88. In light of the Company's stated intent to fund a proportion of its capital investment with internally generated funds, the Department's recommended flotation cost, based on the Company's historical blend of public issuances and non-public issuances, is better supported.

OAG Objection to Flotation Costs

89. The OAG did not conduct its own analysis of an appropriate ROE; however, because it disagreed that any flotation costs should be included, its position was that an additional 15 basis points should be subtracted from the Department's calculated figure, for an ROE of 10.22 percent.[52]

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[46] Ex. 41 at 8-9 and Scheds. 1 and 4 (Reed Rebuttal).
[47] Ex. 41 at 9 (Reed Rebuttal).
[48] Ex. 38 at 12 (Tyson Direct).
[49] Ex. 143 at 23 or 32 (Amit Direct); Ex. 144 at 23 (Amit Rebuttal); Ex. 145 at 15-17 and Scheds. EA-SR-5 and EA-SR-8 (Amit Surrebuttal).
[50] These include Dividend Reinvestment Program (DRIP), and Employee Stock Ownership Plan (ESOP).
[51] Ex. 143 at 31-32 (Amit Direct).
[52] Initial Brief of the Antitrust and Utilities Division of the Office of the Attorney General (OAG Initial Brief) at 39-46; Reply Brief of the Office of the Attorney General (OAG Reply Brief) at 16-20.

90. The OAG compared 10.22 percent to the ROE issued in 44 electric cases in 2011, through December 8, 2011, which had a mean ROE of 10.18 percent and median ROE of 10.0 percent.[53]

91. The OAG argued that the Company relied upon an improper formula to calculate the flotation costs of its public issuances.[54] The Company conceded that its witness at hearing, Mr. Tyson, misstated the formula;[55] however, the Company demonstrated, and the Department concurred, that the revised schedules submitted by the Company's witness Mr. Reed were based on the correct formula.[56]

92. The OAG claimed that the costs of the 2010 stock issuance were overstated by $13 million. This assertion rested in part on the its claim concerning Mr. Tyson's misstatement, but also on its claim that the Company misapplied the formula to a 2010 stock issuance.[57] The Company provided evidence to support the unique features of the 2010 issuance that led to additional flotation costs.[58] The Department concurred that the Company correctly calculated the flotation costs for the public issuances.[59]

93. The OAG also objected to the flotation costs because of its concern that the Company included the costs of common stock issuances associated with the Company's merger with New Century Energy.[60]

94. The Company's Revised Response to OAG Information Request 214 (revised Apr. 21, 2011) showed that the issuance of common equity related to the merger was excluded from the calculation of flotation costs.[61]

95. The Commission previously awarded Interstate Power a ROE of 10.35 percent.[62] The ROE took into account the cost of non-public issuances, although in that case, IPL had relatively low capital requirements and reduced its capital needs by the sale of its transmission assets.[63]

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[53] OAG Reply Brief at 20.
[54] OAG Initial Brief at 42-45.
[55] Xcel Energy Reply Brief at 119-120.
[56] Xcel Energy Reply Brief at 119-120, Ex. 41 at Sched. 4, page 1 of 3 (Reed Rebuttal); Department's Reply Brief at 6-7.
[57] OAG Initial Brief at 42-43.
[58] Ex. 110; Ex. 137 at RLS–11 (Smith Direct).
[59] Ex. 143 at 30 and EA-31, Appendix C (Amit Direct); Department's Initial Brief at 20-23; Department's Reply Brief at 5-7.
[60] OAG Initial Brief at 45-46.
[61] Ex. 144 at 23 and Sched. EA-R-3(Amit Rebuttal); *see also* Ex. 137 at RLS-11 (Smith Direct).
[62] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-001/GR-10-296, Findings of Fact, Conclusions, and Order at 10 (August 12, 2011).
[63] Xcel Energy Reply Brief at 10.

XLI's Proposed ROE

96. XLI proposed an ROE of 9.50 percent.[64] Both the Company and the Department disagreed with XLI's calculation of a 9.50 percent ROE because of the methodology the XLI witness employed.[65]

97. Post-hearing, as part of the Settlement, XLI acceded to the Department's proposed ROE of 10.37 percent, stating that it was "supported by the Department's detailed and extensive testimony."[66]

Conclusion

98. The Company acknowledged that its approach to calculation of the ROE and the Department's approach were quite similar. Although the Company restated its position that an ROE up to 10.85 percent would be reasonable, it also stated that the record supported the Department's recommendation of 10.37 percent, "the floor for a reasonable ROE in this case."[67]

99. Based on the evidence in the record taken as a whole, the ROE of 10.37 percent incorporated into the Settlement is fair and reasonable.

Capital Structure, Cost of Debt, and Overall Rate of Return[68]

100. The Company and the Department agreed upon an appropriate structure prior to the close of the evidentiary hearing. The Settlement incorporated that capital structure.[69]

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.88	6.09	2.85
Short-Term Debt	0.56	2.43	0.01
Common Equity	52.56	10.37	5.45
Total	**100.00%**		**8.31%**

[64] Ex. 125 at 30 (O'Donnell Direct).
[65] Ex. 144 at 1- 12 (Amit Rebuttal); Ex. 41 at 14-24 (Reed Rebuttal).
[66] Post-Hearing Brief of the Xcel Large Industrials at 5.
[67] Xcel Energy Reply Brief at 11, 13 (support for the Department's "midpoint," which is 10.35 percent).
[68] Summary of Issues, No. 52(Capital Structure), No. 54 (Cost of Long-term Debt) and No. 55 (Cost of Short-term Debt).
[69] Department's Initial Brief at 42, 49; Ex. 145 at 10-12 (Amit Surrebuttal); *see also* Ex. 39 at 3-4 (Tyson Rebuttal).

101. The Department evaluated each aspect of the capital structure and determined that the capital structure was reasonable, as compared to the companies in the Company's comparison group.[70]

Calculation of Short-Term Debt[71]

102. The OAG challenged the Company's method of calculating short-term debt balances, which is to use the debt at the end of the month. As an example, OAG stated that the Company's end-of month-snapshot for December 2010 shows no short-term debt, but from December 2 through December 15, the Company had outstanding commercial paper up to $47 million. The OAG also pointed out that the Company's witness, Mr. Tyson, stated that increases in short-term debt occur around the 25th of the month, but the end-of-month increase is not always reflected in the Company's end-of-month balance. The OAG argued that, since short-term debt is the lowest cost form of capital, by understating the amount of short-term debt in the capital structure, the Company proposed to recover a higher return on capital than it actually incurs.[72]

103. The OAG asserted that the short-term debt should be calculated on the basis of the average daily balance for each month, or maximum monthly short-term debt balance, rather than the end-of-month balance and requested that the Company be compelled to do so in its next rate filing.[73]

104. The Department disagreed in part with the OAG's argument that the Company should have calculated short-term debt balances by using average daily balances rather than end-of-the-month balances.[74] Rather, the Department agreed that for a <u>forecasted</u> period, it is typical to use end-of-month rather than average daily balances as the Company did, but the Department agreed that the average daily balance should be used to calculate <u>actual</u> costs of short-term debt.[75]

105. The Company provided updated information for its short-term debt through August 31, 2011, which showed a decrease in the balance and percentage of short-term debt. The Company did not propose to increase the percentage of common equity to reflect the updated information, but offered the information in support of the reasonableness of its short-term debt calculation.[76]

106. The Company has not agreed to use average daily balances rather than end-of-month balances in its forecasting, but has agreed to follow the "common practice" of updating with the actual daily balances as that information becomes available.[77]

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[70] Department's Initial Brief at 42-45.
[71] Summary of Issues, No. 55.
[72] OAG Initial Brief at 26-27; Ex. 137 at 12-13 (Smith Direct).
[73] OAG Initial Brief at 27-28.
[74] Ex. 144 at 23 (Amit Rebuttal).
[75] Ex. 144 at 24 (Amit Rebuttal); Department's Initial Brief at 46.
[76] Xcel Energy Reply Brief at 108, and Attach. A.
[77] Xcel Energy Reply Brief at 109.

107. Initially, XLI proposed a cost of 0.88 percent for short-term debt,[78] but is a party to the Settlement and did not provide support for that position or pursue it post-hearing.

108. The OAG criticized the Company's use of the NSP Credit Facility and Utility Money Pool as sources of short-term financing.[79] It did not propose a different cost of short-term debt.

Cost of NSP's Credit Facility

109. The Company has a credit facility to provide a backup source of short-term borrowing if the Company is unable to issue commercial paper or borrow from other sources such as the Company's Utility Money Pool (an intercompany borrowing facility between Xcel Energy's operating companies, discussed below). Prior to March 2011, the Company and NSP-Wisconsin had a combined credit facility, but that agreement expired.[80] As of March 2011, NSP-Minnesota and NSP-Wisconsin each have a new, separate revolving credit agreement, so that each pays the full cost of its own revolving credit facility.[81]

110. With this new credit agreement, the Company has increased its available credit facility capacity from $400 million to $500 million because of its anticipated need for short-term borrowing in the coming years. There are four factors contributing to the Company's liquidity requirements:

> (1) the total capital commitments over the life of the revolving credit agreement, including total projected capital investment and scheduled long-term debt maturities;
>
> (2) liquidity required to manage variability in operating cash flow due to changes in sales and operating expenses;
>
> (3) borrowing capacity credit facility size relative to the scale of the enterprise as determined by its total capitalization; and
>
> (4) the projected level and volatility of natural gas purchase requirements for both generation fuel and local natural gas distribution requirements.

The Company has $6.5 billion of projected capital investment and scheduled long-term debt maturities for 2011–2015, after cancellation of the Merricourt Wind Project, including a $450 million bond maturing in 2012.[82] The Company's costs for its Credit Facility include upfront fees and a fixed monthly charge.

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[78] Ex. 125 at 24 (O'Donnell Direct).
[79] Summary of Issues, No. 55.
[80] Ex. 39 at 13-14 (Tyson Rebuttal).
[81] Tr. Vol. 2 at 25-26 (Tyson).
[82] Ex. 39 at 12-13 (Tyson Rebuttal).

111. OAG criticized both the size of the credit facility and its increased costs. The Company fully explained its need for greater access to short-term credit and its creation of a credit facility separate from its former joint facility with NSP-Wisconsin. The Department analyzed the increase in the size of the credit facility and determined that the increase was well-supported by the Company's need to assure access to future short-term loans at a time when the Company projects a significant increase in future short-term debt.[83] Also, the fixed costs of the Company's credit facility are incorporated into the 2.06 percent cost of short debt that the Department has determined is reasonable.[84]

Utility Money Pool

112. NSP-Minnesota also has access to the Utility Money Pool, an inter-company revolving credit facility that allows the Xcel Energy operating subsidiaries, including NSP-Minnesota, Public Service Company of Colorado, and Southwestern Service Company, access to short-term cash and working capital. The level of funding available through the Utility Money Pool is subject to both FERC- and state-approved limits and is dependent on the level of voluntary lending to the pool by each of the participating utilities. The operating subsidiaries are not required to access the Utility Money Pool but it is available when it provides a lower cost of borrowing, a better return on short-term investment or greater borrowing flexibility.[85]

113. The Utility Money Pool does not provide the assurance of available cash that the Company's committed credit facility provides; it is a secondary source of liquidity.[86] Loans are provided on a demand basis and may be called at any time. The Company's credit facility is its primary source of liquidity; the Money Pool is a method to optimize use of cash that may otherwise be idle by providing it short-term to one of the other affiliated companies as an unsecured overnight loan.[87]

114. OAG raised concerns about the Company's participation in the Utility Money Pool, the extent of its potential liability for the unsecured loans, and the costs of borrowing from its credit facility to lend to a participant in the Utility Money Pool. It did not recommend that the Commission should end the Company's participation, but rather stated that the Company had not demonstrated that participation in the Utility Money Pool was in the public interest.[88]

115. The Department agreed with the Company that the use of the Utility Money Pool is reasonable, primarily because the Company has demonstrated that it can borrow short-term from the Utility Money Pool at a rate below market. Also, the Company's test-year debt does not include any money pool loan and therefore has no impact on the test-year costs of short-term debt. The Department pointed out that the

[83] Ex. 144 at 21-22 (Amit Rebuttal); Ex. 145 at 9 (Amit Surrebuttal).
[84] Ex. 143 at 50-51 (Amit Direct).
[85] Ex. 38 at 4-5 (Tyson Direct); Tr. Vol. 2 at 26, 47-49 (Tyson).
[86] Tr. Vol. 2 at 26 (Tyson).
[87] Tr. Vol. 2 at 49-51 (Tyson).
[88] OAG Initial Brief at 32-35.

Company is required to make regular filings with the Commission about its Utility Money Pool activities, including monthly borrowing, lending and interest rates.[89]

116. Since OAG did not recommend any specific change to the Company's costs of short-term debt, and the overall costs of short-term debt are reasonable, there is no basis to adjust the capital structure set forth in the Settlement Agreement.

Conclusion

117. Based on the evidence in the record taken as a whole, the capital structure incorporated into the Settlement, with a resulting 8.31 percent rate of return is fair and reasonable.

Monticello Life Cycle Management/Extended Power Uprate (LCM/EPU) Project[90]

118. The life cycle management activities include capital investments needed to keep Monticello operating safely and reliably for an additional 20 years. The extended power uprate work includes the capital investments needed to add an additional 71 MW of generating capacity. Much of the investment supports both projects.[91]

119. The Settlement included recovery of $11.549 million in costs for the portions of the Monticello LCM/EPU project that were placed in service in 2011.[92] This is a reduction of approximately $1.1 million associated with the Fall 2011 outage, which was cancelled due to delay in the Nuclear Regulatory Commission (NRC) EPU license amendment. The 2011 revenue requirement is based on June 2011 ending balances of in-service project costs being placed into Plant in Service, with the other expenditures reflected in Construction Work In Progress for the remainder of 2011 at the June level.[93] The investment included in Plant in Service is being used to generate electricity. Although the EPU portion of the project has not yet been licensed, the Company asserted that the two purposes are so intertwined that the work cannot be tracked separately. In some circumstances, equipment has been sized larger to accommodate the EPU.[94]

120. The settlement amount excludes: (1) all costs budgeted for the previously scheduled Fall 2011 outage; (2) $45 million for the expected NRC license amendment fees; and (3) all 2012 costs. The 2012 Step-In Adjustment will be addressed separately.

121. The Department and Chamber of Commerce initially questioned the 2011 costs. The Department was concerned because the level of expense presented in the rate case exceeded the costs identified by the Company when it applied for the

[89] Department's Reply Brief at 9-11.
[90] Summary of Issues, No. 41 (Monticello LCM/EPU); Settlement at C.2.
[91] Ex. 18 at 29-30 (Koehl Direct); Ex. 20 at 12-14 (Koehl Rebuttal).
[92] Ex. 185 at 3 (Ostberg Post-Hearing Supp.).
[93] Ex. 185 at 2-3 (Ostberg Post-Hearing Supp.).
[94] Ex. 20 at 14 (Koehl Rebuttal); Tr. Vol. 7 at 22-29.

certificate of need for the uprate. Although the Company has not spent more than its total project estimate to date, it anticipates that the total cost will exceed the estimates included in its application for the certificate of need.[95]

122. The Company asserted that the LCM/EPU cost increases were largely the result of unforeseen added planning, engineering and installation costs. Although the estimated cost of the equipment and removal was largely accurate, some of the installation costs were not accurately estimated because the new equipment required new configurations and controls to be installed in an existing plant. Each change was carefully reviewed to assure that it did not affect safety.[96]

123. The Department also questioned which of the costs were properly expensed and which should have been capitalized. In light of the Company's increased nuclear outage costs, the Department acceded to the Company's figures in this rate case, but restated its position that refurbishing costs should generally be capitalized.[97]

124. At hearing, the Chamber of Commerce objected to including the costs associated with the EPU before the NRC and Midwest Independent System Operator (MISO) gave approval to operate at the higher rating, and supported a compliance filing.[98] The Settlement addressed the Chamber's concerns.[99]

125. The Company has agreed to provide a compliance filing within a reasonable period of time after the project is complete, outlining the total costs for the project and the additional capacity achieved, to submit to a full prudence review of the entire project, and to refund any costs deemed imprudent.[100] For this purpose, in the Settlement, the Company waived any claim that such a decision would be retroactive ratemaking.[101]

Conclusion

126. Based on the evidence in the record as a whole, the Settlement's resolution of the 2011 costs of the Monticello LCM/EPU is reasonable.

State Energy Policy (SEP) Rider[102]

127. In developing its Test Year, the Company made adjustments for investments and costs related to several riders, which allow for cost recovery outside of the rates.[103] The SEP Rider allows the Company to recover costs related to legislative

[95] Ex. 20 at 14-16 (Koehl Rebuttal); Ex. 96 (Response to OES IR 1194); Tr. Vol. 7 at 16 (Koehl) and 55 (Ostberg).
[96] Tr. Vol. 7 at 17-18 (Koehl).
[97] Ex. 171 at 12-15 (Campbell Surrebuttal).
[98] Ex. 120 at 6-9 (Schedin Direct); Ex. 121 at 5-7 (Schedin Surrebuttal).
[99] Ex. 121 at 6-8 (Schedin Surrebuttal).
[100] Summary of Issues, No. 41; Tr. Vol. 4 at 113 (Ostberg).
[101] Settlement at C.2.
[102] Summary of Issues, No. 64; Settlement at C.3.
[103] Ex. 70 at 90 (Heuer Direct).

mandates, including: (a) annual payments to the Prairie Island Indian Tribe; (b) the Company's portion of the cost of Minnesota's Reliability Administrator; (c) costs related to State Building Guidelines; and (d) wind integration study costs.[104]

128. In its Direct Testimony, the Company proposed moving approximately $2.442 million from the SEP Rider to base rates.[105] The Department recommended the costs continue to be recovered through the rider rather than incorporated into base rates because some of the components of the SEP may expire in 2012 and 2013, and because of possible double recovery.[106] In its Rebuttal Testimony, the Company stated that, in light of the Department's objection, it was largely "indifferent" to whether the SEP Rider continued.[107]

129. In the Settlement, the Company agreed to continue the SEP Rider. Because the Company recovered these costs during 2011 through the SEP Rider, it was not included in the test year or in the interim rate calculation. Thus, this agreement continues the status quo.[108]

130. Other riders, or portions of riders, will be included in the base rate revenue requirement and the final rates. These include the Environmental Improvement Rider (EIR); Transmission Cost Recovery (TCR) Rider; Mercury Control Rider (MCR); and Renewable Energy Standards (RES) Rider.[109] There was no disagreement concerning the incorporation of these riders into rates.

Conclusion

131. The Settlement's resolution of the treatment for the SEP Rider and the incorporation of the other identified riders into rates is reasonable.

Compensation[110]

132. In this proceeding, the parties challenged a number of the Company's compensation expenses. Some disputes were resolved prior to the close of the evidentiary hearing, but many others were not. The Settlement addressed the remaining compensation issues as a group, reducing the Company's total compensation request by $7.5 million, without allocating the reduction to specific issues.

133. In its initial filing, the Company's 2011 Test Year included an increase of $41 million for compensation. In its Notice and Order for Hearing, the Commission directed the ALJ to evaluate the Company's salary and benefits history for the past three years.

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[104] Ex. 70 at 106 (Heuer Direct).
[105] Ex. 70 at 104 (Heuer Direct).
[106] Ex. 147 at 23-25 (Peirce Direct).
[107] Ex. 73 at 19-20 (Heuer Rebuttal).
[108] Settlement Agreement at 4.
[109] Ex. 70 at 90 (Heuer Direct).
[110] Settlement at C.4.

134. Total employee compensation has risen since 2009 to the adjusted 2011 Test Year. Cash compensation costs have risen by an average 2.73 percent per year (from $303.4 million to $320.2 million), and total non-cash compensation costs have risen by an average of 8.87 percent per year (from $55.5 million to $65.8 million), which is entirely attributable to increased pension costs. With the exception of pension costs, employee benefits costs have declined slightly since 2009 (from $53.809 million to $53.780 million).[111]

135. There were many aspects of compensation that were analyzed in the course of the proceeding, and the Company agreed to reductions to compensation, totaling $6.532 million. These included the following:

- Reduction in bargaining unit base salaries - $524,094;
- Reduction in incentive compensation plan coverage - $578,000;
- Lower percentage cap for incentive compensation to be recovered in rates - $985,000;
- Increase in the pension discount rate - $673,000;
- Medical plan changes - $3,772,000.

136. In the Settlement, the Company agreed to reduce compensation expenses by an additional $7.5 million (a total reduction of more than $14 million from its initial request for compensation expenses), but it did not allocate the reductions to any specific budget item. Rather, in an effort to respond to the overall concerns of the parties about the level of compensation increase included in the rate request, it agreed to reduce the total included for compensation by a lump sum to resolve the remaining issues, which include base compensation; the annual incentive plan; pension and retirement plans (qualified and unqualified); other retirement and post-employment benefit expenses and account balances; and healthcare costs.

137. If the Settlement is approved, the increase in compensation expenses in the 2011 Test Year would be about $27 million. It the Settlement is not approved, the Company seeks a proposed increase for compensation of about $34.5 million.

138. Because the Settlement did not allocate the $7.5 million among the remaining disputed compensation issues, one must evaluate its reasonableness first by examining the parties' arguments concerning each component of the compensation and then by combining the results for all the components. The Department's and OAG's objections to each compensation component are analyzed below. Then, the conclusions on each component are summarized to compare the result with the $7.5 million reduction in compensation expense that is included in the Settlement.

[111] Ex. 43 at 49, Table 4 (Moeller Rebuttal).

Cash Compensation Increases[112]

139. The Company included salary increases of 2.75 percent in 2010 and 2.50 percent in 2011 in its Test Year expenses. Rather than relying on inflation alone, the Company's estimate includes: (1) review of external market surveys for base salary increases; (2) comparison of increase in base salary for bargaining and non-bargaining employees; (3) economic conditions; and (4) Company performance.[113]

140. Salary or cash compensation, as discussed here, has two components: base salary and Annual Incentive Payments (AIP).

141. The Department and the OAG challenged the Company's cash compensation. Each one offered different data to support their proposed level of total compensation to be included in Test Year expenses. The Department's approach was to reduce the base salaries by a specified percentage while the OAG recommended eliminating the total amount budgeted for Annual Incentive Payments (AIP). Both the Department and the OAG asserted that the Company's market surveys overstated the Company's reasonable level of cash compensation.

142. The Company's stated goal of its compensation program is "to attract, retain and engage talented employees, which results in the business delivering safe, reliable, low-cost service to our customers."[114] To that end, it relies upon market survey data to ensure that its compensation levels are comparable with its competitors.[115]

143. Total compensation has several components, including base salary, incentive pay and benefits. The market survey data used by the Company compares cash compensation but does not include benefits.[116] AIP is considered an important part of the Company's cash compensation and it is considered part of "base salary" or cash compensation reported in the market surveys.[117]

144. The Company offered evidence from five independent base salary surveys, showing a range of projected 2011 salary increases:

2.8 – 3.0 percent for all companies on a national basis;

3.0 – 3.1 percent for all utilities on a national basis;

2.6 - 3.0 percent for the Minneapolis area.

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[112] Summary of Issues, No. 3 (base salaries, non-bargaining employees), No. 78 (Annual Incentive Plan), No. 60 (Job Evaluation).
[113] Ex. 51 at 19 (Figoli Rebuttal).
[114] Ex. 47 at 1 (Figoli Supp. Direct).
[115] Ex. 47 at 1 (Figoli Supp. Direct).
[116] The Company conceded that the market surveys look at cash compensation and not at total compensation including benefits. Tr. Vol. 3 at 92-93, 97-99, 103 (Figoli).
[117] Ex. 47 at 4 (Figoli Supp. Direct).

The figures were about 0.5 percent lower for 2010. The combined increases for the two years were:

5.1 – 5.6 percent for all companies on a national basis;

5.4 – 6.3 percent for all utilities on a national basis;

4.9 – 5.5 percent for the Minneapolis area.[118]

The Company asserted that its proposal to increase salaries by 5.25 percent for 2010-2011 is neither excessive nor unreasonable because it is below the bottom of the national range for utilities, below the midpoint of the national range for all companies, and close to the midpoint of the local range.[119]

145. In its initial rate filing, the Company included 2011 AIP costs of $19,901,861, an increase of $6.3 million above the $13.6 million approved in its last electric rate case. Approximately $2.75 million of the increase was related to a larger number of employees and higher base salaries. The remainder was driven by the change of targets for incentive compensation, updated based upon a four-year average.[120] Long-term incentive costs for executive employees (approximately $5.9 million) were removed from the Test Year expenses.[121]

146. However, as summarized above, the Company agreed to some reduction in compensation during the proceeding. It reduced AIP by $578,000 because of Company changes to the AIP available to non-exempt employees.[122] It agreed to lower the cap on AIP as a percentage of base pay from 25 percent to 15 percent, reducing the level of AIP included in Test Year expense by $985,000.[123] It also agreed to reduce base salaries for bargaining unit employees, a reduction of $524,000.[124]

The Department's Position

147. Even with the Company's reductions, Department contended that the salary increases for non-bargaining unit employees were still too high. It questioned the validity of the Company's studies. Because the Company used a forecasted Test Year, the studies were based on forecasted salary and compensation for 2011, rather than actual payouts. What companies projected they would pay, particularly in incentives, could overstate the amounts actually paid. As an example, the Department pointed to the discrepancy between the Company's 2008 forecasted AIP, which was much greater than the amount of AIP actually paid out in 2009.[125]

[118] Ex. 51 at 22-23 (Figoli Rebuttal); Xcel Energy Reply Brief at 26.
[119] Ex. 51 at 23 (Figoli Rebuttal); Xcel Energy Reply Brief at 26.
[120] Ex. 46 at 8-9 and Sched. DAF-1 (Figoli Direct).
[121] Ex. 46 at 9 (Figoli Direct).
[122] Xcel Energy Brief in Support of Settlement at 25; Summary of Issues, No. 29.
[123] Xcel Energy Brief in Support of Settlement at 25; Summary of Issues, No. 43.
[124] Xcel Energy Reply Brief at 23; Department's Initial Brief at 56; Summary of Issues, No. 45.
[125] Ex. 178 at 43-44 (Lusti Direct).

148. The Department based its analysis on Global Insight data that it believed more accurately and fairly represented salary increases for the year. Global Insight data is an independent source of labor-related inflation forecasts. The Department recommended reducing the non-bargaining unit salaries, decreasing Test Year expenses by $1,856,330 and Test Year rate base $308,071, to bring the salary increases in line with Global Insight labor cost increases of 1.80 and 1.86 percent for 2010 and 2011.[126] The Department's witness focused not on the actual increase that the Company could or would award, but rather on the reasonable level of increase that the ratepayers should bear.[127]

149. The Company contended that reliance solely on the Global Insight inflation rate was inappropriate because the Company's salary increases reflect both cost of living increases and merit increases earned through AIP.[128] Increases based upon inflation alone would not be sufficient for the Company to compete for employees.[129] The Company conceded that it uses Global Insight inflation factors as a proxy for inflation in its five-year budgets, but it uses market surveys rather than inflation to determine salary increases.[130]

150. The Department acceded to the 15 percent cap on AIP because it provides incentives for the Company employees without placing an undue burden on ratepayers. Nonetheless, its witness acknowledged that most ratepayers would conclude that no AIP is reasonable because few of them are eligible to receive performance bonuses in their own jobs.[131]

The OAG's Position

151. The OAG, like the Department, asserted that the Company's total cash compensation was too high. It focused on the AIP, which it contended was still too high and should be entirely eliminated. The 2011 Test Year expenses include $19.0 million as the AIP component of cash compensation.[132]

152. The Company's AIP is paid for performance on three sets of goals: corporate, business unit and individual performance. However, an earnings-per-share threshold must be met before any AIP is paid.[133]

153. Like the Department, the OAG believed that the market surveys overstated reasonable compensation levels, and that elimination of the AIP would bring the total cash compensation into better alignment with reasonable costs. The OAG used Bureau of Labor Statistics (BLS) data as a reference point for compensation comparisons. BLS data showed that total compensation increased 1.4 percent in 2009

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[126] Ex. 195 at DVL-U-7, column (c) (Lusti Update); Department's Initial Brief at 56.
[127] Ex. 179 at 12-13 (Lusti Surrebuttal).
[128] Ex. 51 at 19 (Figoli Rebuttal).
[129] Ex. 51 at 21-23 (Figoli Rebuttal); Xcel Energy Reply Brief at 24.
[130] Ex. 51 at 20 (Figoli Rebuttal).
[131] Ex. 179 at 15 (Lusti Surrebuttal).
[132] Tr. Vol. 1 at 26 (Poferl); Summary of Issues, No. 43.
[133] Tr. Vol. 3 at 45 (Figoli).

and 2.00 percent in 2010, and BLS cash compensation increased 1.5 percent in 2009 and 1.6 percent in 2010.[134]

154. Based on the BLS reports, the OAG asserted that the Company should further reduce its compensation below the level set forth in the Settlement by an additional $7.1 million, a total of $21.2 million below the $41 million in the Company's initial filing, and the level of reduction that the OAG had initially proposed.[135]

155. The OAG asserted that Company's total compensation costs increased by 10.15 percent between the 2009 and 2011 rate cases, including a 6.95 percent increase in cash compensation costs and a 28.92 percent increase in non-cash compensation costs.[136] The Company disputed the comparisons upon which the OAG relied. It contended that total cash compensation paid to its employees increased by 2.73 percent per year and total compensation costs increased by 3.70 percent per year; if qualified pension costs were excluded, its total compensation costs increased by 2.32 percent per year.[137] The increase in pension costs is more fully discussed below.

156. The Company's response to the OAG echoed its response to the Department: its workforce is not comparable to the U.S. workforce as a whole, and the proper comparison is not with BLS data but with the market of comparable companies with whom it must compete to attract and retain employees. The total compensation, rather than AIP alone, is the appropriate focus for comparison, and based on the appropriate comparison, its total compensation was competitive with the relevant market.[138]

157. The OAG also objected because no AIP is paid unless corporate earnings per share hit certain targets, which benefits shareholders and not ratepayers.[139] Moreover, virtually all business units are rewarded for "truly exceptional performance." The Company's business unit goals are sometimes referred to as Key Performance Indicators (KPI). A threshold level of performance is expected to earn a portion of the incentive, with greater performance to hit the target and truly exceptional performance to exceed that level. As the OAG pointed out, for 2010, the last available figures, one business unit was awarded 99.87 percent of the target bonuses; all others exceeded 100 percent, ranging up to 135 percent.[140]

[134] Ex. 137 at RLS-36 (Smith Direct). As compared to all civilian workers, private industry figures varied slightly; 2.1 percent in 2010 and 1.2 percent in 2009. *See also* Ex. 140 at RLS-12 (Smith Surrebuttal) (increase in total compensation for average workers remains at 2.0 percent per year through first quarter of 2011).
[135] OAG Reply Brief at 14.
[136] Ex. 140, Sched. RLS-10, Attach. A (Smith Surrebuttal) (NSP Response to OAG IR 299).
[137] Ex. 43 at 49, Table 4 (Moeller Rebuttal).
[138] Ex. 51 at 32 (Figoli Rebuttal); Xcel Energy Reply Brief at 151-153.
[139] Ex. 51 at 33 (Figoli Rebuttal); Tr. Vol. 3 at 45 (Figoli). The OAG also criticized one of the business goals - to achieve success in rate cases, citing Ex. 140, Sched. RLS-16 (Smith Surrebuttal). However, that misrepresents the KPI, which more broadly addresses oversight of rate proceedings.
[140] OAG Initial Brief at 79, summarizing Ex. 103, Attach. B.

158. The Company contended that incentive pay better serves the ratepayers than a merit increase. The merit increase is added to base salary and becomes part of the Company's fixed costs; the incentive pay must be re-earned each year, based on performance. If excellent performance does not continue, the incentive pay will be reduced or eliminated. The Company contended that this approach has slowed base-pay growth and allows it to meet its compensation goals at lower cost.[141]

159. The Company also stressed that it has agreed to limit the level of AIP included in Test Year expenses to 15 percent of base salary, which assures that the ratepayers are not paying more for compensation than is reasonable. Also, any AIP that is not earned by employees (hence, not expended by the Company) will be returned to ratepayers, as part of a refund mechanism that has been in operation for several years.[142]

160. The OAG emphasized that many members of the public spoke against what they perceived as excess compensation paid to the Company executives.

161. Total executive compensation includes both AIP and long-term incentives.[143] Excluding the long-term incentives and placing a cap on the percentage of salary that can be awarded as AIP are consistent with the OAG's goal of placing a portion of the executive compensation on the shareholders rather than the ratepayers.

162. In determining appropriate compensation levels, the Commission looks at whether the compensation for key management employees is excessive, inconsistent with industry norms, or misaligned with ratepayer interest, and allows the company to structure the compensation packages in accord with its best business judgment. The Commission will also look at how the amounts compare with the compensation approved in the prior rate case.[144]

163. It is acceptable to link compensation of key personnel to the Company's performance, but the total compensation must be reasonable and aligned with ratepayer interests.

XLI's Position

164. XLI recommended a disallowance of $6.3 million to exclude the portion of the AIP related to achievement of corporate financial goals, such as meeting target

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[141] Ex. 51 at 30-31 (Figoli Rebuttal).
[142] Xcel Energy Reply Brief at 151.
[143] Ex. 46 at 9 (Figoli Direct).
[144] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E015/GR-09-1151, Findings of Fact, Conclusion of Law, and Order (Nov. 2, 2010) at 29.

earnings-per-share.[145] XLI's view was that this portion of the incentive plan solely benefits shareholders and not ratepayers.[146]

165. The Company contended that its financial performance affects the cost of debt and equity needed to fund investment in the capital assets required to provide reliable service. Strong financial performance, including both prudent cost management and earnings for shareholders, will help the company finance its investments at low cost.[147]

166. XLI accepted the Company's $7.5 reduction in total compensation to resolve this issue.

Conclusion – Cash Compensation

167. It is reasonable to consider both base salary and AIP in determining the reasonableness of the Company's cash compensation. The market studies upon which the Company relied may overstate reasonable compensation, but the broad market data upon which the Department and the OAG relied may understate the wage increases that the Company must pay to attract and retain skilled workers. The Company's approach to allocating cash compensation between base salaries and AIP is a reasonable business decision. The Company has agreed that it will refund to ratepayers any AIP that is not awarded to its employees.

168. By placing a cap of 15 percent on AIP and removing long-term incentives from its request, the Company has reduced the requested cash compensation to a level that is fair and reasonable. In evaluating the reduction to compensation in the Settlement, no further reduction for cash compensation should be considered.

Pension and Retirement Plans[148]

169. The Company's 2011 Test Year, as originally filed, included a 26.6 percent increase in employee benefits, including pension, health care and other benefits, as compared to 2010 actual costs.[149]

170. The Company revised its initial rate filing to reflect a change in the XES discount rate from 5.25 percent to 5.50 percent, with a corresponding reduction to qualified O&M pension expense and a related downward adjustment to qualified capitalized pension.[150] Other pension and retirement issues remained in dispute.

[145] XLI acknowledged that its proposed disallowance might decrease in light of the Company's agreement to lower the included AIP to 15 percent of compensation. Tr. Vol. 5 at 68-70 (Pollock).
[146] Ex. 124 at 6, 33-39 (Pollock Direct).
[147] Ex. 51 at 33-34 (Figoli Rebuttal).
[148] Summary of Issues, No. 2 (Pension Expense); No. 5 (Non-Qualified Pension Costs); No. 56 (FAS 106 O&M).
[149] Ex. 161 at 30-33 (Campbell Direct).
[150] Ex. 195 at DVL-U-7, column (v) and DVL-U-4, column (j) (Lusti Update).

171. The O&M Minnesota jurisdictional amounts for qualified and nonqualified pension expense for 2008 to 2011 are:[151]

	2008	2009	2010	2011 Test Year	2011 Update
Qualified	($359,646)	$1,738,335	$7,599,084	$12,727,136	$12,054,318
Non-Qualified	$1,527,388	$1,310,423	$1,365,191	$1,282,463	$1,353,463

172. For 2008-2010, the amounts reflect the actual pension expense incurred by the Company, while the 2011 amounts are projected. From 2010 to the 2011 updated figure, pension costs for qualified employees increase 58.63 percent; pension costs for non-qualified employees drop by 0.86 percent.

173. Using its proposed discount rate and lower wage increase assumption, the Department proposed an overall decrease of $6,031,718 for O&M expense and $1,140,039 reduction to rate base.[152]

Qualified Pension Expense[153]

174. The Company asserted that its pension programs are an important component of total compensation and contribute to workforce stability. The Company has two qualified pension plans that that apply to this rate request: one for NSP-Minnesota employees (NSP-M Plan): and one for its Xcel Energy employees (XES Plan). Although technically part of the same plan, the expenses, assets and liabilities are determined separately for each group of employees.[154] The NSP-M Plan pension costs are determined under the Aggregated Costs Method, while the pension costs for the XES Plan are determined under the FAS 87 method.[155]

175. Pension costs reflect the current costs of retirement obligations that will be paid in the future and are based on actuarial determinations that include: (1) the expected level of future obligations to retirees; (2) the current costs of paying those obligations; (3) earnings from pension assets; and (4) the gains and losses on pension assets.[156]

176. The Test-Year pension expense for the NSP-M Plan and XES Plan in the Company's initial rate filing totaled approximately $14.6 million compared to $1.7 million

[151] Ex. 161 at 39 and NAC-9 (Campbell Direct).
[152] Ex. 195 at DVL-U-7, column (w) and DVL-U-4, column (k) (Lusti Update).
[153] Summary of Issues, No. 2 and No. 17.
[154] Ex. 42 at 2 (Moeller Direct).
[155] Ex. 42 at 11 (Moeller Direct). The Settlement includes an agreement to use the Aggregate Cost Method for the NSP-M pension plan.
[156] Ex. 43 at 7 (Moeller Rebuttal).

in 2009.[157] During the proceeding, it reduced its discount rate for the XES Plan and reduced its proposed recovery to $12.054 million.[158]

177. The Company's 2011 updated costs are based on an assumed wage increase of 4.0 percent (incorporating expected inflation, merit increase, and promotions over the employee's career); and a discount rate of 5.50 percent for the XES pension plan and 8.00 percent for the NSP-M pension plan.[159]

178. In years past, earnings on the pension assets have helped keep costs included in rates low, but the Company's increased pension costs in this case reflect the 2008 market decline in pension plan assets.[160] The decrease in asset values led to higher amortization of asset losses being phased in between 2009 and 2013, shrinking the asset base and lowering the returns. In addition, for the XES Plan, the discount rate used to develop the 2011 Test Year decreased. The lower discount rate contributed to a higher level of pension expense for the XES Plan.[161] Pa ssage of the Pension Protection Act requires that the Company restore its pension fund losses over a relatively short time period.[162]

179. The Department contended that the Company's pension figures were based upon an unreasonably low discount rate, an unreasonably high wage-increase assumption, no employee contribution and lack of independence between the Company and its actuary.[163] The Department would moderate the effects of the 2008 market drop, using an average level of discount rates over the past three years of 8.416 percent for NSP-Minnesota and 6.333 percent for XES. It would also use a two percent wage increase assumption. The lower wage increase and higher discount rate would result in an overall decrease of $6,031,718 for O&M pension expense and a $1,140,039 reduction to rate base.[164]

180. The Department asserted that its projected costs are based on reasonable and conservative assumptions and reflect the likely and reasonable expense going forward until the Company's next rate case.[165] It did not further reduce the projected

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[157] Ex. 42 at 3, 13 (Moeller Direct); Ex. 43 at 4 (Moeller Rebuttal).
[158] Ex. 43 at 50 (Moeller Rebuttal). *See* Ex. 171 at 27-28 (Campbell Surrebuttal); Summary of Issues, No. 17.
[159] Ex. 43 at 9 (Moeller Rebuttal).
[160] This is the company's first electric rate case with any pension expense arising out of the NSP-M Plan since 1992; in its most recent rate case, approximately $2 million for the XES Plan was included in rates. *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-08-1065, Order at (Oct. 23, 2009) (*2008 Electric Rate Case);* Ex. 42 at 4 (Moeller Direct).
[161] Ex. 42 at 3 (Moeller Direct).
[162] Ex. 42 at 13 (Moeller Direct).
[163] Ex. 161 at 42-43 (Campbell Direct).
[164] Ex. 161 at 42 (Campbell Direct); Ex. 171 at 33 (Campbell Surrebuttal); Ex. 195 at DVL-U-7, column (w) and DVL-U-4, column (k) (Lusti Update).
[165] Ex. 161 at 36-37 (Campbell Direct).

costs to reflect its concern that employees are not contributing to the pension costs or that there has been improvement in the performance of the financial market in 2011.[166]

The discount rate

181. The Department stressed that the volatility of the market makes predicting pension expense difficult. A small change in the discount rate can have a significant effect on the pension expense. In this case, an increase of 25 basis points for the XES Plan resulted in a decrease of nearly $700,000.[167] The Department does not believe that it is reasonable to use one point in time to calculate pension expense, but rather that the rate should be based on the likely, representative and reasonable expense going forward.[168] By using an average for a number of years, the volatility is smoothed out.[169]

182. The Department emphasized that the Company's pension liabilities were fully funded as recently as 2008, demonstrating that volatility can cause large swings, in this case from $2.0 to $12.054 million, over a few years. Rather than looking at one point in time, the average discount rate over three years assures a more reasonable calculation of expense. As the Department pointed out, an increase in pension expense does not increase the payout to Company employees; rather, it increases the rates.[170]

183. The Company does not accept the Department's position that using a three-year average is reasonable. The increased costs are not the result of excessive pension expense, but rather the 2008 drop in the stock market. Using the average and lowering the included expense will shift costs to future ratepayers. The Company stood by its claim that the calculation must be derived from the asset/liability relationship at a point in time, to assure that pension expense is based on objective data.[171]

184. The Company based its discount rate for the XES Plan on a method that comported with FAS 87, using a "bond matching study," which looks at the yields on bonds that mature at the time the Company's pension obligations will be payable. Its assumptions were driven from measurements taken on December 31, 2010, the close of the Company's fiscal year, based on the long-term yields for bonds.[172] The average yield on the bonds was the basis for the Company's discount rate.[173] Compared to other acceptable methods of calculating the discount rate, this method of bond matching yielded a higher discount rate.[174]

185. The Company's calculation of the discount rate for the NSP-M Plan is based on the Aggregate Cost Method, which uses estimated long-term return on assets

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166 Ex. 171 at 34, 37 (Campbell Surrebuttal).
167 Ex. 171 at 30-31 (Campbell Surrebuttal).
168 Ex. 171 at 32-33 (Campbell Surrebuttal).
169 Ex/ 171 at 30-31 (Campbell Surrebuttal).
170 Ex. 171 at 26 (Campbell Surrebuttal).
171 Ex. 43 at 9-12 (Moeller Rebuttal); Xcel Energy Reply Brief at 30-31.
172 Ex. 45 at 6 (Vogl Rebuttal).
173 Ex. 43 at 10-12 (Moeller Rebuttal).
174 Ex. 43 at 13-14 (Moeller Rebuttal).

and is consistent with the estimates used by other companies. Both the FAS 87 methods and the Aggregate Cost Method are actuarily sound, and the Company's assumptions are subject to independent audit.[175]

186. The Company's witness stated that the bond matching study was performed by Towers Watson, with the Company's input on approach and selected bond portfolio.[176] The Department questioned the Company's involvement in the development of the assumptions upon which the discount rates were calculated, including its role in the selection or exclusion of the bonds that are evaluated.[177] Rather, the Department relied upon the Company's own experience to set an appropriate discount rate.

187. The Department pointed out that in the most recent Otter Tail Power rate case, it had asserted that Otter Tail Power's discount rate of 6 percent, derived from the FAS 87 Method for pension expense, was too low and that averaging expenses over five years was more reasonable.[178] The ALJ recommended that an average was a better measure, and the Commission agreed.[179]

188. The Commission also used an average to determine the appropriate discount rate in the recent Minnesota Power rate case.[180]

189. The Department's argument in support of an average is compelling. From the perspective of ratepayers, it is reasonable to use an average rate to smooth out the volatility of this expense, even if the company has accurately calculated the Test Year expense. An average is also consistent with several Commission decisions. Based on the evidence in the record as a whole and in the event that the Settlement is not accepted, the pension obligation should be recalculated with a discount rate of 8.416 percent for NSP-M and 6.333 percent for XES.

Wage increases

190. The Department also challenged the Company's assumption in its pension expense projection that employee salaries will increase at four percent each year, including both inflation and job promotions. This is higher than the 1.6 percent increase in the Consumer Price Index (CPI) in 2010, and also higher than the 3.8 percent in 2008, when prices of commodities grew at record levels.[181]

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[175] Ex. 43 at 9-10,14-15 (Moeller Rebuttal).
[176] Ex. 43 at 12 (Moeller Rebuttal).
[177] Ex. 171 at 36 (Campbell Surrebuttal).
[178] Ex. 171 at 45-46 (Campbell Surrebuttal).
[179] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Electric Service Rates in Minnesota,* Docket No. E-017/GR-10-239, Findings of Fact, Conclusions and Recommendation, at 46; Findings of Fact, Conclusion and Order at 27 (April 25, 2011).
[180] *In the Matter of the Application of Minnesota Power to Increase Rates for Electric Service in Minnesota,* E-015, GR-09-1151, Findings of Fact, Conclusion and Order at 25 (Nov. 2, 2010).
[181] Ex. 161 at 43 (Campbell Direct); Ex. 171 at 38-39 (Campbell Surrebuttal); Ex. 42 at 20-22 and Sched. 7 (Moeller Direct).

191. As with the discount rate, the Department contended that the Company's assumption was not reasonable and would lead to excessively high rates.[182]

192. The Company has consistently used the four percent increase in its projections since 2007. The Company argued that the Department's two percent increase would be at the bottom of the wage assumptions used by 179 comparable companies.[183] The four percent increase includes a 2.5 percent inflation factor, based on historical averages, and an additional 1.5 percent to account for productivity increases and promotions as employees move up through the pay grades. It argued that this inflation factor is close to the 2.3 percent long-term rate of inflation projected by the Federal Reserve Bank of Philadelphia in February, 2011.[184]

193. The Company claimed that the Department's proposed two percent increase was insufficient to cover the inflation alone and would not be representative over the long run. It disagreed with the Department's reliance on the recent CPI and comments by ratepayers that they have not seen their wages increase. Also, the Company pointed out that, if the Department expected that the Company will look long-term in setting the discount rate, it should do the same for projecting wage increases.[185]

194. The Company has demonstrated that its consistent use of a 4.0 percent wage increase in its pension calculation is reasonable.

Employee contributions to pension

195. Although not factored into its proposed reduction to pension expenses, the Department maintained that the lack of employee contribution affected its views of the reasonableness of the pension expense. The Company conceded that employees do not contribute to the pension plan, but asserted that the pension plan should be viewed in conjunction with the Company's 401(k) plan. For the 401 (k) plan, employees must contribute eight percent of pay to receive the full company match. Thus, the Company claims that its employees do share in a portion of the cost of providing their post-retirement benefits.[186] Also, the employee contributions to a 401 (k) plan can be made with pre-tax dollars, whereas employee contributions into a pension plan must be made on an after-tax basis. If employees contribute to both types of plans, it complicates the tax treatment of pension payouts.[187] Because of the tax consequences, the Company claimed that only four percent of all private sector pension plans require employee contributions. In contrast, public sector plans ordinarily require an employee contribution because of differing tax treatment, which allows employee contributions on a pre-tax basis.[188]

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[182] Ex. 171 at 42 (Campbell Surrebuttal).
[183] Ex. 45 at 9-10 (Vogl Rebuttal); Ex. 102 (List of 179 Companies in Salary Table); *See also* Xcel Energy Reply Brief at 35 (Table).
[184] Ex. 43 at 22-25 (Moeller Rebuttal); Xcel Energy Reply Brief at 36.
[185] Xcel Energy Reply Brief at 38.
[186] Ex. 45 at 2-3 (Vogl Rebuttal).
[187] Ex. 45 at 3 (Vogl Rebuttal).
[188] Ex. 45 at 3-4 (Vogl Rebuttal).

196. As the Department pointed out and the Company admitted, no employee is required to contribute to the 401(k) plan; the contributions are voluntary. In addition, the ratepayers fund the Company's matching contribution to that plan, adding to the costs paid for the employees' retirement.[189]

197. The Company offered an alternative refund mechanism to address the Department's concerns, to refund any amount by which the amount included in the Test Year exceeds actual pension costs for 2011 and 2012.[190]

198. The Department did not agree with this proposal because it did not believe that the Company had demonstrated that its pension costs are reasonable, and a refund mechanism is not a reasonable substitute for setting reasonable pension expense. The Department pointed out that the Commission has not accepted a refund alternative in other recent cases.[191]

199. The Department also recommended that the Commission require the Company in its next rate case to fully support the reasonableness of having ratepayers pay for 100 percent of the Company's pension obligation.[192] The Department's request is reasonable and will assure that there is full consideration of the ratepayers' contribution to the employees' pension.

200. The Chamber of Commerce expressed its concern about the growing pension costs. It recommended that the Company replace its defined benefit plans with defined contribution plans for both union and non-union employees.[193] The Chamber of Commerce did not address this issue in its post-hearing briefs and did not propose a specific dollar reduction.

Conclusion – Qualified Pension Costs

201. The Company has demonstrated that using a four percent increase in its pension calculation is fair and reasonable, however, it has not demonstrated that its discount rates are reasonable. In evaluating the reduction to compensation in the Settlement, a three-year average discount rate should be used to recalculate the reasonable qualified pension expense.

Non-qualified pension costs[194]

202. The Department conducted a limited review of the Company's non-qualified pension expense and concluded that it was acceptable.[195] It also examined

[189] Ex. 171 at 43-44 (Campbell Surrebuttal). The ALJ is not aware that the record includes information about the proportion of retirement payouts made from pensions and the 401 (k) plan, or the employee contributions to the 401 (k) plan.
[190] Ex. 44 at 35 (Moeller Rebuttal).
[191] Department's Initial Brief at 82.
[192] Department's Initial Brief at 83.
[193] Ex. 120 at 11 (Schedin Direct)
[194] Summary of Issues, No. 5.
[195] Department's Initial Brief at 83.

the Company's two forms of non-qualified pension plans: a "restoration plan" that makes up for any benefits that would be paid to the employee but for IRS compensation limits, and a "Supplemental Employee Retirement Plan" (SERP), which provides supplemental compensation at a level it deems necessary to assure that its plan is market-competitive for its executives.[196] Although these pension benefits are "non-qualified," that is, taxable to the employee, they are deductible business expenses for the Company. The current IRS compensation limit is $245,000.[197] Above that level, the Company's five percent contribution to the defined benefit plan falls into this cost category, because it is not a "qualified" contribution for IRS purposes.[198]

203. The Department reviewed the plans to determine whether the level of pension expenses should be included in ratepayer recovery. It recommended reduction of the executive-only nonqualified pension costs, in whole or in part, because it is not reasonable for ratepayers to pay for benefits needed to offset limits set by the IRS.[199] It acknowledged that it has not examined these costs closely in prior rate cases.[200] It does not oppose ratepayer responsibility for a reasonable level of employee pension costs. However, it claims that the Company has failed to show why the ratepayer should provide 100 percent of the funding. Its position is that the pension costs are "overly generous."[201] The full exclusion of non-qualified pension expense would reduce expenses by $1,353,463, which includes $777,378 of SERP costs.[202]

204. In the recent Otter Tail Power rate proceeding, the ALJ recommended that the supplemental executive pension expenses be excluded, and the company did not take exception to the recommendation.[203]

205. The OAG pointed out that other states have excluded SERP, reasoning that the utilities will still be able to recover the level of pension to this group that it recovers for its other employees, and that it is not the obligation of ratepayers to make the executives whole from the perceived "inequity" of IRS tax regulation.[204] The OAG does not assert that the Company may not pay SERP, but, rather, that such payments should be absorbed by shareholders until the Company more prudently manages compensation increases.[205] The OAG recommended eliminating the full costs of the unqualified pension plans, $1.3 million.[206]

[196] Ex. 51 at 48-50 (Figoli Rebuttal).
[197] Tr. Vol. 3 at 61-62 (Figoli).
[198] Tr. Vol. 3 at 61-62 (Figoli).
[199] Ex. 195 at DVL-U-7, column (x) (Lusti Update); Ex. 173 at 4 (Campbell Opening Statement).
[200] Tr. Vol. 6 at 120 (Campbell).
[201] Department's Initial Brief at 84.
[202] Summary of Issues, No. 5.
[203] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Electric Service Rates in Minnesota,* Findings of Fact, Conclusions and Recommendation at 52, Docket No. E-017/GR-10-239.
[204] See OAG Initial Brief at 85, citing decisions from Arizona, Oregon, Washington and Connecticut.
[205] OAG Initial Brief at 74-76.
[206] OAG Initial Brief at 83-86.

Conclusion – Non-Qualified Pension Costs

206. It is reasonable to fund pension above the IRS-approved limit at the same level of contribution other employees receive and to the extent that the cash compensation is included in rates. The IRS limit is not the sole determinant of reasonableness. However, payment for SERP, an optional benefit with no test of reasonableness, is not reasonable and should not be included in rates.

207. In evaluating the reduction to compensation in the Settlement, the non-qualified pension should be allowed to the extent that the employee's cash compensation is included in rates. The SERP costs should be excluded.

Insurance Expense[207]

208. The Company's 2011 Test Year, as originally filed, included a 10.2 percent increase for Total Insurance, as compared to 2010 actual costs.[208]

209. The Department evaluated the Test-Year insurance expenses for Active Health Care, Retiree Medical Care (FAS 106), and Long-Term Disability (FAS 112). During the course of the proceeding, the Company agreed to the following O&M reductions of $3,772,461:

- $2,890,966 – Active Health Care
- $809,134 – Retiree Medical Care (FAS 106)
- $72,361 – Long-Term Disability (FAS 112)

210. The Company also agreed to a corresponding decrease in the capitalized costs of $1,312,417.[209]

211. The Department maintained that additional reductions should be made to the expense for Retiree Medical Care[210] and Long-Term Disability.[211]

212. Retiree Medical Care is subject to FAS 106 accounting standards and Long-Term Disability is subject to FAS 112 accounting standards; they are frequently referred to by those account numbers.

213. Retiree Medical Care includes post-retirement medical costs for medical, dental, vision and life insurance. It is no longer offered to active employees, and, as a result, this benefit covers a decreasing group of retirees.[212] The Department asserted that further reduction is warranted because the Company's discount rate of 5.5 percent

[207] Summary of Issues, No. 57 (FAS 112 O&M); No. 9 and No. 19 (Retiree Healthcare Insurance Costs).
[208] Ex. 161 at 30-33 (Campbell Direct).
[209] Summary of Issues, No. 9; Ex. 195 at DVL-U-7, column (y) and DVL-U-4, column (l) (Lusti Update).
[210] Summary of Issues, No. 56, No. 58 and No. 59.
[211] Summary of Issues, No. 57 and No. 58.
[212] Ex. 161 at 57 and NAC-9 (Campbell Direct).

is too low, the actuary's assumptions were influenced by the Company, the costs are shrinking as the pool of retirees shrinks, and because the Company over-recovered FAS 106 costs in 2009 and 2010.[213]

214. As with pension expense, for both Retiree Medical Care and Long-Term Disability, the Department argued that the Company's actuary relied upon unreasonable assumptions and calculated a discount rate that is too low. The Department pointed to the Company's actual discount rates from 2006 to 2010, and its estimated discount rate for 2011 (in italics).[214]

2006	2007	2008	2009	2010	*2011*	*2011Update*
5.75%	6.00%	6.25%	6.75%	6.00%	*5.25%*	*5.50%*

215. Based on the historical discount rates, the Department recommended using the average discount rate of 6.15 percent to calculate insurance costs.[215]

216. Using the 6.15 percent discount rate, the Department recommended additional reductions of $217,515 in FAS 106 expense and a reduction of $209,428 to FAS 112 expense, a total reduction of $426,943 to O&M insurance costs, and an additional adjustment of $150,316 reduction to the capitalized portion of insurance costs.[216]

217. The Company confirmed that it establishes discount rates under FAS 106 and FAS 112 in the same way that it calculates the pension discount rate under FAS 87.[217] Again, the Company asserted that using an historical average offered no assurance of meeting the conditions during the time that new rates are in effect, that it has relatively little latitude in establishing the discount rates, and that all of the Company's assumptions are subject to an independent audit.[218]

218. The Department disagreed, asserting that an average is a more likely predictor than one point in time because pension costs are paid out over time.[219]

219. In further support of its position, the Department pointed out that the Company's actual O&M portion of FAS 106 costs were lower in 2009 and 2010 than the

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[213] Ex. 161 at 56 (Campbell Direct); Ex. 171 at 53 (Campbell Surrebuttal).
[214] Ex. 161 at 54 and NAC-14 (Campbell Direct); Ex. 171 at 55-56 (Campbell Surrebuttal).
[215] *Id.*, Department's Initial Brief at 91.
[216] Ex. 171 at 58-59 (Campbell Surrebuttal); Ex. 195 at DVL-U-4, columns (l) and (m) and DVL-U-7, columns (z) (Lusti Update).
[217] Ex. 43 at 39 (Moeller Rebuttal).
[218] Ex. 43 at 39-40 (Moeller Rebuttal).
[219] Ex. 171 at 57 (Campbell Surrebuttal).

amount included in the Company's 2008 Electric Rate Case, which led to over-recovery of costs for both years.[220]

220. The Company countered that the lower costs for 2009 and 2010 came from cost-savings initiatives that were reflected in the 2011 Test Year.[221]

Conclusion – Insurance Expense

221. The Company has failed to show that using a discount rate based on one point in time is reasonable. In evaluating the reduction to compensation in the Settlement, the Department's discount rate of 6.15 percent should be used to calculate insurance costs.

Change in Accounting for Accumulated Funding for Retirement Medical Care[222]

222. The OAG proposed that the Company change its accounting for the prepaid accumulation of Retirement Medical Care in order to avoid excessive prepaid funding in the Company's rates. The level of prepaid FAS 106 costs is $63 million, and the amount has been growing every year. The OAG conceded that the Company must record expense according to generally accepted accounting principles (GAAP), and particularly as required by FAS 106, which recognize the expense when it is earned and not when the benefit is paid. Prepayments are recognized on the Company's books and included as a reduction to rate base. Amortizing the funds over four years would reduce rates by approximately $10 to $15 million.[223] The OAG pointed out that, when the expense was measured by payments to former employees, there was not a significant accumulation of ratepayer funds. Under the current accounting, there is a significant accumulation of the ratepayers' funds to cover future expense.[224]

223. The Company did not respond to the OAG's request for information on when the balance would reverse or equal zero. If the Company were to reduce or eliminate its future benefit obligations, ratepayers may have funded the obligations unnecessarily.[225]

224. The Company countered that the Commission has directed the utilities to handle these costs on an accrual basis and with general ratemaking principles that match rate recovery with the period in which expenses are accrued. A shift to cash accounting would place the burden of the payouts on future ratepayers and be contrary to established Commission policy.[226]

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[220] Ex. 161 at 55-56 and NAC-15 (Campbell Direct); Ex. 171 at 53-54 (Campbell Surrebuttal).
[221] Ex. 43 at 36-37 (Moeller Rebuttal).
[222] Summary of Issues, No. 77.
[223] Ex. 134 at 26-29 (Lindell Direct); Ex. 136 at 38-42 (Lindell Errata Surrebuttal); OAG Initial Brief at 47-49; OAG Reply Brief at 15.
[224] Ex. 136 at 40 (Lindell Errata Surrebuttal); OAG Initial Brief at 48.
[225] Ex. 136 at 41-43 (Lindell Surrebuttal).
[226] Ex. 43 at 42 (Moeller Rebuttal).

225. The Company has demonstrated that its accounting is consistent with the Commission's direction to handle expenses on an accrual basis. Although a shift to cash accounting may benefit ratepayers in this case, in the long run, there is no evidence that the shift would be to their benefit.

Summary of Compensation

226. The Company demonstrated that the level of cash compensation included in its revenue requirement is reasonable. The Company has not demonstrated that the discount rate used to calculate qualified pension expense is reasonable. Pension expense should be recalculated with the discount rate at 8.416 percent for the NSP-M Plan and 6.333 percent for the XES Plan. The non-qualified pension expense should be allowed to the extent that the employee's cash compensation is included in rates and SERP should be excluded. The costs for insurance, including Retiree Medical Care and Long-Term Disability, should be recalculated using a discount rate of 6.15 percent.

227. The Company's requested costs must be recalculated to reflect the preceding finding and compared to $7.5 million in order to determine the reasonableness of the Settlement.[227] It would appear that the $7.5 million in the Settlement would be relatively close to this figure. If the two figures are roughly comparable or the Settlement reduction is greater, the compensation portion of the Settlement is reasonable.

Rate Mitigation – Change to Accumulated Depreciation[228]

228. Several parties urged the Company to change its method of calculating depreciation as a way to reduce the Company's revenue requirement, with the attendant benefits to ratepayers. There were two kinds of changes that were proposed: (1) increase the life expectancy for production plant; and (2) amortize the difference in actual and theoretical accumulated depreciation reserve for Transmission, Distribution and General Assets.

229. As part of the Settlement, the Company agreed to reduce 2011 Test Year depreciation expense by $30.0 million, to be effective January 1, 2011. The reduction had two parts: $4.5 million relating to an extension of the useful life of two plants, Riverside and High Bridge; and $25.5 million to adjust the Transmission and Distribution depreciation. The latter had three components: a slight lengthening of average useful life; a reduction in the cost of removal; and a downward adjustment to the depreciation rate.[229]

230. No party specifically opposed this part of the Settlement.[230]

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[227] Ex. 195 at DVL-U-7, columns (c), (w), (x) and (z) (Lusti Update).
[228] Summary of Issues, No. 80 and No. 81.
[229] Settlement Agreement at 10 and Attach. A.
[230] *See* OAG Reply Brief at 3.

231. If the Settlement is not approved, the Company maintained that its requested level of depreciation should be approved because it is reasonable and consistent with Commission guidelines.[231] The Company used the useful life for production plant that was approved by the Commission in previous dockets and has used the depreciation rates for Transmission, Distribution, and General Assets that are based on its five-year depreciation study and approved by the Commission.[232]

232. Absent the Settlement, the Company does not accept the proposals of XLI, the Chamber of Commerce or the OAG to reduce depreciation expense. It would stand by its depreciation expense calculation, which is based upon the Commission's approved depreciation guidelines.[233]

233. XLI recommended that the life expectancy for production plant be revised to comport with the Company's Integrated Resource Plan (IRP), which identifies when its plant may need to be replaced. By extending the life expectancy, there would be a balance of accumulated depreciation that could be amortized. XLI also proposed that the difference between actual and theoretical accumulated depreciation for Transmission, Distribution and General Assets be calculated, and the difference amortized over five years. Together, these changes would reduce the Test Year depreciation expense by approximately $45 million per year.[234]

234. The Chamber of Commerce agreed with XLI that the life expectancy of production plant should be increased and the difference between actual and theoretical accumulated depreciation should be amortized for Transmission, Distribution and General Assets, but it asserted that the excess accumulated depreciation should be amortized over the remaining useful life of the facility.[235]

235. The OAG also supported a change in the depreciation accounting, but would amortize the accumulated depreciation over five years, beginning July 1, 2011. It pointed out that there would be a corresponding reduction in the revenue requirement for 2012 sufficient to cover the Company's requested step-in adjustment.[236]

236. The Company's position is reasonable and consistent with Commission precedent. The useful life of production plant should not be extended solely because of the Company's reference to them in the IRP. Rather, a decision to change the useful life must take into account both the costs and benefits of doing so, as the Commission did when it granted the Company approval to extend the remaining lives of Prairie

[231] Xcel Energy Reply Brief at 166.
[232] Xcel Energy Reply Brief at 168; *In the Matter of Xcel's Request for Approval of the Annual Review of Remaining Lives Depreciation for Electric and Gas Production and Gas Storage Facilities for 2010,* Order, June 16, 2010, Docket No. E,G002/D-10-173; reaffirmed, *In the Matter of Xcel's Request for Approval of the Annual Review of Remaining Lives Depreciation for Electric and Gas Production and Gas Storage Facilities for 2011,* Order, Sept. 8, 2011, Docket No. E,G002/D-11-144.
[233] Xcel Energy Reply Brief at 165-175.
[234] Ex. 65 at 20-22 (Pollock Direct); Ex. 107.
[235] Ex. 121 at 17 (Schedin Surrebuttal).
[236] Ex. 135 at 14-15 (Lindell Rebuttal).

Island and Black Dog Units 3 and 4.[237] The Company pointed out that any change to the useful life of the Allen King Plant or Sherco Units 1, 2 and 3 would require a full analysis of the investment required to extend the remaining life, taking into account future environmental costs and federal regulations.[238]

237. There is also no basis to amortize the accumulated depreciation reserve for Transmission, Distribution and General Assets over five years, which would conflict with the Commission's requirement to use straight-line depreciation.[239] The rules allow an exception, if there is specific justification and certification by the Commission.[240] There was no evidence in this record to change the remaining lives of these asset groups. An evaluation of the remaining lives will be done in the Company's 2012 five-year study, which must be filed no later than September 1, 2012. The Company has agreed to accelerate that filing to July 2012, with rates approved in that proceeding to be effective as of January 1, 2013.[241]

238. Although the Company did not agree to the changes in depreciation accounting requested by the other parties, it agreed to the reduction in the depreciation revenue requirement in order to provide rate relief in this proceeding and because it anticipated that the adjustments included in the Settlement will be fully supported by the Company's 2012 five-year study.[242]

239. The Company's offer to reduce depreciation is a significant part of the Settlement that will reduce the revenue requirement and provide rate relief. The Department's letter of December 2, 2011, explains the pros and cons of this portion of the Settlement.[243] Under the Commission's current practice, the depreciation life is typically assigned at the low, conservative number of years. In this way, if there is a need for significant future capital additions, extending the remaining life helps to pay the costs of the capital additions. The capital costs are recognized as they occur and can be offset by recognizing the life extension. Extending the useful life now assumes that the facilities will be the most cost-effective option in the future.

240. The Department did not oppose this portion of the Settlement, so long as the changes are fully supported by the Company's future depreciation filings.[244]

241. The $30 million change in depreciation will help moderate the increase to customer rates at this time. In light of the current economic circumstances and customer resistance to increased rates, it may be appropriate to exchange lower rates

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[237] Tr. Vol. 3 at 172-73 (Perkett) (change to the useful life for Black Dog and Prairie Island approved by the Commission).
[238] Xcel Energy Reply Brief at 171-172; *See also* Ex. 66 at 20-22 (Perkett Rebuttal).
[239] *See* Minn. R. 7835.0500, subp. 14, and Minn. R. 7835.0900 (2011). Minnesota Rules are cited to the 2011 Edition.
[240] Minn. R. 7835.0900.
[241] Ex. 66 at 24 (Perkett Rebuttal); Xcel Energy Brief in Support of Stipulation and Settlement at 12.
[242] Xcel Energy Brief in Support of Stipulation and Settlement at 12.
[243] Edocket Doc. No. 201112-68896-01.
[244] Department's letter addressing the partial Settlement, Dec. 2, 2011, at 4-6; Edocket Doc. No. 201112-68896-01.

now for higher future costs, so long as the Company is able to justify the extended lives in its future deprecation filings. However, by moving the depreciable lives from a lower to a higher number of years, capital investments near the end of the life may not be absorbed by extension of the expected life and may increase future rates.

242. The Company's CEO and President, Ms. Poferl stated: "We project that our infrastructure investments and operational cost trends will continue to increase for the foreseeable future while our sales will grow slowly. [T]hese dynamics will cause us to experience significant revenue deficiencies in each of the next several years…."[245]

243. The Settlement requires the Commission to weigh the benefit of keeping rates low now with the possibility that rates may be subject to greater increases in the future. Since the parties anticipate that the depreciation change will be substantiated in the Company's 2012 five-year study, it is a reasonable method of providing rate mitigation. If the Settlement is not approved, the Company's requested depreciation expense should be approved until the five-year study has been completed.

Tax Effect of Bonus Depreciation[246]

244. The parties disputed the appropriate tax treatment of bonus depreciation and net operating loss. The Company has accumulated deferred income taxes (ADIT). Because income taxes are calculated for Xcel Energy, taking into account the gains and losses of its subsidiaries, NSP-M may have tax benefits that are offset by the losses of other subsidiaries.

245. The issue was resolved by the parties, with the exception of the OAG. The Company agreed to exclude $1.7 million from the revenue requirement associated with additional bonus tax depreciation and net operating loss. The Company also agreed to refund to customers the revenue requirements associated with the consumption of the deferred tax asset when Xcel Energy uses net operating losses to obtain deferral of NSP-M's current taxes. This is estimated to reduce the aggregate revenue requirements by approximately $60 million over the period from 2012-2015. The amount and timing of the return will be trued up to actual results; any change in the total amount will be subject to Commission approval. The Company agreed to take certain steps to reflect the liability on its books and file regular compliance reports.[247] The Settlement incorporated the agreement.[248]

246. The OAG agreed with the exclusion of the $1.7 million from the revenue requirement, but did not agree with deferred accounting for the approximately $60 million. It asserted that the Company should provide the ratepayers with the immediate benefit of lower tax liability. It pointed to the Commission's decision in *In re Northern*

[245] Ex. 14 at 16, lines 7-11 (Poferl Direct).
[246] Summary of Issues, No. 49, No. 50 and No. 51.
[247] Ex. 105 (Robinson Opening Statement); Ex. 173 (Campbell Opening Statement).
[248] Settlement at 10.

States Power Co., where the Commission did not allow NSP to postpone passing on tax benefits resulting from net operating loss.[249]

247. The Company argued that the OAG's position could cause the Company to lose bonus and accelerated income tax depreciation, and is inconsistent with tax normalization. It offered the testimony of James J. Duevel, an experienced corporate tax accountant, who provided an explanation of the relevant provisions of the tax code and the basis for his conclusion that the OAG's recommendations would be inconsistent with its provisions.[250] The OAG did not offer a federal tax expert to rebut Mr. Duevel's testimony, and its witness on the topic acknowledged that he lacks such expertise.[251]

248. The Company supported its position that it has not abandoned the stand-alone approach to tax treatment.[252] It also demonstrated that the information relied upon by the OAG from the Company's annual reports was incomplete because of the different timing of the report and the filing of the Company's tax returns.[253]

249. The Chamber of Commerce objected to the roll-in of costs associated with three wind projects, in part because of its concern that the roll-in would not adequately reflect depreciation and tax benefits.[254] It did not pursue this issue in its post-hearing submissions; it appears that the concern is addressed by the Company's agreement to separately account for the deferred tax benefits of depreciation.

Conclusion

250. The terms of the Settlement that resolve the issue of appropriate treatment of depreciation, including treatment of accumulated bonus depreciation, are reasonable.

2012 Step-in Adjustment[255]

251. The Settlement includes recovery of $14.8 million for the 2012 costs associated with the work completed through June 30, 2011, for the Monticello LCM/EPU projects, adjusted for a 10.37 percent ROE, cash working capital, and property taxes. The $14.8 million is based on a full year of costs for investments placed into service by the end of June 30, 2011.[256]

252. As part of this proceeding, the Company requested $28.8 million as a four-part 2012 step-in adjustment to its 2011 test year. The largest component was $15.1 million to reflect the full year of costs for investment in the Monticello LCM/EPU project.

[249] 253 P.U.R.4th 40, 2006 W.L. 3487650 (Mn.P.U.C. 2006), at 19, cited at OAG Reply Brief at 8.
[250] Ex. 64 at 3-13 (Duevel Rebuttal); *see also* Ex. 63 at 3-10 (Robinson Rebuttal).
[251] Ex. 136 at 25 (Lindell Surrebuttal).
[252] Xcel Energy Reply Brief at 145-147.
[253] Xcel Energy Brief at 144-145; *see also* Tr. Vol. 3 at 127-128 (Robinson); Ex. 106.
[254] Ex. 120 at 16-17 (Schedin Direct); Ex. 121 at 12-13 (Schedin Surrebuttal).
[255] Summary of Issues, No. 41 (Monticello LCM/EPU); No. 74 (2012 Step-in Adjustment); No. 75 (2012 Sales Forecast); No. 76 (2012 Step-in Adjustment – Rate Design).
[256] Ex. 185 at 4-5 (Ostberg Post-Hearing Supp.).

There were three other components of the Company's requested 2012 step-in adjustment that were dropped in the Settlement:

- Transmission Investment: $4.1 million to recover a full year's depreciation expense and the related adjustments on 2011 transmission investment that will be providing service to customers in 2012. The Company expected to place approximately $61.2 million of transmission investment into service during 2011 that will not be recovered through the transmission rider.[257]

- Distribution Investment: $5.4 million to recover a full year's depreciation expense and related adjustments on 2011 distribution system investment that will be providing service to customers in 2012. The Company expected to place approximately $101 million of distribution projects into service in 2011.[258]

- Nuclear Fuel Outage Authorization: $4.7 million to recover the actual nuclear fuel outage costs that will be deferred and amortized over the useful life of the outages. The amortized outage costs in 2012 reflect costs incurred in 2010 and 2011, plus a nuclear fuel outage scheduled to begin in February 2012.[259]

253. The Company submitted an updated 2012 cost of service study (COSS) with its Rebuttal Testimony to support its position that approving the step-in adjustment would not result in the company over-earning in 2012. The updated COSS showed an unrecovered revenue requirement of approximately $91.1 million more than the 2011 revenue requirement. Thus, the Company asserted that, even if the Commission granted the Company's requested 2012 step-in adjustment, the Company would still have a revenue short-fall.[260]

254. If the Settlement is not approved, the Company seeks the entire $28.8 million 2012 step-in adjustment, to reflect the four known and measureable changes in capital projects that occurred in 2011 and early 2012.[261]

255. Several parties opposed the 2012 step-in adjustment, in whole or in part. The Department agreed that the recovery of the Monticello LCM/EPU portion was appropriate, but opposed the recovery of the other components. The Chamber of Commerce, XLI and Commercial Group opposed the entire 2012 step-in adjustment, but have agreed to the terms of the Settlement. The OAG has consistently opposed the entire 2012 step-in adjustment.

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[257] Ex. 74 at 7-8 (Ostberg Direct); Ex. 76 at 5 (Ostberg Rebuttal) (reflecting subtraction of Fox Lake transmission line and Hiawatha substation).
[258] Ex. 74 at 8-9 (Ostberg Direct).
[259] Ex. 74 at 9-10 (Ostberg Direct); Ex. 76 at 6 (Ostberg Rebuttal) (reducing the 2012 amount).
[260] Ex. 76 at 3 (Ostberg Rebuttal) (the $44.7 million step-in adjustment included in the Rebuttal was reduced to $28.8 million in Ostberg's Post-Hearing Supplemental Testimony).
[261] Xcel Energy Reply Brief at 18, 23.

256. Under most circumstances, the Commission does not allow step adjustments. In a forecast test year, the rate base is typically calculated as the simple average of the beginning and ending balances of the test period. In the alternative, the Commission has allowed the calculation of the rate base using a 13-month average of the monthly plant balances. Neither of the two methods allows for recovery of the entire year-end balance without averaging.[262]

257. The Department agreed to permit recovery of the portion of the step-in tied to the Monticello LCM/EPU because the Commission had already conducted a preliminary review of the costs in its determination to grant a certificate of need. The Department conditioned its approval of this portion of the step-in adjustment upon the Company's agreement to a future review of the prudency of the expense and to refund to ratepayers any amount deemed imprudent. Absent such an agreement, the Department opposed any 2012 step-in adjustment.[263] The Company's agreement to provide a compliance filing and refund any overpayment is included in the Settlement.[264]

258. The Department opposed the other three 2012 step-in adjustments. Typically, costs outside the test year of the general rate case are not recoverable. In this case, the test year of 2011 was in advance of the application, which made the review more difficult than a test year based on historical costs. To include costs for yet another year compounded the difficulty of reviewing reasonableness.[265] None of the other three adjustments included costs previously reviewed in a certificate of need or other proceeding, and none of the three were large enough individually to warrant another rate case. The Department's view was that the Company could manage the costs through other means.[266]

259. The OAG objected to any 2012 step-in adjustment. Although it acknowledged that there are exceptions to general ratemaking, such as riders, deferred accounting and trackers, the exceptions insulate the Company from the risk of non-recovery of costs, which may increase the investors' earnings. The OAG likened the request for a step-in adjustment to the Company's efforts to obtain legislation allowing for multi-year rate cases.[267]

260. The OAG's opposition to the Settlement as a whole is based in significant part on the 2012 step-in adjustment. The Company has argued that the adjustment for the Monticello LCM/EPU is a "known and measurable change" and it meets a compelling need. The OAG correctly pointed out that the costs that the Company seeks to recover in the step-in adjustment for the Monticello LCM/EPU have changed at several points during this proceeding, increasing from the Company's direct testimony to its rebuttal testimony and then decreasing in its post-hearing supplemental testimony.

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262 Ex. 178 at 14 (Lusti Direct).
263 Ex. 179 at 28-29 (Lusti Surrebuttal).
264 Settlement at C.2.
265 Ex. 179 at 26 (Lusti Surrebuttal).
266 Ex. 179 at 30 (Lusti Surrebuttal).
267 OAG Initial Brief at 6.

Also, the estimated total project costs continue to rise and the project timeline has been delayed.[268]

261. Although the costs have been shifting, the 2012 step-in adjustment is limited in the Settlement to the costs incurred through June 2011, normalized to the annual cost for those expenditures in 2012. Because the 2011 Test Year does not reflect the full effect of the investments, the rates in effect for 2012 without the step-in adjustment would be inadequate to recover the revenue requirement of the investment.[269]

262. In the event that the 2012 step-in adjustment is approved, the Company and the Department agreed that the Company would reduce the revenue adjustment by a sales factor that represents the difference between 2011 and 2012 sales levels, restating 2012 sales at 2011 sales levels. This would assure a match between revenues and billings.[270]

Conclusion

263. The 2012 step-in adjustment for Monticello LCM/EPU is reasonable. In the event that the Settlement is not approved, it is reasonable to include this limited 2012 step-in adjustment because the costs have been previously reviewed and approved, but the Company has failed to demonstrate that the three step-in requests for transmission investment, distribution investment and nuclear fuel outage authorization are reasonable.

Non-Asset-Based Margins[271]

264. The Settlement includes a resolution of the proper treatment of the Company's cost and margins associated with non-asset-based trades. Currently, the Company allocates to ratepayers 25 percent of non-asset based margins, which flow through the Fuel Clause Adjustment (FCA). Removing the costs and the margins resulted in a reduction of $1.372 million from ratemaking. This reduction is reflected in the $122.9 million base revenue requirement the Company supported at the close of hearing.[272]

265. There are two types of wholesale margins – asset-based and non-asset-based. Asset-based margins arise from the sale of unused energy from the NSP-M resources, installed or procured to serve retail customers. Since the cost of the production that creates the asset-based margins is fully recovered in rates, 100 percent of the margins are paid to the ratepayers.[273]

[268] OAG Initial Brief at 6-26; OAG Reply Brief at 25-27.
[269] Ex. 185 at 3, Table 1 (Ostberg Post-Hearing Supp.).
[270] Summary of Issues, No. 76; Ex. 148 at 3 (Peirce Surrebuttal); Department's Initial Brief at 181; Xcel Energy Proposed Findings of Fact, ¶ 100; Ex. 87 at 19-20 (Huso Rebuttal).
[271] Summary of Issues, No. 24; Settlement at C.8.a.
[272] Xcel Brief in Support of Stipulation and Settlement at 40.
[273] Ex. 70 at 113-114 (Heuer Direct).

266. Non-asset-based margins are earned by the Company from wholesale energy transactions that are not part of retail service. Examples of such transactions are third-party supplied electricity or financial transactions that are not purchased to meet the needs of retail customers and are resold.[274]

267. Non-asset-based trading is relatively new and was first recognized in the Company's 2005 rate case. In the 2009 rate case, the Company committed to perform incremental and fully allocated cost studies of its non-asset-based trading activities so that the costs could be better evaluated. Absent such studies, the Company allocated twenty five percent of the margins to ratepayers to compensate for use of Company staff, computers and other support.[275] The Department previously agreed to this allocation, pending the outcome of the studies.

268. The Company conducted incremental and fully allocated cost studies for 2007 to 2009 to support its proposed treatment of non-asset-based margins. Its study results showed:

Incremental cost (average)	$530,518
25 percent sharing mechanism (average)	$895,948
Fully allocated cost (average)	$1,129,548

269. The fully allocated cost for 2011 was $1,372,392 and $1,412,447 for 2012.[276]

270. The Company argued that it is appropriate to compare the sharing mechanism with the incremental costs because those are the costs that would be eliminated if non-asset based trading ceased. The sharing mechanism fully covers the incremental costs and contributes to common costs. The Company argued against using the fully allocated costs, which include a portion of overhead that would not go away if this activity ceased.[277]

271. In further support of its position, the Company argued that non-asset-based activities are risky and earn thin margins, which might not, over time, be able to support the fully allocated costs.[278] And, it argued, the ratepayers benefit from the Company's activities in this market.

> By participating in the non-asset based market, the Company is better able to mask its asset-based portfolio needs in the bilateral market. This provides a benefit to ratepayers because when the market knows that our asset-based resources are either long (or short), the market has an

[274] Ex. 70 at 114 (Heuer Direct).
[275] Ex. 70 at 116 (Heuer Direct).
[276] Ex. 70 at 117 and Sched. 16 (Heuer Direct).
[277] Ex. 70 at 117-118 (Heuer Direct).
[278] Ex. 73 at 34-35 (Heuer Rebuttal).

incentive to adjust the prices they are willing to pay for purchase (or prices they are willing to accept to sell power).[279]

272. Based on the results of the Company's studies, the Department recommended that the current cost allocation be replaced. It proposed that non-asset-based trading be subject to fully allocated cost accounting, with all of the allocated cost assigned to asset-based trading, and the margins removed from the rate base.[280] This would reduce the 2011 Test Year revenue requirement by $1.372 million, based on the fully allocated cost study filed by the Company, and the 25 percent margin credit would be terminated. The net effect would reduce the revenue requirement by $259,000.[281]

273. The Department argued that use of the fully allocated costs is important because it would assure full separation of an activity that is not regulated by the Commission. The Company uses its name, employees, hardware, software, day-to-day access to market information, and other administrative support to conduct non-asset-based trading. Focusing only on the incremental costs that would be avoided if the non-asset based trading stopped undervalues the use of the shared resources.[282]

274. Although the Department acknowledged that the non-asset-based trading could benefit the ratepayers by masking the Company's need to serve load, that benefit was insufficient to mix the activity with ratesetting.[283] Removing the activity entirely from the ratemaking would be consistent with the Commission's efforts to assure that utilities separate their unregulated enterprises and do not subsidize them through cost sharing.[284]

275. XLI proposed that the current allocation be adjusted so that 50 percent of the margins, rather than 25 percent, is shared with ratepayers. It asserted that the Company had significantly undervalued its shared operations and the value of credit.[285] This position was supported by the Chamber of Commerce.[286] The Company opposed XLI's proposal because it would reimburse ratepayers more than the embedded costs of the non-asset-based trading, and impose unreasonable risk on the Company.[287]

276. In the Settlement, the Company agreed to the Department's proposal. This would remove the fully allocated costs and any margins from the rate proceeding

[279] Xcel Energy Reply Brief at 48-49; Heuer Rebuttal at 36.
[280] Ex. 161 at 10-11 (Campbell Direct); Ex. 171 at 17-22 (Campbell Surrebuttal); Department's Initial Brief at 60-67.
[281] Ex. 73 at 36 (Heuer Rebuttal).
[282] Ex. 161 at 7 (Campbell Direct).
[283] Ex. 171 at 20 (Campbell Surrebuttal).
[284] Department's Initial Brief at 61-67, citing *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-08-1065, Order at 32-33 (Oct. 23, 2009) (*2008 Electric Rate Case)*, evaluating possible cross-subsidization between regulated and unregulated utility enterprises, and Commission decision in Otter Tail Power *supra*, E017/GR-10-239.
[285] Ex. 124 at 26, 32 (Pollock Direct); Ex. 126 at 22 (Pollock Surrebuttal).
[286] Ex. 121 at 13-15 (Schedin Surrebuttal).
[287] Xcel Energy Reply Brief at 50.

and place both the risks and benefits of this unregulated activity on the shareholders. If approved, this approach would affect final rates but not interim rates, which did not include the non-asset based margin or credit. XLI and the Chamber of Commerce agreed that removal of the costs and margins from ratesetting would address their concerns.[288]

277. The Settlement would also require the Company to remove the language addressing non-asset-based trading from its FCA tariff.[289]

278. The Company has agreed to submit an incremental and fully-allocated cost study of non-asset-based trading with its next rate case.[290]

Conclusion

279. The Settlement provision removing the fully allocated costs and any margins of non-asset-based trading from the rate proceeding is reasonable.

Nuclear Refueling Outage Expense[291]

280. The Settlement retains the nuclear fuel deferral and amortization methodology that has been approved in previous Commission orders.[292] The OAG opposed the deferral and amortization methodology in those dockets, and renews its opposition in this proceeding. Prior to the Commission's approval of the change in accounting method, the Company reported its costs in the month incurred. Since outages do not occur regularly within each year and the costs are very high, the direct expense method did not match the costs to the benefits and led to uneven recovery. In 2008, the Commission allowed the Company to shift to deferral and amortization accounting for these costs directly associated with a planned nuclear power plant refueling outage.[293]

281. The OAG reasserted that: nuclear refueling costs, once deferred, become a regulatory asset, which carries with it a presumption of reasonableness; the Company should not earn a return on the deferral; the accounting is very complex and difficult to evaluate and verify; and future ratepayers should not pay for past outage costs.[294] The

[288] Post-Hearing Brief at XLI at 6-7; Chamber of Commerce Initial Brief at 1.
[289] Ex. 161 at 11 (Campbell Direct); Initial Brief of Department at 67.
[290] Xcel Energy Reply Brief at 47, f.n. 189.
[291] Summary of Issues, No. 79; Settlement at C.8.b.
[292] *In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation, for Accounting Treatment for Nuclear Refueling Outage Costs,* Docket No. E-002/M-07-1489, Order Approving Change in Accounting Methodology with Conditions (Sept. 16, 2008) (*Nuclear Refueling Outage Accounting* Order); *2008 Electric Rate Case,* Order at 32-33 (Oct. 23, 2009).
[293] *Nuclear Refueling Outage Accounting* Order; Ex. 22 at 2 (Everson Rebuttal).
[294] OAG Initial Brief at 95-101; OAG Reply Brief at 12-13; Ex. 134 at 21 (Lindell Direct); Ex. 136 at 6-9 (Lindell Surrebuttal).

OAG recommended normalization of the expense, based on a four-year historical average cost.[295]

282. The Company conceded that it has an on-going obligation to demonstrate that its refueling costs are reasonable, and that it is subject to the Commission's on-going authority to review cost prudency.[296] It also conceded that the calculations are complicated. However, the Company maintained that filing annually provided more transparency and review than including the costs in rate-case test year expense.[297]

283. In its Order approving the use of the deferral and amortization method of accounting for nuclear refueling costs, the Commission found that it was an acceptable accounting method that would spread the costs over the full re-fueling cycle and present a more representative cost method; the costs would be subject to a review for reasonableness; and that the Company would bear the burden of proving the reasonableness of the costs. The Order obligated the Company to file a compliance report and to track actual costs, amounts deferred, and the amortization as support for test-year re-fueling costs. The Commission reserved the right to change the form of cost recovery in future rate cases.[298]

284. The Company denied that future ratepayers would bear the cost because the amortization occurs over a period of 18 to 24 months, the typical period between outages.[299] Thus, the Company contended that outage costs are currently providing customer benefits, and that the OAG approach would not match refueling costs with the time period that customers would benefit.[300]

285. The Company also asserted that it is reasonable to include nuclear outage revenues and expenses in rate base to either compensate customers for the use of their money or compensate the Company for expending funds and amortizing the cost over the 18- to 24- month period, similar to capitalized projects.[301]

286. The deferral and amortization method incorporates a carrying charge to reflect the time value of money until the costs are recovered. So long as the practice of including a carrying charge is balanced with payment to ratepayers when costs are deferred, the practice is reasonable.

287. The Commission addressed each of the OAG's arguments in the Company's *2008 Electric Rate Case*. It concluded that deferral and amortization of the

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[295] The OAG's approach is estimated to reduce the Test Year costs by $846,000. Xcel Energy Settlement Brief at 41, apparently comparing the Company's figure with the $50,120,568, recommended by OAG, adjusted to account for the Wisconsin interchange agreement, Ex. 134 at 20-21 (Lindell Direct); OAG Initial Brief at 101.

[296] Xcel Brief in Support of Settlement at 42; Ex. 22 at 10 (Everson Rebuttal)

[297] Ex. 22 at 11 (Everson Rebuttal).

[298] *Nuclear Refueling Outage Accounting* Order at 6-7.

[299] The Commission noted that a full refueling cycle is approximately 18 to 24 months. *Nuclear Refueling Outage Accounting* Order at 7, f.n. 6; Ex. 22 at 5 (Everson Rebuttal).

[300] Ex. 22 at 4 (Everson Rebuttal).

[301] Ex. 22 at 4-5 (Everson Rebuttal).

nuclear refueling costs would likely increase accuracy, stability, and predictability in rates, which serves the public interest. It noted that the costs were subject to review for reasonableness and, although direct expense accounting is the most common method of tracking and recovering operational expenses, other methods are permitted.[302]

Conclusion

288. The OAG has failed to demonstrate that the Commission's approval of the deferral and amortization of the nuclear refueling costs should be reconsidered. The Company has demonstrated that its costs are reasonable and that the treatment of the costs is consistent with the Commission's prior practice. The Settlement provision retaining the nuclear fuel deferral and amortization methodology is reasonable.

Revenue Requirement - Sales Forecast[303]

289. The sales forecast is not addressed directly in the Settlement. However, the sales forecast is a significant factor in the calculation of the revenue requirement. At the Department's request, the Company updated its sales forecast data.[304] Near the end of the June evidentiary hearing, the Company's updated base-level revenues, incorporating sales data through March 2011, were stated in Exhibit 152. The corrected sales forecast decreased operating revenues by $4.872 million.[305]

290. Upon review of the Company's full revenue model[306] and the updated sales forecast data, the Department agreed that the Company's projected power sales and customer numbers were reasonable.[307]

291. The Department also requested that the Company provide a quantitative cost benefit analysis of any requested cost changes if MISO implements its proposed resource adequacy construct.[308] The Company agreed to do so.[309]

Objections to Late-Produced Data

292. The Commercial Group initially challenged the updated sales forecast and late submission of Exhibit 152,[310] buts its concerns were resolved through the Settlement.[311]

293. The OAG asserted that the Company should not be permitted to update its revenue projection during the course of the hearing, particularly when the data upon

[302] *2008 Electric Rate Case* Order at 32-33.
[303] Summary of Issues, No. 39.
[304] Ex. 37 at JEM-2 (Marks Rebuttal); Ex. 152; Ex. 115 (Heuer Opening Statement).
[305] Ex. 195 at DVL-U-7, column (ao).
[306] Ex. 116 (CD-public) and Ex. 117 (CD-non-public) (Revenue Model and Other Materials).
[307] Tr. Vol. 5 at 210 (Ham); Ex. 195 at DVL-U-7, column (ao) (Lusti Update).
[308] Ex. 149 at 13 (Ham Direct).
[309] Xcel Energy Reply Brief at 51.
[310] Amended Response of the Commercial Group to Issues Outline Summary, Aug. 22, 2011.
[311] Commercial Group Initial Brief at 1.

which the update was based was not freely shared with all parties in a timely way. It quoted the Commission's "Statement of Policy Updating Test Year Information:"

> The Commission has used, and will continue to accept the use of the future test year, based upon conditions which are expected to exist when the rates are placed into effect. When faced with the question on how to update future test year projections, the Commission will consider the most recent data to the extent that new evidence to be admitted:
>
> 1. Can be substantiated by the utility offering the data through testimony, supporting documentation, schedules, and work papers; and
> 2. Is admitted within a reasonable time in the course of the proceedings to allow all parties opportunity to obtain in-depth familiarity with the new data, to cross-examine the utility's witnesses regarding it, and to offer such evidence in surrebuttal as necessary.[312]

294. The Policy also states that the determination of whether to consider the new information must:

> balance the interests of using more recent, actual data to base future rates on versus the need to verify last minute filing of data. When wholly new data is furnished at the end of the case, procedural due process, as well as basic considerations of fairness, require time for the adversarial testing of the data.[313]

295. In this instance, the revenue model was re-run near the close of the hearing and the updated information was not shared with all the parties at the same time.

296. The Company's witness, Ms. Marks, provided an updated sales forecast to all parties in her Rebuttal testimony, and they had the opportunity to question her about it. At that time, the Department requested that the revenue model be re-run at the "rate code" level, and its witness, Mr. Ham, testified that re-running the model was necessary to demonstrate the reasonableness of the test-year sales volume.[314] All parties were served with Mr. Ham's testimony, were on notice of the Department's request, and could have asked for the update.

297. Mr. Ham, and the Company's witness, Mr. Huso, testified without contradiction that the revenue model was re-run to update it with the sales forecast that

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312 OAG Initial Brief at 38, and Attach. 3.
313 Attach. 3, Statement of Policy on Updating Test Year Information, at 2.
314 Ex. 151 at 5 (Ham Surrebutal).

Ms. Marks provided in her rebuttal testimony.[315] The model did not change; just the input did.

298. Mr. Huso was called for re-examination on June 8, 2011, to address questions about the data. At the close of the evidentiary hearing that day, in response to objections by some parties that they did not have sufficient time to review the revised revenue projection, a date was set for Mr. Huso to be re-called to testify if any party notified the ALJ by June 13, 2011, that it wished to question him further. No party requested that Mr. Huso be re-called for questions. Thus, the OAG has waived its objection to the admissibility of the updated revenue projection.

299. Although the OAG's concerns are understandable, and there may be circumstances that would warrant exclusion of the updated data, in this case the data will provide more accurate information to reach a final decision concerning the rates. It is possible that the change in the revenue requirement might have prompted other parties to examine the revenue model more carefully, but information about the model had been available throughout the proceeding,[316] the parties were on notice that the Department had requested an update to reflect the changes in the sales forecast, and the parties had the opportunity to re-call Mr. Huso for questions.

300. The Commercial Group and OAG correctly pointed out that rate cases of this magnitude require review and analysis of an overwhelming amount of information and not all parties are equally well-staffed to process it. Care should be taken to assure that all parties are aware of updated information that directly affects key components of the rate case, especially when the subject of the update has been at issue in the proceeding and the updated information has been provided to the requesting party.

"Stay-Out" Provision[317]

301. The Company agreed in the Settlement that it would not file a new general rate case that would result in interim rates taking effect prior to January 1, 2013, subject to approval of the Settlement revenue requirement, including the 2012 step-in adjustment and approval of its request for deferred accounting or rider to recover 2012 property tax increases. The Settlement acknowledges that the Commission may elect to modify the Settlement's terms, and the parties to it may elect to accept that modification,[318] but if the revenue requirement is reduced or the Company is denied deferred accounting or a rider to recover its property tax increase, the "stay-out" provision has no effect.[319]

[315] Tr. Vol. 5 at 201-202 (Ham); Tr. Vol. 6 at 163-167 (Huso).
[316] Tr. Vol. 6 at 164 (Huso).
[317] Settlement at J.
[318] Settlement at K; Minn. Stat. §216B.16, subd. 1a (b).
[319] Settlement at J.

Rate Design Issues Resolved by the Settlement

Distributed Generation Tariff[320]

302. The Company proposed cancelling the small wind and small non-wind distributed generation (DG) tariffs and making some additional administrative changes to the DG tariff. The remaining DG Tariff encompasses the terms and conditions available for all DGs of 10 MWs or less.[321] Also, passage of Minn. Stat. §§216.1612 and 216.1613 has made the tariffs obsolete.[322] The Department recommended approval of the proposed changes to the DG Tariff.[323]

303. The Chamber of Commerce requested that the Company set a firm price for any study needed to determine necessary DG interconnection facilities.[324] As part of the Settlement, the Company agreed to work with the Chamber of Commerce to modify the tariff language to provide for firm cost estimates to perform interconnection studies, and to complete studies within a reasonable time.

Rates for Solar Facilities[325]

304. The Chamber of Commerce recommended that the Company develop a new DG Solar rate that: (a) would not have standby requirements; (b) would not have demand charge penalties; and (c) would reflect the Special MISO Mod E accrediting rating for solar installations.[326] The Company responded that it did not have the necessary information to determine the reasonableness of the Chamber's request.[327]

305. As part of the Settlement, the Company agreed to study the load profile of larger solar facilities and share the results with the Chamber by August 15, 2012.

Energy Charge Credit[328]

306. The Energy Charge Credit (ECC) is a component of demand-metered rates applied to customers with load factors in excess of 55 percent.[329] The Chamber of Commerce suggested that the Company increase the credit, and the Company agreed, increasing the ECC from \$0.009/kWh to \$0.010/kWh.[330]

307. The parties to the Settlement agreed that the increased credit would moderate the effect of the stratification-based rate design on high load customers,

[320] Summary of Issues, No. 73 (a); Settlement at F.1.
[321] Ex. 79 at 14-19 (Zins Direct).
[322] Ex. 147 at 20-21 and SLP-6 (Peirce Direct).
[323] Ex. 147 at 21-22 (Peirce Direct).
[324] Ex. 120 at 35-36 (Schedin Direct).
[325] Summary of Issues No. 73 (b); Settlement at F.2.
[326] Ex. 120 at 38-40 (Schedin Direct).
[327] Ex. 82 at 20-24 (Zins Rebuttal).
[328] Summary of Issues, No. 72 (c); Settlement at F.4.
[329] Ex. 87 at 11 (Huso Rebuttal).
[330] Ex. 87 at 12 (Huso Rebuttal), Ex. 121 at 31 (Schedin Surrebuttal).

appropriately reflecting principles of cost causation. The parties also agreed that the revenue shortfall would be assigned to and recovered from the C&I customer class.

Peak-Controlled (Interruptible) Service[331]

308. The Company requested approval for changes to the tariff language. Some language changes reflected schedule changes; others removed reference to the minimum demand charge differential, which may be eliminated in the future.[332]

309. The Chamber of Commerce objected to the Company's proposed increase to the Interruptible Service discount. For purposes of the Settlement, the Company and the Chamber, as well as the other signatory parties, agreed that the Company's position was acceptable, except that the Short Notice discount would remain at $5.55 per kW. The rates would be adjusted as follows:

- Tier 1SN - $5.55
- Tier 1B - $4.49
- Tier 1C - $5.05
- Tier 2A - $3.10
- Tier 2B - $3.82
- Tier 2C - $4.30

310. The Company agreed to modify tariff language to clarify the availability of Competitive Service Rider and Competitive Market Rider options, and to assign and recover the resulting revenue shortfall from the C&I customer class.[333]

311. The Department concluded that the proposed changes to the Interruptible Service discounts were reasonable,[334] and the agreement was incorporated into the Settlement.

Studies, Reporting and Other Agreements Included in the Settlement

Bad Debt Information and Analysis.[335]

312. The Company agreed to study the effect of low income programs on bad debt levels as requested by the OAG and present the results of the study in its next general rate proceeding.

[331] Summary of Issues, No. 72 (d); Settlement at F.3.
[332] Ex. 84 at 8-10 (Huso Direct).
[333] Settlement at F.3, pages 14-15.
[334] Ex. 148 at 5-6 (Peirce Surrebuttal).
[335] Summary of Issues, No. 23; Settlement at D.1.

Sales Forecasts Prefiling In Future Rate Cases.[336]

313. The Company agreed with the Department's request to provide all data used in its test year sales forecasts at least 30 days prior to filing future general rate cases.[337]

Five-Year Depreciation Study

314. To support use of depreciation for rate mitigation, the Company agreed to accelerate filing its five-year depreciation study to July 2012, with rates approved in that proceeding to be effective as of January 1, 2013.[338]

Non-Asset-Based Trading Cost Study

315. The Company agreed to submit an incremental and fully-allocated cost study of non-asset-based trading with its next rate case.[339]

MISO Resource Adequacy Cost Changes

316. The Company agreed to provide a quantitative cost benefit analysis of any requested cost changes if MISO implements its proposed resource adequacy construct.[340]

Interconnection Studies[341]

317. The Company agreed to work with the Chamber of Commerce to modify the tariff language to provide for firm cost estimates to perform wind interconnection studies, and to complete the studies within a reasonable time.

Solar Facilities Study[342]

318. The Company agreed to study the load profile of larger solar facilities and share the results with the Chamber by August 15, 2012.

Aggregate Cost Method[343]

319. The Company agreed to use the Aggregate Cost Method of accounting for purposes of the NSP-M pension plan.[344]

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[336] Summary of Issues, No. 66; Settlement at D.3.
[337] Summary of Issues, No. 66; Ex. 37 at 6 (Marks Rebuttal).
[338] Ex. 66 at 24 (Perkett Rebuttal); Xcel Energy Brief in Support of Stipulation and Settlement at 12.
[339] Xcel Energy Reply Brief at 47, f.n. 189.
[340] Xcel Energy Reply Brief at 51.
[341] Settlement at F. 1.
[342] Settlement at F.2.
[343] Not listed in Summary of Issues; Settlement C.8.
[344] *See* Ex. 42 at 7-11 (Moeller Direct).

Monticello LCM/EPU Compliance Update[345]

320. The Company agreed to provide a compliance update within a reasonable period of time after the Project is complete, outlining the total costs and the additional capacity achieved. If the Commission subsequently determined that any of the costs were imprudent, the Company agreed that imprudent costs would be refunded and waived any claim of retroactive ratemaking.[346]

Fuel Clause Incentive[347]

321. The Company agreed to develop a fuel clause incentive for informal consideration by stakeholders by July 20, 2012. Upon agreement by interested stakeholders on an acceptable fuel clause incentive, the Company will, within sixty days, present the proposed incentive to the commission for review and approval. The Department preferred that the issue be addressed under a generic docket, applicable to other investor-owned utilities.[348]

322. The OAG pointed out that, for the Test Year, NSP recovered approximately $849 million for fuel and purchased power costs. As it did in the Company's last rate case, the OAG took the position that the Commission should impose a three percent cap on the increase in fuel costs that are passed through to the ratepayers because there are insufficient incentives for the Company to keep the costs down.[349] Although it acknowledged that the Commission had opened a docket to address the issue, efforts have bogged down. In the OAG's view, the matter could be resolved for the Company in this docket by establishing the three percent cap. If no cap is adopted, the OAG asks the Commission to reactivate the stakeholder process and establish objectives for an incentive mechanism.[350]

323. The Department agreed that there should be incentives for all publicly-owned utilities to keep fuel costs low, but it does not believe that there is a rational basis for the OAG's selected three percent cap or that the Company's proposals are well-conceived. Rather, it asserts that a previously opened docket is the more appropriate route to determine the incentives.[351] The Department conceded that the work in that docket had been suspended because of other workload, but that the effort should be revived and the issues addressed there.[352] The Chamber of Commerce witness

[345] Summary of Issues, No. 41; Settlement C.2.
[346] Tr. Vol. 4 at 112-113 (Ostberg).
[347] Summary of Issues, No. 72 (h); Settlement at D.2.
[348] Ex. 157 at 12-13 (Ouanes Surrebuttal), *In the Matter of the Commission's Investigation into the Appropriateness of Continuing to Permit Electric Cost Adjustments,* Docket No. E999/CI-03-802.
[349] Ex. 134 at 6-13 (Lindell Direct).
[350] Ex. 136 at 32-38 (Lindell Surrebuttal).
[351] *In the Matter of the Commission's Investigation into the Appropriateness of Continuing to Permit Electric Cost Adjustments,* E999/CI-03-802.
[352] Ex. 157 at 10-13 (Ouanes Surrebuttal).

recommended that the issue should be addressed in a new fuel management docket, designed to provide ratepayers with improved fuel price stability.[353]

324. The record in this proceeding is not sufficiently developed to determine what cap, if any, should be imposed on the Company, and what incentives, if any, should be created to encourage the Company to purchase fuel and power at the lowest reasonable cost.

Conclusion

325. The portion of the Settlement addressing Studies, Reporting and Agreements is reasonable.

Expenses Not Specifically Addressed By The Settlement

326. The Settlement is intended to fully resolve all issues related to the revenue requirement, even though it did not specifically address some disputed Test Year expenses that remained in dispute at the close of the hearing. If the Settlement is approved, the revenue requirement would be at the Settlement levels for 2011 and 2012, fully resolving all the issues, including those that were not specifically addressed in the Settlement. The view of the settling parties is that the $30 million change in depreciation expense will mitigate any rate increase and more than offset any remaining disputed expenses.

327. The disputed cost items that were not specifically addressed in the Settlement will be evaluated to determine the effect of excluding them. Also, in the event that the Settlement's resolution of the revenue requirement is not accepted by the Commission, each disputed item must be considered.

Costs Disputed by the Department

Xcel Energy Foundation Administrative Costs[354]

328. The Department accepted the Company's proposed Test Year expenses for charitable contribution expenses of $1,878,632, as consistent with Minn. Stat. § 216B.16, subd. 9, which allows only 50 percent of the qualified charitable contributions to be recovered as operating expenses. However, the Department opposed recovery of $330,380 for the administrative costs of operating the Company's foundation, through which the charitable contributions are made.[355] The Department contended that the Company's charitable giving helps build the Company's goodwill.[356]

329. In recent Xcel electric and gas rate cases, the Commission found that it was not reasonable or consistent with the public interest for the Company to recover the

[353] Ex. 121 at 17-18 (Schedin Surrebuttal).
[354] Summary of Issues, No. 13.
[355] Ex. 158 at 10-11 (La Plante Direct); Ex. 195 at DVL-U-7, column (j) (Lusti Update).
[356] Ex. 159 at 8-9 (La Plante Surrebuttal).

foundation administrative costs from ratepayers. The Commission acknowledged that it has permitted utilities to include up to 50 percent of their actual charitable contributions in rates, but that it does not necessarily follow that the administrative costs associated with the contributions should also be included. The Commission's rationale was that, although the charitable donations are valuable, neither statute nor policy compels the utility to make charitable contributions as a requirement of providing service. The utility determines the manner and means by which it makes its contributions; there is no statutory standard that would require the existence of a free-standing foundation. The Commission's view is that the shareholders, not the ratepayers, benefit from the goodwill engendered by the contributions.[357]

330. Similarly, the Commission accepted the ALJ's recommendation to deny the administrative costs associated with charitable donations in the recent Otter Tail Power electric rate case.[358]

331. While acknowledging past Commission decisions, the Company maintained that those decisions were based on assumptions that were disproven in this proceeding. It argued that the charitable contributions could not be made without the administrative costs; that the foundation does not develop goodwill except through its charitable contributions; that the foundation lowers the costs of making charitable contributions; and there will be an adverse effect on the continuation of the foundation if the administrative costs are not allowed.[359]

332. With regard to goodwill, the Company maintained that the foundation does not enhance goodwill; rather, it enhances the benefits of the charitable giving. Because the charitable giving enhances goodwill, it strengthens the Company's reputation and "key relationships." It enhances its connection with customers and encourages choices and behaviors that benefit the customers, such as safety and energy management. The Company's view is that the charitable contributions contribute to goodwill, unaffected by the type of administrative structure that administers them.[360]

333. The Company also argued that the foundation structure was the most efficient and responsible way to manage the charitable giving, with centralized staff, standard accounting practices, consistent grant-making process and consolidated database management across the states. By operating with one website and one set of

[357] Department's Initial Brief at 95-96, quoting *In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Natural Gas Service in Minnesota,* Findings of Fact, Conclusions of Law and Order, Docket No. G002/GR-09-1153 at 15 (Dec. 6, 2010).
[358] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota,* Findings of Fact, Conclusions and Order at 7, Docket No. E-1017/GR-10-239 (April 25, 2011), Edocket Doc. No. 20114-61715-01, adopting Findings of Fact, Conclusions and Recommendation of ALJ at 55-56 (Feb. 14, 2011), Edocket Doc. No. 20112-59536-01.
[359] Xcel Energy Reply Brief at 51-56.
[360] Ex. 17 at 5-6 (McCarten Rebuttal).

guidelines, the foundation can provide consistent information.[361] In addition, the foundation structure allows a tax credit that benefits all customers.[362]

334. The Company maintained that its charitable contributions were not a promotional effort, nor were they given to increase sales or build brand recognition. Rather, the Company viewed them as commitments to customers and communities so that the communities will be stable, economically healthy places to live and work.[363] It disputed the Department's implication that the foundation benefits shareholders at the expense of customers. Rather, it asserted that the contributions and the expense to administer them are aligned with the ratepayers' interest in strong communities.[364]

335. If the Commission chooses to disallow recovery of the administrative expenses, the Company stated that it will view the decision as a signal that, as a matter of public policy, the Commission does not consider the activities legitimate costs of doing business. The Company must factor that into its decision whether to provide charitable contributions.[365]

336. In its Rebuttal Testimony, the Company argued that, at a minimum, 50 percent of the administrative costs should be allowed, consistent with the level of recovery allowed for the charitable contributions.[366] Post-hearing, it argued that the administrative costs should be fully recoverable.[367]

337. The Commission has disallowed the administrative costs for the foundation in recent cases. None of the arguments put forward by the Company persuasively demonstrate the error of those decisions. Although the Commission may choose to revisit the question, the precedent is clear and the Company has failed to demonstrate that the foundation administrative expenses are reasonable.

338. If the Settlement is not accepted, the ALJ finds that the foundation's administrative costs are not reasonable and should be disallowed.

Investor Relations Costs[368]

339. The Company 2011 Test Year included a total of $2,962,146 for Investor Relations; $937,550 was allocated to the Minnesota jurisdiction, which the Company seeks to recover.[369] The Department would limit the recovery to 50 percent of the costs, disallowing $466,789.[370]

[361] Ex. 17 at 4-5 (McCarten Rebuttal).
[362] Ex. 17 at 2 (McCarten Rebuttal).
[363] Ex. 17 at 3 (McCarten Rebuttal).
[364] Ex. 25 at 16 (Poferl Rebuttal).
[365] Ex. 17 at 7-8 (McCarten Rebuttal).
[366] Ex. 17 at 2, 9 (McCarten Rebuttal).
[367] Xcel Energy Reply Brief at 56.
[368] Summary of Issues, No. 8.
[369] Ex. 58 at 39-41 (Locker Direct).
[370] Ex. 171 at 25 (Campbell Surrebuttal; Ex. 195 at DVL-U-7, column (s) (Lusti Update).

340. Investor relations costs include the following activities:

- Communications to investors and the financial community;
- Coordinating transactions with the transfer agent;
- Shareholder record-keeping functions; and
- Planning for annual shareholder meetings.[371]

341. In response to the Department's testimony that the identified costs should be borne by shareholders rather than ratepayers, the Company responded that the activities help achieve positive credit ratings and strong investor demand for its long-term debt securities, and are necessary for listing and sale of its shares. Access to public markets is especially important in light of the Company's significant investment plans. These activities help the Company manage its financing costs.[372]

342. The Department conceded that the expenses might have some benefit to ratepayers, but asserted that the Company had failed to offer any means to allocate the portion that would benefit ratepayers rather than shareholders. Also, some of the expenses, such as the costs of the Company's annual shareholder meeting, solely benefit the shareholders. Based on the information provided, the Department revised its recommendation and would allow recovery of 50 percent of the costs of investor relations.[373]

343. The Company demonstrated that the expense has some benefit to ratepayers, but argued that quantification is not feasible and is an inappropriate reason to disallow a portion of the costs.[374]

344. The Company has demonstrated that the costs of investor relations benefit both ratepayers and shareholders and that the benefits to the ratepayers are difficult to quantify. However, some of the costs, including the costs of the annual shareholder meeting, are of no benefit or partial benefit to the ratepayers. The Company has failed to demonstrate that including all of the costs of investor relations is reasonable. Absent a more exact method of allocation, the Department's position to allow 50 percent of the investor relations costs is reasonable.

345. If the Settlement is not accepted, the ALJ finds that 50 percent of the investor relations costs are reasonable and should be allowed.

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[371] Ex. 58 at 39-41 (Locker Direct).
[372] Ex. 39 at 15-17 (Tyson Rebuttal).
[373] Department's Initial Brief at 101; Ex. 171 at 25 (Campbell Surrebuttal); Ex. 195 at DVL-U-7, column (s) (Lusti Update).
[374] Xcel Energy Reply Brief at 58.

Proper Amortization of One-Time Costs and Rate Case Expenses

346. The Company and the Department disagree about the proper amortization period for certain one-time costs. This includes both 2011 Test Year one-time costs and the unamortized balance of 2009 Test Year one-time costs. They also disagree about the amortization period for 2011 rate case expenses, and whether the unrecovered 2009 rate case expenses should be carried forward into 2011 Test Year expenses.

347. The Company requested a two-year amortization period because it will file a rate case no later than November 2, 2012, with interim rates taking effect no later than January 2, 2013.[375]

348. The Department advocated for a three-year amortization period based on the historical average of the number of years between Company rate cases, with the exception of two outliers, and that the Commission typically relies upon the historical average in setting the amortization period.[376]

349. The Department also asserted that certain items that the Company included in O&M expenses should either be capitalized or treated as one-time expenses and amortized over three years.

Proper amortization period for one-time costs[377]

350. In this proceeding, there are 13 one-time expenses, excluding rate case expenses, for which an appropriate amortization period must be selected.[378] The dollars in parentheses represent the year-end 2010 unamortized balance.[379]

- 2009 Rate Case SO2 Allowances ($1,098,000)
- 2009 Rate Case Mercury Deferral ($4,306,000)
- 2009 Rate Case Private Fuel Storage ($4,255,000)
- 2009 Rate Case MISO day 2 Costs ($6,553,000)
- 2009 Rate Case Time of Use ($309,000)
- 2009 Rate Case Levee Station ($223,000)
- 2009 Rate Case Nuclear Accounting Change Revenue ($3,441,000)

[375] Xcel Energy Reply Brief at 59.
[376] Ex. 158 at 13-15 (La Plante Direct).
[377] Summary of Issues, No. 7.
[378] Ex. 73 at 46-47 (Heuer Rebuttal) If it is determined that the Grand Meadow gearbox repairs should be amortized (Summary of Issues, No. 10), the same amortization period would apply.
[379] Ex. 158 at 17- 20 (La Plante Direct); Ex. 73 at 46-47 (Heuer Rebuttal).

- Prior Years Income Tax Trackers ($512,000)

- 2011 Rate Case SO2 Allowances ($80,000)

- 2011 Income Tax Tracker ($3,859,000)

- 2011 Rate Case Energy Innovation Corridor ($1,364,000)

- Monticello Obsolete Inventory ($600,000)[380]

- Riverside Plant Remediation ($200,898)[381]

351. For a number of these items, the Commission previously granted deferred accounting and allowed the Company to recover the costs in a subsequent rate case. Some of the items pertain to revenue to be returned to ratepayers.[382]

352. The 2011 Test Year expenses would decrease by approximately $1.303 million if the amortization period for these expenses was changed from two years to three years.[383]

353. The Company and the Department also disputed the amortization period for the 2011 rate case expense, relying upon the same arguments.[384] The Company amortized the 2011 rate case expenses over two years. A change to three years would reduce 2011 Test Year rate case expenses by $238,000.[385]

354. If the Company incurs a one-time cost and includes the full amount of that cost in the test year revenue requirement, and rates remain in effect longer than one year, the Company would recover the full amount of the one-time cost in each year until interim rates went into effect in the next rate case.[386] In order to avoid over-recovery, it is necessary to amortize such costs over a period longer than one year. However, when another rate case is filed before the costs are fully recovered, the Company will seek to include the uncollected costs in the new test year revenue requirement. To the extent possible, the amortization period should match the period between rate cases to prevent over or under recovery of the costs.[387]

355. In the Company's *2008 Electric Rate Case*, the Department recommended a four-year amortization period, and the Company did not oppose the recommendation. However, the Company filed this rate case after two years, and it has one-time 2009 test year costs that are not fully recovered. In addition it has one-time 2011 test year costs to recover. The Company anticipates that it will file its next rate case in 2013.

[380] Ex. 171 at 59-61 (Campbell Surrebuttal); Summary of Issues, No. 20.
[381] Ex. 171 at 65-67 (Campbell Surrebuttal); Summary of Issues, No. 21.
[382] Ex. 158 at 21 (La Plante Direct).
[383] Ex. 195 at DVL-U-7, columns (f), (af) and (ah) (Lusti Update).
[384] Summary of Issues, No. 7 and No. 12.
[385] Ex. 195 at DVL-U-7, column (g) (Lusti Update).
[386] Ex. 73 at 46 (Heuer Rebuttal).
[387] Xcel Energy Reply Brief at 59-60; Tr. Vol. 6 at 64-65 (La Plante).

Because of the length of time between the 2009 and 2011 rate cases, and the anticipated 2013 rate case, the Company used a two-year amortization period for one-time expenses.[388] Although it is not bound to file its next rate case in 2013, the Company pointed out that any over-recovery because of delay would be a deferred obligation, returned when the next rate case is filed.[389]

356. The Company's president testified that she projected "revenue deficiencies of between $95 to $150 million each year from 2011 to 2015,"[390] due to significant infrastructure investment and increase in operational expenses with slow sales growth.[391] The Company also plans to accelerate its five-year depreciation study so that results can be used in the 2013 test year.[392] Thus, a 2013 rate case is very likely.

357. Although it understands that using an historical average has precedent, the Company pointed out instances where the Commission has deviated from the average when the circumstances warranted it. For example, in 2007, the Commission allowed the Company to deviate from the average in its natural gas rate case, based on the timing of the prior case and the Company's expressed intent to file its next gas rate case in three years. In permitting the shortened amortization period, the Commission noted these facts and added that the intervals between rate cases appear to be cyclical, with periods of frequent and less frequent rate cases.[393]

358. The Commission is aware of the current frequency of rate case filings.

359. In light of the frequency of recent rate cases and the virtual certainty that the Company will file its next case in 2013, the circumstances support the Company's selection of a two-year amortization period.

2011 Rate Case Expenses[394]

360. As with other one-time expenses, the Company asserted that 2011 rate case expenses should be amortized over two years, and the Department argued for a three-year amortization period on the basis that there was no compelling reason to deviate from the normal procedure in setting the amortization period.[395]

361. The same analysis and conclusion applies; under the circumstances, the two-year amortization period is reasonable.

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[388] Xcel Energy Reply Brief at 60.
[389] Xcel Energy Reply Brief at 61; Ex. 73 at 50 (Heuer Rebuttal).
[390] Ex. 14 at 11 (Poferl Direct).
[391] Ex. 14 at 16 (Poferl Direct).
[392] Ex. 65 at 24 (Perkett Rebuttal).
[393] Xcel Energy Reply Brief at 62, quoting *In the Matter of the Application of Northern States Power Company...for Authority to Increase Rates for Natural Gas Service in Minnesota,* Findings of Fact, Conclusion of Law and Order at 8, G002/GR-06-1429, (Sept. 10, 2007).
[394] Summary of Issues, No. 7 and No. 12.
[395] Ex. 158 at 12-15 (LaPlante Direct); Department's Initial Brief at 103; Ex. 73 at 47-48 (Heuer Rebuttal).

362. The OAG objected to requiring ratepayers to pay all of the rate case expenses, with no test of prudence or reasonableness, which has led to seemingly limitless rate case expenses. As an example, the OAG pointed out that the Company had nine attorneys involved in the case: six in-house counsel, and three from private law firms. It called 29 different witnesses. The OAG maintained that the Company has *carte blanche* to spend any amount without regard to the impact on ratepayers. It recommended disapproving the entire 2011 rate case expense.[396]

363. In light of the increased frequency of rate cases, the OAG argued that rate case costs should no longer be treated as "one-time expense." Instead, the rate case costs should be normalized by including them with the regulatory, legal and consulting expense included in the test year. In its view, the normalized expenses are already reflected in the test year and the rate case expense should be denied.[397]

364. The ALJ agrees that the Company was heavily staffed throughout the hearing, although its attorneys and staff provided many summaries and updates that benefitted the other parties and the ALJ. Based on the information in this record, one cannot conclude that the Company's expenditure of resources was excessive, or that the normalized level of regulatory, legal and consulting expenses would be sufficient to cover its rate case costs. It is not reasonable to disallow all of the costs, as the OAG proposed. If a pattern develops where the Company files rate cases every two or three years, it may be logical to change current practice and move the expenses into its general operations.

365. A two-year amortization period is reasonable for one-time expenses, including the 2011 Rate Case Expense.

2009 Rate Case Expense[398]

366. The Company included the uncollected 2009 rate case expense in its test year. The Department objected to including any of the uncollected rate case expense, which would reduce the revenue requirement by $398,000.[399]

367. The Company justified the inclusion of the 2009 rate case expense because those costs were approved in that case, to be amortized over four years. The unamortized balance at year end 2010 was $797,000. The 2011 Test Year would be the third year, and the Company proposed continuing the amortization through 2011 and 2012, the period that the Company expects that this requested rate will be in effect.[400]

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[396] OAG Initial Brief at 109-110. That amount is approximately $1,843,000. The Summary of Issues, No. 7, states that the Department reflected the Company's $103,430 update; it is not clear whether that was an addition or deletion from $1,843,000 included in direct testimony, Ex. 70 at 153 (Heuer Direct).
[397] Ex. 134 at 23-24 (Lindell Direct).
[398] Summary of Issues, No. 7 and No. 11.
[399] Ex. 158 at 15-16 (La Plante Surrebuttal); Ex. 195 at DVL-U-7, column (h) (Lusti Update).
[400] Ex. 70 at 152 (Heuer Direct).

368. Generally, there is no true-up mechanism between rate cases. The utility controls the timing of its rate case and can avoid uncollected expense by filing its next rate case later. Ratepayers do not receive a rebate when the time period between rate cases extends beyond the amortization period, except with Commission approval. The Department cites many examples where the Commission has disallowed recovery of unamortized rate-case expenses.[401]

369. The Company countered that there has been a change in practice to include deferral of any over-recovery, and its obligation to refund over-recovery was in place when the Commission approved the four-year amortization period for the 2009 rate-case expense. The Company has committed to the same deferral of over-recovery for refund in its next rate case and sees no basis to treat the 2009 rate-case expenses any differently than other one-time expenses approved in the 2009 rate case.[402]

370. The OAG opposed recovery of the 2009 rate case expenses for the same reasons that it opposed recovery of the 2011 rate case expenses.[403]

371. Unlike other amortized one-time expenses, the costs of pursuing a rate case are uniquely within the Company's control, as is the timing of each rate case filing. It is appropriate to place the risk of under-recovery on the Company and its shareholders rather than ratepayers, as a counterweight to other incentives the Company may have to file a request for increased rates. Absent any Commission decision to the contrary, it is appropriate to follow its precedent and deny the continued amortization of the 2009 rate-case expenses. The Commission must decide whether the newly-agreed upon mechanism for deferral and refund should alter its past practice.

372. If the Settlement is not accepted, the ALJ finds that the 2009 Rate Case Expense is not reasonable and should be disallowed.

Operating & Maintenance (O&M) Cost of Minnesota Valley and French Island Unit 3 Plant[404]

The Department and the Company resolved an issue concerning the depreciation expense for the removal of the Minnesota Valley and French Island Unit 3 generating facilities, which are not in operation but will continue in rate base.[405] However, the Department did not agree to allow the O&M costs for the two facilities since they are not in operation and not used by ratepayers.[406] The disputed Minnesota Valley O&M costs are $310,000; the disputed French Island Unit 3 O&M costs are $80,000.[407]

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401 Ex. 158 at 16 (La Plante Direct); Department's Initial Brief at 103-105.
402 Ex. 73 at 50-51 (Heuer Rebuttal).
403 OAG Initial Brief at 109-110.
404 Summary of Issues, No. 14 and No. 18.
405 Summary of Issues, No. 63; Ex. 159 at 4-5 (La Plante Surrebuttal).
406 Ex. 158 at 5-6, LL-8, LL-19 (La Plante Direct).
407 Ex. 29 at 4, 7-8 (Graika Rebuttal); Ex. 195 at DVL-U-&, columns (n) and (l) (Lusti Update).

373. The Company argued that O&M costs are needed for Minnesota Valley to mow, remove snow, pump water as needed, for inspections and to keep the area safe.[408] The Minnesota Valley facility has been retired; the expense is estimated to continue until 2013, and then to decrease to $150,000.[409] The decommissioning cost and the write-off of the accumulated reserve has been approved by the Commission, and will be recovered through depreciation expense for 6.5 years.[410]

374. French Island Unit 3 will be repaired and refurbished so that it can be returned to operation in 2014 (classified as Held for Future Use). Between now and then, a certain level of maintenance and inspections is necessary.[411] Plant Held For Future Use is allowed a rate of return but not depreciation.[412]

375. In order to assure that French Island Unit 3 does not deteriorate, a certain level of maintenance and inspection is necessary.[413]

376. The Department agreed that it was reasonable to retain Minnesota Valley and French Island Unit 3 in the rate base to cover the costs for decommissioning, but recovery of the costs for maintenance and inspection was not warranted because the facilities no longer benefit ratepayers.[414]

377. Minnesota Statute Section 216B.16, subd. 6, allows for depreciation of property that is used and useful in rendering service, but does not link operation and maintenance expenses to the same standard. The Company argued that the O&M costs are related to prior investment in units needed to meet customer energy requirements in the past, and for French Island Unit 3, to meet those requirements in the future.[415]

378. In support of its position, the Company relied upon the Supreme Court's decision in *In the Matter of the Request of Interstate Power Co. for Authority to Change Its Rates for Natural Gas Service in Minnesota (Interstate).*[416] The issue in *Interstate* was whether the Company would be allowed to include in its operating expenses the costs of cleaning up a gas facility that had not been used for many years, but for which the company bore some responsibility. The Supreme Court affirmed the Commission's decision to allow cost recovery through a rate increase, noting that it was not a perfect solution but it was not unfair or unreasonable, nor did it exceed the Commission's statutory authority.[417] The Supreme Court also found that it was an appropriate

[408] Ex. 29 at 2-4 (Graika Rebuttal).
[409] Ex. 29 at 4 (Graika Rebuttal).
[410] Ex. 66 at 13 (Perkett Rebuttal).
[411] Ex. 29 at 5 (Graika Rebuttal).
[412] Ex. 66 at 16 (Perkett Rebuttal).
[413] Ex. 29 at 5 (Graika Rebuttal).
[414] Ex. 159 at 6 (La Plante Surrebuttal).
[415] Xcel Energy Reply Brief at 78-81.
[416] 574 N.W.2d 408 (Minn. 1998).
[417] 574 N.W.2d at 414-415.

exercise of the Commission's quasi-judicial capacity to allow the costs because the gas facility had been used and useful at the time the pollution occurred.[418]

379. In *Interstate,* there was an obvious nexus between the use of the gas facility and the pollution that required clean-up. The ratepayers benefitted from the use of the gas facility at the time that the pollution was caused.

380. Applying the *Interstate* decision to the facts here leads to different results for Minnesota Valley and French Island Unit 3. For Minnesota Valley, the Company seeks to recover costs to maintain a facility that no longer benefits ratepayers. The Company chose to take the facility off line at some point prior to its demolition. Although it no doubt had good reasons to do so, and the Commission approved the decommissioning, the delay requires costs that have no current benefit to the ratepayers and do not arise from the previously attained benefit. Unlike the facts in *Interstate*, the costs have no relation to the benefit the ratepayers gained while the facility was operating.

381. In contrast, the ratepayers have a stake in the continued upkeep and inspection of French Island Unit 3 until it returns to service. By maintaining the facility, the costs to refurbish it will be decreased.

382. The O&M costs for French Island Unit 3 are reasonable and should be allowed; if the Settlement is not accepted, the ALJ finds that the O&M costs for Minnesota Valley are not reasonable.

<u>Software Maintenance Costs</u>[419]

383. The Company and the Department dispute whether software costs should be part of O&M, or treated as one-time capital expenses and amortized.[420] Amortizing the software costs over three years would reduce expenses by $933,333.[421]

384. The Company contended that this issue is based upon a misunderstanding.

385. The Company agreed that purchased software, such as the Windows 7 operating system, has a useful life greater than one year and should be capitalized. The Company purchases new maintenance agreements when it purchases new software. The maintenance costs may be based on a percentage of the purchase price of the software. Although the license fee or installation cost is capitalized as part of the asset, the ongoing updates, troubleshooting and general support are covered by the

[418] 574 N.W.2d 415.
[419] Summary of Issues, No. 6.
[420] Ex. 171 at 61-65 (Campbell Surrebuttal); Ex. 73 at 51 (Heuer Rebuttal).
[421] Ex. 171 at 65 (Campbell Surrebuttal).

maintenance agreement, and recur year after year for the time the Company uses the system, to keep the system up-to-date and operating.[422]

386. If the duration of the contract is one year or less, the Company assigns the cost to one year. In most cases, the maintenance contracts are paid through annual fees, generally with escalators to increase the costs each year.[423] When the Company enters into a multi-year contract and prepays the fees, the Company amortizes the costs over the period covered by the maintenance fee. If the prepaid expense is immaterial, it is expensed in the year incurred.[424]

387. The Company's approach is reasonable. To the extent that the contracts are for a specified period to provide maintenance and support, the cost should be spread over the contract period. When the Company prepays for a maintenance agreement that provides service over more than one year, it is treated as an expense in the first year of the contract and a prepaid expense for the remaining years of the contract, effectively amortizing the cost over the period of the contract.[425] This is consistent with the Department's position, and no change to Test Year expense is necessary.

<u>Grand Meadow Wind Project O&M</u>[426]

388. The Grand Meadow Wind Project is a 100.5 MW wind farm approved by the Commission and operational in 2008. The Company requested an increase of $1,048,386 in 2011 Test Year O&M expenses related to gearbox repair and rebuilding. The Department agreed to accept a portion, the $418,736 related to oil changes, as an expense, but opposed treating $250,000 for gearbox repairs as expense rather than as a capitalized cost. The Department also opposed any recovery of the $360,000 budgeted to replace generator bearings.[427]

389. The Company explained that the gearbox is considered a "rotatable spare," that is, it is held in inventory until it is installed and the removed unit is refurbished and placed into inventory until it is needed for replacement. The rotation between in-service and inventory is what designates the units as rotatable spares.[428] The cost of the crane and labor to change the gearbox was capitalized; the cost to rebuild the gearbox was not associated with the change to the gearbox and was expensed.[429] In making the distinction, the company relied on its policy, adopted in

[422] Ex. 66 at 7 (Perkett Rebuttal).
[423] Ex. 31 at 5 (Alhachich Direct).
[424] Ex. 66 at 7-8 (Perkett Rebuttal).
[425] Maintenance agreements may include vendor patches (i.e. repairs to the software asset) and upgrades to the software, arguably extending the useful life of the asset. Ex. 31 at 5 (Ahachich Direct).
[426] Summary of Issues, No. 10.
[427] Ex. 171 at 97-98 (Campbell Surrebuttal).
[428] Ex. 66 at 10 (Perkett Rebuttal).
[429] Ex. 29 at 15-16 (Graika Rebuttal).

response to FERC rules, identifying the replacement of a gearbox as a capital expenditure and the repair of a gear box as O&M.[430]

390. The Department failed to see the distinction.[431]

391. The Company has demonstrated that it had a reasonable basis for capitalizing certain costs related to the gearbox replacement while expensing the $250,000 for rebuilding the gearbox to place it back in service.

392. The Company included $360,000 for generator repairs because other companies had experienced generator bearing failures starting in the third year of operation and the Company anticipated that it would experience them. It had projected 6 generator failures in the 2011 Test Year and estimated costs of $60,000 for each one.[432]

393. The Department disallowed the $360,000 increase associated with generator repairs because there had not been any generator bearing failures at Grand Meadows, and both the number of failures and costs associated with each one were speculative. The Company provided no documentation to support the costs.[433]

394. The Company has failed to provide sufficient support for the $360,000 increase associated with possible generator bearing failures.

395. If the Settlement is not accepted, the ALJ finds that the costs of generator repairs associated with bearing failures are not reasonable.

Recovery of Nobles Wind Farm Additional Capital Costs[434]

396. The Company has incurred costs for Nobles Wind Farm Project (Nobles) that exceed the amount that the Commission approved for recovery through the Renewable Energy Standards (RES) Rider. Initially, the Company requested recovery of $13,703,000 to recover its additional capital costs, but reduced its request to $9,697,994 during the proceeding. The revenue requirement associated with the additional actual capital costs is $1,878,000. The Company asserted that it is entitled to recover revenue sufficient to enable it to meet the cost of furnishing services, the Nobles costs were reasonable and prudently incurred, and the costs varied only two percent from the original estimates included in the Nobles RES eligibility filing.[435]

397. The Company's acquisition of Nobles was approved by the Commission in 2009, and the Company was authorized to recover its estimated costs through the RES Rider. The Company first requested recovery of its additional costs through its 2009

[430] Ex. 66 at 10 and Sched. 4 (Capitalization Policy for Wind Turbine Generator Unit) (Perkett Rebuttal).
[431] Ex. 171 at 95 (Campbell Surrebuttal).
[432] Ex. 171 at 95-96 (Campbell Surrebuttal); Ex. 161 at NAC-34 (Xcel Response to OES IR 1123) (Campbell Direct).
[433] Ex. 171 at 96-97 (Campbell Surrebuttal).
[434] Summary of Issues, No. 4.
[435] Xcel Energy Reply Brief at 82.

RES Rider filing.[436] In that case, as in this case, the Department argued against recovery of capital costs in excess of the original estimate provided by the Company in the RES eligibility filing.[437] The Commission denied recovery of the additional capital costs at that time, limiting recovery through the RES Rider to the previously approved estimates, and noting the Department's arguments. However, it left the door open for the Company to recover the additional costs in its next rate case "upon a showing that it is reasonable to require ratepayers to pay for any such additional costs."[438]

Cost Recovery

398. The Department argued that costs in excess of those identified in the RES eligibility filing should not be recoverable. The Chamber of Commerce agreed with the Department. It argued that the Company should be bound by the costs it presented to the Commission at the time of its selection as a wind provider, which were a factor in that selection. Providers of power who have an approved Power Purchase Agreement (PPA) with the Company would be compelled to deliver at the agreed-upon price, without the option of seeking recovery of additional expenses from the ratepayers. When the Company presented the Nobles project to the Commission for approval, it was making a similar claim to deliver power at a price based on its projected costs. Thus, the Chamber claimed, it would be poor policy to allow the Company as the wind developer to benefit by recovering excess costs from the ratepayer that the Commission would not allow another wind developer to recover. The Department and the Chamber of Commerce would not place the burden of an underestimate on the ratepayers.[439]

399. The Company argued that the analogy to a PPA is not appropriate. As a regulated utility, it is obligated to reflect a reduction in costs as well as increased costs; the holder of a PPA is not. As an example, the Company claimed that ratepayers will benefit from the bonus depreciation changes that will reduce the present value of revenue requirements associated with the Nobles project.[440]

400. The Department acknowledged that ratepayers would not benefit from the bonus depreciation provision of the tax code but that the Nobles project overruns should be denied and the tax benefits allocated to shareholders.[441]

401. The Company also argued that the Commission has allowed amendment to PPA prices, citing the testimony of its witness, James Alders.[442] However, Mr. Alders' comment concerning revised PPA's was related to a commission docket to

[436] *In the Matter or the Petition of Northern States Power…for Approval of the 2010 Renewable Energy Standard Cost Recovery Rider and 2009 Renewable Energy Standard Tracker Report (2010 RES Rider Docket),* Order Approving 2010 RES Rider and 2009 RES Tracker Report, Establishing 2010 RES Charge, and Requiring Revised Tariff (Order) (April 22, 2010), Docket No. E002/M-09-1083.
[437] Xcel Energy Reply Brief, quoting 2010 RES Rider Docket Order at 4; Ex. 161 at 91-92 (Campbell Direct).
[438] 2010 RES Rider Docket, Order at 5; Ex. 27 at 25-27 (Graika Direct).
[439] Ex. 161 at 96-97 (Campbell Direct).
[440] Ex. 24 at 7 (Alders Rebuttal).
[441] Ex. 171 at 90 (Campbell Surrebuttal).
[442] Xcel Energy Reply Brief at 87, f.n.308, citing Tr. Vol. 1 at 159 (Alders).

clarify ownership of renewable energy credits. Mr. Alders stated that Xcel Energy and the counterparties were encouraged to negotiate settlements, and some price adjustments to PPA's were made as part of that negotiation. One cannot conclude from his statement that any price adjustment was passed through to ratepayers through rates.[443]

402. The Company attempted to analogize to the cost increase allowed for biomass PPA's pursuant to Minn. Stat. § 216B.2424, subd. 5a(e).[444] That provision was limited in time and set a cap on price. Its narrow tailoring better supports the position that increased costs are not ordinarily allowed.

403. The Company also pointed to the language of the RES Rider Statute, which allows the Commission to approve a rate schedule that provides for the automatic adjustment of charges to recover prudently incurred investments, expenses or costs associated with the facilities constructed, owned or operated to comply with the RES.[445]

404. The Company's reliance on the RES Rider Statute to support recovery of increasing costs is misplaced. The Commission has already determined that the statute allows recovery only of the amounts included in the initial estimates at the time the project was approved. The Commission acknowledged that the Company had unrecovered costs, but placed the burden on the Company to demonstrate in this proceeding that it was reasonable to require ratepayers to pay the additional costs through rates.[446]

405. If the Settlement is not approved, the ALJ finds that the Company has failed to demonstrate that additional capital costs for the Nobles project should be allowed in its rate base.

Reasonableness of the Nobles Costs

406. In the event that the Commission determines that allowing the Company to recover its reasonable, increased costs is permissible, the Department challenged the reasonableness of some of those costs.

407. The Company described three categories of cost: labor, non-labor and contingencies.[447] The Company and the Department agreed on the reasonable level of labor costs.[448]

408. The non-labor costs have three components: project overhead, landowner payments and interconnection costs. The Company and the Department agreed on the

[443] Tr. Vol. 1 at 158-159 (Alders).
[444] Xcel Energy Reply Brief at 87, f.n. 308.
[445] Xcel Energy Reply Brief at 85-86, citing Minn. Stat. § 216B.1645, subd. 2a.
[446] *2010 RES Rider Docket*, Order at 5.
[447] Ex. 27 at 28 (Graika Direct).
[448] Ex. 24 at 13 (Alders Rebuttal); Ex. 171 at 84 (Campbell Surrebuttal); Ex. 173 at 6 (Campbell Opening Statement); Department's Initial Brief at 125.

interconnection costs.[449] They disagreed on the other two components, landowner payments and project overhead.

409. The Department challenged the increased costs for the landowner payments because it was concerned that it included double payments.[450] Landowners were given the choice between an up-front lump sum payment and annual payments over the life of the project. The two options are designed to give landowners approximately equivalent alternatives on a present value basis, but the Company accounts for the two types of payment differently. The single lump sum payment is treated as a capital expenditure, while the annual payments are an O&M expense. The Company's capital costs increased because more customers than anticipated selected that option than selected the annual payments.[451] However, the Company has demonstrated that there was no double-counting of the payments – the two figures together represent the total landowner payments for the project and do not change the cost of energy generated by Nobles in any material way.[452]

410. The landowner payments are reasonable costs of the project.

411. The Company allocated overhead costs that cannot be directly or indirectly assigned, such as corporate administrative, supervision and general expenditures. The company periodically conducts studies to identify capital support activities that are not assignable, places them in a capital pool, and distributes them to capital projects in proportion to size. As the Nobles capital costs increased, so did its allocated project overhead.[453]

412. The Department did not agree with including the additional project overhead costs, $380.000. It maintained that the Company had failed to show what costs had gone up to warrant the additional allocation of overhead.[454]

413. The Company's explanation for the calculation of additional project overhead was not tied directly to any particular increased cost; rather, it was based upon the application of the Company's indirect cost allocation methodology to the increased capital cost.

414. If the Commission determines that it is reasonable to allow recovery of the increased capital costs, above the estimates previously approved, the increased overhead allocation would logically follow, as consistent with the Company's indirect cost allocation methodology.[455]

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[449] Ex. 24 at 20 (Alders Rebuttal); Ex. 171 at 86-87 (Campbell Surrebuttal); Department's Initial Brief at 126.
[450] Ex. 173 at 5-7(Campbell Opening Statement).
[451] Ex. 27 at 15 (Graika Direct); Ex. 24 at 19 (Alders Rebuttal).
[452] Ex. 24 at 19 and Sched. 5 (Alders Rebuttal).
[453] Ex. 24 at 18-19 (Alders Rebuttal).
[454] Ex. 171 at 86 (Campbell Surrebuttal).
[455] It is not clear to the ALJ whether this overhead, if not allocated here, would have been allocated to other projects included in the rate calculation.

415. In addition to labor and non-labor costs, the Company had a third category of Nobles cost increases that it requested, for contingency costs. The Department challenged the $6,200,000 that the Company requested, concluding that the appropriate amount, as demonstrated by the Company, was $2,167,994.[456] The Company concurred with this figure.[457]

416. In the event that the Commission determines that the Company should be allowed to recover capital costs in excess of the amount recovered through the RES Rider, the Company's landowner costs and project overhead are reasonable; the agreement with the Department concerning contingency costs is reasonable.

Smart VAR[458]

417. The Smart VAR Management Pilot Project is a component of the Central Corridor Utility Zone. Initially, the Company requested deferred accounting for 2010 expenses, but it dropped that request and made a corresponding adjustment.[459] The Department and the Company have limited the issue to whether the Company should recover its full 2011 Test Year expense of $134,000, or only three quarters of that amount.

418. The Department contended that only three quarters of the expense should be borne by ratepayers and the remaining balance borne by shareholders because it did not believe that the Company had made timely requests for grant support for the project.[460] The Company explained why it could not make grant requests after it began installing smart capacitor controls; it did not explain its failure to seek grant funding before installation began.[461]

419. The Company has demonstrated that its costs for Smart VAR are reasonable. The Department has not claimed that the Smart VAR costs are unreasonable, nor has it offered any authority for its position that the Company should have submitted grant proposals to recover a portion of the cost.

Costs Disputed by the OAG

Bad Debt Expense[462]

420. The Company initially included $12,773,490 for 2011 Test Year bad debt expense. In response to concerns raised by the OAG, it reduced the revenue

456 Ex. 171 at 88 (Campbell Surrebuttal).
457 Ex. 24 at 23, Table 4 (Alders Rebuttal); Xcel Energy Reply Brief at 82, f.n. 300.
458 Summary of Issues, No. 22.
459 Ex. 73 at 74-75, Sched. 5b, column 23; Ex. 195 at DVL-U-7, column (au) (Lusti Update).
460 Ex. 173 at 7 (Campbell Opening Statement).
461 Xcel Energy Reply Brief at 93.
462 Summary of Issues, No. 23.

requirement by $2.399 million to $10.375 million, the same level of bad debt expense that it incurred for 2010.[463]

421. The Company determined bad debt expense by applying the percentage of historical actual bad debt, using a 121- month rolling average through the first quarter of 2010, times commodity revenues, to calculate a debt ratio.[464]

422. The Company's bad debt expense has declined in recent years. The Company attributed the decline to improved customer collection initiatives.[465]

423. The OAG attributed the decline in bad debt expenses to decreases in the commodity costs of energy, particularly natural gas, and the increased funding dedicated to energy affordability programs in recent years.[466] The Company agreed that lower fuel costs and low income programs have also lowered bad debt expense and are taken into account in the calculation.[467]

424. The OAG claimed that the Company is able to over-recover bad debt expense because of the method employed to divide up bad debt between gas and electric customers, and because the Company does not forecast any effect of affordability programs on bad debt. It contended that $10.4 million, added to the amount approved in the Company's most recent gas rate case, will allow the Company to recover $14,575,879, which exceeds its actual 2010 expense by $1.2 million.[468]

425. As the Company correctly pointed out, the rate case is built on a 2011 Test Year; one expense for 2010 should not be examined separately from all other expenses and revenues to determine whether there has been over or under recovery.[469] The Company followed a rational process by which it allocated bad debt expenses at a total operating company level, and properly applied write-offs or payments on arrearage. Then, the Company assigned bad debt expense to utility and jurisdiction using the 48-month historic average of retail revenues to utility and jurisdiction, updated annually.[470] The Company's approach was reasonable.

426. Affordability programs help improve customer payments and reduce bad debt expense. The Company received an increase of nearly $20 million from these programs between 2007 and 2010.[471] The OAG is concerned that the Company cannot quantify the effect that the affordability programs have on the level of bad debt expense, particularly customer arrearages, late payments, and bad debt.[472]

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[463] Tr. Vol. 1 at 185-187 (Gersack); Tr. Vol. 4 at 71 (Heuer).
[464] Ex. 32 at 6 and Sched. 3 (Gersack Direct).
[465] Ex. 32 at 8-9 (Gersack Direct); Ex. 33 at Sched. 1, 170-172 of 172 (Gersack Rebuttal).
[466] Ex. 137 at 17-19 (Smith Direct).
[467] Xcel Energy Reply Brief at 131.
[468] OAG Initial Brief at 51-54.
[469] Xcel Energy Reply Brief at 132.
[470] Ex. 32 at 6 (Gersack Direct).
[471] Tr. Vol. 1 at 188 (Gersack); Ex. 140 at 19 and Sched. 8 (Smith Surrebuttal).
[472] Ex. 137 at 16-18 (Smith Direct).

427. The Company admitted that it cannot quantify the impact that such programs have on its bad debt, although it is certain that the programs are very beneficial to customers.[473] When the Company receives funds from affordability programs, they are applied to customer accounts or reduce outstanding customer account receivables, which are reflected in the Company's bad debt expense forecast.[474]

428. The OAG has failed to explain why correlating the reduction in bad debt expense to the affordability programs is important. The Company has acknowledged that the affordability programs may help reduce bad debt, but it is only one of many factors. Since commodity price, weather, the overall economy and the Company's debt collection efforts all play a role, and the actual reduction in bad debt is reflected in the bad debt ratio, it is not clear why allocation of savings to one factor or another is significant.

429. The OAG also challenged $448,182, the portion of the bad debt that is unrelated to retail customers, but tied to items such as unpaid damage claims against third parties, unpaid billings for contribution in aid of construction, and non-retail commodity bad debt. The OAG asserted that the Company had failed to demonstrate why the ratepayers would be responsible for these categories of unpaid debt.[475]

430. The Company acknowledged that its bad debt includes third party failures to pay money owed to the Company. Information about those recoveries was included in a response to the OAG.[476] However, it also pointed out that it has other income than retail rates and when other income is received, it offsets the revenue requirement.[477]

431. In order to address its concerns, the OAG proposed that the Company's bad debt expense be reduced to $9,138,368. That amount, added to the amount approved for recovery from gas customers, would allow the Company to recover its actual 2010 bad debt expense, on a combined gas and electric basis. The OAG's rationale was that the Company relied upon a methodology that incorporates both electric and natural gas bad debt expenses, and it should not be allowed to recover more than its actual costs through the combined ratesetting.[478]

432. The Company has provided a rational explanation for its calculation of bad debt expense and has further reduced its 2011 Test Year expense. There is no basis to reduce the expense to the level proposed by the OAG. The Company has demonstrated that its reduced bad debt expense is reasonable.

[473] Tr. Vol. 1 at 191 (Gersack).
[474] Ex. 33 at 2 (Gersack Rebuttal); Tr. Vol. 1 at 189-190 (Gersack).
[475] OAG Initial Brief at 55-56. The Brief includes Attachment 1, an email from the Company, provided to OAG after the close of the June portion of the evidentiary hearing. The email was not offered into evidence, and the Company had no opportunity to address it at hearing.
[476] Ex. 33 at Sched. 1 (Gersack Rebuttal).
[477] Xcel Energy Reply Brief at 134.
[478] OAG Initial Brief at 56-57.

433. To better ascertain the possible correlation between gas and electric revenue and bad debt, the Company has agreed to file testimony supporting its joint electric and gas commodity revenue forecast, including natural gas sales volumes and fuel prices, in its next electric rate case.[479] The OAG requested that this agreement be reflected in the Commission's Order.[480]

Corporate Aviation[481]

434. The Company included $730,000 in 2011 Test Year expense to recover 50 percent of the budgeted corporate aircraft costs, an approximate 62 percent reduction from the corporate aviation costs approved in the Company's last rate case.[482] The Company argued that including just 50 percent of the corporate aviation costs was reasonable.[483]

435. The Company asserted that the corporate aircraft facilitate its business; approximately 89 percent of the trips were to and from cities where it has significant employees and business operations. Other trips transported employees and executives to stock analyst meetings, state and federal commission and agency meetings, Edison Electric Institute meetings, and Board of Director meetings. Remaining trips were for maintenance or to address passenger scheduling.[484]

436. To support its claim of prudency, the Company commissioned a cost-benefit analysis of corporate aircraft use in 2008 and 2009. The study showed that the Company's corporate aviation costs were slightly below to slightly above comparable commercial air travel for 2008 and slightly above comparable commercial airline travel for 2009, in part because of a one-time valuation adjustment and a decrease in use.[485]

437. The OAG argued that the entire corporate aviation expense should be removed. It calculated that the round trip cost associated with flying a passenger on one of the corporate jets was over $5,000. Most of the flights were between Denver and St. Paul; the OAG estimated the cost of a round trip commercial flight cost to be between $200 and $300. The OAG examined a draft of the Company's study and noted that the Company claimed that use of the corporate aircraft saved employees approximately two hours, most of which represented time waiting in the airport. The OAG contended that the compensation cost per hour would have to be excessive to justify the high value placed on the time waiting.[486]

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[479] Xcel Energy Update to Summary of Issues at 9 (Dec. 12, 2011); Edocket Doc. No. 201112-69163-01.
[480] OAG Initial Brief at 50, f.n. 170.
[481] Summary of Issues, No. 82.
[482] Ex. 54 at 26 (O'Hara Rebuttal); Ex. 70 at 141-42 (Heuer Direct).
[483] Xcel Energy Reply Brief at 161.
[484] Ex. 137 at Sched. 34 (Smith Direct) (Xcel Response to OAG IR 1110).
[485] Ex. 54 at 27-28 (O'Hara Rebuttal).
[486] Ex. 137 at 45-49 (Smith Direct).

438. The OAG noted that the Company did not dispute its calculation but, instead, at tempted to justify the benefits derived from corporate aviation, including increased in-flight productivity, reduced stress and fatigue, and personal security.[487]

439. Because the Company applied generic descriptions to the travel, such as employee relations, business matters or business meetings, the OAG was not able to calculate the number of flights that could be justified by cost savings.[488] For this reason, the OAG recommended that no amount be included for corporate aviation expense.[489]

440. Ratepayers have difficulty understanding why costs for corporate aviation should be included in rates. The Company pays its top executives handsomely - enough to pay their own costs if they prefer the convenience, reduced stress and comfort of using private aviation. At the same time, the Company uses the high rates of compensation to value the time saved by flying on corporate aircraft. There may be instances where the combined airfares for a group to fly on commercial flights would be sufficient to cover the costs of the corporate aircraft. But the notion of reduced stress and time savings for Company employees who are likely to have access to airline lounges and fly business or first class is not compelling to ratepayers. When economic times are tough and any rate increase is a hardship to some, the idea of paying any amount for corporate aircraft for executives, board members and employees is offensive to many and signals to them that the Company fails to appreciate the impact of a rate increase.[490]

441. The Company has reduced its corporate aviation costs by 60 percent from the level that the Commission approved in the 2008 Electric Rate case. The Company has demonstrated that it is reasonable to include some costs for corporate aviation in its rates. The Company's agreement to better track the purpose of employee expenses should be extended to use of corporate aircraft.

Costs Disputed by the Chamber of Commerce

Advertising Expense[491]

442. The Company requested $2,088,341 for costs related to advertising in the 2011 Test Year.

443. The Chamber of Commerce objected to the Company's use of the tagline "Responsible by Nature." It maintained that the use of the tagline was not authorized by statute and has "advertising value."[492] However, the Chamber of Commerce did not respond to the Company's rebuttal testimony, which included copies of the advertising

[487] Ex. 55 at 27 (O'Hara Rebuttal); Ex. 137 at 46 and Sched. 34 (Smith Direct).
[488] Ex. 137 at 48 (Smith Direct).
[489] OAG Initial Brief at 94; OAG Reply Brief at 33.
[490] Ex. 140 at 24 (Smith Surrebuttal).
[491] Summary of Issues, No. 87.
[492] Ex. 120 at 40 (Schedin Direct).

that included the tagline, or defend its application of the statute in its post-hearing submissions.

444. The statute precludes allowing the rate to include any portion of a public advertisement that *inter alia* "is designed primarily to promote good will for the public utility or improve the utility's public image."[493] It permits a public utility to disseminate information that: "(1) is designed to encourage conservation of energy supplies; (2) is designed to promote safety; or (3) is designed to inform and educated customers as to financial services" available to them.[494]

445. The Department applied the statutory criteria set forth in Minn. Stat. § 216B.16, subd. 8, as well as the Commission's Advertising Policy, and concurred with the Company that the primary purpose of the advertisement containing the tagline was to encourage conservation, promote energy and educate customers about the services available to them.[495]

446. The Company has demonstrated that its advertising expense, including use of the tagline "Responsible by Nature," is reasonable.

447. The following is a list of reductions to the Company's proposed revenue requirement that should be made if the terms of the Settlement are not accepted. The list does not include the compensation reductions discussed above.

Summary of Reductions to Revenue Requirement Not Addressed in the Settlement

- Foundation Administrative Costs - $330,380
- Investor Relations - $466,789
- 2009 Rate Case Expenses - $398,000
- Minnesota Valley O&M - $310,000
- Grand Meadow Generator Bearings - $360,000
- Nobles Wind Farm - $1,878,000

TOTAL: $3,743,169

448. The total reductions are relatively small in comparison to the revenue requirement and are offset by the Company's agreement to mitigate the rate increase by a change in depreciation. The Company has asserted that it would not have agreed to change its depreciation but for the Settlement.

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[493] Minn. Stat. § 216B.16, subd. 8 (a)(4).
[494] Minn. Stat. § 216B.16, subd. 8 (b).
[495] Ex. 146 at 2-4 (Davis Direct).

Conclusion – The Terms of the Settlement are Reasonable

449. Overall, the terms of the Settlement are fair and reasonable. As discussed in detail above, it offers a compromise of several disputed issues related to the revenue requirement, including an ROE of 8.31 percent, a reasonable capital structure, the 2011 costs of the Monticello LCM/EPU, the SEP Rider and other identified riders, treatment of depreciation expense, the 2012 step-in adjustment for the Monticello LCM/EPU, removal of non-asset-based trading from rates, and the deferral and amortization of the nuclear refueling costs. Although the Settlement does not separately address the disputed compensation issues, the Settlement's reduction of compensation by $7.5 million is a reasonable approximation of the Company's reasonable compensation costs when separately evaluated. The Settlement did not resolve some of the expense issues, listed in the preceding section, which would have further reduced the Company's revenue requirement. However, the relatively small reduction tied to those disputed expenses is more than offset by the Company's agreement to alter its depreciation calculation.

450. The provisions of the Settlement that incorporated the sales forecast, rate design issues, and Studies, Reporting and Other Agreements are also fair and reasonable.

451. The Settlement did not resolve most issues concerning rate design. Those will be analyzed in the following findings.

Rate Design Principles

452. Although some rate design issues were resolved by the Settlement, key issues concerning the Class Cost of Service Study, Revenue Apportionment and Customer Charges were not addressed by the Settlement.

453. Once the Commission has determined the utility's revenue requirement, it must determine which customer classes should pay for the costs reflected in the revenue deficiency, and how rates should be constructed to recover those costs from customers.

454. Rates must be just and reasonable, and an important aspect of reasonable rates is their design. Rate design is largely a quasi-legislative function, involving policy decisions.[496]

455. The Commission has relied on the following four principles in establishing reasonable rate design:

[496] *See* Minn. Stat. § 216B.03; *Matter of Request of Interstate Power Co. for Authority to Change Its Rates For Natural Gas Service in Minnesota*, 559 N.W.2d 130, 133 (Minn. App. 1997), *aff'd* 574 N.W.2d 408 (Minn. 1998).

- Rates should be designed to allow the Company a reasonable opportunity to recover its revenue requirement, including cost of capital;

- Rates should promote the efficient use of resources, sending an appropriate price signal to customers that reflects the cost of serving them and encourage conservation;

- Rate changes should be gradual in order to limit rate shock to the customers;

- Rates should be understandable and easy to administer to help ensure that customers understand their energy bills.[497]

These principles are based on the provisions of Minnesota statutes, which require that rates must be reasonable and not unreasonably discriminatory either by class or by person.[498] Rate design should favor energy conservation and the use of renewable energy.[499] Doubts about the reasonableness of the rates should be resolved in favor of the consumer.[500]

Class Cost of Service Study (CCOSS)

456. Once the revenue requirement is calculated, the utility must determine the appropriate rates to charge each rate class to generate the required revenue. Typically, the first step in determining the appropriate rate design is to conduct a "class cost of service study" (CCOSS). The purpose of the CCOSS is to attempt to identify the actual cost of providing service to each rate class, based on its load and service characteristics. There are three steps in performing a CCOSS. First, costs are functionalized, or grouped according to their purpose. Second, costs are classified based on how they are incurred. Third, costs are allocated to the various customer classes. Although there is a relationship between the expense and the class, it may not always be precise. The results of the CCOSS are a starting point to establish the rates so that revenue is recovered from each customer class at a level that takes its costs into account.[501]

457. The functionalized costs are classified as "customer," "demand,' and "energy" costs according to how they are incurred. "Customer" costs are those operating and capital costs that vary with the number of customers regardless of the customers' energy consumption. They include the costs of metering, billing, tracking accounts and responding to customer questions. "Demand" costs are those costs incurred to serve the peak demand on the system (such as the size of the distribution system) and are not affected by the number of customers to be served. "Energy" costs

[497] Ex. 147 at 3 (Peirce Direct).
[498] Minn. Stat. §§ 216B.07 and 216B.03.
[499] Minn. Stat. §§ 216B.03, 216C.05.
[500] Minn. Stat. § 216B.03.
[501] Ex. 154 at 3 (Ouanes Direct).

consist of those costs that vary with the quantity of energy produced (such as cost of fuel).[502]

458. The functionalized, classified costs are usually allocated to customer classes as follows:

- Customer-related costs are allocated among the customer classes based on the number of customers, typically weighted to reflect difference among the classes;
- Demand-related costs are allocated among the customer classes based on the demand imposed by the class on the system during specific peak hours; and
- Energy-related costs are allocated among the customer classes based on the energy that the system supplies to serve the various customer classes.[503]

459. The Company has prepared an embedded CCOSS for the 2011 Test Year and the 2012 step-in adjustment. It has used the same basic stratification methodology for many years, which was approved in the Company's most recent electric rate case.[504]

460. The Company assigned costs to four classes: Residential, Commercial and Industrial (C&I) Non-demand, C&I Demand, and Street Lighting (Lighting).[505]

461. At the Department's request, the Company re-ran the CCOSS to include the Midwest Independent Transmission System Operator (MISO) updated wind capacity credit and to reclassify two wind projects in the same way as other production plant costs, 96 percent demand-related and four percent energy-related, rather than 100 percent demand-related. The corrected CCOSS also incorporated a change in the classification of the generation step-up facilities. The corrected CCOSS decreased the Residential class contribution to the revenue requirement by about $11.7 million, with a corresponding increase in C&I Demand class contribution of about $11.6 million. The Department recommended approval of the corrected 2011 CCOSS.[506]

462. The Chamber of Commerce, XLI and the OAG disputed the Company's CCOSS.

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[502] Ex. 154 at 4-5 (Ouanes Direct).
[503] Ex. 154 at 5-6 (Ouanes Direct).
[504] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order at 44 (Oct. 23, 2009).
[505] Ex. 79 at 4 (Zins Direct).
[506] Ex. 157 at 8-10, 13-14 (Ouanes Surrebuttal) Tr. Vol. 6 at 30-30 (Ouanes); Ex. 82 at Sched. 1 (Zins Rebuttal).

XLI's Objections

463. XLI criticized the stratification methodology as contrary to industry practice.[507] However, in light of the Commission's prior approval of its use, XLI proposed six changes to the CCOSS that, in its view, would more properly allocate costs, with significant effect. XLI argued that the scope of the difference is evidence that the Company's CCOSS methodology is flawed;[508] the Company maintained that the changes would approximate the results of using an entirely different CCOSS methodology.[509]

Allocation of Demand Costs

464. XLI proposed two adjustments to the Company's allocation of generation demand ("capacity") costs. It asserted that: (1) the Company should not incorporate a winter peak into its allocation of demand-related production and transmission plant costs; and (2) the Company has included double-counting of demand.

465. The Company included non-summer months in its calculation of capacity costs. XLI maintained that only summer months should be used because the Company is a summer-peaking utility.[510] Since demand costs are those incurred to meet peak demand, XLI maintained that the Company should limit its determination to the summer months, which is also consistent with the Company's system planning.[511]

466. XLI maintained that the issue was not whether specific plants are needed to meet demand in non-summer months, but what drives the Company to incur the cost of peaking capacity. Peaking capacity is needed to maintain reliability during the most crucial time periods, which occur in the summer. With sufficient capacity to meet that demand, the resource is available, of course, to meet needs throughout the year.[512]

467. Also, XLI maintained that the Company was double-counting the capacity used both at peaking and for average demand. It prepared a chart that it claimed showed how the investment used "around the clock" (or average demand) and already allocated on a weighted average kilowatt-hour basis, was also being allocated to peak (or excess) demand. XLI claimed that, since the peaking plant is only needed to serve load in addition to or in excess of the load served around the clock, it was that cost alone that should allocated.[513]

[507] Ex. 124 at 48-50 (Pollock Direct).
[508] XLI Reply Brief at 3.
[509] Xcel Energy Rate Design Brief at 5; Ex. 82 at 45 (Zins Rebuttal).
[510] Ex. 124 at 52 (Pollock Direct), quoting the Company's resource plan.
[511] Ex. 127 at 27-28 (Pollock Surrebuttal).
[512] Ex. 127 at 28 (Pollock Surrebuttal).
[513] Ex. 124 at 53-54 and Sched. 12 (Pollock Direct); Ex. 127 at 30 and Sched. S2 (Pollock Surrebuttal). Schedule S2 is reprinted at XLI Initial Brief at 11. *See also* Tr. Vol. 5 at 124-125 (Pollock).

468. In response to the Company's defense of its allocation, XLI opined that if excess demand drives the Company's allocation of costs between seasons, it should also drive the allocation to customer classes.[514]

469. The effect of XLI's generation capacity allocators would significantly shift cost responsibility to the Residential class from the C&I Demand class.[515]

	Company	XLI
Residential	34.5%	43.0%
C&I Demand	61.7%	53.0%

470. The Company explained how energy-related costs were separated from capacity-related costs, its use of the winter and summer peaks, and also explained why it did not double-count average demands. Its process of cost identification and separation is completely separate from the development of the class allocation factors.[516]

471. The Company has fully explained its reasonable method for allocation of generation demand costs.[517]

Generation Step-Up Transformers

472. Step-up transformers increase the voltage from a generation facility to match the voltage of the transmission to which the generation is connected. The Company functionalized the step-up transformers to generation based on the Commission's Order Adopting Boundary Guidelines for Distinguishing Transmission from General and Distribution Assets (Boundary Guidelines Order),[518] and classified generation step-up investment and related costs as 72 percent demand-related and 28 percent energy-related.[519]

473. XLI disputed the Company's allocation of any portion of the step-up substations to energy-related costs, claiming that there was no logical connection between these substations and the energy cost. The Company later revised the figure,

[514] Ex. 127 at 29 (Pollock Surrebuttal).
[515] Ex. 82 at Sched. 9 (Zins Rebuttal); *see also* Ex. 124 at Sched. 12 (Pollock Direct).
[516] Ex. 82 at 33 (Zins Rebuttal); Xcel Energy Rate Design Brief at 6-9.
[517] Xcel Energy Rate Design Brief at 6-8.
[518] Xcel Energy Rate Design Brief at 8, quoting *In the Matter of a Proceeding to Develop Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions,* Order Adopting Boundary Guidelines for Distinguishing Transmission from Generation and Distribution Assets, at 4, Docket No. E999/CI-99-1261 (July 26, 2000) (Boundary Guidelines Order).
[519] Ex. 124 at 56 (Pollock Direct).

agreeing to stratify the step-up facilities based on the same percentages as the plants of which they are a part.[520]

474. XLI argued that the Boundary Guidelines Order should not apply because it was intended to address issues of jurisdiction, not the allocation of costs. Step-up transformers are functionally unlike generation (*i.e.* do not generate energy) and are unaffected by peak load. The Order is limited to the functional unbundling of assets; the Commission was addressing the need to separate generation, transmission and distribution because different utilities might provide different components, and for other reasons as well. The Order stated:

> The Commission adopts the attached guidelines [with appendices] for the purpose of determining the functional boundaries between the transmission and generation functions, and between the transmission and distribution functions. The Commission directs parties to use the guidelines and appendices in all future proceedings involving functional unbundling and other relevant proceedings.[521]

475. XLI's distinction may be worth further consideration by the Commission. However, the Company has demonstrated that it has categorized the step-up transformer consistently with the Boundary Guidelines Order.

Other Production O&M Expenses

476. The Company has O&M costs related to production plants, other than fuel and purchased power expenses. These include labor, materials, supplies, and the supervision and engineering expenses associated with operating and maintaining the Company's power plants. The Company stratifies these Other Production O&M costs into demand-related and energy-related, based on the corresponding stratification percentage of the power plant investment, including nuclear fuel costs, which are capitalized and therefore treated as investment.[522] It classified 15 percent of Other Production O&M Costs as demand-related and 85 percent as energy-related, based on the company's classification of production plant.[523]

477. XLI disagreed with the Company's allocation. Because some of the expenses do not change with the amount of output, XLI would allocate more of the cost to demand: 35 percent demand-related and 65 percent as energy-related. Specifically, XLI classified costs as follows:

- Operating labor-related expense and maintenance of structures were classified to demand;

[520] Tr. Vol. 4 at 154-155 (Zins).
[521] Boundary Guidelines Order at 4.
[522] Ex. 82 at 37 (Zins Rebuttal).
[523] Ex. 124 at 58-59 (Pollock Direct).

- Operating materials and maintenance of boilers, electric plant and miscellaneous equipment were classified to energy; and

- Supervision & engineering expenses were prorated on the amount of previously classified labor expense.[524]

478. The Company stratified these expenses in the same way that it stratified the production plant, allocating a proportion as demand-related and a proportion as energy-related. The Company did not agree that costs that do not vary with output should be allocated to demand. As an example, power plant investment costs are fixed, but the entire investment cost is not treated as demand-related. Some portions, such as nuclear fuel, are capitalized but allocated as energy-related costs. Costs such as burning, handling and safekeeping of the nuclear fuel inventory are also energy-related and should be allocated accordingly.[525]

479. Although the Company has used a rational method for allocation of the Other O&M costs, XLI has raised an issue that warrants some additional consideration to determine whether the proportional allocation followed by the Company is a reasonable proxy for the assignment of the costs, and is consistent with the cost allocation manual issued by the National Association of Regulatory Utility Commissioners (NARUC).[526] However, some of XLI's alternative allocations, such as the allocation of all maintenance of boilers, electric plant and miscellaneous equipment as energy-related costs, and allocation of all labor-related expense as demand-related, are not compelling.

Interruptible Service Credits

480. The parties to the Settlement reached an agreement concerning the rates for Interruptible service; however, the allocation of Interruptible service credits or rate discount for purposes of the CCOSS is disputed.

481. XLI had several objections to the Company's treatment of Interruptible service payments (or credits). It asserted that the company's treatment differed from its approach in the last rate case; and objected to use of the term "discount" because it incorrectly implied that Interruptible ("load management") customers were paying rates below cost.[527] It objected to the company's treatment of the Interruptible discounts as a cost of peaking capacity and its allocation of those costs based on firmed-up loads, asserting that the costs violated "cost causation" principles because peaking costs should not be charged to the Interruptible customers. XLI also asserted that the Company's allocation method was contrary to FERC guidance and incompatible with the Company's approach to system planning.

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[524] Ex. 124 at 59 (Pollock Direct).
[525] Ex. 82 at 37-38 (Zins Rebuttal).
[526] *See* NARUC *Electric Utility Cost Allocation Manual,* January 1992.
[527] Ex. 124 at 60-61 (Pollock Direct).

482. The Company denied that it had made any substantive change to its treatment of the Interruptible rate discount in the CCOSS. Its only change was minor, a relabeling of one line of data.[528]

483. The Company treated the Interruptible discounts as a cost of peaking capacity, and allocated the cost to all classes based on firm loads (*i.e.* the class loads that would be realized with load control). It explained:

> [T]he Company's CCOSS ... allocates all costs of service (including the costs of peaking capacity purchased from interruptible customers) to the customer classes in order to determine rates for firm reliable service. Then, after the fact, the Company's interruptible rate programs offer customers market-based discounts from the firm service rate in order to buy back an optimum amount of firm service entitlement (peaking capacity) from willing customers.[529]

484. The Company also explained why it considered the Interruptible service credits or "payments" to be discounts. The company calculated the cost of peaking capacity from Interruptible rate programs to be an average of $70 per kW. This is about 150 percent of the total average embedded costs of peaking capacity, reflecting forecasted higher future avoided costs. When higher future avoided costs are subtracted from current embedded cost rates, the resulting rate to Interruptible customers is below the embedded cost of service.[530]

485. XLI's main objection was that allocation of peaking costs to customers who do not contribute to those costs violates the rate-making principle of cost causation.[531] It objected to treating Interruptible customers as firm customers whose discounts are the cost of the peaking capacity purchased from them. It argued that the Company should measure the results of the CCOSS using firmed up revenues, and the corresponding credits should be separately allocated to firm customers. XLI would either exclude the Interruptible load from the CCOSS or treat the Interruptible load as firm but allocate the credits to the firm loads.[532]

486. The Company responded that its approach did not violate any "cost causation" principle and its approach is correct when future avoided costs will exceed the average embedded CCOSS for peaking.[533]

487. XLI's two remaining arguments have no merit. Although XLI cited a FERC ruling to support its point, it was not possible to determine whether the CCOSS methodology or the cost and rate-design details were the same. The Department

[528] Ex. 82 at 40 (Zins Rebuttal).
[529] Ex. 82 at 44 (Zins Rebuttal).
[530] Ex. 82 at 40-41 (Zins Rebuttal).
[531] Ex. 124 at 64 (Pollock Direct).
[532] Ex. 124 at 63 and Sched. 15 (Pollock Direct).
[533] Ex. 82 at 42 (Zins Rebuttal).

objected to the relevance of the FERC Order, and XLI did not respond to the Department's objection.[534]

488. Although XLI took issue with the Company's approach to calculating the costs of peak capacity and its assignment among the classes, the Company has followed the approach consistently, and it has been approved the Commission. That it does not equate to the Company's approach to resource planning is not relevant here. No other party agreed with XLI that the Company's method of cost allocation for interruptible service credits was unreasonable.

489. The Company follows a process that allocates all costs of service, including the costs of peaking capacity purchased from the interruptible customers, to set rates for firm reliable service. Then, it offers market-based discounts from the firm service rate to obtain the necessary level of capacity. The Company has demonstrated that its method of calculating Interruptible service discounts is reasonable.

Chamber of Commerce Objections to the CCOSS

490. The Chamber of Commerce disputed the Company's treatment of its wind assets in the CCOSS and would allocate 96 percent of the wind assets to energy and four percent to demand.[535] The result of the Company's allocation, the Chamber claimed, is that the cost is disproportionately allocated to high load-factor ratepayers.

491. The Chamber of Commerce argued that, since wind is not purchased as least-cost energy, it should not be allocated as such, pointing out that the Company's witness, Mr. Zins, acknowledged that the Company used a least cost presumption in its acquisition of resources.[536] The Chamber also claimed that the Department failed to recognize that the focus of the investment is not to satisfy energy or demand needs but, rather, to satisfy legislative policy.[537]

492. The Chamber of Commerce pointed to the high cost of wind resources and the evidence that such resources were not least cost when compared to replacement power purchased through MISO. It asserted that ratepayers are paying a premium for a policy mandate, which supports the Chamber's claim that more of the cost should be allocated to demand rather than to energy.[538]

493. The Chamber of Commerce proposed three alternative methods to allocate costs more appropriately while supporting the policy behind wind investment.

- Allocating the costs of wind resources 50 percent to energy and 50 percent to demand;

[534] Ex. 88 at 43 (Zins Rebuttal); Ex. 127 at 34-37 (Pollock Surrebuttal).
[535] The Chamber of Commerce used the term "capacity" rather than demand.
[536] Tr. Vol. 4 at 151 (Zins); Chamber of Commerce Initial Brief at 4.
[537] Chamber of Commerce Initial Brief at 4; Chamber of Commerce Reply Brief at 1.
[538] Ex. 121 at 19-20 (Schedin Surrebutal); Chamber of Commerce Initial Brief at 3-4.

- Identify output weighted savings in \$/MWh since the plant has been in service (i.e., the sum of hourly wind output multiplied by hourly prices, divided by total output), and classify the result as energy-related; allocating the difference between the levelized cost in \$/MWh and the output weighted savings as demand-related; or

- In accordance with the system average class responsibility, based on percent of base rate responsibility by class.[539]

494. The Company's witness stated that a greater allocation of wind to demand rather than energy would have an insignificant effect on the cost distribution, approximately 0.3 percent, and would further complicate an already complicated fuel clause calculation.[540]

495. To resolve this issue, the Company and the Chamber of Commerce have agreed to examine the treatment of wind capacity in the Company's next rate case.[541]

OAG Objections to the CCOSS

496. The OAG restated its consistent position that the Company's fully-embedded CCOSS is an imprecise, unreliable method of determining a particular class's costs of service. It stressed that the study should be used to determine a range of class cost responsibility rather than precise values, and it objected to any argument that the CCOSS demonstrates that the residential customer class costs are subsidized.[542]

497. The OAG had two specific objections to the Company's CCOSS. It objected to the Company's premise that all customer classes should produce an equal rate of return and that failure of the class to achieve the overall rate of return is a subsidy to that class.[543] The OAG asserted that the premise was flawed because it failed to take into account whether the usage patterns of the class were more or less risky than the Company's overall risk. The OAG's second concern was that the E8760 allocator used by the Company reflects marginal hourly energy costs that do not match the company's actual hourly energy costs. For these reasons, the OAG's position is that the CCOSS is one tool that can guide the Commission's assignment of revenue responsibility, but other factors must be considered.[544]

498. The Commission has previously considered the OAG's objections to the fully-embedded CCOSS approach, but has relied upon it, tempered by other factors, when allocating revenue among the classes.

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539 Chamber of Commerce Initial Brief at 5; Chamber of Commerce Reply Brief at 2.
540 Tr. Vol 4 at 147-148 (Zins).
541 Tr. Vol. 4 at 149 (Zins); Xcel Energy Rate Design Brief at 13; Chamber of Commerce Initial Brief at 6.
542 OAG Initial Brief at 101-102.
543 *See* Ex. 79 at 4 (Zins Direct).
544 *See* OAG Initial Brief at 101-102.

499. The Company has demonstrated that its CCOSS is reasonable.

Revenue Apportionment

500. The Company, the Department and XLI provided class revenue allocation recommendations. The OAG supported the Department's recommendation. The Chamber of Commerce advocated for strict application of the CCOSS, without adjustment.

501. In addition to promoting conservation, environmental protection and efficient energy use, the law also prohibits unreasonable rates: "Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers."[545]

502. There is no requirement that the rates for all classes are equal, but any rate difference must be reasonable and supported by one or more of the rate-design principles. Cost-based rates will minimize inter-class subsidies. An inter-class subsidy occurs when the revenue responsibility apportioned to a class of customers fails to recover the cost of serving those customers, and the difference is made up by over-recovering costs from other customer classes. Minimizing inter-class subsidies is perceived to be "fair" to all ratepayers, but, in addition, it gives the customers accurate information about the cost of their electric use. If customers believe that electricity is less expensive than its actual cost, they may not have the appropriate incentive to reduce their energy use.[546]

503. It is difficult to make perfect cost allocations because the CCOSS is not precise. In addition, rates may need to be moderated to comply with the rate design principle that rate changes should be gradual.

The Company's Revenue Allocation

504. The Company's starting point for distribution of revenue responsibility across classes was the CCOSS. Since the results of the 2011 and 2012 CCOSS were close, it used an average of the two years as the guide for cost-based revenue allocation. By comparing revenue by class, the Company could determine the difference between the revenue and the costs. It adjusted the revenue allocation by moving the Residential class target half way to the cost-based level, an approach previously approved by the Commission.[547]

505. For the C&I Non-Demand class, the Company moved the target half way to the cost-based level, and then added an additional increment so that the increase rose to half the level of the Residential class increase, maintaining an historical relationship between the classes. It also assigned an increase to the class that is

[545] Minn. Stat. § 216B.07.
[546] Ex. 147 at 8 (Peirce Direct).
[547] Ex. 84 at 4 (Huso Direct), citing *2008 Electric Rate Case,* Order.

substantially below the retail average, although the allocation placed the class above cost.[548]

506. The Lighting class revenue responsibility was set at the present level rather than at the CCOSS-indicated level, to avoid a sharp differential in the class rate increase.[549]

507. The C&I Demand class revenue was set to recover the remaining revenue requirement, with the propose increase placing it slightly below its full cost level.[550]

508. The Company made some adjustments to the allocation in its Rebuttal testimony to reflect adjustments made to the CCOSS.[551]

The Department's Revenue Allocation

509. The Department recommended adoption of its proposed revenue apportionment. Its allocation would not change if the Commission adopts a different revenue requirement.[552]

510. In its proposed allocation, the Department attempted to balance the goal of setting cost-based rates with moderating the impact to customer bills.[553]

511. The Company's allocation and the Department's allocation can be compared as follows:[554]

Customer Class	**Percent of Total Revenue (Xcel)**	**Percent of Total Revenue (Dep't)**	**Percent Increase in Responsibility (Xcel)**	**Percent Increase in Responsibility (Dep't)**	**Proposed as % of Cost (Xcel)**	**Proposed as % of cost (Dep't)**
Residential	35.8	35.7	5.7	5.1	100.1	99.7
C&I Non-Demand	4.0	3.8	2.9	1.0	104.0	102.1
C&I Demand	59.3	59.6	5.8	6.3	99.5	99.9
Lighting	0.9	0.9	0.0	0.0	108.9	108.8
Total	100.0	100.0	5.6	5.6	100.0	100.0

548 Ex. 84 at 4-5 (Huso Direct).
549 Ex. 84 at 5 (Huso Direct).
550 Ex. 84 at 5 (Huso Direct).
551 Ex. 87 at 1-2 (Huso Rebuttal).
552 Department's Initial Brief at 166; Ex. 148 at 2 (Peirce Surrebuttal).
553 Ex. 147 at 9 (Peirce Direct).
554 Department's Initial Brief at 165 (Table 11) and 166 (Table 12).

512. The Department's allocation brings C&I Demand closer to cost and to the Residential class.

513. Neither the Department nor the Company proposed an increase or decrease in the revenue responsibility for the Lighting class. Although the Lighting class apportionment is above the cost of serving those customers, the class represents less than one percent of Xcel's total revenues.

514. The Company asserted that the Department's approach to the C&I Non-Demand class gave more consideration to approximating 100 percent of cost and less to the percent increase for each class; the Company's allocation would keep the C&I Non-Demand percent increase closer to the other classes.[555]

515. The Department's revenue allocation is more reasonable than the allocation proposed by the Company. The C&I Non-Demand class will have a smaller increase than the other two large classes, but its contribution will still be slightly above cost. Although rates for both the Residential and C&I Demand classes will be set slightly below cost, their increases will be greater than the C&I Non-Demand class and bring them closer to a full-cost rate.

XLI's Proposed Revenue Allocation

516. XLI's proposed revenue allocations were based on its modifications to the CCOSS and significantly reduced the allocation to the C&I Demand class. XLI would recover the lost revenues from Residential and C&I Non-Demand customers.[556] In addition, XLI disputed the Department's position that all classes of customers except the residential class should be at or above cost. XLI argued that the Department did not provide a basis for that position. Also, XLI argued that the Settlement would significantly lower the revenue requirement, further diminishing any argument favoring a residential class subsidy. XLI contended that its proposed revenue allocation would move all classes slightly closer to costs, consistent with the principle of gradualism.[557]

517. XLI also pointed out that the Commission recently directed the Company to apply $2 million to its POWER ON program, an affordability program for electric customers.[558] This infusion of funds would provide further protection from a rate increase for the low-income residential customers with the greatest need. In its view, continuing any subsidy for residential customers is unwarranted.[559]

518. XLI's revenue allocation is not reasonable because it is not based on a reasonable CCOSS.

[555] Ex. 87 at 3 (Huso Rebuttal).
[556] Ex. 124 at Sched. 22 (Pollock Direct).
[557] XLI Reply Brief at 7-8.
[558] *In the Matter of a Petition by Xcel Energy for Approval of a Credit Mechanism for a Department of Energy Settlement Payment with Deferred Accounting,* E002/M-11-807 (Dec. 16, 2011), Edocket Doc. No. 201112-69273-01.
[559] XLI Initial Brief at 19-20.

Chamber of Commerce's Proposed Allocation

519. The Chamber of Commerce advocated that the Commission rely on the CCOSS when apportioning revenue responsibility, without subsidy to any rate class. Although it generally agreed with the factors to be weighed in revenue allocation, it disagreed with how the Department weighed them. It stated: "Given the disproportionate growth in energy allocation through riders, the C&I Demand class has already seen higher jumps in rates than other low load-factor ratepayers."[560] It opposed "overcharging one class in order to subsidize another containing a majority of ratepayers who have not shown a need for such a subsidy, [which] has the effect of spreading the subsidy so thin that the benefit to those with a true need is rendered immaterial."[561] It concluded that all residential ratepayers do not need a subsidy; thus, the subsidy should be reduced and targeted to those in need.[562]

Conclusion

520. The Department's proposed revenue allocation is the most reasonable and best balances the rate-setting principles. It brings the classes (except Lighting) closer to cost; it slightly moderates the increase to the Residential class to keep it just below cost, and reduces class subsidy. Also, it maintains comparability between the Residential and C&I Demand classes' relationship to full cost. Although the C&I Non-Demand class will have a smaller increase than the Residential and C&I Demand classes, it will still be paying slightly above cost.

Customer Charges

Residential and Small Business (Residential) Customer Charges[563]

521. The Company's proposed changes to customer charges other than for the Residential class were uncontested.

522. The Company proposed to increase the monthly customer charge for all Residential class customers by $1.00, for overhead Residential customers from $6.50 to $7.50 per month, and for underground Residential customers from $8.50 to $9.50 per month. Two other subcategories of Residential customers would also see a $1.00 increase. The purpose of the monthly charge is to help recover the fixed customer-related costs. The average customer-related cost, as established in the CCOSS, is $16.45 per month for a Residential customer.[564]

560 Chamber of Commerce Reply Brief at 3.
561 Chamber of Commerce Reply Brief at 3.
562 Chamber of Commerce Reply Brief at 3.
563 Summary of Issues, No. 72 (a).
564 Ex. 84 at 8 (Huso Direct).

523. The OAG was the only party to oppose the $1.00 increase, preferring that more costs be recovered through the usage charge.[565]

524. The Department has consistently advanced the position that the basic monthly customer charge should approximate the fixed customer costs for that class. It supported the Company's proposed increase in the monthly Residential customer charge because the increase will move the class closer to recovering its fixed charges. Historically, the basic monthly charge has been much below that level, with the difference made up through the energy charge. Just as the Department seeks to avoid subsidies across classes, it also seeks to limit intra-class subsidies. Intra-class subsidies arise when some customers within the class pay less than the cost to serve them and the difference is made up by other customers in the class. The higher usage customers will cover their own costs, but will also contribute to the fixed costs of service to lower-usage customers.[566]

525. One of the reasons advanced for holding down the fixed charge is to assure that low-income Residential customers have low charges, based on the assumption that low-income customers also use less energy than average customers. However, if low income customers have higher-than-average levels of energy consumption, they are harmed by adoption of customer charges set below cost because they are helping to make up for the costs incurred to serve lower usage customers.[567]

526. To evaluate the effect of an increase in the basic charge on low-income customers, the Department first calculated the amount of monthly usage necessary to cover the fixed customer costs. Based on its calculation of the fixed costs, $16.45, that level was approximately 700 kWh per month. Customers using less do not pay for all of the fixed customer costs; customers using more subsidize lower users.[568]

527. The Department evaluated the Company's data to determine whether low-income customers were also low-usage customers, comparing usage for all Residential customers with usage for customers receiving assistance from one of the energy assistance programs. By this measure, the low-income customers are approximately five percent of the all residential customers. The average annual low income customers' usage was lower than 700 kWh per month, but their usage varied throughout the year, and exceeded the average in several months.[569]

528. Based on its evaluation, the Department concluded that the low-income customers were subsidizing the households that use less than 700 kWh. The Department's analysis is partly correct. However, in the same months that the low-income customers used more than 700 kWh, so did all customers, and typically by a

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565 Ex. 135 at 17-18 (Lindell Rebuttal). A member of the public objected to the differential between the overhead and underground charges. No party offered evidence on this topic, but the distinction is incorporated into the current residential charges.
566 Ex. 147 at 10-12 (Peirce Direct).
567 Ex. 147 at 12-13 (Peirce Direct).
568 Ex. 147 at 13-15 (Peirce Direct).
569 Ex. 147 at 15-16 (Peirce Direct).

greater margin. Also, there were several months when the low-income customers were well below 700 kWh. It may be more accurate to conclude that the amounts paid by low-income customers in high usage months helped to offset their below-cost payments in low-usage months. The overall average reflected that low-income customers used less energy than the break-even level and paid less than their full cost.[570]

529. The Company and the Department wish to avoid over-collecting fixed costs from higher usage customers. This is supported by Minn. Stat. § 216B.03, which directs that rates shall not "be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers."

530. Neither the Department nor the Company proposed collecting the full fixed customer cost through the basic charge. In order to avoid rate shock, they agreed that adding $1.00 to the basic charge will move customers closer to paying cost-based rates and decrease the intra-class subsidization while avoiding a large increase. With the increase in the monthly charge, the energy charge per kWh will fall slightly.[571]

531. The Department's evaluation demonstrated that a $1.00 increase in the monthly charge is not likely to have an adverse impact on low-income customers. Although they will pay $1.00 more each month in the basic charge, their variable costs will be lower, and their total monthly payments will be spread more evenly through high and low usage months.

532. The OAG has consistently opposed increases in the basic monthly charge, in part because of its dissatisfaction with the CCOSS allocation of costs, and in part to assure that low-income, low-usage customers do not overpay. The OAG correctly pointed out that many Residential customers object to increases in their basic charge, particularly if they are low-income, low-usage customers. Those customers believe that an increase in the basic charge runs counter to their efforts to conserve and bring their costs down; they can reduce usage but not the basic charge.[572]

533. By keeping the monthly charge well below the average monthly cost of serving the Residential customers, low-usage, low-income customers will continue to benefit. The Company's proposal to increase the basic monthly charge for Residential customers is reasonable and consistent with the charges approved by the Commission in recent cases.[573]

534. To address the concern of the OAG and some members of the public, it may be appropriate in the next rate case to evaluate low-income customers with very low usage, to determine if there is any significant number who may be adversely affected by an increase in the monthly charge.

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[570] Ex. 147 at 16-17, Table 5 (Peirce Direct).
[571] Ex. 147 at 17 (Peirce Direct).
[572] OAG Reply Brief at 31.
[573] Ex. 147 at 10, Table 13 (Peirce Direct) (Minnesota Power: $8.00; Otter Tail Power: $8.50; Interstate Power & Light: $8.50).

Windsource[574]

535. Windsource is an optional program that allows customers to receive a self-designated portion of their energy from renewable energy generation. The Company's position is that the current rate for Windsource is not recovering the cost of the service because of changes in four cost items:

- An increase in purchased energy costs;
- A decrease in the capacity credit to the program;
- A partly offsetting decrease in administration costs;
- A true-up recovery amount resulting from under-recover in 2011.[575]

536. The company requested an increase in the rate from $3.53 per 100 kWh block to $4.30 per 100 kWh block.[576] The rate is partially offset by a reduction in the Fuel Clause Adjustment, which has a variable value, $2.62 per 100 kWh in 2011.[577]

537. The Company agreed that if the Windsource rate changed, customers would have the opportunity to change their commitment to the program.[578]

538. In a prior docket, the Commission directed the Company to discuss all options for keeping program costs down, including purchase of renewable energy credits (RECs) or limiting customer participation, and calculating the impact on the Windsource charge, as a condition for seeking authority to change the Windsource charge.[579]

539. To comply, the Company developed six alternative plans. Option 1 used the Moraine II wind project to meet needs. Options 2 through 5 used Moraine II in varying combinations with RECs. Option 6 limited program participation. The Company recommended Option 5: Limit Moraine II to keep the rate at 3.53 cents per 100kWh block in 2011 by purchasing RECs; use Moraine II to meet energy needs in 2012, increasing the rate to $4.46.[580]

540. The Department supported either Option 4 or Option 5. Option 4 was similar to Option 5; it limited Moraine II as needed to maintain the rate at $3.53 per 100 kWh block in both 2011 and 2012.[581] However, the Department's support for Option 4 was conditional upon the Commission requiring that the Company demonstrate that it

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[574] Summary of Issues, No. 72 (k).
[575] Ex. 79 at 22-23 (Zins Direct).
[576] Ex. 82 at Sched. 5 (Zins Rebuttal).
[577] Xcel Energy Initial Rate Design Brief at 19, f.n. 59.
[578] Ex. 81 at 5 (Zins Supp. Direct); Ex. 154 at 20 (Ouanes Direct).
[579] Ex. 79 at 26 (Zins Direct), quoting Commission's Order (June 21, 2010), Docket No. E002/M-09-1177.
[580] Ex. 81 at 2-5 (Zins Supp. Direct); Ex. 82 at Sched. 5, page 4 of 4 (Zins Rebuttal).
[581] Ex. 157 at 5-7, 14 (Ouanes Surrebuttal).

would not over-recover the amount of capacity credit provided to Windsource participants, or that it propose a mechanism to address any such over-recovery.[582]

541. The cost of the program is subject to change as new wind resources become available and as a result of changes by MISO to the capacity factors for wind generation. For these reasons, the Company proposed an annual true-up of the costs and rates.[583] In a prior docket, the Department had opposed an annual true-up,[584] but it now supports it because the amounts at stake are growing[585]

542. The Department and the Company agreed that any RECs used to satisfy Windsource obligations should be obtained only from the Midwest Renewable Energy Tracking System, the RECs must be directly tied to energy delivered to the MISO system, and the RECs must satisfy Commission-established requirements for wind energy used for Windsource customers.[586]

543. Several members of the public criticizéd the proposed increase to the Windsource rate. The Department attached some of the comments opposing the increase to its testimony.[587] Others are summarized in Attachment B. These customers emphasized their commitment to renewable energy, but also their efforts to cut their energy use. Some asserted that Windsource rate increases should not exceed other rate increases.

544. The Company has agreed to conduct a Windsource market survey to assess customer satisfaction with the program and customer sensitivity to price increases. It would attempt to determine a "threshold" price premium above which demand for the program would drop, as well as customers' understanding of the trade-off of using RECs rather than more expensive wind generation. The Company's preliminary information suggests that there is a "psychological threshold" of about 2.0 cents per kWh; programs that have a price-premium of 2.0 cents or less seem to be more popular than those with a higher price-premium. The Company would report the results in a compliance filing.[588]

545. The Company's proposed change to the Windsource charge is reasonable. Selection between Option 4 and Option 5 is a policy choice, balancing the goal of spurring wind development with the appropriate use of RECs to control price. Until the Company's study of price sensitivity and customer understanding of the RECs is completed, the ALJ recommends selection of Option 4 to avoid a large, unpopular increase in the Windsource rate.

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[582] Ex. 157 at 7 (Ouanes Surrebuttal).
[583] Ex. 79 at 25-26 (Zins Direct).
[584] Ex. 154 at 19-22 and Ex. SO-39 at 8-9 (Ouanes Direct).
[585] Ex. 157 at 5-7, 14 (Ouanes Surrebutal).
[586] Ex. 157 at 14 (Ouanes Surrebuttal).
[587] Ex. 157 at SO-S-1 (Ouanes Surrebuttal).
[588] Ex. 82 at 6-8 (Zins Rebuttal).

Resolved Rate Design Issues

Fuel Clause Rider[589]

546. The Department proposed a revision to provision 4 of the Fuel Clause Rider (FCR) Tariff. The Department's purpose was to allow for recovery of renewable energy program costs, while at the same time avoiding double recovery of those costs in base rate or other riders. The Company and the Department agreed to the following revision to that provision: "All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contracts, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders."[590]

547. The Department also asserted that the cost of energy may change as a result of this rate case and, if that change is significant, the base cost of energy should be reconsidered and reflected in final rates.[591] The Company and Department have agreed to an annual true-up of the costs and rates of the Windsource program.[592]

Conservation Improvement Program.[593]

548. The Company proposed some changes to the level of Conservation Cost Recovery Charge, the corresponding Conservation Improvement Program Adjustment Factor, and an allocation of Conservation Improvement Program costs. The Department agreed.[594]

Municipal Pumping Service[595]

549. The Suburban Rate Authority challenged the Company's proposal to change the rate design for Municipal Pumping Service. The Company agreed to retain the existing rate design in this rate case, and not to propose a change prior to the second electric rate case following this one.[596] The Department concurred.[597]

550. The Suburban Rate Authority requested that the Commission approve its agreement with the Company.[598]

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589 Summary of Issues, No. 72 (h).
590 Ex. 82 at 3-4, and Sched. 4 (Zins Rebuttal); Ex. 157 at 4 (Ouanes Surrebuttal).
591 Ex. 154 at 16 (Ouanes Direct).
592 Ex. 79 at 25-26 (Zins Direct); Ex. 157 at 5-7, 14 (Ouanes Surrebutal).
593 Summary of Issues, No. 72 (i).
594 Ex. 146 at 11-15, 17 (Davis Direct).
595 Summary of Issues, No. 72 (g).
596 Ex. 88 at 4 and Sched. 1 (Huso Surrebuttal).
597 Ex. 147 at 20 (Peirce Direct).
598 Suburban Rate Authority Post-Hearing Brief at 2-3.

551. The Chamber of Commerce requested that the Company conduct a study prior to cancelling the tariff.[599] The Company's agreement to retain the tariff would appear to resolve that issue.

Other Tariff Changes

552. The Department agreed upon changes to the Company's tariffs.[600] No other party offered testimony.[601]

- Street Lighting Energy Service and Street Lighting Energy Service-Metered
- Standby Service Rider and Supplemental Service Rider
- Service Reconnection Charges
- Dedicated Switching Charge
- Excess Footage Charges
- Winter Construction Charges
- Classification of Customers[602]

Agreements About Reporting and Filing Requirements Reached At Hearing

553. Bad Debt.[603] The Company has agreed to file testimony supporting its joint electric and gas commodity revenue forecast in its next rate case. The testimony will include its forecast of both natural gas sales volumes and fuel prices.[604]

554. Interest Synchronization.[605] The Company agreed to recalculate the Interest Synchronization as part of its final compliance filing, reflecting the Commission's decision in this proceeding.

555. Tax Effect of Bonus Depreciation – Consumption of Deferred Tax Asset.[606] The Company agreed to refund to customers the revenue requirements associated with the consumption of the deferred tax assets, estimated to return approximately $60 million over the period from 2012 through 2015. The Company agreed that the amount and timing of the consumption of the deferred tax assets will be

599 Summary of Issues, No. 72 (f).
600 Ex. 147 at 29-30 (Peirce Direct).
601 Summary of Issues, No. 72 (e), No. 72 (j), No. 71 (a), No. 71 (b), No. 71 (d), No. 71 (e), No. 71(c).
602 This tariff change was proposed by the Company. The Department did not comment; no party objected.
603 Summary of Issues, No. 23.
604 Xcel Energy Update to Summary of Issues at 9.
605 Summary of Issues, No. 48.
606 Summary of Issues, No. 50.

trued up to actual results and subject to the Commission's approval, in the manner reflected in Exhibit 105, "Tax Normalization and Allowance for Net Operating Losses."

556. Employee Expenses.[607] The OAG carefully reviewed the Company's expenses, including lobbying expenses, and questioned many. The Company agreed to total reductions of $734,856, where costs were inadequately documented, not necessary for the provision of utility service or unreasonably excessive. These included lobbying expenses.[608] The Company made several commitments regarding employee expenses for future rate cases, which included:

- Providing greater detail about the development of its employee expense schedules and rate case adjustment as part of its initial rate case application;
- Implementing improvements in its schedules and rate case adjustments; and
- Providing employee expense data in a manner that will allow stakeholders and regulators to more easily determine whether the expenses were reasonable.[609]

The details of the Company's commitment were spelled out in Exhibit 56, Schedule 1.

557. Lobbying Expenses.[610] The Company's stated policy is to exclude lobbying expenses from the rate request. When some were identified, it agreed to remove them. The OAG requested that, in its next rate case, the Company include a report of the total compensation for employees engaged in lobbying, with an explanation of the costs included and excluded in the rate request. The Company has agreed to do so and the OAG requested that the Commission's order include this requirement.[611]

558. MISO Resource Adequacy. The Company agreed to provide a quantitative cost benefit analysis to recover any and all costs related to changes in the MISO Resource Adequacy Construct.[612]

559. Assignment of Wind Generation to Demand and Energy. The Company and the Chamber of Commerce have agreed to examine the treatment of wind capacity in the Company's next rate case.[613]

560. Windsource Market Survey. The Company has agreed to conduct a Windsource market survey to assess customer satisfaction with the program and

[607] Summary of Issues, No. 32.
[608] Ex. 55 at 19-22 (O'Hara Rebuttal); Ex. 56 at Sched. 1 (O'Hara Surrebuttal).
[609] Ex. 56 at 2 and Sched. 1 (O'Hara Surrebuttal).
[610] Summary of Issues, No. 32.
[611] Tr. Vol. 5 at 158-159 (Smith); OAG Initial Brief at 91.
[612] Xcel Energy Update to Summary of Issues at 10.
[613] Tr. Vol. 4 at 149 (Zins); Xcel Energy Rate Design Brief at 13; Chamber of Commerce Initial Brief at 6.

customer sensitivity to price increases. The Company would report the results in a compliance filing.[614]

561. Jurisdictional Allocation Factors. The Department requested that the Company provide additional information in its next rate case addressing municipal revenues and expenses and whether costs are assigned to retail customers when municipal customers leave the system. In addition, the Department requested that the Company show Total Company information for allocators and CCOSS that include Wholesale customers. The Company did not object to providing this information.[615]

Other Issues

Deferred Accounting for 2012 Property Tax Increases

562. The Company expects a significant increase in 2012 property taxes above the 2011 Test Year levels. It has filed a petition seeking deferred accounting for the increase or a rider, on behalf of both its electric and gas companies.[616] The issue is not directly presented in this rate case, but the "Stay-Out" provision of the Settlement is contingent upon approval of the petition. The Settlement does not preclude the parties from reviewing the Company's petition and taking a position on it.[617]

563. The OAG noted that the company's request for recovery of the 2012 property tax increase outside of the rate proceeding places customers at risk that the 2012 step-in adjustment will be augmented by additional cost recovery.

Electric Service in Roseville

564. Members of the public complained about unreliable service in their areas. *See* Attachment B. The Suburban Rate Authority was particularly concerned about a history of problems in the Roseville area. The Company is aware of the repeated outages in the area.[618] The Suburban Rate Authority chose not to pursue the issue in this docket, but will do so in Docket CI-02-2034, which addresses the Company's outage management system.[619]

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[614] Ex. 82 at 6-8 (Zins Rebuttal).
[615] Ex. 173 at 2 (Campbell Opening Statement).
[616] Petition for Approval of Deferred Accounting for Property Tax Costs, Docket No. E002/M-11-1263 (Dec. 21, 2011); Edocket Document No. 201112-69559-01.
[617] Settlement at G.
[618] Tr. Vol. 1 at 60-61 (Poferl).
[619] Suburban Rate Authority Post-Hearing Brief at 3-5. *See also In the Matter of an Investigation and Audit of Northern States Power Company's Service Quality Reporting,* Order Accepting Independent Audit Report and Requiring Additional Information, Docket No. CI-02-2034 (Sept. 2, 2009), Edocket Doc. No. 20099-41411-01.

Voltage Discounts[620]

565. The Company proposed to increase demand voltage discounts; the Chamber of Commerce objected,[621] but failed to address the issue in post-hearing submissions. Apparently the issue is resolved.

566. Citations to the transcripts or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. Ch. 216B and § 14.50.

2. The public and the parties received proper and timely notice of the hearing and the Applicant complied with all procedural requirements of statute and rule.

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05.

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.

5. If an applicant and intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the Commission. The Commission shall accept or reject the settlement in its entirety. The Commission may accept the settlement if it finds that it is in the public interest and is supported by substantial evidence. If it does not accept the Settlement, it may issue an order modifying the settlement, subject to the approval of the parties, or it may refer the matter for completion of the contested case hearing.[622]

6. As set forth in the Findings of Fact, the record supports acceptance of the Settlement as in the public interest and supported by substantial evidence.

7. Rates set in accordance with the terms of this Report would be just and reasonable.

[620] Summary of Issues, No. 72 (b).
[621] Ex. 121 at 32 (Schedin Surrebuttal).
[622] Minn. Stat. § 216B.16, subd. 1a (b).

8. The final rates ordered by the Commission should be compared to the interim rates set in the Commission's Order Setting Interim Rates, issued December 27, 2010, and a refund ordered to the extent that the interim rate exceeds the final rate, subject to any true-up that is ordered.

9. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

Based upon these Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that:

1. The Company is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. Within ten days of the service date of this Report, the Company file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for 2011, the 2012 step-in adjustment, and the rate design decisions, based on the findings and conclusions made herein.

3. The Commission incorporate the agreements made by the parties in the course of this proceeding into its Order.

4. The Commission require the Company in its next rate case to fully support the reasonableness of having ratepayers pay for 100 percent of the Company's pension obligation.

5. The Company make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: February 22, 2012

Beverly Jones Heydinger
Beverly Jones Heydinger
Administrative Law Judge

Reported: Transcript Prepared
Shaddix & Associates

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700 and 7829.3100, unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Part 7829.2700, Subpart 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.

OAH 15-2500-21773-2
PUC No. E-002/GR-10-971

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota	**ATTACHMENT A RESOLVED ISSUES**

The Following Issues Were Resolved in the Course of the Proceeding and Are Reflected in the Company's Revised Revenue Requirement of $122.941 Million[1]

1. Fox Lake Asset Sale (Issue 15)
2. Midtown Hiawatha Substation (Issue 16)
3. Facilities Cost Allocation (Issue 25)
4. Transmission Study Revenues (Issue 26)
5. 36-Month Interchange Agreement, Demand Allocation Change (Issue 27)
6. Long-Term Capacity Costs (Issue 28)
7. General Allocator of Labor Hours (Issue 30)
8. Nuclear Dues and Fees (Issue 31)
9. Mercury Sorbent - Sherco 3 (Issue 33)
10. Chairman's Fund (Issue 34)
11. Employee Expenses – Gifts (Issue 35) .
12. Merricourt O&M (Issue 37)
13. Fox Lake O&M (Issue 38)
14. 2011 Property Tax (Issue 40)
15. Transmission Network Service (Issue 42)
16. Prairie Island Unit 2 Outage – Reactor Cavity Leakage Work (Issue 44)
17. 2011 Base Salaries for Bargaining Unit Employees (Issue 45)

[1] Issue number refers to the Summary of Issues filed by the Company, Edocket Doc. No. 20116-64364-01. *See also* Ex. 195, DVL-U-4 and DVL-U-7 (Lusti Update).

18. Cash Working Capital (Issue 46)
19. Adjustments for Rounding (Issue 47)
20. Interest Synchronization (Issue 48)
21. 2011 Nuclear Outage Costs (Issue 61)
22. Legal Cost Allocation (Issue 65)
23. Economic Development Expense (not listed)
24. Association Dues (not listed)
25. Charitable Contributions (not listed) (Administrative costs were disputed)
26. Research and Development Costs (not listed)

OAH 15-2500-21773-2
PUC No. E-002/GR-10-971

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota

ATTACHMENT B
SUMMARY OF PUBLIC COMMENT

Public hearings were held at the following times and places:

April 11, 2011, at 1:00 p.m., at Brookdale Regional Library, Brooklyn Center, Minnesota;

April 11, 2011, at 7:00 p.m., at Sabathani Center, Minneapolis, Minnesota;

April 12, 2011, at 7:00 p.m., at Intergovernment Center, Mankato, Minnesota;

April 13, 2011, at 1:00 p.m., at West Minnehaha Recreation Center, St. Paul, Minnesota;

April 13, 2011, at 7:00 p.m., at Woodbury Central Park, Woodbury, Minnesota;

April 14, 2011, at 7:00 p.m., at Bloomington Civic Plaza, Bloomington, Minnesota;

April 20, 2011, at 7:00 p.m., at Lake George Municipal Complex, St. Cloud, Minnesota.[1]

Appearances:

Christopher Clark, Attorney; Al Krug, Managing Director, Regulatory Affairs, on behalf of Northern States Power (NSP, Xcel Energy or Applicant);

[1] Administrative Law Judge Steve M. Mihalchick presided at the St. Cloud public hearing.

Samir Ouanes, Susan Peirce, Hwikwon Ham, Rates Analysts; Dale Lusti, Financial Analyst; Kate O'Connell, Manager, Energy Planning and Advocacy, on behalf of the Department of Commerce, Office of Energy Resources;[2]

Ron Giteck, Assistant Attorney General; John Lindell, Vince Chavez, Financial Analysts, on behalf of the Office of the Attorney General;

Jerry Dasinger, Chris Fittipaldi, Clark Campbell, Tracy Smetana, Jon Brown, Susan Mackenzie, Public Utilities Commission staff members.

The public comment period closed at the close of evidentiary hearing on June 8, 2011. Written comments were filed in the electronic docket system.

SUMMARY OF PUBLIC COMMENT

1. All comments made at the public hearings or submitted in writing were fully considered. The following accurately summarizes the topics raised, although not all persons raising the topic are cited.

General Opposition to Any Rate Increase

2. Many members of the public wanted to register their unhappiness with any rate increase because of the number of persons who are unemployed, underemployed or on fixed incomes. They believed that at a time when families and businesses are cutting costs, Xcel should do the same.[3] The majority of the comments focused on this point; many people outlined in detail their efforts to save money and save energy in order to weather the economic downturn, necessitated by no pay increases, flat social security payments and other financial difficulties.

3. Some persons noted that they have unplugged lights or removed bulbs, unplugged their telephone or television or limited television watching, and taken many other steps to lower usage because they do not have the money to eat, pay for shelter, doctor visits and medicine and do not know how they can pay any more for electricity or use any less.[4]

[2] Previously named Office of Energy Security.

[3] *See e.g.* Tr. Brooklyn Center Hrg. at 17-20 (Dan Hellman); *Id.,* at 31-34 (Tom Schmitt); Tr. Mankato Hrg. at 25-26 (George Putnam); Tr. St. Paul Hrg. at 18-19 (Ora Larson); Tr. Woodbury Hrg. at 14 (Rodney Johnson); *Id.* at 15-16 (Craig Belisle); Tr. St. Cloud Hrg. at 10-11 (Rosa Ravera); email dated Apr. 25, 2011, from Barry and Sandra Wing, Edocket Doc. No. 20114-61999; letter dated May 16, 2011, from Phyllis Hall, and letter dated May 10, 2011, from Arnold N. Hermanson, Jr., Edocket Doc. No. 20116-63223; email dated Mar. 31, 2011, from Kimberly Shropshire, and email dated Mar. 16, 2011, from Gary R. Meyer, Edocket Doc. No. 20114-61315.

[4] *See e.g.* letter dated Mar. 18, 2011, from Mable L. Denis, letter dated Apr. 2, 2011, from Dennis and Elaine Keith, and letter dated Mar. 30, 2011, from Marcia Brucciani, Edocket Doc. No. 20114-61188.

4. Some pointed out the apparent unfairness of Xcel encouraging energy conservation and then seeking a rate increase because its sales were not increasing.[5]

5. The level of executive compensation was especially irksome to members of the public.[6] Karyn Apitz praised the hard work of the line crews who respond to power losses after storms but criticized the perks enjoyed by the company's executives.[7]

6. Nancy Anderson objected to Xcel purchasing naming rights for the Xcel Center in St. Paul.[8]

7. Some asserted that during difficult economic times Xcel should work harder to cut expenses and scale back its requested rate of return.[9] Brian Olson works for a municipality that has taken many steps to cut costs to control its tax levy. At the same time, it is faced with cuts in local government aid. He does not believe that Xcel is being held to the same tight limitations and urges a smaller rate increase.[10]

8. Michael DeMoss objected to increasing the rates for commercial office buildings because neither he nor his tenants could afford an increase. Rather, he thought greater pressure should be applied to cut the Applicant's compensation structure.[11]

Support for and Opposition to Renewable Energy

9. Some members of the public urged Xcel to develop more renewable energy and decrease its reliance on fossil fuels.[12]

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[5] Tr. Minneapolis Hrg. at 33-34 (Carrie Anne Johnson); Tr. Bloomington Hrg. at 17-18 (Brad Starr); email dated Apr. 28, 2011, from Craig Belisle, Edocket Doc. No. 20114-61999; email dated Apr. 13, 2011, from Mary Samoszuk, email dated Mar. 23, 2011, from Leona DeGolier, and email dated Mar. 17, 2011, from Gary Braaten, Osseo Finance Officer, Edocket Doc. No. 20114-61315; letter rec'd Mar. 22, 2011, from Rachelle K. Cammisuli, Edocket Doc. No. 20114-61188.

[6] *See e.g.* Tr. Brooklyn Center at 23-24, 25 (Larry Lindberg); *Id.,* at 27 (Joe Johnson); St. Paul Hrg. at 19 (Ora Larson); Tr. Bloomington Hrg. at 16 (Nancy Anderson); Minneapolis Hrg. at 24-25 (Joan Malerich); email dated April 26, 2011, from Stephanie Fleisher, Edocket Doc. No. 20114-61999; letter rec'd June 1, 2011, from Tracie Sorum, Edocket Doc. No. 20116-63223; letter rec'd April 29, 2011, from Margaret Krause, Edocket Doc. No. 20116-63223; email dated Apr. 11, 2011, from Lynn Riskedal and email dated Apr. 8, 2011, from Dennis L. Wagner, Edocket Doc. No. 20114-61315; letter rec'd Apr. 11, 2011 from Douglas L. Verdier, Edocket Doc. No. 20114-61188.

[7] Letter dated Mar. 31, 2011, Edocket Doc. No. 20114-61188.

[8] Tr. Bloomington Hrg. at 14-15.

[9] *See e.g.* email dated Apr. 9, 2011, from Raymond Voss, and email dated Mar. 31, 2011, from Jon and Sharon Risch, Edocket Doc. No. 20114-61315.

[10] Email dated Mar. 26, 2011, Edocket Doc. No. 20114-61315.

[11] Letter dated Apr. 4, 2011, Edocket Doc. No. 20114-61188.

[12] Tr. St. Paul Hrg. at 22 (Kate Severin).

10. Some also favored further development of nuclear power as an efficient, cost-effective source of energy with little pollution.[13] Others feared the risks presented by nuclear power.[14]

11. Joan Malerich requested that Xcel further encourage use of solar energy for water heaters, greenhouses, cookers and other domestic and industrial uses.[15]

12. In contrast, Michael Urban believes that new government requirements to cut emissions are driving up costs to Xcel and that more coal burning plants should be built, with improved emissions controls.[16] Similarly, George B. and Lucy Nelson believe that traditional methods of generation are efficient and reliable and should not be replaced until renewable energy sources can be employed more cheaply.[17]

Objection to the Increase for WindSource

13. The proposed increase to the WindSource rate drew objections from those who believe that the increase will dissuade customers from participating in the program, which is intended to encourage development of renewable resources. Tom Marzolf objected to pricing wind energy significantly above the base rates.[18] A number of letters were received that made the same point, objecting to any increase in the cost of WindSource participation.[19]

14. Stephanie Fleisher feared that increasing the cost of WindSource would drive some customers out of the program.[20]

Xcel's Failure to Execute Power Purchase Agreement with Community Wind South

15. David Benson is a member of the Nobles County Board of Commissioners and Chair of the Southwest Regional Development Commission, a nine-county commission. Mr. Benson is also a member of the Rural Minnesota Energy Board, a 16-county joint powers board to address energy issues in southwestern Minnesota. One of its projects is Community Wind South, which had been attempting to negotiate a power purchase agreement with Xcel. Mr. Benson asserted that an increase in rates should be contingent upon Xcel fulfilling its obligation to contract for 60 megawatts of community-owned wind development. The Public Utilities Commission imposed this

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[13] Tr. St. Paul Hrg. at 22 (Kate Severin).
[14] Tr. St. Paul Hrg. at 32-35; Minneapolis Hrg. at 20-24 (Joan Malerich).
[15] Tr. St. Paul Hrg. at 30-31; Minneapolis Hrg. at 19.
[16] Email dated Mar. 22, 2011, Edocket Doc. No. 20114-61315.
[17] Letter dated Apr. 1, 2011, Edocket Doc. No. 20114-61188.
[18] Tr. St. Paul Hrg. at 37-38.
[19] Fifteen letters addressing this topic were batched, Edocket Doc. No. 20116-63807, on June 20, 2011. *See also* email from Stuart Johnson, Edocket Doc. No. 20116-63398; letter rec'd Apr. 25, 2011, from Richard Ottman and letter rec'd Apr. 12, 2011, from Pete Swenson, Edocket Doc. No. 20114-61998.
[20] Email dated Apr. 26, 2011, Edocket Doc. No. 20114-61999.

obligation in 2003 as a condition of granting the certificate of need for transmission lines in southwest Minnesota.[21]

16. Mark Willers represented Minwind Energy, which is assisting Community Wind South to develop its project. Mr. Willers encouraged Xcel to complete its negotiations with Community Wind South, and asked that the Public Utilities Commission hold Xcel to its obligation to contract for community-owned wind development.[22]

17. Minwind Energy, LLC, participated as a party to these proceedings. On August 18, 2011, it filed a letter in this docket stating that Xcel Energy and Community Wind South had entered into a power purchase agreement, and Minwind's issues in this proceeding had been resolved.[23]

Accuracy of Xcel's Projected Expenses and Revenue Requirement

18. Stephanie Fleisher agreed with the Department that Xcel had overstated its expenses and underestimated its revenue. In particular, she objected to allowing Xcel to receive a step-in increase in 2012, particularly when it appeared that the company had overestimated the costs for upgrades to its Monticello, Prairie Island and Sherco plants. Ms. Fleisher asserted that the Commission should look closely at Xcel's retained earnings, which could be used for capital expenses. She quoted Xcel Energy CEO Ben Fowke's recent statements that Xcel had met or exceeded its annual earnings objectives for six consecutive years.[24]

19. Josh Sarfity also requested that the Commission carefully examine Xcel's retained earnings, which he estimated to be $1.7 billion, based on Xcel's SEC filings. He asserted that these funds should be reinvested in the company, and that the Commission should carefully examine how the funds will be used.[25]

Concerns About Service Reliability

20. Richard Lampert, a resident of Roseville, raised specific concerns about the number of outages that his neighborhood had experienced. Mr. Lambert had reviewed the System Average Interruption Duration Index (SAIDI) outage reports and noted that the outages in his area significantly exceeded the median values. Because of his experience, he believed that any rate increase should be conditioned upon Xcel

[21] Tr. Mankato Hrg. at 13-16.
[22] Tr. Mankato Hrg. at 18-23. *See also Id.* at 23-25 (Lorence Voehl).
[23] Edocket Doc. No. 20118-65526-01.
[24] Email dated Apr. 26, 2011, Edocket Doc. No. 20114-61999.
[25] Email dated Apr. 10, 2011, Edocket Doc. No. 20114-61315.

supplying the City of Roseville with a feeder performance list and publishing a list of feeders exceeding certain outage limits.[26]

21. Larry Lindberg, a resident of Crystal, was also critical of the service in his area.[27] His view was shared by fellow-resident Tom Schmitt.[28]

22. Mukhtar Thakur, a civil engineer who lives in Woodbury, pointed out problems with service reliability in that community. He pointed out that reliable service may be critical for those with health issues or those dependent upon computers.[29]

23. Marcia Hatling was concerned about service outages in Golden Valley, and pointed to poor tree trimming in the nearby area. She also questioned the Applicant's internal communication because she had reported a power outage each day for four days, but was told on the fourth day that it was the first report that the company had received.[30]

24. Eugene P. Casey objected to inefficiency with meter installation and misleading public information during a power outage, which caused him to suffer the consequences of food spoilage. He understood that outages will occur, but asserted that Xcel should provide better information to customers about the expected duration so that they can take precautionary steps.[31]

25. Jasper Berg noted the large number of outages in the western metropolitan area between July 2010 and January 2011, and power surges leading to circuit failure.[32]

Other Issues

26. A few public members had very specific questions. Jerry Schwarzrock has installed seven turbines on his property as part of the Community Wind North Project. He asked for information about installing a 40 kW generator and the applicable tariffs, and the Applicant attempted to provide the information.[33]

27. Chris Hiatt objected to the lack of pressure consumers can place on Xcel to keep prices low, and their lack of recourse when they believe that pricing is unfair. Because he lives in Minneapolis, his choice is to use gas or electric for cooking and heating, which he sees as no choice at all because he must deal with either Xcel or

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[26] Tr. St. Paul Hrg. at 23-28; Public Exhibit 1; *see also* email dated Apr. 20, 2011, from Jim and Stef DeBenedet, email dated Apr. 15, 2011, from Pete and Laura Carpenter, email dated Apr. 14, 2011, from Jerri Freier and letter from Richard Lambert with feeder performance information and newspaper reports concerning reliability, all at Edocket Doc. No. 20114-61999.
[27] Tr. Brooklyn Center Hrg. at 24.
[28] Tr. Brooklyn Center Hrg. at 30-31.
[29] Tr. Woodbury Hrg. at 16-18.
[30] Letter dated Apr. 5, 2011, Edocket Doc. No. 20114-61188.
[31] Letter dated Apr. 12, 2011, Edocket Doc. No. 20114-61998.
[32] Letter dated Mar. 30, 2011, Edocket Doc. No. 20114-61188.
[33] Tr. Mankato Hrg. at 26-28.

CenterPoint Energy. Although there are theoretical alternatives, realistically there are none.[34] Mr. Hiatt also submitted his comments in writing, co-signed by nineteen supporters.[35]

28. Carrie Anne Johnson objected to Xcel installing expensive, high voltage transmission lines in South Minneapolis rather than providing renewable, distributed energy sources in the area. She does not believe that Xcel has adequately considered broader use of solar power. Also, she does not believe that the Company has adequately prepared for anticipated oil shortages.[36]

29. Kate Severin expressed her dissatisfaction with Xcel receiving an interim rate increase before it had demonstrated the need to increase rates.[37]

30. Joan Malerich proposed that no customer who uses under 600 kW per month have a rate increase, with graduated increases for higher usage. Similarly, she would protect businesses with profit under $100,000 from any increase so that the business could grow.[38]

31. Brad Paine encouraged customers to more aggressively pursue conservation measures, and encouraged Xcel to educate the customers about the options.[39]

32. Joe Johnson expressed his concern about dependence on nuclear power, because of both cost and safety.[40]

33. Tom Schmitt criticized the fuel cost pass-through, the number of add-ons to the bill, and the increased cost of off-peak power.[41]

34. Barbara Leibundguth stated that her family has worked hard to conserve energy and reduce its use of fossil fuels. To that end, they installed solar panels eight years ago. However, she is charged a monthly fee of $6.65 to read the meter plus extra to participate in WindSource. Thus, without using any electricity, her family pays $17 per month because it has chosen to reduce its dependence on fossil fuels. She is not aware of any efforts by Xcel to develop a method to read their meters remotely and requests that the monthly fee be dropped.[42]

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[34] Tr. Minneapolis Hrg. at 27-31
[35] Letter dated May 24, 2011, with attachment, Edocket Doc. No. 20116-63223
[36] Tr. Minneapolis Hrg. at 32-38.
[37] Tr. St. Paul Hrg. at 22-23.
[38] Tr. St. Paul Hrg. at 28-30; Tr. Minneapolis Hrg. at 18-19.
[39] Tr. Brooklyn Center Hrg. at 20-23; *see also Id.*, at 26-27 (Joe Johnson).
[40] Tr. Brooklyn Center Hrg. at 28-29; *see also* Tr. Minneapolis Hrg. at 39-40 (Kim Fortin).
[41] Tr. Brooklyn Center Hrg. at 31-34.
[42] Email dated Apr. 6, 2011, Edocket Doc. No. 20114-61315.

35. David Lunde would like to assure that customers pay the real cost of their energy, without any state or federal subsidy. Mr. Krug and Ms. Mackenzie replied to his questions.[43]

36. David Kang would like Xcel to allow on-line bill paying without a fee, to save both customers and Xcel the costs associated with check processing and the customer's postage cost.[44]

37. Beverly Welch objected to extra charges to customers in Maple Grove for what she understood were upgrades needed for Target and Wal-Mart. She lives in senior housing on a fixed income and could not understand why customers like her were faced with the extra charges for many months.[45]

38. Dave Browne objected to the differential in residential rates for those with underground line service, particularly because maintenance is less for underground lines.[46]

39. Dale Patterson was concerned that there was no public hearing convenient to his home in Dassel, and, with the rise in gas prices, it was difficult for rural customers to attend.[47]

Respectfully submitted,

BEVERLY JONES HEYDINGER
Administrative Law Judge

Telephone: (651) 361-7838

Reported: Janet Shaddix & Associates

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[43] Tr. Woodbury Hrg. at 18-20.
[44] Email dated Apr. 5, 2011, Edocket Doc. No. 20114-61315.
[45] Email dated Mar. 31, 2011, Edocket Doc. No. 20114-61315.
[46] Email dated Mar. 18, 2011, Edocket Doc. No. 20114-61315.
[47] Letter dated Mar. 31, 2011, Edocket Doc. No. 20114-61188.