BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
100 Washington Square, Suite 1700
Minneapolis, MN 55401-2138

FOR THE PUBLIC UTILITIES COMMISSION OF THE STATE OF MINNESOTA
121 Seventh Plaza East, Suite 350
St. Paul, MN 55101-2147

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

PUC Docket No. E-002/GR-13-868
OAH Docket No. 68-2500-31182

PROPOSED FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION SUBMITTED BY XCEL LARGE INDUSTRIALS

The above-entitled matter came on for evidentiary hearing before Administrative Law Judge Jeanne Cochran on August 11, 2014.

In addition to Northern States Power Company d/b/a Xcel Energy ("NSP" or the "Company"), the parties to this proceeding are the Xcel Large Industrials ("XLI");[1] the

[1] Flint Hills Resources, LP; Gerdau Ameristeel US Inc.; Unimin Corporation; and USG Interiors, Inc.

Minnesota Chamber of Commerce (the "Chamber"), Commercial Group ("CG"),[2] Energy Cents Coalition ("ECC"), Suburban Rate Authority ("SRA"), ICI Group ("ICI"),[3] the Clean Environmental Intervenors ("CEI"),[4] the Department of Commerce, Division of Energy Resources ("DOC"), AARP ("AARP"), and the Minnesota Office of the Attorney General, Antitrust and Utilities Division (the "OAG").

Appearances were made by the following: For NSP, Aakash Chandarana, Alison C. Archer, James R. Denniston, Mara Koeller, and Kari Valley, 414 Nicollet Mall, 5th Floor, Minneapolis, MN 55401; Stephen E. Fogel, Xcel Energy Services Inc., 816 Congress Ave., Suite 1650, Austin, TX 78701; and Richard J. Johnson, Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, MN 55102. For the XLI, Andrew P. Moratzka and Sarah Johnson Phillips, Stoel Rives LLP, 33 South Sixth Street, Suite 4200, Minneapolis, MN 55402. For the Chamber, Richard J. Savelkoul, Martin & Squires, P.A., 332 Minnesota Street, Suite W2750, St. Paul, MN 55101. For CEI, Kevin Reuther, 26 East Exchange Street, Suite 206, St. Paul, MN 55101 and Samantha Williams, 20 North Wacker Drive, Suite 1600, Chicago, IL 60606. For ECC, Pam Marshall, 823 E 7th St, St. Paul, MN 55106. For SRA, James M. Strommen, Kennedy & Graven, Chartered, 200 South Sixth Street, Suite 470, Minneapolis, MN 55402. For CG, Alan R. Jenkins, Jenkins at Law LLC, 2265 Roswell Road, Suite 100, Marietta, GA 30062. For ICI, Peder Larson and Connor T. McNellis, Larkin Hoffman, 1500 Wells Fargo Plaza, 7900 Xerxes Avenue South, Minneapolis, MN 55431. For AARP, John B. Coffman, 871 Tuxedo Boulevard, St. Louis, MO 63119. For the DOC, Julia E. Anderson, Linda S. Jensen and

[2] JC Penney Corporation, Inc., Macy's Inc., Sam's East, Inc. and Wal-Mart Stores East, LP.

[3] An ad hoc group of large customers that contract with U.S. Energy Services, Inc. for energy management service and receive electric service from NSP.

[4] Minnesota Center for Environmental Advocacy, Natural Resources Defense Council, The Izaak Walton League- Midwest Office, Fresh Energy, and Sierra Club

Peter Madsen, Assistant Attorneys General, 445 Minnesota Street, Suite 1800, St. Paul, MN 55101-2134. For the OAG, Ian M. Dobson and Ryan Barlow, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, MN 55101-2131.

Notice is hereby given that, pursuant to section 14.61 of the Minnesota Statutes, and the Rules of Practice of the Minnesota Public Utilities Commission (the "Commission") and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions must be electronically filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that such recommendation has no legal effect unless expressly adopted by the Commission as its final order.

I. SUMMARY OF THE ISSUES AND PROCEEDINGS TO DATE

1. On October 3, 2013, NSP filed with the Commission sales forecast data as required by the Commission in its final order in the Company's most recent 2012 general

rate case, MPUC Docket No. E-002/GR-12-961, to be provided 30 days in advance of the filing of NSP's next rate case.

2. On November 4, 2013, NSP filed a multi-year rate case with the Commission that requested an two-year rate increase of $192.7 million or 6.9 percent effective January 3, 2014, based on a 2014 test year, and $98.5 million, or 3.5 percent, based on a 2015 test year for a total increase of $291.2 million or 10.4 percent ov the two years. The 2014 and 2015 revenue deficiencies are each based on using a 10.25 percent rate of return on equity. The Company also sought an interim rate increase of $127.4 million on an annualized basis to be charged to ratepayers until the Commission decides this rate petition.

3. On November 5, 2013, the Commission issued a notice requesting comments on whether the Company's multi-year rate case filing should be accepted as complete and referred to the Office of Administrative Hearings ("OAH") for a contested case proceeding.

4. On November 13, 2013, the Commission received comments from the DOC recommending that the Commission find NSP's filing to be substantially complete and that the matter be referred to the OAH for a contested case proceeding.

5. On November 14, 2013, XLI filed comments recommending that the matter be referred to the OAH for a contested case proceeding. Between November 5 and December 26, 2013, the Commission also received comments from at least six NSP ratepayers and shareholders regarding the Company's requested rate increase and/or executive compensation.

6. On December 12, 2013, the matters came before the Commission.

7. On December 31, 2013, NSP submitted a filing required by Order Point 9 of the Commission's September 3, 2013 Order in MPUC Docket No. E-002/GR-12-961, which required NSP to provide an analysis and report on the Sherco Unit 3 total costs, insurance recoveries, and costs not covered by insurance in its November 2013 rate case filing, and to provide the completed accounting and report by December 31, 2013.

8. On January 2, 2014, the Commission issued three orders: First, in its Order Accepting Filing and Suspending Rates the Commission found the filing to be substantially complete and suspended the operation of the proposed rate schedule.

Second, the Commission's Order Setting Interim Rates approved NSP's proposed interim rate increase to cover a revenue deficiency of approximately $127,406,000 per year, to be implemented by January 3, 2014 - that is, 60 days after its November 4, 2013 filing.

Third, the Commission's Notice and Order for Hearing referred the matter to the OAH for contested case proceedings.

In its January 2, 2014, Notice and Order for Hearing, the Commission identified the following issues for parties to address in the course of the contested case proceedings.[5]

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

(b) Is the rate design proposed by the Company reasonable?

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

(d) Has the Company fully complied with past Commission orders?

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[5] Notice and Order for Hearing at 2.

(e) How should the Commission incorporate into this case the results of the ongoing investigation into the prudence of NSP's expenditures for life cycle management and the extended power uprate at the Monticello Nuclear Generating Plant?

(f) How should the proceeds of any insurance claims and litigation proceeds related to the Company's Sherburne County Generating Station Unit 3 be incorporated into NSP's rates?

(g) What will be the short- and long-term consequences of the rate mitigation strategy proposed by the Company?

In addition, the Commission stated that parties may also raise and address other issues relevant to the Company's proposed rate increase.

9. On January 31, 2014, Xcel filed its "Bad Debt Study – Supplemental Information", in compliance with Order Point 31 of the Commission's September 3, 2013, Findings of Fact, Conclusions, and Order in Docket No. E002/GR-12-961.

10. On January 31, 2014, ALJ Cochran held a prehearing conference.

11. On February 7, 2014, following discussion at the prehearing conference, including discussion of item (e) from the Commission's Notice and Order for Hearing, incorporation of information from MPUC Docket No. E-002/CI-13-754 (ITMO a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns, (13-754 or Monticello Cost Overrun Investigation)), the Xcel filed its limited waiver of its rights under Minn. Stat. § 216B.16, subds. 2(a) and (e) and 19, and agreed to a date on or about March 24, 2015 for a final determination by the Commission, as well as other commitments.

12. On February 14, 2014, ALJ Cochran issued the First Prehearing Order and a Protective Order. In her Prehearing Order, ALJ Cochran noted that the Commission's Notice

and Order for Hearing named Xcel, the Department, and the Office of the Attorney General – Antitrust and Utilities Division (OAG) as parties. The ALJ granted the Petitions for Intervention filed by the Commercial Group.

13. ALJ Cochran's First Prehearing Order set procedures for parties in the case and established the following schedule:

February 28, 2014	Intervention
June 5, 2014	Direct Testimony (Intervenors)
July 7, 2014	Rebuttal Testimony
August 4, 2014	Surrebuttal Testimony
August 8, 2014	Status Conference
August 11-18, 2014	Evidentiary Hearing
September 10, 2014	Draft Issue Matrix
September 23, 2014	Initial Briefs
September 30, 2014	Comments to Issues Matrix
October 7, 2014	Final Issues Matrix (Company)
October 14, 2014	Reply Briefs and Proposed Findings of Fact
December 22, 2014	ALJ Report

14. On March 5, 2014, ALJ Cochran granted the intervention requests of the MCC and CEI.

15. On March 14, 2014, ALJ Cochran granted, with limitations, the intervention request of AARP. The ALJ limited AARP's participation to the issues of rate design and decoupling, as well as any service quality issues that affect the unique interests of its members.

16. On March 14, 2014, the ALJ denied the petition of Minnesota Power (MP) to intervene as a party. The ALJ ordered that MP may file an amicus curiae brief of up to 40 pages no later than September 30, 2014, to which parties may respond.

17. On June 5, 2014, the following parties filed direct testimony in accordance with the schedule set forth in the ALJ's First Prehearing Order: OAG, DOC, ECC, the Commercial Group, the Chamber, the ICI Group, AARP and XLI.

18. On June 6, 2014, the Department filed its Direct Testimony, which was late-filed the previous evening. On June 25, 2014, the ALJ granted the Department's Motion for a one day extension to June 6, 2014, for good cause shown. The ALJheld public hearings as follows:

- Earle Brown Heritage Center, Minneapolis, Minnesota at 1:00 p.m. on June 23, 2014.
- Sabathani Center, Minneapolis, Minnesota at 7:00 p.m. on June 23, 2014.
- West Minnehaha Recreation Center, St. Paul, Minnesota at 1:00 p.m. on June 24, 2014.
- Woodbury Central Park, Woodbury, Minnesota at 7:00 p.m. on June 24, 2014.
- Civic Center, Mankato, Minnesota at 7:00 p.m. on June 25, 2014.
- Eden Prairie Community Center, Eden Prairie, Minnesota at 7:00 p.m. on June 26, 2014. Three members of the public testified.
- Lake George Municipal Complex, St. Cloud, Minnesota at 1:00 p.m. on June 27, 2014.

19. On July 7, 2014, the following parties filed Rebuttal Testimony: the DOC, OAG, ECC, CEI, AARP, XLI, and NSP.

20. On July 16, 2014, ALJ Cochran and ALJ Mihalchick convened a joint prehearing conference for the present docket and the Monticello Cost Overrun Investigation. The July 17, 2014, Joint Prehearing Order determined that the protective order in the present docket will be used in the Monticello Cost Overrun Investigation, and that the issues to be considered in the above dockets are as follows:

(a) The issue of the reasonableness and prudence of the costs for the Life Cycle Management and Extended Power Uprate at the Monticello Nuclear Generating Plant will be addressed in the Monticello Cost Overrun Investigation.

(b) The issue of whether the Extended Power Uprate should be considered "used and useful" during 2014 will be addressed in the Monticello Cost Overrun Investigation.

(c) The issue of cost allocation between the Extended Power Uprate and Life Cycle Management will be addressed in the Monticello Cost Overrun Investigation.

(d) The issue of the recovery and amortization of expenses from the Monticello Cost Overrun Investigation will be addressed in Xcel's Multi-Year Rate Case.

21. On August 4, 2014, the following parties files Surrebuttal Testimony: DOC, OAG, ECC, MCC, ICI (filed on August 5th), CEI, AARP, XLI and NSP.

22. On August 8, 2014, the ALJ convened a status conference to facilitate and orderly and efficient evidentiary hearings.

23. The evidentiary hearings were held on August 11-15, 2014, in the Commission's large hearing room.

24. On September 10, 2014, NSP filed its Preliminary Issues List, in compliance with the ALJ's directive, that identified the Company's view of the issues that are resolved between one or more parties, and issues that remain contested.

25. On September 23, 2014, parties filed Initial Briefs and responses to the Issues Matrix.

26. Reply Briefs and proposed Findings of Fact were filed October 14, 2014.

27. Based upon the proceedings to date, the parties' written submissions, this ALJ makes the following findings, recommendations, and conclusions.

II. FINDINGS OF FACT

A. Burden of Proof

28. It is NSP's burden to demonstrate its proposal is reasonable.[6] "Every rate made, demanded or received by a public utility…shall be just and reasonable…Any doubt as to reasonableness should be resolved in favor of the consumer."[7] The Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding by stating:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To

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[6] MINN. STAT. § 216B.16 subd. 4 ("The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.").

[7] MINN. STAT. § 216B.03.

> state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[8]

29. In NSP's 2012 rate case, the Commission explained the differences in its roles by acknowledging that on purely factual matters it acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court, requiring facts to be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.[9] The fact that the Commission reviews matters in both quasi-judicial and quasi-legislative capacities does not change the utility's burden in proving its case. In NSP's 2012 rate case, the Commission went on to state that

> [u]tilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable under the "just and reasonable" standard set by statute.[10]

30. That the proposed rates meet this "just and reasonable" standard is a burden imposed on the utility, which it must establish by a preponderance of the evidence.[11] This standard is defined as "whether the evidence submitted, even if true, justifies the conclusion

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[8] *In re Northern States Power Co.*, 416 N.W.2d 719, 722-23 (Minn. 1987).

[9] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 5 (Sept. 3, 2013).

[10] *Id*.

[11] *N. States Power Co.*, 416 N.W.2d at 722.

sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[12]

B. The EPU Portion of the Monticello Project is not Used and Useful

1. NSP Failed to Meet its Burden of Proof that the Monticello EPU is "Used and Useful"

31. NSP proposes to include the full cost of the uprate portion of the Monticello Life Cycle Management/Extended Power Uprate ("Monticello LCM/EPU" or "Monticello Project") project in its 2014 revenue requirement. The Monticello Project collectively represents about $74.9 million of NSP's Minnesota retail test year revenue requirements.[13]

32. In the last case, the Commission found that the EPU portion of the project was not yet used and useful because it was still operating at pre-uprate levels. In particular, the Commission said that that the portion of the project attributable to the EPU "cannot serve ratepayers until it is licensed by the [Nuclear Regulatory Commission]" and that "portion of the project should not earn a return before it is used and useful in providing service to ratepayers."[14] The Commission went on to state that the "Company may be allowed to recover those costs in

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[12] *Id*.

[13] Pollock Direct at 20:8-9; Direct Testimony of Anne E. Heuer, Exhibit ___ (AEH-1) at 142.

[14] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 19.

future rate cases once the EPU is in service, subject to the plant being used and useful and subject to a determination that the costs—including cost overruns—were prudent." [15]

33. Under Minnesota law, a utility is only allowed cost recovery on assets that are used and useful in providing service. The applicable statute states:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property *used and useful in rendering service to the public*, and to earn a fair and reasonable return upon the investment in such property.[16]

34. NSP continues to fail to meet its burden to show that the Monticello EPU is used and useful in rendering service to the public. At the time the evidentiary hearings were held in this case, the Monticello plant was operating at pre-uprate levels and NSP could not say with certainty when the plant would be able to operate at full uprate levels. [17]

35. At the end of 2013 and in March 2014 NSP received two required license amendments for the EPU project late last year from the NRC.[18] NSP was not, however, able to immediately begin operating the plant at the full uprate 671 MW level after receiving those license amendments.[19] Instead, NSP was required to complete a power ascension process

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[15] *Id.*; *see also* Clark Rebuttal at 23:15-18.

[16] Minn. Stat. § 216B.16, subd. 6.

[17] Ex. 53, O'Connor Rebuttal at 7:23-27, 8:1-7.

[18] Ex. 53, O'Connor Rebuttal at 4.

[19] Ex. 53, O'Connor Rebuttal at 5:25-27, 6:1-8.

overseen by the NRC and requiring various interim approvals from the NRC at different stages.[20] The original anticipated schedule for the power ascension process was delayed as a result of issues identified when analyzing data collected during the ascension process.[21] As of the evidentiary hearings, these issues had not yet been resolved to the satisfaction of the NRC.[22] At that time, NSP still believed that the power ascension process could be completed by the end of 2014, but could not confirm that timeline with certainty. [23] During this power ascension process, the plant has operated at no higher than 640 MW and has not operated at that or any uprate level on a sustainable basis.[24]

36. The power ascension process cannot be completed until NSP completes each step of the process to the satisfaction of the NRC. During cross-examination, NSP witness Timothy O'Connor explained that the Monticello license includes a first-time power ascension process that NSP has to perform the first time NSP raises output from 600 to 671 MW.[25] He further explained that this process is overseen by the NRC and that there are several points in the process that require concurrence or approval from the NRC.[26] As Christopher Clark explained at the evidentiary hearings, "just about everything [NSP does] at [its] nuclear plant is driven by the

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[20] Ex. 53, O'Connor Rebuttal at 6:11-27.

[21] Ex. 53, O'Connor Rebuttal at 10; Ex. 55, O'Connor Surrebuttal at 5.

[22] Evidentiary Hearing Transcript, Vol. 1, 232:19-25, 233:1-17.

[23] Ex. 53, O'Connor Rebuttal at 7:23-27, 8:1-7.

[24] Evidentiary Hearing Transcript, Vol. 1, 231:18-21.

[25] Evidentiary Hearing Transcript, Vol. 1, 228:8-22.

[26] Evidentiary Hearing Transcript, Vol. 1, 228:16-22, 231:5-9.

NRC."[27] Thus, as in the last case, NSP's ability to operate the EPU project at full uprate levels on an on-going and sustainable basis remains subject to NRC approval.

37. Since NSP has not demonstrated a substantive change in circumstances since last year, it has not met its burden to justify including Monticello EPU costs in rate base. Determining the appropriate adjustment amount depends on resolution of certain issues in the Monticello prudence review docket,[28] including the percentage of the total Monticello LCM/EPU project attributable to the EPU. Given the statutory obligation for the Commission to err in favor of the ratepayer, the ALJ recommends that any EPU costs be excluded from rate base until it is used and useful in rendering service to ratepayers.

C. The Commission Should Require NSP to Amortize its Depreciation Reserve Surplus to Mitigate the Rate Increase

38. How to address a surplus depreciation reserve has been an issue in NSP's recent rate cases. In the last case, the Commission found that, regarding NSP's transmission, distribution, and general plant, there was no dispute among the parties that NSP had accrued a depreciation surplus or that the surplus should be amortized.[29] In particular, the Commission found that NSP had accumulated a $265 million depreciation surplus in its transmission,

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[27] Evidentiary Hearing Transcript, Vol. 2, 123:18-19.

[28] Minnesota Public Utilities Commission Docket No. E002/CI-13-754.

[29] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 28.

distribution, and general plant accounts and ordered that this surplus be amortized over eight years.[30]

39. In this case, NSP is proposing to amortize a $228 million (Minnesota retail) depreciation surplus over three years in order to moderate the 2014 and 2015 revenue requirement.[31] The ALJ recommends that the Commission accept NSP's proposal.

40. With respect to production plant accounts, the Commission directed the parties to more fully explore in the next rate case (i.e., the pending case) the issue of whether a depreciation surplus exists and whether it should be amortized.[32]

41. In response to the Commission's order, NSP filed testimony in this case on the existence of a depreciation surplus for production plant. NSP's analysis indicates that as of December 12, 2012, there was a surplus nuclear depreciation reserve of $97.5 million, or $72.5 million for the Minnesota retail jurisdiction.[33]

42. XLI witness Jeffry Pollock reviewed this analysis on behalf of XLI and determined that NSP understated the magnitude of the surplus by a substantial amount.[34] Mr.

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[30] *Id.* at 29.

[31] Ex. 95, Robinson Direct at 30-31; Ex. 260, Pollock Direct at 9:19-10:1.

[32] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order, at 29.

[33] Ex. 260, Pollock Direct at 10:18-20; Ex. 92, Perkett Direct at 46.

[34] Ex. 260, Pollock Direct at 11.

Pollock concluded that NSP has accumulated a $208 million (Minnesota retail) surplus in its nuclear depreciation reserve using plant balances as of December 31, 2013.[35]

43. None of the parties addressing this issue in testimony provided analysis disputing the existence of a surplus – again, NSP's own analysis demonstrates a surplus.[36] The issue in dispute in this case is the size of the surplus and the appropriate way to use it.

44. Even though NSP's nuclear licenses have fixed lengths, the life spans of the nuclear plants are not necessarily fixed. NSP has previously successfully extended the lives of both the Monticello and Prairie Island plants.[37] Further life extensions likely would have the effect of increasing the present surplus.[38] And future extensions seem plausible given impending federal greenhouse gas regulations.[39]

45. According to the National Association of Regulatory Utility Commissioners: [T]he purpose of depreciation is not to build a reserve for the future…the sole purpose of depreciation accounting is to rateably allocate the capital costs of the property over its average service life through current charges to utility expenses.[40]

46. The $208 million nuclear depreciation surplus should be used to mitigate NSP's proposed 2014-2015 revenue requirement by $25.7 million (a benefit to all ratepayers), assuming

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[35] Ex. 264, Opening Statement of Jeffry Pollock.

[36] Ex. 263, Pollock Surrebuttal at 11:13-20.

[37] Ex. 263, Pollock Surrebuttal at 18:1-5.

[38] Ex. 263, Pollock Surrebuttal at 18:6-11.

[39] Ex. 94, Perkett Rebuttal at 14:15-19.

[40] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices,* at 1, 187 (Aug. 1996).

the surplus is amortized over five years. The ALJ recommends using the surplus to mitigate rates in 2014-2015 because it is better for ratepayers on a net present value basis,[41] is accepted practice supported by the Commission's order in the last case, and is consistent with NSP's proposed three-year amortization of the transmission, distribution, and general plant surplus in this case.

D. The Commission Should Require NSP to Promptly Address the Need for Fuel Clause Rider Reform

47. The Fuel Clause Rider ("FCR") is designed to allow recovery of the cumulative balance of any unrecovered and over-recovered fuel and purchased energy costs incurred in prior months.

48. Significant costs are recovered by NSP via the FCR – NSP anticipates approximately $836 million of costs in 2014.[42]

49. In principle, NSP is required to demonstrate that costs recovered under the FCR are reasonable and prudent. However, the enormous amount of time and resources required to review costs recovered through FCR effectively shifts this burden to regulators and ratepayers.[43]

50. Stakeholders have been discussing FCR reform within and outside of the AAA dockets, but there has been little progress toward meaningful reform. Despite sharing proposals

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[41] Ex. 263, Pollock Surrebuttal at 13:14-14:11.

[42] Ex. 260, Pollock Direct at 28:16-17 (citing Ex. 105, Huso Direct Schedule 5).

[43] See examples provided by XLI in Mr. Pollock's Direct Testimony. Ex. 260, Pollock Direct at 26-27.

and comments in early 2014, no formal action has been taken by NSP, the Department, or the Commission to implement FCR reform.[44]

51. In order to address the unfair burden the current FCR review places on regulators and ratepayers, XLI proposed that the Commission order NSP to propose a new FCR design in its next rate case or within 90 days of the Commission's final order in this case, whichever is earlier.[45]

52. In response to XLI's proposals, NSP witness Mr. Clark agreed in concept that an incentive-based plan is an appropriate goal for fuel clause reform.[46] However, rather than agree to NSP filing a reform proposal at the end of this case, Mr. Clark recommended that the issue continue to be addressed in the AAA dockets.[47] But Mr. Clark did not identify any specific reasons that NSP could not develop and file a reform proposal within the timeline proposed by XLI other than a preference to keep the discussion in the AAA dockets.[48] He also noted that NSP has had "numerous" internal discussions on the subject.[49] NSP has already invested substantial effort into analyzing FCR reform options and has not identified any specific reason that it cannot proceed with making a formal proposal. Given the lack of progress on FCR reform in the AAA dockets and the general agreement among the parties that an incentive-based mechanism is the appropriate type of reform, there does not appear to be any reason to continue delaying reform.

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[44] Evidentiary Hearing Transcript, Vol. 2, 125:12-23.

[45] Ex. 260, Pollock Direct at 29.

[46] Ex. 100, Clark Rebuttal at 43:9-10.

[47] Ex. 100, Clark Rebuttal at 43:11-15.

[48] Evidentiary Hearing Transcript, Vol. 2, 126:6-10, 16-24.

[49] Evidentiary Hearing Transcript, Vol. 2, 125:14-18.

53. The ALJ recommends that NSP be ordered to propose a new FCR design in its next rate case or within 90 days of the Commission's final order in this case, whichever is earlier, consistent with the principles articulated by XLI for an incentive-based FCR:

- Establish an effective incentive for NSP to control both fuel and purchased energy costs in a manner that results in overall savings for customers;
- Avoid causing chronic over- or under-recovery without necessarily guaranteeing dollar-for-dollar recovery;
- Emphasize that the burden of proof is on NSP to show that costs recovered are just and reasonable; and
- Allow for administratively efficient review of fuel and purchased energy costs by the Department, the Commission, and customers.[50]

E. NSP's CCOSS should be Accepted with an Adjustment.

54. As with the other aspects of NSP's petition for a rate increase, NSP bears the burden of demonstrating its CCOSS is the equitable starting point for designing just and reasonable rates.

1. CCOSS Overview

55. In general terms, a class cost of service study is an analysis used to determine each class's responsibility for a utility's total costs by separating the utility's total costs into portions on behalf of the various customer classes. [51] This analysis consists of the following three steps: (1) a *functionalization* of costs, (2) a *classification* of those costs' primary causative factors, and (3) an *allocation* of those costs among the various customer classes. [52]

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[50] Ex. 260, Pollock Direct at 32:4-12.

[51] Ex. 101, Peppin Direct at 1.

[52] Ex. 101, Peppin Direct Schedule 2 at 2.

56. A utility's investments and expenses are functionalized as production, transmission, distribution, and other functions.[53] Once functionalized, the next step is to determine the primary causative factor (*i.e.*, demand/capacity related, energy related, or customer related).

57. There are various types of CCOSS methods that can be employed, with the analyst being charged to find the economic theory that is most representative to measure cost-causation.[54] NSP proposes to continue using what it calls the "stratification method" for classifying costs functionalized as production, a method that classifies production costs between peak capacity and baseload components by comparing the replacement cost of peaking capacity to the replacement cost of other types of generation. [55]

58. Once a particular CCOSS method is chosen, the next step is to develop allocators that appropriately allocate costs among customer classes.[56]

2. NSP's Methodology for Classifying Production-Related Costs Should be Modified.

59. Stratification identifies plant investment incurred to provide capacity (i.e. demand-related) and investment that is a substitute for fuel costs (i.e. energy-related). NSP described its plant stratification approach as follows:

> The Company classifies fixed production plant into capacity versus energy-related sub-functions. The capacity-related portion of the

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[53] Ex. 101, Peppin Direct Schedule 2 at 3.

[54] *Evidentiary Hearing Transcript*, Vol. 3, 97:3-8.

[55] Ex. 102, Peppin Direct at 12-13.

[56] Ex. 101, Peppin Direct Schedule 2.

> fixed costs of owned-generation is based on the percent of total fixed costs of each generation type that is equivalent to the costs of a comparable peaking plant (the generation source with the lowest capital costs and the highest operating costs). The percent of total generation costs that exceeds the costs of a comparable peaking plant are sub-functionalized as energy-related.[57]

60. Mr. Pollock identified two flaws in NSP's methodology: 1) NSP uses current replacement value of its existing gas turbine and diesel plants, which is not the same as the costs NSP would incur to install a new peaking unit and 2) NSP's cost classification relies on undepreciated replacement values even though rates are set using net depreciated investment.[58] The factors used by NSP understate the value of capacity relative to energy, resulting in misallocation of production plant-related costs.

61. To correct for the first error, NSP should use costs it would incur to install a new peaking unit— specifically $696/kW, the amount Xcel utilized for determining the capacity credit in its Windsource program.[59]

62. To correct for the second error, NSP should use net depreciated investment as opposed to undepreciated investment.[60]

63. For all of these reasons the ALJ recommends that plant stratification analysis be based on depreciated replacement value, consistent with the values shown on Schedule 21 in Mr. Pollock's surrebuttal testimony.

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[57] Ex. 102, Peppin Direct at 12.

[58] Ex. 260, Pollock Direct at 34-35.

[59] Ex. 260, Pollock Direct at 34:21-35:1 (citing Peppin Direct, Schedule 10).

[60] Ex. 260, Pollock Direct at 35:2-4.

F. The Commission Should Exercise its Discretion to Set Rates at Cost

64. NSP's proposed revenue allocation must be supported by a preponderance of the evidence and result in just and reasonable rates.[61]

65. Rates should reflect the actual costs of providing service as closely as possible because "cost based rates are equitable, provide appropriate price signals for all customer classes, encourage conservation and efficiency, and address the very serious and real problem that NSP's industrial rates are not competitive."[62]

66. Moving C&I Demand rates to cost has a range of benefits for industrial customers and other NSP ratepayers.

67. In addition to mitigating effect of uncompetitive rates on sales, moving industrial rates to cost is equitable while also promoting engineering efficiency, stability, and conservation.[63]

68. Rates that reflect cost-of-service principles are equitable because each customer pays what it actually costs the utility to provide service to that customer.[64] Cost-based rates also promote engineering efficiency because well-structured energy and demand charges will provide customers with proper incentives to minimize their costs, which in turn minimize utility costs.[65]

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[61] *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. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, pg. 5 (May 14, 2012).

[62] Ex. 263, Pollock Surrebuttal at 31:7-10.

[63] Ex. 260, Pollock Direct at 41:15-18.

[64] Ex. 260, Pollock Direct at 41:19-42:1.

[65] Ex. 260, Pollock Direct at 42:3-7.

Cost-based rates promote stability by aligning customer use patterns with changes in revenue and expenses.[66]

69. Finally, cost-based rates encourage conservation by sending accurate price signals to help customers avoid wasteful or inefficient use.[67]

70. The ALJ recommends that the Commission use its discretion to set rates at cost.

G. The Commission Should Exercise its Discretion to Set Rates at Cost

71. In addition to moving rates closer to cost, the ALJ recommends implementing several rate design strategies to address NSP's increasingly uncompetitive C&I rates, including (1) setting the short notice demand charge at a fair level, (2) refining the definition of on-peak, and (3) establishing a Renew-A-Source program.

1. NSP Should Modify its Proposed Rate Design for Short Notice Demand Customers to Better Reflect the Benefits These Customers Provide.

72. Short notice service is one of several service options that allow NSP to curtail interruptible load when there are insufficient resources to meet customer demand.[68] Short notice customers must have a minimum controllable demand of 3 MW and be willing to interrupt load to a predetermined level within 10 minutes' notice.[69]

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[66] Ex. 260, Pollock Direct at 42:8-11.

[67] Ex. 260, Pollock Direct at 42:12-16.

[68] Ex. 260, Pollock Direct at 48:8-10.

[69] Ex. 260, Pollock Direct at 48:11-13.

73. Interruptible customers provide substantial value to NSP and other ratepayers by allowing capacity additions to be deferred and by providing contingency reserves.[70] The Federal Energy Regulatory Commission has described interruptible power as providing "insurance" in the event the utility experiences extreme weather, understates load growth, or sustains outages of a major resource.[71] Short notice interruptible customers are compensated in the form of credits against demand charges, the net effect of which is lower demand charges for interruptible customers.

74. NSP is proposing to increase the amount of value of the short notice interruptible credits at less than one-third of the corresponding increase in demand charges.[72] NSP is proposing to increase Tier 1 Short Notice credits by 5.4% while increasing Tier 1 Short Notice demand charges by 19.3%.[73] The net effect of NSP's proposal is to reduce compensation to short notice interruptible customers.

75. Further, NSP's proposal also fails to properly compensate the customers for the capacity value they provide.[74] NSP estimates a new CT would cost approximately $696/kW.[75]

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[70] Ex. 260, Pollock Direct at 50-51.

[71] Ex. 260, Pollock Direct at 51-52 (citing and quoting *Louisiana Public Service Commission and the Council of the City of New Orleans v. Entergy Corporation et al.*, Docket Nos. EL00-66-000, ER00-2854-000 & EL95-33-002, Opinion No. 468 ¶¶ 74-75 (Mar. 8, 2004)).

[72] Ex. 260, Pollock Direct at 52-53.

[73] *Id*.

[74] Ex. 260, Pollock Direct at 53-55.

[75] See supra, pg. 14, Ex. 260, Pollock Direct at 53, and Ex. 102, Peppin Direct at Schedule 10.

The corresponding revenue requirement for this value is $12.16 per kW month.[76] Thus, the average proposed credit of $5.85 is less than half of the cost NSP would incur to provide comparable short-notice generation capacity.[77] Although NSP offered testimony asserting that interruptible load is not directly comparable to a peaking plant,[78] NSP failed to specifically provide any evidence to support that testimony or generally support a more than 50% discount to the actual value of a CT resource.

76. Assuming that NSP's proposed firm demand charges are approved, the ALJ recommends that short notice interruptible credits be proportionately increased as shown in the chart provided on page 55 of Mr. Pollock's direct testimony. In other words, "if NSP receives only 50% of its proposed base revenue increase, the annualized Short-Notice Peak controlled demand charge should be $4.12 per kW."[79]

2. NSP should Modify its Definition of On-Peak to Provide Better Price Signals for Time of Use Customers

77. Time-of-use rates are intended to send price signals to customers that electricity usage is more expensive during on-peak periods than during off-peak periods.[80] Customers are encouraged by higher prices to minimize usage during on-peak hours and shift load to off-peak hours.

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[76] Ex. 260, Pollock Direct at 53:9-10. Although NSP Witness Huso was unable to verify this math during cross-examination, XLI notes that the figure is set forth in a calculation on line 5 of Schedule 10 to NSP Witness Peppin's direct testimony.

[77] Ex. 260, Pollock Direct at 53:10-12.

[78] Ex. 107, Huso Rebuttal at 36:14-15.

[79] Ex. 260, Pollock Direct at 55:8-10.

[80] Ex. 260, Pollock Direct at 57-58.

78. NSP's definition of peak periods has remained unchanged for many years even though circumstances impacting the effectiveness of the price signals established by them have changed in recent years. For example, NSP turned over functional control of certain transmission facilities to join MISO in 2002 and revised its demand allocation methodology in the last rate case.[81] MISO recently changed its resource adequacy requirements such that each load serving entity must maintain sufficient capacity to meet the projected annual coincident peak load and provide a sufficient reserve margin.[82] NSP's new demand allocation methodology in its CCOSS recognizes that NSP is a predominantly summer-peaking utility and therefore allocates the capacity-related portion of generation plant using the summer coincident peak.[83]

79. Even though NSP is a predominantly summer-peaking utility, NSP's current definition of peak periods includes non-summer months that are less critical for determining resource adequacy under MISO rules.[84] It would be more consistent with the predominant summer peak and the summer coincident peak demand allocator in NSP's CCOSS to limit the on-peak period to summer months.[85]

80. If peak periods were confined to summer months, customers would receive stronger price signals and have a greater ability to respond. Under the current peak-period

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[81] Ex. 260, Pollock Direct at 56:21-23.

[82] Ex. 260, Pollock Direct at 56:23-57:1 (citing MISO, *Resource Adequacy Business Practice Manual* § 1.2, at 9 (Aug. 2013)).

[83] Ex. 260, Pollock Direct at 57:5-8 (citing Docket No. E002/GR-12-961, Rebuttal Testimony and Schedules of Michael A. Peppin, Exhibit ___ (MAP-2), at 3).

[84] Ex. 260, Pollock Direct at 58:3-8.

[85] Ex. 260, Pollock Direct at 58:10-12 & Schedule 14.

definition (12-hour period on all week days throughout the year), it is difficult for 24-hour customers to respond with any meaningful and sustained changes to their usage patterns.[86] And since NSP's demand-related costs are allocated based on summer coincident demand, refining the definition of peak periods would better reflect cost-causation.[87]

81. At the evidentiary hearings, NSP witness Steven Huso "absolutely" agreed that, as a general matter, rates should be designed to reflect proper price signals for efficient use of resources.[88] And further, Mr. Huso agreed that a narrower peak period would provide customers with a greater opportunity to respond and shift load.[89]

82. The ALJ recommends refining NSP's definition of peak periods in order to send more effective price signals to customers.

3. The Commission Should Exercise its Discretion to Set Rates at Cost

83. XLI proposed that NSP establish a new renewable energy purchase option for industrial customers. In particular, XLI recommended establishing a "Renew-A-Source" program that pairs large high-load factor customers that operate 24 hours a day with renewable energy resources, such as wind, that primarily operate during off-peak hours.[90] Such a program could "match" the output of a defined portfolio of renewable resources with a qualifying

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[86] Ex. 263, Pollock Surrebuttal at 41:1-15.

[87] Ex. 263, Pollock Surrebuttal at 40:14-21.

[88] Evidentiary Hearing Transcript, Vol. 2, 166:1-4.

[89] Evidentiary Hearing Transcript, Vol. 2, 175:13-15.

[90] Ex. 260, Pollock Direct at 59-60.

customer's load under a long-term agreement.[91] If well-structured, renewable energy could be made affordable to industrial customers while also driving down the price of renewable resources by creating a new and stable source of long-term demand for them.[92]

84. NSP has expressed its commitment to pursue discussions with stakeholders of XLI's Renew-A-Source proposal and even described the idea as a "very exciting opportunity."[93]

85. In order to insure that this concept moves forward, the ALJ recommends that (1) NSP to work with interested stakeholders to develop a Renew-A-Source tariff or similar program, consistent with the structure proposed by XLI, [94] in a set timeframe determined by agreement stakeholders or (2) if no agreed timeframe is reached, the Commission should order NSP to file a Renew-A-Source or similar tariff in its next rate case or within 60 days of the final order in this case, whichever is earlier.

86. Based on the above findings of fact the ALJ makes the following conclusions.

III. CONCLUSIONS

87. The Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Chapter 216B and Section 14.50 of the Minnesota Statutes.

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[91] Ex. 260, Pollock Direct at 60-61.

[92] Ex. 260, Pollock Direct at 61.

[93] Ex. 100, Clark Rebuttal at 47-48; Evidentiary Hearing Transcript, Vol. 2, 133:13 (Clark).

[94] *See* Ex. 260, Pollock Direct at 61-62.

88. The public and the parties received proper and timely notice of the hearing and the Company complied with all procedural requirements of statute and rule.

89. "Every rate made, demanded or received by a public utility…shall be just and reasonable…Any doubt as to reasonableness should be resolved in favor of the consumer."[95]

90. That the proposed rates meet this "just and reasonable" standard is a burden imposed on the utility, which it must establish by a preponderance of the evidence.[96] This standard 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."[97]

91. Rates set in accordance with the terms of this Report would be just and reasonable.

92. Any Findings of Fact more properly designated as Conclusions are hereby adopted as such.

93. Based upon these Conclusions, the ALJ makes the following Recommendations.

IV. RECOMMENDATIONS

94. NSP failed to demonstrate, by a preponderance of the evidence, that allowing costs associated with the EPU portion of the Monticello Project results in just and reasonable rates.

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[95] MINN. STAT. § 216B.03.
[96] *In re Northern States Power Co.*, 416 N.W.2d at 722.
[97] *Id*.

95. The Commission is well within its authority to balance the parties' competing interests and policy goals to amortize the substantial nuclear depreciation reserve surplus consistent with the public interest. The Commission should amortize the $208 million surplus over 5 years to help mitigate NSP's proposed rate increase via a $25.7 million reduction to NSP's proposed revenue requirement.

96. NSP should be ordered to file an incentive-based FCR reform proposal in its next rate case or within 90 days of the final order in this case in order to establish an effective mechanism to ensure that fuel and purchased energy costs recovered through the FCR are reasonable and prudent;

97. NSP's CCOSS should be expected with the above-described modification to NSP's methodology for Classifying Production Plant-Related Costs because it yields more equitable results founded on cost-causation principles under the just and reasonable standard;.

98. The Commission should exercise its discretion to set rates based on cost of service, in accordance with the CCOSS as revised per the previous paragraphs.

99. To ensure that rates are just and reasonable, the above rate design proposals should be adopted in order to address NSP's increasingly uncompetitive industrial rates.

100. The Company should make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: December 22, 2014

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Hon. Jeanne M. Cochran
Administrative Law Judge