OAH 22-2500-37994
MPUC E-002/GR-21-630
MPUC E-002/M-21-748

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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 the State of Minnesota

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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 the State of Minnesota	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS**

An evidentiary hearing was held before Administrative Law Judge Christa L. Moseng on December 13 and 14, 2023, at the Public Utilities Commission, St. Paul, Minnesota in the above-captioned matter.

Public hearings were held on October 4, 2022 in Golden Valley and Woodbury, on October 5, 2022 in Red Wing, on October 6, 2022 in St. Cloud, on October 20, 2022 in St. Paul, On October 21, 2022 in Minneapolis, and on November 3, 2022 in Mankato. Virtual public hearings were held on October 31, November 2, 2022, and December 9, 2022. Written public comments were received until January 6, 2023.

Post-hearing briefs were filed on January 11, 2023, and reply briefs and proposed findings were filed on January 27, 2023. The hearing record closed upon receipt of the last post hearing briefs on January 27, 2023.

On February 8, 2023, the Judge reopened the record for the limited purpose of authorizing supplemental briefing on 2023 Minn. Laws Ch. 7. The hearing and contested case record finally closed on February 24, 2023, the date supplemental briefing was due.

Appearances:

Eric F. Swanson, Elizabeth H. Schmiesing, and Joseph M. Windler of Winthrop and Weinstein, and Matthew B. Harris, Shubha M. Harris, and Ian M. Dobson of Northern States Power Company, d/b/a Xcel Energy (the Company, Xcel, or NSPM), appeared on behalf of the Company.

Elizabeth M. Brama and Valerie T. Herring, Taft Stettinius & Hollister LLP, also appeared on behalf of the Company.

Katherine Hinderlie, Richard E.B. Dornfeld, and Greg Merz, Assistant Attorneys General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources (the Department or DOC).

Kristin K. Berkland,[1] Joseph C. Meyer, and Peter G. Scholtz, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General Residential Utilities Division (OAG).

Brian Edstrom, Senior Regulatory Advocate, and Annie Levenson-Falk, appeared on behalf of the Citizens Utility Board of Minnesota (CUB).

Carol A. Overland, Legalectric Inc., appeared on her own behalf.

Alan R. Jenkins, Jenkins at Law, LLC, appeared on behalf of the Commercial Group.

James M. Strommen and Joseph L. Sathe, Kennedy & Graven, appeared on behalf of the Suburban Rate Authority (SRA).

Andrew P. Moratzka and Riley A. Conlin, Stoel Rives, LLP, appeared on behalf of the Xcel Large Industrials (XLI).

Catherine Fair and Pam Marshall, appeared on behalf of the Energy CENTS Coalition (ECC).

Scott Strand, Erica McConnell, and Bradley Klein, Environmental Law & Policy Center, appeared on behalf of the Just Solar Coalition (JSC).

Stephanie Fitzgerald and Amelia J. Vohs, Minnesota Center for Environmental Advocacy, appeared on behalf of the Clean Energy Organizations (CEO).

Jorge Alonso and Jason Bonnett appeared for the Staff of the Public Utilities Commission.

STATEMENT OF THE ISSUES

On October 25, 2021, the Company filed a petition to increase its electric rates in Minnesota through a three-year Multi Year Rate Plan (MYRP), to reflect the cost of providing service, including an appropriate return on common equity. It requested a net increase in electric base rate revenues of $395.97 million, or 12.2%, for 2022, an incremental $150.51 million, or 4.8%, for 2023, and an incremental $131.24 million, or 4.2%, for 2024, based on present revenues. On December 23, 2012, the Minnesota Public Utilities Commission (Commission) issued a Notice of and Order for Hearing, referring the matter to the Minnesota Office of Administrative Hearings (OAH) for contested case proceedings.

[1] Ms. Berkland subsequently withdrew as counsel in this matter. Notice of Withdrawal (Dec. 30, 2022) (eDockets No. 202212-191727-01).

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

1. Whether the test year revenue increase sought by the Company is reasonable or will result in unreasonable or excessive earnings.

2. Whether the rate design proposed by the Company is reasonable.

3. Whether the Company's proposed capital structure and return on equity are reasonable.

4. Issues from past Commission orders.

5. Reasons for significant changes since the last rate case, including but not limited to, the following:

    a. $31.4 million increase in power production costs,

    b. $24.5 million increase in transmission costs,

    c. $17.8 million increase in distribution costs,

    d. $26.2 million increase in customer service and information costs, and

    e. $41.7 million increase in administrative and general costs.

6. What interest rate should be applied to any prospective interim rate refunds.

7. How proposed rates align with the State's energy policy goals, including those articulated in Minn. Stat. § 216C.05 (2022).

8. Decisions made in *In the Matter of Xcel Energy's Petition for Approval of a Workforce Training and Development Program Pilot*, Docket No. E002/M-21-558, to ensure they are properly reflected in the 2022 Test Year.

9. Any other issues identified by the Commission.

FINDINGS OF FACT

I. Summary of the Application

1. The Company's Application proposed a three-year Multi Year Rate Plan (MYRP), that included a request to increase electric rates in Minnesota, to provide a net increase in electric base rate revenues of $395.97 million, or 12.2%, for 2022, an incremental $150.51 million, or 4.8%, for 2023, and an incremental $131.24 million, or 4.2%, for 2024, based on present revenues. The Application was based on a 2022 test year with 2023 and 2024 plan years as part of the MYRP.

2. Over the course of the proceeding, several of the financial issues were resolved among the parties. The Company also updated its cost of service as new

information became available. The Company reduced its request in Rebuttal Testimony, and now requests approval of a net increase in electric base rate revenues of $233.5 million, or 7.1%, for 2022, an incremental $94.4 million, or 3.0%, for 2023, and an incremental $107.3 million, or 5.4%, for 2024, based on present revenues.

II. The Parties

3. The Company is a Minnesota corporation that serves Minnesota customers and a subsidiary of Xcel Energy, Inc., a public utility holding company with four utility subsidiaries that serve customers in eight states.

4. The Minnesota Department of Commerce, Division of Energy Resources (the Department) represents the interests of the State's ratepayers in rate proceedings.[2] 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.

5. The Office of the Attorney General – Residential Utilities Division (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.[3]

6. Xcel Large Industrials (XLI) is an ad hoc consortium of large industrial customers of Xcel Energy, consisting for purposes of this filing of Flint Hills Resources Pine Bend, LLC; Marathon Petroleum Corporation; and USG Interiors, Inc. Their costs of production could be significantly affected by a rate increase.[4]

7. Citizens Utility Board of Minnesota (CUB) is a non-profit advocate for Minnesota's residential utility consumers. CUB is a resource for Minnesotans on energy and utility issues and advocates for residential utility consumers in energy-related legislative and regulatory proceedings.[5]

8. The Energy CENTS Coalition (ECC) promotes affordable utility service for low- and fixed-income Minnesotans. ECC intervened in this proceeding to protect the financial interests of low-income customers.[6]

9. The Clean Energy Organizations (CEO) in this proceeding include Fresh Energy and the MCEA. CEO states that its representative organizations have "an interest

[2] Minn. Stat. § 216A.07, subd. 3 (2020); Minn. R. 7829.0800, subp. 3 (2021).
[3] Petition to Intervene on Behalf of Office of Attorney General – Residential Utilities Division at 1 (Jan. 7, 2022) (eDockets No. 20221-181319-01).
[4] Petition to Intervene of the Xcel Large Industrials at 1-3 (Jan. 6, 2022) (eDockets No. 20221-181287-02).
[5] Petition to Intervene of the Citizens Utility Board of Minnesota at 1-2 (Nov. 8, 2021) (eDockets No. 202111-179579-01).
[6] Petition to Intervene of the Energy CENTS Coalition at 1 (Jan. 4, 2022) (eDockets No. 20224-185329-01).

in advancing resource choices that minimize or eliminate pollutant emissions, advance renewable energy, focus on equitable outcomes and maximize energy efficiency."[7]

10. The Just Solar Coalition (JSC) states that it is "a diverse coalition of rural and urban solar developers, community organizers, environmental justice groups, faith leaders, workforce developers and others that share a common vision of ensuring a just transition for both workers and energy users into the green energy economy."[8]

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

12. The Suburban Rate Authority (SRA) is a joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, most served by Xcel Energy. The SRA primarily focused on issues related to street lighting.[10]

III. Procedural Background

13. On October 25, 2021, the Company filed this general rate case by filing an application (the Application) seeking a net increase in electric base rate revenues of $395.97 million, or 12.2%, for 2022, an incremental $150.51 million, or 4.8%, for 2023, and an incremental $131.24 million, or 4.2%, for 2024, based on present revenues.[11]

14. On November 2, 2021, the Commission issued a notice to potentially interested parties requesting comments on three topics: (i) whether the Commission should accept the Application as substantially complete in compliance with Minnesota statutes, rules, and Commission orders, (ii) whether the Commission should refer the matter to the OAH for a contested case hearing, and (iii) whether there are other issues or concerns related to the matter.[12]

15. On November 8, 2021, the Department filed comments concluding that the Company's filing complied with the filing requirements, and recommended the Commission accept the Application as complete as of the October 25, 2021 filing date and refer the matter to the OAH for a contested case proceeding.[13]

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[7] Petition to Intervene of the Clean Energy Organizations at 2 (Apr. 29, 2022) (eDockets No. 20224-185329-01).
[8] Petition to Intervene of the Just Solar Coalition at 2 (Apr. 29, 2022) (eDockets No. 20224-185355-01).
[9] Petition to Intervene of the Suburban Rate Authority at 1 (Jan. 13, 2022) (eDockets No. 20221-181458-01).
[10] Petition to Intervene of the Suburban Rate Authority at 1 (Jan. 13, 2022) (eDockets No. 20221-181458-01).
[11] *See* Ex. Xcel-22 at 3 (Chamberlain/Liberkowski Direct) (Xcel Energy's Application, Direct Testimonies, Schedules, Workpapers and associated materials, collectively, referred to as Initial Filing).
[12] Notice of Comment Period on Completeness and Procedures at 1 (Nov. 2, 2021) (eDockets No. 202111-179412-01).
[13] DOC Comments at 5–6 (Nov. 8, 2021) (eDockets No. 202111-179576-01).

16. On December 23, 2021, the Commission issued an order accepting the Company's filing, suspending the proposed rates, and extending the timeline for its decision.[14]

17. In a separate order, the Commission also approved the Company's 2022 interim rate request, but deferred action on the Company's 2023 interim rate request and permitted Xcel to resubmit its 2023 interim rate request with updated financial information at least 90 days before the proposed implementation date.[15]

18. In a third order, the Commission referred the case for contested case proceedings.[16]

19. The initial parties to the contested case proceeding were Xcel Energy, the Department, and CUB.[17]

20. On December 24, 2021, Carol A. Overland (Overland) filed a Petition to Intervene.[18]

21. On January 3, 2022, the Company objected to Carol A. Overland's Petition to Intervene, arguing that Overland's petition did not meet the standard required by rule to intervene and that Overland's interests are adequately represented by an existing party.[19]

22. Also on January 3, 2022, Carol A. Overland filed a response to the Company's objection.[20]

23. On January 4, 2022, ECC and the Commercial Group each filed Petitions to Intervene.[21]

24. On January 7, 2022, the OAG filed a Petition to Intervene.[22]

25. On January 10, 2022, XLI filed a Petition to Intervene.[23]

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[14] ORDER ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIMELINE at 3–4 (Dec. 23, 2021) (eDockets No. 202112-180961-02).
[15] ORDER SETTING INTERIM RATES (Dec. 23, 2021) (eDockets No. 202112-180961-03).
[16] NOTICE OF AND ORDER FOR HEARING at 6–7 (Dec. 23, 2021) (eDockets No. 202112-180961-01).
[17] FIRST PREHEARING ORDER at 2 (Jan. 19, 2021) (eDockets No. 20221-181694-01).
[18] ORDER DENYING PETITION TO INTERVENE OF CAROL A. OVERLAND at 3 (Feb. 23, 2022 (eDockets No. 20222-183094-01).
[19] *Id.*
[20] *Id.*
[21] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS at 1 (Jan. 21, 2022) (eDockets No. 20221-181838-02).
[22] *Id.* at 1–2.
[23] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS at 2 (Jan. 21, 2022) (eDockets No. 20221-181838-02).

26. On January 10, 2022, the Judge held a prehearing conference via telephone.[24]

27. On January 13, 2022, SRA filed a Petition to Intervene.[25]

28. On January 19, 2022, the First Prehearing Order established the following schedule of proceedings:[26]

Document or Event	**Due Date**
Intervention Deadline	April 29, 2022
Direct Testimony, Intervenors	October 3, 2022
Prehearing Conference (Hearing Logistics)	October 4, 2022, at 9:30 a.m.
Rebuttal, All Parties	November 8, 2022
Surrebuttal, All Parties	December 6, 2022
Status Conference	December 9, 2022, at 9:30 a.m.
Evidentiary Hearings	December 13 - 16, 2022
Draft Issue Matrix (Company)	January 6, 2023
Initial Briefs	January 11, 2023
Response to Issues Matrix	January 20, 2023
Reply Briefs and Proposed Findings of Fact	January 27, 2023
Administrative Law Judge Report	March 31, 2023
Exceptions to ALJ Report	April 17, 2023
PUC Order	June 30, 2023

29. On January 20, 2022, the Judge issued a Protective Order that regulated the use and disclosure of nonpublic data in these proceedings.[27]

[24] *See* FIRST PREHEARING ORDER at 1 (Jan. 19, 2022) (eDockets No. 20221-181694-01).
[25] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS at 2 (Jan. 21, 2022) (eDockets No. 20221-181838-02).
[26] FIRST PREHEARING ORDER at 3 (Jan. 19, 2021) (eDockets No. 20221-181694-01).
[27] PROTECTIVE ORDER at 1 (Jan. 20, 2022) (eDockets No. 20221-181794-01).

30. No party filed an objection to the petitions of ECC, the Commercial Group, OAG, XLI, or SRA within the required time for a response. On January 21, 2022, the Judge granted the petitions of these parties.[28]

31. On January 27, 2022, the Judge held a hearing via telephone concerning the Petition to Intervene of Carol A. Overland.[29] The Company and Overland participated in the hearing and no other parties took a position as to the Petition.[30]

32. On February 23, 2022, Carol A. Overland's Petition to Intervene was denied, as Overland did not articulate an interest that was sufficiently distinct from those represented by the Department; however, Overland was permitted to offer evidence, question witnesses at the evidentiary hearing, and file written post-hearing briefs without party status, subject to the First Prehearing Order and the Protective Order.[31]

33. On April 29, 2022, JSC and CEO each filed Petitions to Intervene.[32]

34. No parties filed an objection to the petitions of JSC and CEO within the required time for a response. On June 13, 2022, the Judge granted the petitions of these parties.[33]

35. On September 30, 2022, the Company resubmitted its 2023 interim rate request to the Commission, to be effective January 1, 2023.

36. On October 3, 2022, the Department, OAG, XLI, CUB, ECC, CEO, JSC, SRA, and the Commercial Group filed Direct Testimony.[34]

37. On October 26, 2022, the Commission required Xcel to remove from this proceeding its costs associated with certain proposed Electric Vehicle programs so they could be considered in a separate contested case proceeding.[35]

38. On November 10, 2022, the Department filed a Motion to Strike all or portions of Rebuttal Testimony of Company witnesses Jeffrey West, Amy Liberkowski,

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[28] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS at 3 (Jan. 21, 2022) (eDockets No. 20221-181838-02).
[29] ORDER FOR HEARING ON PETITION TO INTERVENE at 1 (Jan. 21, 2022) (eDockets No. 20221-181838-01).
[30] ORDER DENYING PETITION TO INTERVENE OF CAROL A. OVERLAND at 3–7 (Feb. 23, 2022 (eDockets No. 20222-183094-01).
[31] ORDER DENYING PETITION TO INTERVENE OF CAROL A. OVERLAND at 1, 6 (Feb. 23, 2022 (eDockets No. 20222-183094-01).
[32] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS OF THE JUST SOLAR COALITION AND THE CLEAN ENERGY ORGANIZATIONS at 1–2 (June 13, 2022) (eDockets No. 20226-186539-01).
[33] ORDER GRANTING UNOPPOSED INTERVENTION PETITIONS OF THE JUST SOLAR COALITION AND THE CLEAN ENERGY ORGANIZATIONS at 1–2 (June 13, 2022) (eDockets No. 20226-186539-01).
[34] *See* eDockets Nos. 202210-189478-01–07, 202210-189481-01–02, 202210-189482-01–09, 202210-189485-01–06, 202210-189486-01–02, 202210-189487-01–02, 202210-189487-01–02, 202210-189494-01–03, 202210-189497-01–07, 202210-189500-01–03, 202210-189508-01–05, 202210-189510-01–03, 202210-189513-01–10.
[34] *See* eDockets Nos. 202211-190502-01–10, 202211-190503-01–03, 202211-190504-01–09, 202211-190506-01–10, 202211-190510-01, 202211-190516-01–03, 202211-190469-01–02.
[35] Notice of and Order for Hearing (Oct. 26, 2022) (eDockets No. 202210-190138-01).

Benjamin Halama, and Mark Moeller. The Department sought to strike portions of Xcel's Rebuttal Testimony pertaining to two issues: (1) the remaining lives of Sherburne County Unit 3 (Sherco Unit 3) and Allen S. King (King) coal-fired electric generating plants, and (2) a request to track nitrogen oxide (NOx) allowance expenses. The Department argued that this testimony was not responsive to any Direct Testimony and introduced new information that should have been included in an earlier round of testimony.[36]

39. On November 14, 2022, the Judge ordered parties wishing to respond to the Department's Motion to file responses by November 21, 2022, and set a motion hearing for November 22, 2022.[37]

40. On November 21, 2022, the Company filed an Opposition to Motion to Strike, and OAG and XLI filed responses supporting the Motion.[38] The Company argued that the objected-to testimony should be permitted as consistent with the First Prehearing Order, and that it could not have been reasonably included earlier, as the Sherco Unit 3 and King testimony is responsive to the Department's testimony proposing to account for the depreciable life of Monticello Nuclear Generating Plant, and the NOx allowance expense tracker proposal relates to a change in circumstances.[39]

41. The Judge heard oral argument on the Motion to Strike on November 22, 2022.

42. On November 28, 2022, the Company filed a letter with the Commission proposing to withdraw its 2023 Interim Rate Petition in its entirety if the Commission approves the Company's new proposal to credit excess revenues from the 2023/2024 MISO planning Auction as an offset to its 2023 revenue requirement in the MYRP proceeding.[40]

43. On November 30, 2022, the Judge issued an Order partially granting the Motion to Strike, finding the testimony concerning Sherco Unit 3 and King was not untimely because it was responsive to direct testimony, but finding the testimony concerning deferred accounting for the NOx allowance expense tracker was a new issue and that Xcel had not shown good cause for its inclusion. Accordingly, the Judge struck Rebuttal Testimony concerning the NOx allowance tracker from the record.[41]

44. On December 6, 2022, the Company, the Department, OAG, XLI, CUB, CEO, JSC, and SRA filed Surrebuttal Testimony.[42]

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[36] ORDER PARTIALLY GRANTING MOTION TO STRIKE at 3–4 (Nov. 30, 2022) (eDockets No. 202211-190981-01).
[37] ORDER SETTING MOTION RESPONSE DEADLINE AND MOTION HEARING at 1–2 (Nov. 14, 2022) (eDockets No. 202211-190609-01).
[38] ORDER PARTIALLY GRANTING MOTION TO STRIKE at 2 (Nov. 30, 2022) (eDockets No. 202211-190981-01).
[39] ORDER PARTIALLY GRANTING MOTION TO STRIKE at 5 (Nov. 30, 2022) (eDockets No. 202211-190981-01).
[40] Late Filed Letter at 2 (Nov. 28, 2022) (eDockets No. 202211-190896-01).
[41] ORDER PARTIALLY GRANTING MOTION TO STRIKE (Nov. 30, 2022) (eDockets No. 202211-190981-01).
[42] *See* eDockets Nos. 202212-191134-01–03, 202212-191136-01–03, 202212-191137-01–04, 202212-191138-01, 202212-191139-01, 202212-191140-01–07, 202212-191141-01–03, 202212-191142-01–03, 202212-191143-01–02, 202212-191150-01–02, 202212-191152-01–08, 202212-191153-01–03.

45. Also on December 6, 2022, the Commission held a hearing to evaluate the Company's Interim Rate Petition withdrawal proposal.[43]

46. The evidentiary hearing was held on December 13 and December 14, 2022, in the Small Hearing Room of the Commission's offices in St. Paul.[44]

47. On January 7, 2023, the Governor signed into law 2023 Minn. Laws Ch. 7. Certain provisions of the law pertain to rate proceedings under Minn. Stat. § 216B.16 and became effective the next day.

48. On January 10, 2023, the Commission approved the Company's request to credit excess revenues from the 2023/2024 MISO planning resource auction as an offset to its 2023 revenue requirement, approved the Company's request for a tracker and annual true-up mechanism to account for future variances in planning resource auction revenues compared to amounts credited to customers in base rates, and accepted the Company's withdrawal of its second interim rate increase request.[45]

49. On January 27, 2023, the Department filed a Motion to Take Official Notice.

50. On February 8, 2023, the Judge authorized supplemental briefs on the effect of 2023 Minn. Laws Ch. 7 on positions or arguments in this proceeding.[46] The Judge reopened the evidentiary hearing record for the limited purpose of receiving authorized supplemental briefs.[47]

51. On February 10, 2023, the Company filed its reply to the Department's Motion to Take Official Notice.

52. On February 24, 2023, Xcel, the Department, JSC, CUB, CEO, XLI and OAG filed supplemental briefs.[48] The parties generally agreed that 2023 Minn. Laws Ch. 7 did not materially affect any issue or position taken in this proceeding, except to reinforce each party's existing arguments and positions.

53. On March 29, 2023, the undersigned granted the Department's Motion to Take Official Notice.

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[43] ORDER APPROVING ALTERNATIVE PROPOSAL AND REQUEST TO WITHDRAW PROPOSED INTERIM RATE INCREASE at 2 (Jan. 10, 2023) (eDockets No. 20231-192016-01).
[44] *See* Evidentiary Hearing Transcript Volumes 1-2.
[45] ORDER APPROVING ALTERNATIVE PROPOSAL AND REQUEST TO WITHDRAW PROPOSED INTERIM RATE INCREASE at 3 (Jan. 10, 2023) (eDockets No. 20231-192016-01).
[46] ORDER AUTHORIZING SUPPLEMENTAL BRIEFING (Feb 8, 2023).
[47] *Id*.
[48] *See* eDockets Nos. 20232-193422-01 (Xcel supplemental brief), 20232-193421-02 (the Department supplemental brief), 20232-193420-02 (JSC supplemental brief), 20232-193418-02 (CUB supplemental brief), 20232-193416-02 (CEO supplemental brief), 20232-193414-01 (XLI supplemental brief), and 20232-193408-01 (OAG supplemental brief).

IV. Comments from the Public

54. Over 500 written public comments were filed by the January 6, 2023, deadline. In addition, more than 40 individuals provided oral comments at the 10 public hearings held across the Company's service territory. The vast majority of the public comments were from residential customers of the Company, although some business customers also provided comments. A full summary of the public comments is included as Attachment A to this report.

55. While the public raised a specific concerns on a variety of topics, there was concern about the size of the proposed rate increases was widespread. Customers with fixed- and low-incomes expressed concern about their ability to pay for an increase in their electric rates when they are experiencing little or no increase in their incomes. In addition, a number of customers felt that the increased conservation efforts of customers should not result in increased rates. Some customers expressed concern that the Company had not been controlling its costs sufficiently. There were also objections to the Company's executive compensation. Business customers expressed a concern that higher rates would adversely affect their businesses and prices for consumers.

V. Legal Standards

56. Minnesota law establishes the basic standard for the Commission's determination of utility rates: "Every rate made, demanded, or received by any public utility . . . shall be just and reasonable."[49]

57. The Commission's obligation to determine whether rates are just and reasonable is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers . . . ."[50]

58. This balancing is set forth in Minn. Stat. § 216B.16, subd. 6:

> 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.

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[49] Minn. Stat. § 216B.03. Minnesota Statutes are cited to the 2022 Edition unless otherwise indicated.
[50] *In re Request of Interstate Power Co. for Auth. to Change Its Rates for Gas Serv. in Minn.*, 574 N.W.2d 408, 411 (Minn. 1998).

59. The Commission has explained its traditional ratemaking process as being a comprehensive process—one that allows a full and complete review of all issues, and not an overly narrow consideration of singular changes in individual costs:[51]

> Ratemaking involves a host of complex and interrelated issues: necessary operating, maintenance, and capital expenses, reasonable cost of capital, appropriate capital structure, reasonable revenue projections, proper attribution of the costs of providing service, fair return on investment. Rates are set in general rate cases because they provide the comprehensive review of a utility's financial situation necessary for understanding these issues and how they affect one another.

60. 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.[52] 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."[53] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[54]

61. Minnesota courts have rejected the notion that the "just and reasonable" standard or the resolution of doubt in favor of the consumer permits the Commission to simply drive rates as low as it would like without balancing the interests of the utility and ratepayers after review of the record as a whole.[55]

62. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. It evaluates the facts, including the claimed costs, and also evaluates the reasonableness of placing the burden of the costs on the ratepayers.[56]

63. Throughout its testimony and argument relating to issues in this proceeding, JSC alluded to principles of "Energy Justice," which it argued the Commission should incorporate into its implementation of its statutory authority.[57] JSC views Energy Justice as providing a critical lens for the Commission to use when executing its ratemaking obligations under longstanding Minnesota law.[58]

64. JSC cited the Initiative for Energy Justice's The Energy Justice Workbook, which describes Energy Justice as comprising four constituent principles: Recognition

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[51] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-002/GR-89-865, ORDER DENYING PETITIONS FOR RECONSIDERATION AND DENYING TRANSITIONAL RATE INCREASE at 6 (Nov. 26, 1990).
[52] Minn. Stat. § 216B.16, subd. 4.
[53] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[54] Minn. Stat. § 216B.03.
[55] *Hibbing Taconite Co. v. Minnesota Public Service Commission*, 302 N.W.2d 5, 10 (Minn. 1980).
[56] *In re Northern States Power Co.,* 416 N.W.2d at 722–23.
[57] Ex. JSC-6 at 8 (Chan Surrebuttal); Ex. JSC-5 at 12-13 (Rábago Direct).
[58] Ex. JSC-3 at 38-50 (Chan Direct); Ex. JSC-6 at 1-9 (Chan Surrebuttal).

Justice, Procedural Justice, Distributional Justice, and Restorative Justice.[59] JSC's testimony defined Energy Justice, provided significant context, and set forth JSC's views regarding inequities in the energy delivery system and the impact of those inequities on low-income and Black, Indigenous, and People of Color (BIPOC) communities.[60]

65. JSC argued that the Commission's determinations in this proceeding should endeavor to remedy inequities in the provision of electric service, particularly those concerning low-wealth customers burdened by energy costs and racial disparities in the provision of electric service.[61] JSC urges the Commission to continue incorporating equity and Energy Justice into its decision-making in a way that is especially meaningful in this proceeding, since this case involves decisions about significant investments and cost recovery by Xcel, and in turn significant economic and other impacts on customers.[62]

66. JSC offered long-term recommendations and "a vision for a more just, resilient and cost effective system in the future." JSC urged the Commission to "center Energy Justice as a normative principle for its decision" by "consider[ing] the normative goals of Energy Justice as themselves worthy of prioritizing in setting rates that advance the public interest."[63]

67. The Company agreed with JSC that Energy Justice is an important issue. Company witness Nicholas Martin, the Company's Director of Strategic Outreach and Advocacy, described Xcel Energy's efforts to further Energy Justice, including:

i. convening an Equity Stakeholder Advisory Group (ESAG) to advise the Company on equity in the design and implementation of energy payment assistance, energy efficiency, renewable energy, and workforce diversification programs;[64]

ii. leading the Resilient Minneapolis Project, which will install solar/battery microgrids at three community centers in BIPOC neighborhoods to help them function as reliance hubs for vulnerable communities in an emergency;[65]

iii. developing partnerships with Native Nations and non-profits serving the Twin Cities Native community;[66]

iv. advancing energy equity and environmental justice concerns through its integrated resource planning, energy efficiency, renewable

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[59] Initiative for Energy Justice, THE ENERGY JUSTICE WORKBOOK at 9, 66–68. *available at* https://iejusa.org/wp-content/uploads/2019/12/The-Energy-Justice-Workbook-2019-web.pdf (defining "energy justice" and providing alternative definitions).
[60] *See, e.g.,* Ex. JSC-1, *passim* (Porter Direct); Ex. JSC-3, *passim* (Chan Direct); Ex. JSC-9, *passim* (Madden Surrebuttal).
[61] Ex. JSC-5 at 21-22 (Rábago Direct).
[62] JSC Initial Br. at 13.
[63] Ex. JSC-1 at 7 (Porter Direct); Ex. JSC-2 at 49-50 (Chan Direct).
[64] Ex. Xcel-83 at 1 (Martin Rebuttal).
[65] Ex. Xcel-83 at 1 (Martin Rebuttal).
[66] Ex. Xcel-83 at 1 (Martin Rebuttal).

energy, and electric vehicle programs, resiliency efforts, and stakeholder outreach;[67] and,

v. working with the ESAG accomplish the goals established by the Commission in the Company's Energy Equity Docket.[68]

68. The Company's actions, as discussed above, are directed at achieving Energy Justice policies mentioned by JSC, such as improving affordability of electricity for low-income and BIPOC communities and investing in resilience in those communities.[69]

69. The Company also recognized it could do more to involve the BIPOC communities it serves and explicitly center equity in its energy plans and programs.[70]

70. The Company disagreed, however, with some of JSC's recommendations, arguing that certain recommendations could be counter-productive to both JSC's and the Company's shared goal of a more just energy future. The Company disagreed with JSC's assertions that distributed energy resources (DERs) are possibly an exclusive means to creating a decarbonized, equitable energy system. Company witness Mr. Martin testified that some DERs, such as Community Solar Gardens have been harmful to equity. Mr. Martin explained that while the Company is working to better enable distributed solar, improve the interconnection process, accelerate interconnection timelines, and reduce costs, it considers large scale renewables an important component in creating a decarbonized, equitable system.[71]

71. The Company also disagreed with JSC's assertion that fundamental changes in the energy industry are required, including abandoning the vertically-integrated business model in favor of an "open access" Distribution System Operator (DSO) model. The Company's primary concern regarding JSC's assertion was that JSC did not provide any analysis of costs or the impact on affordability. Further, the Company witness Mr. Martin testified that a fundamental, complex, and time-consuming change to the entire industry is not necessary to achieve both decarbonization and Energy Justice. In support, Mr. Martin pointed to Company actions designed to achieve both, including:[72]

i. enabling and integrating DERs on the distribution system;

ii. reducing timeframes and costs to interconnect to the distribution system; and

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[67] Ex. Xcel-83 at 5 (Martin Rebuttal).

[68] *In the Matter of Efforts to Advance Workforce Diversity, Inclusive Participation, and Equitable Access to Utility Services for Xcel Energy*, MPUC Docket No. E002/M-22-266.

[69] Ex. Xcel-83 at 15, 18-19, 41-42 (Martin Direct).

[70] Ex. Xcel-83 at 5 (Martin Rebuttal).

[71] Ex. Xcel-83 at 27-34 (Martin Rebuttal).

[72] Ex. JSC-2 at 19-21 (Kristov Direct); Ex. Xcel-83 at 36 (Martin Rebuttal).

iii. integrating solar, storage, efficiency, demand response, EVs, electrified heating, and microgrids into the Company's systems.

72. XLI witness Mr. Jeffry Pollock claimed that the principles of Energy Justice "are irreconcilable with standard, accepted ratemaking practices," and that to his knowledge no public utility commission has ever subjected an entire ratemaking process to the standard.[73]

73. The Judge agrees with the Company and JSC that a general rate case for one utility is inadequate for addressing broad, societal, and systemic matters—particularly when they are raised in intervenor direct testimony and other potentially interested parties have missed the opportunity to be part of the discussion. Many of the broader issues raised by JSC are, to the extent they concern Xcel, best addressed in the Company's Energy Equity Docket and through the Equity Stakeholder Advisory Group, where they can be given full consideration.

74. Ratemaking routinely gives rise to disputes among stakeholders about specific issues which fundamentally reduce to disputes about what would constitute just and reasonable rates. The ratemaking process is a mechanism for balancing the arguments and interests concerning justice and equity (among other things) as they relate to a specific utility's claimed costs of providing necessary utility service[74] and to customer-class allocation of the utility's revenue requirement.[75]

75. Because the Commission's ordinary legal standard in a general rate proceeding requires it to balance competing interests to determine just and reasonable rates, the Judge recommends that the Commission apply its ordinary legal standard in this proceeding.

VI. Undisputed or Resolved Issues

76. Several issues were undisputed or resolved during the proceeding. A summary of each issue, and its basis for resolution, is provided below. Citations to transcripts or hearing exhibits in these Findings of Fact are not inclusive of all applicable evidentiary support in the record.

A. Expense or Rate Base Related Issues

77. The following expense or rate-base-related issues are undisputed or have been resolved among the parties.

[73] Ex. XLI-2 at 5 (Pollock Rebuttal).
[74] *See In re Northern States Power Co.,* 416 N.W.2d at 729 (discussing the competing interests of ratepayers and investors).
[75] *St. Paul Area Chamber Of Commerce v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977) (discussing the "many countervailing considerations" at play when determining a just an reasonable allocation of a utility's revenue requirement).

1. Nuclear Decommissioning Accrual

78. The Company identified $26.9 million as the Minnesota jurisdictional annual accrual level for nuclear decommissioning for 2022 through 2026. Nuclear decommissioning is the method used to accumulate the final removal costs for the Company's three nuclear units, which are funded externally in a trust per Nuclear Regulatory Commission rules. The annual accruals for nuclear decommissioning are calculated from a detailed engineering cost estimate to remove the plant and to store the fuel until the federal government takes possession of all the fuel assemblies.[76]

79. The Department recommended reducing the nuclear decommissioning accrual to $21.6 million, pointing to the Commission's approved accrual amount in the Company's 2022-2024 Nuclear Plant Decommissioning docket to reflect the expectation that the Monticello Nuclear Generating Plant (MNGP) will operate for an additional ten years. This recommendation results in an annual revenue requirement reduction of approximately ($5.4 million) for the years 2022 through 2026.[77]

80. The Company agreed with the Department's recommendation to reduce the annual nuclear decommissioning accrual to $21.6 million to reflect the expected extension of MNGP's operational life for an additional ten years.[78]

81. The parties' agreement is reasonable and the Judge recommends reducing the annual nuclear decommissioning accrual accordingly.

2. Nuclear Hydrogen Operations and Maintenance (O&M)

82. The Company included a nuclear hydrogen project in its budget for the plan years 2022, 2023, and 2024. The project, funded in large part by a grant from the Department of Energy (DOE), will attempt to demonstrate that Xcel can use the steam and electricity generated from nuclear energy to generate hydrogen, through a process known as high temperature steam electrolysis (HTSE). The project is expected to take approximately two years beginning in 2024.[79]

83. The Department did not object to the project or inclusion of its costs in the Company's budget but recommended that the Company revise the incremental O&M expense for the project that was updated in discovery after negotiations with the DOE.[80]

84. The Company agreed that an adjustment was appropriate based on the updated funding from the DOE, but differed in the amounts from the Department's proposed adjustment to account for the Minnesota jurisdictional amount net of interchange. The resulting nuclear hydrogen O&M costs are as follows:[81]

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[76] Ex. Xcel-65 at 62 (Moeller Direct).
[77] Ex. DOC-7 at 16 (Skayer Direct).
[78] Ex. Xcel-68 at 7 (Moeller Rebuttal).
[79] Ex. Xcel-34 at 19-20 (Gardner Direct).
[80] Ex. DOC-22 at 65-66 (Campbell Direct).
[81] Ex. Xcel-35 at 13-14 (Gardner Rebuttal); Ex. Xcel-82 at 17-18, (BCH-2), Schedule 4 (Halama Rebuttal).

2022: $1.099 million

2023: $0.506 million

2024: $1.345 million

85. The Department agreed with the updated numbers. No other party provided testimony on the issue.[82]

86. The parties' agreement is reasonable. The Company's inclusion of the nuclear hydrogen O&M expenses, as represented in the Rebuttal Testimony of Company witness Benjamin Halama, should be approved.

3. Monticello Nuclear Plant Life Extension

87. The Department recommended extending the Monticello Nuclear Generating Plant's (MNGP) depreciation life for ten years.[83]

88. The Department bases its recommendation on the following reasons:[84]

i. the Commission approved the ten-year extension in Xcel's Integrated Resource Plan (IRP),[85]

ii. the Commission approved the ten-year life extension in Xcel's decommissioning study,[86]

iii. the Commission approved a similar ten-year extension in Xcel's 2008 rate case for the Prairie Island Nuclear Generating plant,[87]

iv. there are material capital costs included in this rate case related to the Monticello nuclear plant, and

v. the ten-year life extension is the midpoint of the twenty-year extension being requested from the NRC in first quarter of 2023.

89. Company witness Mark Moeller also noted that any extension of MNGP's remaining life must recognize the risk that the required regulatory approvals have not

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82 Ex. DOC-23 at 8 (Campbell Surrebuttal).

83 Ex. DOC-22 at 72 (Campbell Direct).

84 Ex. DOC-22 at 72 (Campbell Direct).

85 *In re 2020-2034 Upper Midwest Integrated Resource Plan of N. States Power Co. d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filing at 3 (Apr. 15, 2022) (eDockets No. 20224-184828-01).

86 *In re N. States Power Co. d/b/a Xcel Energy's 2022-24 Triennial Nuclear Plant Decommissioning Study & Assumptions*, MPUC Docket No. E002/M-20-855, Order Approving Decommissioning Study, Decommissioning Accrual, and Taking Other Action at 10 (Aug. 24, 2022) (eDockets No. 20228-188577-01).

87 *In the Matter of the Application of Xcel for the Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E002/GR-08-1065, Findings of Fact, Conclusions of Law, and Order at 13-14 (Oct. 23, 2009).

been, and may not be, granted. If these approvals are not obtained, an additional adjustment to the revenue requirement could be required.[88]

90. The Company agreed that it is reasonable to extend the depreciation life of the MNGP by ten years for purposes of determining the Company's revenue requirement in this case, but only in conjunction with depreciable life adjustments for Sherco Unit 3 and King coal plants. The Company noted that in the IRP cited by the Department, the Commission ordered the early retirement of Sherco Unit 3 and King coal plants. The Company argued that regulatory consistency would indicate that these shorter lives also be reflected in the Company's revenue requirements, receiving the same treatment as the MNGP.[89]

91. There is a dispute over the Company's proposal to change the depreciation lives of the Sherco Unit 3 and King coal plants, which is subsequently discussed in the Contested Issues section.

92. No other party provided testimony on the issue of the extension of MNGP's remaining life.

93. The Judge recommends that the depreciation life of MNGP be extended by ten years.

4. Wind Farm Life Extension

94. The Department recommends extending the life of 11 of the Company's wind farms from 25 to 35 years.[90] These 11 wind farms are: Blazing Star I, Blazing Star II, Community, Courtenay, Crowned Ridge, Dakota Range, Foxtail, Freeborn, Jeffers, Lake Benton, and Mower.[91]

95. The Company hired Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to prepare an engineering study regarding the expected life of its wind facilities.[92] This study concluded that there are no substantive performance or maintenance issues with the Company's wind facilities that would prevent them from operating as designed for 35 years.[93] The study noted that this conclusion was based on the assumption that the appropriate level of maintenance is performed on these wind facilities to support continued operations and that the wind farms are operated and maintained in accordance with good utility practice and manufacturer's recommendations.[94]

96. Company witness Randy Capra testified that extending the life of the Company's wind facilities will result in additional O&M and capital costs as components

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[88] Ex. Xcel-38 at 3 (Moeller Rebuttal).
[89] Ex. Xcel-83 at 4 (Moeller Rebuttal).
[90] Ex. DOC-94 at 14 (Skayer Direct).
[91] Ex. Xcel-67 at 8 (Moeller Rebuttal).
[92] Ex. Xcel-39 at 13 (Capra Rebuttal).
[93] Ex. Xcel-39 at 13 (Capra Rebuttal).
[94] Ex. Xcel-39 at 13-14 (Capra Rebuttal).

will likely need to be repaired or replaced when these wind farms are operated beyond their original 25-year design life.[95]

97. The Company supports the Department's recommendation to extend the life of these 11 wind farms from 25 to 35 years but will continue to review these wind farms in the Company's Remaining Lives filing, which is the annual review of the remaining lives and dismantling costs.[96]

98. The Department's recommendation to extend the life of 11 of the Company's wind facilities from 25 to 35 years is reasonable and should be adopted.

5. Pension Expense and Deferred Balance

99. The Company included pension expense in its five-year forecast, including pension expense associated with the NSPM Plan determined under the Aggregate Cost Method (AGM), and pension expense associated with the Xcel Energy Services (XES) Plan determined in accordance with Financial Accounting Standards Board's Statement of Financial Accounting Standard No. 87 (FAS 87). The Company stated that approximately 75% of the Company's qualified pension expense relates to the NSPM Plan and 25% relates to the XES Plan. [97]

100. The Commission previously approved a plan allowing the Company to defer pension expense amounts over the XES Plan cap, resulting in a $15.9 million deferred balance. The Company proposed amortizing the cumulative deferred balance over the three years of the MYRP, or $5.3 million for the years 2022, 2023, and 2024.[98]

101. The Department asked the Company to explain where the Commission approved the continuing use of the ACM for the NSPM Plan, and the Company provided a response to the Department's Information Request showing the Commission's approval of an agreement between the Company and OAG in Docket No. G002/GR-09-1153. The Department did not object to the Company's Pension Expense and Deferred Balance proposals.[99]

102. No other party provided testimony on the issue.

103. The Judge recommends approval of the Company's pension expense and the Company's proposal to amortize the cumulated deferred balance of the XES Plan over the MYRP term.

[95] Ex. Xcel-39 at 14 (Capra Rebuttal).
[96] Ex. Xcel-67 at 9 (Moeller Rebuttal).
[97] Ex. Xcel-57 at 9, 42 (Schrubbe Direct).
[98] Ex. Xcel-57 at 47-50 (Schrubbe Direct); MPUC Docket No. E002/GR-12-961.
[99] Ex. DOC-21 at 38 (Campbell Direct).

6. Transformer Sales

104. In 2022, the Company sold three different transformers used at its Forbes, Nobles, and Grand Meadow wind farms.[100] Each of these sales was approved by the Commission in three different dockets.[101] The Company adjusted its MYRP Forecast revenue requirements to reflect these transformer sales by removing the transformer costs and adding sales revenue.[102]

105. The Department agreed with the Company's proposed adjustments to reflect these three transformer sales in 2022.[103] The Company's proposed adjustments should be adopted.

7. North Dakota Investment Tax Credit (NDITC)

106. The Department recommended including a credit for the NDITC in the Minnesota Electric Jurisdiction revenue requirement calculation.[104]

107. Xcel agreed with the Department's proposal and included the offset in its MYRP Forecast revenue requirements in its rebuttal.[105]

108. The Judge has reviewed the agreement of the parties and finds it reasonable and consistent with the public interest.

8. EV Deferral Update

109. In previous proceedings, the Commission approved deferral of certain EV program O&M and depreciation expenses, consistent with the EV statute.[106] The Company requested recovery of these deferred costs for prior years in this rate case.[107]

110. The amount of these costs was not ascertainable at the time of the initial filing. In rebuttal, the Company proposed that the costs would increase its Minnesota

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[100] Ex. Xcel-39 at 23 (Capra Rebuttal).
[101] *See In the Matter of Northern States Power Company's (Xcel Energy) Petition for Approval of the Sale of Used Transformer to Intermountain Rigging and HeavyHaul*, MPUC Docket No. E002/PA-21-656, Order (Jan. 26, 2022); *In the Matter of Northern States Power Company's Petition for Approval of the Sale of Used Electrical Equipment to Sunbelt Solomon Services, LLC*, MPUC Docket No. E002/PA-21-101, Order (Apr. 5, 2022); *In the Matter of the Petition of Northern States Power, doing business as Xcel Energy for Approval to Sell Used Electrical Equipment to Sunbelt Solomon Service, LLC*, MPUC Docket No. E002/PA-22-273, Order (July 27, 2022).
[102] Ex. Xcel-82 at 22 (Halama Rebuttal).
[103] Ex. DOC-23 at 12 (Campbell Surrebuttal).
[104] Ex. DOC-3 & 4 at 8–10 (Soderbeck Direct).
[105] Ex. Xcel-82 at 13 (Halama Rebuttal).
[106] Ex. Xcel-41 at 149 (Bloch Direct); Ex. Xcel-80 at 121 (Halama Direct).
[107] Ex. Xcel-41 at 149 (Bloch Direct); Ex. Xcel-80 at 121 (Halama Direct).

Electric Jurisdiction revenue requirement by $305,000 for 2022, $287,000 for 2023, and $270,000 for 2024.[108] The Department agreed with these amounts.[109]

111. Because the parties' agreement is reasonable, the Judge recommends that the Commission approve recovery of these deferred costs in this rate case.

9. EV Rebates

112. At the time the Company filed this rate case, the Company had an open petition pending before the Commission relating to EV pilots and programs, including a proposal to build public EV charging stations throughout rural Minnesota and a proposal to offer rebates for electric light duty vehicles, transit buses, and school buses.[110] The Company sought to recover, in this case, capital and O&M expenses for 2022 to 2024 associated with these programs.[111]

113. On April 27, 2022, the Commission issued an order approving the Company's proposal to build the public EV charging stations but denying the Company's proposed rebate program.[112] The Commission ordered the Company to incorporate any resulting changes to cost recovery into this rate case.[113]

114. The Company estimated that the denial of the EV rebates program resulted in revenue requirements reductions of $6,238,000 for 2022, $16,124,000 for 2023, and $21,577,000 for 2024.[114] The Department agreed with these figures and considered this issue resolved.[115]

115. The Judge recommends that the Commission approve the EV rebates adjustments.

10. EV Programs

116. In addition, the Commission later considered the Company's proposal to include certain EV program costs in this rate case.[116] The Commission referred the matter

[108] Ex. Xcel-82 at BCH-R-3, Schedules 3a-3c.
[109] Ex. DOC-5 at 6 (Soderbeck Surrebuttal).
[110] Ex. Xcel-41 at 147-48 (Bloch Direct); Ex. DOC-4 at 48 (Soderbeck Direct).
[111] Ex. Xcel-41 at 149 (Bloch Direct).
[112] *In re Xcel Energy's Petition for Approval of Electric Vehicle Programs as Part of Its COVID-19 Pandemic Economic Recovery Investments*, MPUC Docket No. E-002/M-20-745, Order Approving Public Charging Station Proposal at 9-10 (Apr. 27, 2022).
[113] Order Approving Public Charging Station Proposal at 11 (Apr. 27, 2022).
[114] Ex. Xcel-82 at 8 and Exhibit BCGH-2, Schedules 3a-c, page 2 (Halama Rebuttal).
[115] Ex. DOC-5 at 8 (Soderbeck Surrebuttal).
[116] *In re Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications*, MPUC Docket No. E002/M-22-432, Notice of and Order for Hearing (Oct. 26, 2022).

to the OAH, and required the Company to remove costs associated with the EV programs from this rate case.[117]

117. The Company reduced its requested revenue requirement consistent with the Commission's Order, in the amounts of $1,067,000 for 2022, $2,528,000 for 2023, and $6,517,000 for 2024.[118] The Department confirmed these figures and considered this issue resolved.[119]

11. Legacy Meter Regulatory Asset

118. The Company is in the process of deploying Advanced Metering Infrastructure (AMI) meters as part of its larger advanced grid initiative. This deployment will result in the early retirement of legacy meters with an unrecovered net book value the Company estimates at $28 million on December 31, 2024.[120]

119. The Company proposed that any remaining book value at the time AMI meter deployment is complete will be transferred to a regulatory asset and deferred for recovery as part of the Company's next rate case. In rebuttal testimony, Company witness Mr. Moeller explained that the Company is currently separating the meters into two Federal Energy Regulatory Commission (FERC) sub-accounts and following accounting guidance for depreciation. Mr. Moeller proposed using a fourteen-year average service life for the legacy meter regulatory asset to maintain the current proposed remaining life and accrual rate.[121]

120. The Department agreed with the Company's proposal and recommended that the Commission approve creating the legacy meters regulatory asset. Department witness Ms. Skayer agreed with Mr. Moeller that the regulatory asset will stabilize the amortization expense for ratepayers and will not shorten the legacy meters' current remaining life. Ms. Skayer also pointed to the Commission's decision to allow Dakota Electric to recover an undepreciated balance for meters in 2018.[122]

121. No other party provided testimony on the issue.

122. The parties' agreement is reasonable and the Judge recommends approving the Company's proposal to create a regulatory asset for legacy meters.

12. TCR Rider Removal

123. The Transmission Cost Recovery (TCR) Rider is authorized by Minn. Stat. § 216B.16, subd. 7b, to allow the recovery of Minnesota jurisdictional costs related to

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[117] *In re Petition of Northern States Power Company for Approval of a Public Charging Network, an Electric School Bus Pilot, and Program Modifications*, MPUC Docket No. E002/M-22-432, Notice of and Order for Hearing at 5 (Oct. 26, 2022).
[118] Ex. Xcel-82 at 5-6 (Halama Rebuttal); Ex. DOC-5 at 10-11 (Soderbeck Surrebuttal).
[119] Ex. DOC-5 at 11 (Soderbeck Surrebuttal).
[120] Ex. Xcel-66 at 60 (Moeller Direct).
[121] Ex. Xcel-66 at 60 (Moeller Direct); Ex. Xcel-68 at 17-18 (Moeller Rebuttal).
[122] Ex. DOC-8 at 11 (Skayer Surrebuttal).

transmission and grid modernization investments and for MISO charges incurred for projects for which MISO assigns regional costs under Schedule 26 and Schedule 26A of its Tariff.[123]

124. The Company proposed continued use of the TCR Rider during the MYRP.[124] To prevent double recovery, the Company made an adjustment to its rate request so that the costs and revenues addressed through the TCR Rider were excluded from this rate case.[125]

125. During discovery, the Company discovered an error in one aspect of the TCR Rider removal—the calculation of internal labor amounts for the forecasted periods in the AMI project.[126] To remedy this error, in Rebuttal Testimony the Company reduced its Minnesota Electric Jurisdiction revenue requirement by $386,000, $1,172,000, and $2,012,000 in 2022, 2023, and 2024 respectively.[127] The Department confirmed these figures and considered this issue resolved.[128]

126. The parties' agreement is reasonable and the Judge recommends approving recovery based on the Company's updated revenue requirement.

13. Nuclear Production Tax Credits

127. The Inflation Reduction Act of 2022 (IRA) became law in August 2022. Among other things, the IRA created a new production tax credit (PTC) for existing nuclear resources.[129] The Company may receive PTCs related to the annual production at its nuclear facilities.[130] However, the potential value of these nuclear PTCs cannot yet be estimated—it depends on implementation guidance to be issued by the federal government.[131]

128. At present there is no mechanism for returning the value of nuclear PTCs to customers.[132] The Company proposed a new tracker and annual true-up via the Fuel Clause Adjustment (FCA) rider filing to return nuclear PTCs to customers if and when they are generated.[133]

[123] Ex. Xcel-79 at 111 (Halama Direct).
[124] Ex. Xcel-79 at 98, 111-113 (Halama Direct).
[125] Ex. Xcel-79 at 98-99; Ex. DOC-6 at 12-13 (Soderbeck Surrebuttal).
[126] Ex. Xcel-82 at 45 (Halama Rebuttal).
[127] Ex. Xcel-82 at 45, BCH-2, Schedule 3a-c, page 4, row 84, column 20 (Halama Rebuttal); Ex. DOC-6 at 13 (Soderbeck Surrebuttal).
[128] Ex. DOC-6 at 13 (Soderbeck Surrebuttal).
[129] Ex. Xcel-70 at 25 (Arend Rebuttal).
[130] Ex. Xcel-82 at 57 (Halama Rebuttal).
[131] Ex. Xcel-82 at 57-58 (Halama Rebuttal); Ex. Xcel-70 at 26 (Arend Rebuttal).
[132] Ex. Xcel-70 at 25 (Arend Rebuttal).
[133] Ex. Xcel-82 at 57-58 (Halama Rebuttal).

129. The Department agreed with the Company's proposal to track nuclear PTCs that it earns and return them to customers through the annual FCA rider filing, and considered this issue resolved.[134]

130. The parties' agreement is reasonable and the Judge recommends approving the Company's proposal for a new tracker and annual true-up via the Fuel Clause Adjustment (FCA) rider filing to return nuclear PTCs to customers if and when they are generated.

14. EV Program O&M Expense - FERC Account 912

131. Consistent with treatment in prior rate cases, the Company proposed to include certain forecasted costs, relating to O&M associated with EV programs, in FERC Account 912 in each year of the MYRP.[135]

132. Expense Account 912 is the FERC account in the administrative and general category for Demonstrating and Selling Expenses. The Company reduces its revenue, in part, by the expenses in this account when calculating its net income—and subsequently the revenue requirement.[136]

133. The Department recommended adjustments based on historical year-over-year percentage increases, rather than on the Company's estimates, for these FERC Account 912 expenses.[137]

134. In rebuttal, the Company explained why the costs in FERC Account 912 had increased compared to previous years, and how the Department's proposal would overlap with costs it had already removed as part of its Rebuttal Testimony.[138]

135. In light of the explanation and information provided by the Company, the Department withdrew its recommendation, and considered this issue resolved.[139]

136. This agreement is reasonable and the Judge recommends approving the Company's proposal.

15. Excess Footage and Winter Construction Charges

137. Xcel originally proposed to increase surcharges assessed for service lines above certain thresholds, referred to as excess footage charges.[140] It later informed the Department that it "is no longer proposing any changes to its excess footage charges in

[134] Ex. DOC-6 at 15 (Soderbeck Surrebuttal).
[135] Ex. Xcel-82 at 41 (Halama Rebuttal).
[136] Ex. DOC-3 at 36 (Soderbeck Direct).
[137] Ex. DOC-3 at 36-41 (Soderbeck Direct).
[138] Ex. Xcel-43 at 23-28 (Mensen Rebuttal); Ex. Xcel-82 at 41 (Halama Rebuttal).
[139] Ex. DOC-6 at 18 (Soderbeck Surrebuttal).
[140] Ex. Xcel-84 at 48-49 (Peppin Direct).

this proceeding. Xcel Energy will make any necessary updates in rebuttal to account for this change."[141]

138. Xcel also proposed increasing the surcharges assessed for certain winter construction activities, as set forth in section 5.1.A.2. of Xcel's tariff. Specifically, Xcel proposed increasing the thawing charge from $600 to $685 per frost burner and increasing the service extension charge from $3.80 per trench foot to $8.90 per trench foot.[142] However, Xcel later updated its proposed thawing charge to $640 per frost burner.[143] The Department reviewed the company's supporting analysis and concluded it was reasonable.

139. No other party addressed or objected to Xcel's proposed excess footage charges and winter construction charges.

140. The Judge has reviewed the proposed resolutions and concludes that they are reasonable.

141. The Judge recommends that the Commission approve the parties' resolutions of the excess footage and winter construction charge issues.

16. Secondary Calculations

142. The parties agree that to the extent the Commission does not accept the Company's revenue requirement proposal as set forth in Rebuttal Testimony, adjustments will affect "secondary calculations" such as the ADIT prorate, cash working capital, the cost of capital as applied to approved components of the revenue requirement, net operating loss, and interest synchronization.[144]

143. The Judge recommends that the Commission should direct the Company to update these secondary calculations in any compliance filing determining the revenue requirements for the MYRP approved in this case.

17. Software as a Service (SaaS)

144. The OAG initially recommended denial of the Company's request to defer future costs associated with SaaS investments. In Rebuttal Testimony, the Company agreed to remove its request for deferral of costs associated with SaaS.[145] The Company also noted that because the initial proposal was a deferral of costs incurred outside the MYRP, withdrawing this proposal has no effect on the revenue requirement.[146]

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[141] Ex. DOC-15, SC-D-2 (Collins Direct) (Xcel Response to DOC IR 702).
[142] Ex. Xcel-84 at 49 (Peppin Direct).
[143] Ex. DOC-15, SC-D-3 (Collins Direct) (Xcel Response to DOC IR 703).
[144] Ex. Xcel-82 at Section V (Halama Rebuttal); see Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 201 (Campbell).
[145] Ex. Xcel-51 at 13-18 (Remington Rebuttal).
[146] Xcel Energy Reply Br. at 54-55.

145. The OAG agreed that it would be reasonable for the Company to withdraw this request.[147]

146. The Judge agrees that it would be reasonable for the Company to withdraw its proposed deferred accounting mechanism for SaaS costs from consideration.

B. Revenue Related Issues

1. Sales Forecast – 2022 Test Year

147. For the 2022 test year, the Company proposes to use actual, weather-normalized 2022 sales and customer count data to set rates to remove any risk of under- or over-forecasting actual sales.[148] The Company indicated it would submit its actual, weather-normalized 2022 sales data, along with other necessary information by February 1, 2023.[149]

148. The Department supports the Company's proposal to use actual, weather-normalized 2022 sales and customer counts to set rates for the 2022 test year.[150] No other party submitted testimony related to the Company's 2022 sales and customer count forecast.

149. The parties' agreement is reasonable and the Judge recommends approving the use of actual, weather-normalized 2022 sales and customer counts to set rates for the 2022 test year.

2. MISO Capacity Auction Revenues

150. In its initial filing, the Company included bilateral capacity revenues in the 2022 to 2024 MYRP but did not include actual 2022–2023 MISO Planning Resource Action (PRA) revenues because the auction proceeds were not known until April 2022. While the Company received approximately $153 million in MISO PRA revenue for 2022-2023, the Company received between $0 and $700,000 annually over the nine prior planning years.[151] As a result, the Company's MYRP forecasts were substantially lower than the 2022–2023 MISO PRA revenues.

151. The Department initially proposed setting the capacity revenues for the MYRP at the level achieved in the 2022 to 2023 MISO Planning Year, but did not account for the Zonal Deliverability Benefits also received.[152] Ultimately, the parties agreed that (1) the Company would adjust the MISO PRA revenues in the MYRP to recognize the amounts received from June 2022 to May 2023, corrected for Zonal Delivery Benefits and

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[147] Ex. OAG-9 at 78 (Lee Surrebuttal).
[148] Ex. Xcel-75 at 20 (Goodenough Direct). The Company committed to filing this information by Feb. 1, 2023 to calculate the final present revenues and final authorized revenue deficiency for the 2022 test year. Ex. Xcel-77 at 9 (Goodenough Rebuttal).
[149] Ex. Xcel-77 at 8 (Goodenough Rebuttal).
[150] Ex. DOC-9 at 4, 24 (Shah Direct).
[151] Ex. Xcel-82 at 9 (Halama Rebuttal).
[152] Ex. Xcel-82 at 10-11 (Halama Rebuttal).

additional MISO capacity auction proceeds from prior years, and maintain the same level for the remainder of the MYRP; (2) the Company will implement a tracker through the conclusion of the next rate case, to account for any variance (up or down) in the amount included in the MYRP as compared to the baseline established in this case; and (3) the Company will report all actual capacity revenues from the MISO PRA or any other sales of capacity revenues (including bilateral contracts) as part of the tracker.[153]

152. The parties' agreement is reasonable, as it will ensure the Company's rates reflect no more or less revenue than the Company actually receives, in relation to a highly volatile revenue stream. The Judge therefore recommends that the resolution of this issue should be approved.

C. Cost of Capital

153. In order to determine an appropriate overall rate of return for Xcel Energy, it is necessary to determine the amount of long-term debt, short-term debt and common equity needed by the Company to finance its operations (the capital structure) and the cost of each of these components. The only contested cost of capital issue concerns the appropriate return on equity to be allowed, which is addressed in the Contested Issues findings, below.

1. Capital Structure

154. Xcel Energy proposed a capital structure for the 2022 test year and the 2023 and 2024 plan years as follows:[154]

	2022	2023	2024
Long-term debt	46.89%	46.50%	47.08%
Short-term debt	0.61%	1.00%	0.42%
Common Equity	52.50%	52.50%	52.50%

155. The Department reviewed the Company's proposed capital structure and found it to be reasonable.[155] No other party provided testimony on this issue.

156. The parties' agreement is reasonable and the Judge recommends approving the Company's Capital Structure.

[153] Ex. Xcel-82 at 11 (Halama Rebuttal); Ex. DOC-23 at 6 (Campbell Surrebuttal).
[154] Ex. Xcel-24 at 30-44 (Johnson Direct); Ex. Xcel-26 at 2-3 (Johnson Rebuttal); Ex. Xcel-27 at 18-22 (D'Ascendis Direct).
[155] Ex. DOC-1 at 53-62, 102 (Addonizio Direct).

2. Cost of Long-Term Debt

157. The Company proposed Long-Term Debt (LTD) balances and costs for the 2022 test year and the 2023 and 2024 plan years as follows:[156]

	Long-Term Debt Balance	Long-Term Debt Costs
2022 Test Year	$6.9 billion	4.13%
2023 Plan Year	$7.3 billion	4.12%
2024 Plan year	$7.7 billion	4.09%

158. The Department updated the Company's proposed cost of LTD to account for changes in interest rates, including changes in the interest rates of Xcel Energy-issued bonds. Department witness Mr. Addonizio changed the interest rates on Xcel's 2022 issuance, first in Direct Testimony and again in Surrebuttal Testimony, resulting in LTD proposed costs of 4.19%, 4.33%, and 4.40% for the years 2022, 2023, and 2024, respectively.[157]

159. The Company agreed to the Department's proposed updates to the costs of LTD.[158]

160. No other party provided testimony on the issue.

161. The Judge concludes the parties' agreement is reasonable and the Judge recommends approving the Company's cost of Long-Term Debt.

3. Cost of Short-Term Debt

162. The Company proposed short-term debt balances and costs for the 2022 test year and the 2023 and 2024 plan years as follows:[159]

	Short-Term Debt Balance	Short-Term Debt Cost
2022 Test Year	$88.9 million	-0.94%
2023 Plan Year	$156.6 million	0.80%
2024 Plan year	$68.3 million	1.47%

163. The Department updated the Company's proposed cost of short-term debt to account for changes in interest rates on comparable commercial paper. Department witness Mr. Addonizio changed the interest rates on Xcel's 2022 issuance, first in Direct

[156] Ex. Xcel-24 at 33 (Johnson Direct).
[157] Ex. DOC-1 at 59-60 (Addonizio Direct); Ex. DOC-2 at 3 (Addonizio Surrebuttal).
[158] Ex. Xcel-26 at 2-3 (Johnson Rebuttal).
[159] Ex. Xcel-24 at 35 (Johnson Direct).

Testimony and again in Surrebuttal Testimony, resulting in short term debt proposed costs of 3.73%, 3.50%, and 4.17% for the years 2022, 2023, and 2024, respectively.[160]

164. The Company agreed to the Department's proposed updates to the costs of short-term debt.[161]

165. No other party provided testimony on the issue.

166. The parties' agreement is reasonable and the Judge recommends approving the Company's cost of short-term debt.

D. Class Cost of Service Study (CCOSS)

1. Allocation of Economic Development Discounts

167. Economic development discounts are intended to attract and incentivize large customers to site and maintain load within the Company's service territory, thereby increasing revenue and generating incremental revenues.[162] In the Company's CCOSS, economic development discounts were applied as a reduction to the revenues from the Commercial and Industrial (C&I) Demand customer class.[163] The costs for these discounts were then allocated among customer classes based on total revenue.[164]

168. XLI recommended that the CCOSS allocate the economic development discount costs with a base revenue allocator because total revenues include costs recovered under various riders and clauses, including fuel cost recoveries.[165] XLI explained that the variable costs for fuel are not comparable with the fixed costs offset by large customers that receive the economic development discounts.[166]

169. The Company agreed that XLI's recommendation is reasonable because the economic development discounts are related to base revenues.[167]

170. The Judge recommends that XLI's proposed adjustment to the CCOSS should be adopted.

[160] Ex. DOC-1 at 60-61 (Addonizio Direct); Ex. DOC-2 at 3 (Addonizio Surrebuttal).
[161] Ex. Xcel-26 at 2-3 (Johnson Rebuttal).
[162] Ex. XLI-1 at 24 (Pollock Direct).
[163] Ex. Xcel-84 at 11 (Peppin/Barthol Direct).
[164] Ex. Xcel-84 at 11 (Peppin/Barthol Direct).
[165] Ex. XLI-1 at 24 (Pollock Direct).
[166] Ex. XLI-1 at 24 (Pollock Direct).
[167] Ex. Xcel-87 at 23 (Barthol Rebuttal).

E. Multi-Year Rate Plan Issues

1. Term of Plan

171. The Company proposed a three-year MYRP, with a test year of calendar year 2022 and plan years of calendar years 2023 and 2024. No party objected to the Company's proposal.[168]

172. The Judge finds the Company's proposed three-year MYRP reasonable and appropriate.

2. Capital True-Up

173. The Company proposed a capital true-up mechanism modeled after the mechanism approved by the Commission for the Company's 2016–2019 MYRP. The proposed capital-related revenue requirements true-up is a "one way" true-up, meaning that the Company will make refunds if its capital-related revenue requirements in any year fall below the Commission-approved capital-related revenue requirements. If, on the other hand, the Company's capital-related revenue requirements exceed the Commission-approved capital related revenue requirements, the Company cannot surcharge customers.[169]

174. No other party took a position on the proposal.

175. The Judge recommends that the Commission approve the Company's proposed capital true-up for the three-year MYRP. The proposal provides the Company with flexibility to manage its business while protecting customers from any overbudgeting by the Company.

3. Property Tax True-Up

176. The Company proposed to use a true-up mechanism to ensure that customers pay only the property taxes that are actually incurred.[170]

177. The true-up is expected to function as follows: the Company would submit an annual compliance filing showing the actual property tax expense for a given year as compared to the amount included in rates for that year.[171] Any over-recovery would be refunded or, symmetrically, any under-recovery would be charged, through an appropriate mechanism at that time.[172]

[168] Ex. Xcel-22 at 28 (Chamberlain Direct). The Department included information relating to adjustments for 2025 and 2026 to facilitate Commission evaluation of a five-year MYRP. The information is included in this report for the same purpose, although the Judge recommends approval of the three-year MYRP.
[169] Ex. Xcel-22 at 36 (Chamberlain Direct).
[170] Ex. Xcel-69 at 15 (Arend Direct).
[171] Ex. Xcel-69 at 15 (Arend Direct).
[172] Ex. Xcel-69 at 15 (Arend Direct).

178. The use of a true-up is reasonable because property tax expense has to be estimated many months before the actual amount is known, and because the amount of property tax expense can vary from year to year depending on inputs that the Company cannot control.[173] This true-up process has been in place since the Company's 2016 MYRP, and the Company believes it has worked well to date.[174]

179. Although the Department and the Company agree that the property tax true-up mechanism should continue, they disagree on the appropriate baseline from which to calculate surcharges or refunds. This issue is addressed in the contested issues below.

180. No party opposed the proposed property tax true-up.[175] Continuing the property tax true-up mechanism established in Xcel's 2015 rate case reasonably balances ratepayer and shareholder interests by ensuring that Xcel neither over- nor under-recovers its property tax expense.

181. The Company's proposed property tax true-up process is reasonable and should be adopted.

4. Conservation Improvement Program (CIP) Adjustment Factor

182. The Company recovers CIP expenses through a Conservation Cost Recovery Charge (CCRC) bundled into base rates, equal to test-year CIP expenses. CIP cost recovery is then trued-up to actuals annually through the CIP Adjustment Factor (CAF) in the CIP rider.[176] Xcel proposes to update the CCRC to reflect test-year expenses, resulting in a CCRC of $0.004908 per kilowatt-hour (kWh) versus the current CCRC of $0.003133 per kWh. Xcel also proposes to set the CAF at $0.001746 per kWh which equals a corresponding decrease from the CAF level of $0.003521 per kWh at the time the Company filed its direct testimony.[177]

183. Department witness Stephen Collins testified that there is a process to update the Company's CIP Adjustment Factor and recommended that the Commission approve Xcel's CCRC proposal but take no action on the CAF proposal and continue to update the CAF through the separate annual process.[178]

184. The Company agreed with the Department about the calculation of the CIP Adjustment Factor and did not dispute the recommendation to update the CIP Adjustment factor in the separate process.[179]

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[173] Ex. Xcel-69 at 2, 13–15 (Arend Direct); Ex. Xcel-70 at 12, 24 (Arend Rebuttal).
[174] Ex. Xcel-69 at 21–22 (Arend Direct); Ex. Xcel-70 at 22-25.
[175] Ex. DOC-5 at 2, 16–17 (Soderbeck Surrebuttal) (the Department initially recommended a limitation to the true-up calculation, but in Surrebuttal, the Department withdrew that recommendation and considered the true-up mechanism to be a resolved issue).
[176] DOC-15 at 13 (Collins Direct).
[177] DOC-15 at 13 (Collins Direct); Ex. Xcel-84 at 47-48 (Peppin Direct).
[178] DOC-15 at 13–14 (Collins Direct).
[179] Ex. Xcel-87 at 26–27 (Barthol Rebuttal).

F. Additional Issues

1. Non-Regulated Allocation Reporting Requirements

185. Since 2015, the Commission has required the Company to provide certain information related to two unregulated transmission affiliates: Xcel Energy Transmission Development Company, LLC, and Xcel Energy Southwest Transmission Company, LLC.[180]

186. In Direct Testimony, Xcel stated that the transmission companies have not undertaken any relevant projects and it has nothing to report. The Company requested to be released from any further reporting requirements related to Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC, as ordered by the Commission in Docket No. E002/AI-14-759, until any work is undertaken by these affiliated entities.[181] The Department was the only party to provide testimony on this request and recommended the Commission approve the proposal.[182]

187. The record supports, and the Judge recommends, that the Company should be released from any further reporting requirements related to Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC, until any work is undertaken by these affiliates.

188. The Company requested to discontinue inclusion of separate O&M budget narratives and capital substitution/contingent fund discussions from Volume 5 Budget Documentation in future filings. The Company identified these requirements as outdated and noted this information can be located elsewhere in the Company's filings.[183] No party objected to this Company request.

189. The record supports, and the Judge recommends, that the Company should be allowed to discontinue inclusion of separate O&M budget narratives and capital substitution/contingent fund discussions from Volume 5 Budget Documentation in future filings.

2. Street Lighting Stipulation

190. On March 24, 2023, the Company and SRA filed a joint stipulation relating to several issues that had been in dispute between them.[184] According to the stipulation, it resolves "several of the Street Lighting CCOSS and all of Rate Design issues

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[180] *In re Request for Approval of New Administrative Serv. Agreement Between N. States Power Co. and Xcel Energy Transmission Dev. Co., LLC and Xcel Energy Sw. Transmission Co., LLC*, Docket No. E-002/AI-14-759, ORDER (Aug. 5. 2015) (eDockets No. 20158-112998-01).
[181] Ex. Xcel-60 at 27–28 (Baumgarten/Doyle Direct).
[182] Ex. DOC-21 at 58–59 (Campbell Direct).
[183] Ex. Xcel-31 at 29-34 (Ostrom Direct); Ex. Xcel-9 (Volume 5 Budget Documentation).
[184] Joint Stipulation of Suburban Rate Authority and Xcel Energy (Mar. 24, 2023) (eDockets No. 20233-194188-01, -02, -03).

raised by Xcel and SRA set forth as Issues 36 and 48, respectively, in the Combined Issues Matrix filed by Xcel in this proceeding on February 2, 2023."[185]

191. The Judge has reviewed the parties' jointly proposed resolution of the issues covered by the stipulation and finds that the resolution could be reasonable and consistent with the interests of ratepayers and the public. However, because this report is due to the Commission on March 31, 2023, by the time of its issuance there will not have been a reasonable opportunity for parties to review and respond to the stipulation and its proposed resolution of the issues.

192. The Judge recommends that the Commission adopt the terms of the stipulation if they are unobjected to by any party, and disregard related portions of this report that pertain to the resolved street lighting issues. In the event that an objection is raised, or if the Commission disagrees with the recommendation for another reason, a full analysis of the formerly-contested issues remains in this report.

DISPUTED ISSUES

193. The following issues were disputed by one or more parties.

VII. Revenue Requirements

194. The revenue requirement portion of a rate case seeks to determine what revenue is required to meet the utility's required operating income, based upon a "test year" of operations, in this case 2022. Because the Company has proposed a multiyear rate plan, it has also forecasted revenue requirements for 2023 and 2024 "plan years."

195. This section of the report addresses revenue requirement issues that are disputed among the parties involving the rate base, test year expenses and revenues, and rate of return. The disputed revenue requirement issues are addressed in the order that they appear on the Issues Matrix filed by the Company on February 2, 2023.[186]

A. Expense or Rate Base Related Issues

1. Sherco 3 and King Plant Depreciation

196. In Direct Testimony, Company witness Mr. Moeller first raised that the Commission was considering early retirement of Sherco Unit 3 (Sherco 3) and Allen S. King (King) coal plants in MPUC Docket No. E002/RP-19-368 (the IRP Docket).[187]

197. After the Company filed Direct Testimony, the Commission issued its order in the IRP Docket,[188] ordering the retirement of King in 2028 and Sherco Unit 3 in 2030,

[185] Joint Stipulation of Suburban Rate Authority and Xcel Energy at 1.
[186] ISSUES MATRIX (Feb. 2, 2023) (eDockets no. 20232-192904-01).
[187] Ex. Xcel-65 at 38-39 (Moeller Direct).
[188] *In re 2020-2034 Upper Midwest Integrated Resource Plan of N. States Power Co. d/b/a Xcel Energy,* MPUC Docket No. E002/RP-19-368.

and authorizing a ten-year life extension for Monticello Nuclear Generating Plant.[189] The Commission's resource plan decision reduced the probable service life of Sherco 3 by ten years and King by nine years.[190]

198. The Commission's decision to require Xcel to retire Sherco 3 and King was based upon the fact that "multiple resource plan scenarios demonstrated that retiring these units would be a cost-effective option," under the resource planning statute, Minn. Stat. § 216B.2422 (2020).[191]

199. In Direct Testimony, Department witness Nancy Campbell proposed that the depreciation life of the Monticello plant be extended for ten years to account for the life extension approved by the Commission.[192] As discussed in the Resolved Issues section, above, there is no dispute as to this recommendation.

200. In Rebuttal Testimony, Mr. Moeller proposed that the remaining depreciable lives of Sherco 3 and King be shortened to reflect the Commission-ordered early retirement of those plants as a matter of "regulatory consistency."[193]

i. Positions of the Parties

201. Company witness Mr. Halama testified that addressing the shortened lives of these coal plants in conjunction with the extension of Monticello would balance all the approved life changes and help avoid a short-term reduction in depreciation expenses during the MYRP period that would be followed by a large increase in depreciation expenses in the next rate case.[194]

202. The Company proposed two alternatives to incorporate the accelerated depreciation of the coal plants to provide rate relief for 2023:

i. the Company would implement the shortened lives beginning in 2024, instead of 2023;[195] or

ii. the Commission could grant deferral of the incremental depreciation expense until the Company's next rate case and allow the Company to introduce a recovery proposal that could include establishing a regulatory asset.[196]

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[189] IRP Docket, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILING at 30–31 (Apr. 15, 2022) (eDockets No. 20224-184828-01) (IRP Order).
[190] IRP Docket, 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN at 5 (July 1, 2019) (eDockets No. 20197-154051-01).
[191] IRP Order at 13.
[192] Ex. DOC-21 at 72 (Campbell Direct).
[193] Ex. Xcel-67 at 4 (Moeller Rebuttal).
[194] Ex. Xcel-82 at 20 (Halama Rebuttal).
[195] Ex. Xcel-23 at 7 (Liberkowski Rebuttal); Ex. Xcel-82 at 20-21 (Halama Rebuttal); Ex. Xcel-67 at 4 (Moeller Rebuttal).
[196] Ex. Xcel-82 at 21 (Halama Rebuttal).

203. Xcel's proposal to implement the shortened lives in 2024 would result in a $35.1 million increase in base rates for 2024.[197]

204. The Department, OAG, and XLI objected to the timing of the introduction of the depreciable lives of Sherco 3 and King.[198] Each raised concerns about the limited opportunity for record development because Xcel's proposal came in Rebuttal Testimony. Because this proposal was not raised until rebuttal, "other parties that may wish to advocate for [alternative proposals were] less able to advocate for their positions."[199]

205. OAG opposed Xcel's Sherco 3 and King proposals. The Office argued that there are many possible ways to address unrecovered balances of early-retired coal plants. Some examples offered by OAG: the Commission could disallow some or all of the remaining plant balances if it found that continued investment in coal plants had been imprudent, could conclude that early retirement of coal plants is a risk that Xcel's shareholders have already been compensated for through the Company's approved return on equity, or could find that Xcel should have explored securitization or the Inflation Reduction Act's Energy Infrastructure Reinvestment Program as a means to mitigate the impact on ratepayers.[200]

206. OAG argued that Xcel has not met its burden to show that changing the depreciation schedules of Sherco 3 and King would result in just and reasonable rates, and recommended that the Commission make no change to the depreciation schedules currently in effect for the Sherco 3 and King facilities.[201]

207. XLI also opposed Xcel's Sherco 3 and King proposals. XLI recommended that the Commission (1) not modify the accounting lives or depreciation schedule for Sherco 3 or King, (2) require that when each plant is no longer used and useful the costs associated with the plant be removed from rate base but (3) allow Xcel to continue to recover the plant's depreciation expense, O&M expense, property taxes, and property insurance.[202] XLI further recommended that the Commission open an investigation to create a uniform policy for cost recovery of generation assets that are retired early.[203]

208. XLI argued that its proposal "is best suited to address the current regulatory uncertainties surrounding the retirement of baseload, carbon-emitting generation before the end of the plants' operational lives."[204] According to XLI, its proposal "preserves the status quo, protecting ratepayers from a shorter-term rate increase, while preserving the

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[197] Ex. DOC-23 at 60 (Campbell Surrebuttal). XLI's witness testified that the accelerated depreciation of both plants would result in a $60.7 million annual increase in Xcel's annual depreciation expense. Ex. XLI-6 at 17 (LaConte Surrebuttal).
[198] ORDER PARTIALLY GRANTING MOTION TO STRIKE at 4–5 (Nov. 30, 2022) (eDockets No. 202211-190981-01).
[199] Ex. DOC-23 at 63–64 (Campbell Surrebuttal).
[200] Ex. OAG-10 at 3–4 (Twite Surrebuttal) (internal citations omitted); Ex. DOC-23 at 63–64 (Campbell Surrebuttal).
[201] OAG Reply Br. at 2–4.
[202] Ex. XLI-6 at 19 (LaConte Surrebuttal); XLI Reply Br. at 10.
[203] XLI's Proposed Findings of Fact, Conclusions of Law, and Recommendations (XLI's Proposed Findings) at 18, ¶ 176.
[204] XLI Initial Br. at 23.

Company's ability to recover the full undepreciated costs of the facilities and allowing time to address the appropriateness of utilities earning a return on assets that become no longer used and useful."[205]

209. The effect of XLI's proposal during the MYRP would be to allow Xcel to continue to recover the current annual depreciation expense ($50.4 million) for the two plants, leaving Xcel's revenue requirement unchanged.[206]

210. Ultimately the Department agreed with Xcel that Sherco 3 and King's remaining life reduction should be recognized in this rate case, but the Department advocated that the shortened remaining lives should be recognized in 2023 instead of 2024 as Xcel proposed.[207] Although recognizing the shortened remaining lives in 2023 increases depreciation expense in that year, its lowers the 2024 revenue requirement for the Sherco-King depreciation expense from $35.092 million to $27.588 million.[208] Because the 2024 revenue requirement is the final year of the MYRP, the 2024 revenue requirement could remain in place if Xcel does not file a rate case at the end of 2024 or seeks another stay out.[209]

211. The Department recognized that the impacts of inflation may still be felt in 2023 or 2024 when the remaining lives reduction increases rates and leaving the depreciation lives unchanged would be an option if the Commission believes further rate mitigation is necessary.[210]

[205] *Id*. at 24.
[206] Ex. XLI-6 at 19 (LaConte Surrebuttal).
[207] Ex. DOC-23 at 59–62 (Campbell Surrebuttal).
[208] Ex. DOC-23 at 60 (Campbell Surrebuttal).
[209] Ex. DOC-23 at 62 (Campbell Surrebuttal).
[210] DOC Proposed Findings of Fact and Conclusions of Law at 55, ¶ 304.

212. Net adjustments to revenue requirements based on the parties' proposed depreciation schedules for Monticello, Sherco 3, and King would be as follows:[211]

	2023 Impact ($ Million)	2024 Impact ($ Million)
Monticello	($34.518)	($33.352)
Sherco Unit 3 & King – 2023 Start (Department)	$29.021	$27.588
2023 Implementation, Net (Department)	**($5.497)**	**($5,764)**
Sherco Unit 3 & King – 2024 Start (Company)	$0	$35.092
2024 Implementation, Net (Company)	**($34.518)**	**$1.74**
XLI or OAG Proposal, Net	**($34.518)**	**($33.352)**

ii. Relevant Law and Rules

213. Utilities recover capital costs for assets "used and useful" in providing service by depreciating those costs over a number of years.[212] The Commission's rules require generally that the costs of an asset be amortized over its "probable service life," which is defined as the "period of time extending from the date of its installation to the forecasted date when it will probably be retired from service."[213] The Commission's depreciation rules reflect a regulatory preference to avoid intergenerational inequity, and to recover costs from ratepayers who receive the benefit of an asset while it is used and useful.[214]

214. The Commission can vary its depreciation rules.[215] A variance is granted when (A) enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule; (B) granting the variance would not adversely affect the public interest; and (C) granting the variance would not conflict with standards imposed by law.[216]

215. Under Minn. Stat. § 216B.16, subd. 6, the Commission may, but is not required to, allow a utility to recover positive net book value of a facility if the Commission ordered the facility to terminate operations before the end of the facility's physical life "in order to comply with a specific state or federal energy statute or policy."[217]

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[211] Ex. DOC-23 at 60 (Campbell Surrebuttal); Xcel's Initial Br. at 45. The final row of this table is inferred from the uncontested adjustment to the Monticello depreciation schedule and XLI's and OAG's descriptions of their recommendations.
[212] *See, e.g.*, Minn. Stat. § 216B.16, subd. 6.
[213] Minn. R. 7825.0500, subps. 2, 10 (2021).
[214] Ex. DOC-23 at 64 (Campbell Surrebuttal).
[215] Minn. R. 7829.3200 (2021).
[216] *Id*., subp. 1.
[217] Minn. Stat. § 216B.16.

216. At any time prior to conclusion of a multiyear rate plan, the Commission, upon its own motion or upon petition of any party, has the discretion to examine the reasonableness of the utility's rates under the plan, and adjust rates as necessary.[218]

iii. Analysis and Recommendation

217. For the reasons set forth below, the Judge concludes that on this record a recommendation based on XLI's proposal is the most reasonable way to address the Sherco 3 and King depreciation expense amounts in this proceeding.

218. Every party addressing this issue expressed concern about the rate impact of shortening the accounting lives of these plants. Adjusting the Sherco 3 and King depreciation schedules to reflect their shortened useful lives would result in significant ratepayer impacts during the MYRP. Despite recommending that the depreciation schedules be adjusted starting in 2023, the Department acknowledged that the Commission may wish to leave them unchanged for rate mitigation purposes. Xcel's proposal reflected a one-year delay in implementing new depreciation schedules to mitigate the immediate impact to ratepayers.

219. The reasonableness of depreciation schedules established in this proceeding depends upon the likelihood that the Commission would allow rate recovery of Sherco 3 and King depreciation expenses after the plants are no longer used and useful.

220. Every party addressing this issue appears to agree that "the accounting treatment for early-retired facilities is a developing issue."[219]

221. There is significant regulatory uncertainty with respect to post-retirement cost recovery for these specific plants and for generation assets, generally. The Commission has authority to allow post-retirement recovery in certain circumstances but has not articulated a policy that utilities can rely on and plan for.

222. The regulatory uncertainty incentivizes utilities to match accounting lives to policy-driven reduced useful lives of plants—even when doing so would more than double the annual depreciation expense for the plants,[220] and even though there is statutory authority for the Commission to exercise greater flexibility. Providing Xcel, and potentially other utilities, greater certainty around the potential and preferred methods for seeking and obtaining approval for post-retirement recovery would be in the interest of ratepayers and consistent with the public interest in using regulatory tools available to the Commission under Minn. Stat. § 216B.16, subd. 6.

223. The Commission required Xcel to retire Sherco 3 and King to comply with Minn. Stat. § 216B.2422.[221]

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[218] Minn. Stat. § 216B.16, subd. 19 (e).
[219] XLI Reply Br. at 10.
[220] Ex. XLI-6 at 17 (LaConte Surrebuttal).
[221] IRP Order.

224. The timing of the IRP Order relative to the course of this rate proceeding significantly limited the ability of the parties to make a full record on the wide range of alternatives for rate recovery. A fuller record could better allow the Commission to appropriately balance the interests of the utility and its ratepayers, as well as the intergenerational interests of current and future ratepayers.[222]

225. The Commission has varied its depreciation accounting rules to set rates based on generation facilities' remaining accounting lives that did not match their expected useful lives and in the same order required further investigation of a proposed alternative recovery method.[223] The Commission granted a variance based upon its determinations that matching the accounting and expected useful lives would impose an excessive burden on ratepayers, and that the variance would not adversely affect the public interest or conflict with any standards imposed by law.[224]

226. In light of regulatory uncertainty about whether Xcel would be allowed to recover any undepreciated value after the plants are removed from service, and the abbreviated record on the issue in this proceeding, XLI's argument that its proposal preserves the status quo is persuasive. XLI's proposal would allow the Commission an opportunity to consider a fully developed record on the myriad options for post-retirement recovery, make reasoned decisions about the amount or duration of post-retirement recovery that would be just and reasonable, and make adjustments to the depreciation schedules and the method of recovery accordingly.

227. XLI's recommendation would allow Xcel to seek full recovery of any undepreciated balance after the plant is no longer used and useful. XLI's proposal contemplates the Commission more fully evaluating cost recovery in cases involving policy-driven plant retirements.

228. The Department's, Xcel's, and XLI's recommendations would allow Xcel full recovery for Sherco 3 and King. XLI's would allow post-retirement recovery, and the Department and Xcel's would schedule recovery to occur during the plants' probable service lives.

229. The Department's and Xcel's recommendations would avoid intergenerational inequities but would also deprive the Commission of full use of a regulatory tool to mitigate ratepayer impacts of early retirements. Effectively, their recommendations imply at least a preliminary determination that there would be no opportunity for post-retirement recovery and could render the Commission's discretion to authorize post-retirement recovery superfluous or ineffective, despite there being five years before the earliest of the planned retirements.

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[222] With a more complete record the Commission could, for example, conclude that some amount of intergenerational inequity arising from post-retirement cost recovery could be reasonably justified by the benefits of early plant retirement to post-plant-retirement ratepayers.
[223] *In re Appl. of Minn. Power for Authority to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E015/GR-16-664, Findings of Fact, Conclusions, and Order (Mar. 12, 2018) (eDockets No. 20183-140963-01) at 109.
[224] *Id*. at 14.

230. OAG's recommendation appears to be functionally similar to XLI's recommendation during the MYRP. It would have the same impact on the MYRP plan year revenue requirements. But it is silent about whether costs would be stranded after the plants are retired. XLI's proposal is more reasonable because it does not leave unresolved the amount of unrecovered amortized Sherco 3 and King costs that could be stranded upon the plants' retirement.

231. Only the Department's recommendation would match the depreciation schedules to the plants' probable service lives beginning in 2023.

232. Enforcement of Minn. R. 7825.0500 (2021) to match the depreciation of the plants to their probable service life would unnecessarily impose an excessive burden upon ratepayers by increasing the revenue requirement in this rate case by approximately $30 million.

233. A variance of Minn. R. 7825.0500 would not adversely affect the public interest because a variance is in the public interest. The public will benefit from the increased regulatory certainty and the opportunity for the Commission to consider a fully developed record concerning how to implement post-retirement recovery for certain facilities that are ordered to be retired based upon state or federal policy. This benefit to the public is only magnified by the enactment of 2023 Minn. Laws Ch. 7, which accelerated the state's timeline for eliminating carbon-based electricity generation.

234. Finally, a variance of Minn. R. 7825.0500 would not conflict with any standards imposed by law. Varying the rule to implement XLI's proposal would allow Xcel to recover amounts adequate to provide for depreciation of Sherco 3 and King, pending a determination by the Commission to require a different recovery method or depreciation schedule.

235. Accordingly, a variance to the depreciation rules would be warranted.

236. The Judge recommends that the Commission require that Xcel (1) not modify the accounting lives or depreciation schedule for Sherco 3 or King; and (2) when each plant is no longer used and useful, remove from rate base the costs associated with the plant but continue to recover the plant's depreciation expense, O&M expense, property taxes, and property insurance until fully recovered. The Judge further recommends that the Commission specify that the depreciation schedules and recovery method are subject to modification pending (1) an investigation into options for post-retirement recovery for Sherco 3 and King, or (2) a generic investigation into the potential for post-retirement recovery for generation assets that are retired early.[225]

237. Alternatively, if the Commission does not adopt the above recommendation, the Judge recommends that the Commission adopt the Department's proposal because: it allows the Company to reasonably recover its depreciation expenses; it avoids intergenerational inequity; it reasonably minimizes the increase to the 2024 rate base;

[225] This recommendation is similar, but not identical, to XLI's proposal.

and because the Monticello adjustment offsets the Sherco 3 and King revenue requirement increase.

2. General Allocator – Full Time Equivalent (FTE) Hours

238. Xcel requests to change its allocation method to account for employee work in its Minnesota jurisdiction from full-time equivalents to using the number of employees.[226]

239. The Company's employees perform work that benefits multiple jurisdictions, including several states, regulated and non-regulated operations, and both the gas and electric operations in Minnesota. To account for work that cannot be directly assigned to one of these operations, Xcel must use allocators.[227]

240. For purposes of allocating costs that cannot otherwise be direct-assigned to an operating company or non-regulated subsidiary, the Company's General Allocator is used by employees.[228] In its Minnesota jurisdiction, the General Allocator formula uses FTE Hours as a factor, in addition to Total Assets and Revenues, to establish the allocator amount.[229] Other jurisdictions use a "Number of Employees" factor instead of an FTE Hours factor.[230]

241. The Number of Employees factor is based on the number of employees for each operating company, with common officers from XES assigned to Xcel Energy to ensure that no customer of a regulated utility is responsible for costs to support non-regulated activities.[231] The FTE Hours methodology is based on the number of productive labor hours of all operating company and XES employees, including indirect labor hours that are allocated using a ratio that includes the Number of Employees factor.[232]

242. Since 2011, the Commission has required Xcel to use Full Time Equivalent (FTE) hours in its General Allocator. Following Xcel's 2008 rate case, the Commission investigated Xcel's three-part allocation method, which used the number of employees as its labor component.[233] As part of its investigation, the Commission required Xcel to file "an analysis of 99 work orders submitted in the rate case, providing detailed analysis of the cost-allocation process used for each one."[234] The Commission ultimately ordered Xcel to use FTEs instead of the number of employees.[235] The Commission explained that

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[226] Ex. Xcel-60 at 18–19 (Baumgarten/Doyle Direct).
[227] Ex. DOC-21 at 54 (Campbell Direct).
[228] Ex. Xcel-61 at 3 (Doyle Rebuttal).
[229] Ex. Xcel-61 at 3 (Doyle Rebuttal).
[230] *Id*.
[231] Ex. Xcel-61 at 3 (Doyle Rebuttal).
[232] Ex. Xcel-61 at 3 (Doyle Rebuttal).
[233] *See In re N. States Power Co.'s Cost Allocation Procedures and General Allocator*, E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (Mar. 15, 2011) (eDockets No. 20113-60362-01) (2011 General Allocator Order).
[234] 2011 General Allocator Order at 2. (citing *In re Appl. of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 20 (Oct. 23, 2009) (eDockets No. 200910-43195-01).
[235] 2011 General Allocator Order at 4 (eDockets No. 20113-60362-01).

using the number of employees "results in no labor-related costs being allocated to unregulated subsidiaries that do not have their own payrolls. This is unreasonable on its face, since no business can have a labor cost of zero."[236] The Commission also noted that "allocating the full costs of each employee to the subsidiary on whose payroll he or she appears overstates the labor costs of that subsidiary and understates the labor costs of any other subsidiary for whose benefit the employee occasionally performs services."[237]

243. Because Xcel uses the Number of Employees allocator in its other regulated jurisdictions, its General Allocator for XES employees is computed using the Number of Employees allocator, and then adjusted manually for the Minnesota jurisdiction.[238]The manual adjustment excludes some costs because they are based on the Number of Employees method.[239] The manual adjustment results in the removal of 18.3% of total XES labor hours, including "a significant portion of hours charged by administrative functions including Human Resources, Accounting and Finance, Legal, and Business Systems."[240]

244. The Department opposed Xcel's requested change, finding that Xcel had not shown it was reasonable to depart from the Commission's 2011 decision and that the rationale provided in the 2011 decision was still persuasive.[241]

245. To support its request, Xcel stated that the change was needed to "ensure[s] that nonregulated companies receive a reasonable apportionment of allocated costs" and "using Number of Employees with common officers assigned to Xcel Energy Inc. provides for a larger allocation of costs to Xcel Energy's nonregulated companies than using FTE Hours."[242] Xcel also maintained that using number of employees was superior because the Company has the largest number of employees and the costs to support those employees through shared divisions is the largest.[243]

246. The Department examined Xcel's claim that the common officers from Xcel Energy Inc. would provide a larger allocation to nonregulated companies than using FTE Hours. The Department determined that although this would be true for the 13 common officers Xcel used to support its request, these common officers represent only 0.1666% of the headcount. Therefore, none of the costs associated with the remaining 98.8334%

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[236] *Id.* at 1–2 (quoting *In re Appl. of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 20 (Oct. 23, 2009) (eDockets No. 200910-43195-01) (Xcel 2008 Rate Case Order).
[237] 2011 General Allocator Order at 1–2 (eDockets No. 20113-60362-01).
[238] Ex. Xcel-60 at 16-17 and 20-21 (Baumgarten/Doyle Direct).
[239] Ex. Xcel-60 at 20-21 (Baumgarten/Doyle Direct).
[240] Ex. Xcel-60 at 20 (Baumgarten/Doyle Direct).
[241] *See* Ex. DOC-21 at 54–58 (Campbell Direct); Ex. DOC-23 at 36–41 (Campbell Surrebuttal).
[242] Ex. Xcel-60 at 19–20 (Baumgarten/Doyle Direct).
[243] Ex. Xcel-61 at 8 (Doyle Rebuttal).

of employees will be allocated to non-regulated affiliates if they do not have their own payroll, which was a chief concern of the Commission in its 2011 order.[244]

247. The Department also noted that while FTE Hours may allocate more to nonregulated affiliates, this did not address the Commission's concern about over-allocating costs to Minnesota as NSPM is the jurisdiction with the most employees.[245]

248. Xcel argued that because the FTE Hours methodology causes regulated utility operations costs to be borne by non-regulated affiliates and other operating companies, the methodology is "fundamentally inconsistent with Minn. Stat. § 216B.16, subd. 6."[246] Xcel also objected to being required to use the FTE Hours methodology in Minnesota because it is the only jurisdiction that requires it.

249. The Company has not met its burden to establish that allowing it to use the Number of Employees method of allocating employee work would result in just and reasonable rates. Xcel did not demonstrate that use of its preferred allocator would avoid the unreasonable results identified by the Commission in 2011. The Commission's 2011 order came out of an investigation and analysis of Xcel's work orders. Here, Xcel has not provided sufficient data or analysis to show that the Commission's rationale is no longer applicable. Xcel has not shown that the Commission's concerns about under-allocation to jurisdictions with no employees with the number of employees method are no longer relevant. And the Commission's concerns about over-allocation to Minnesota because it hosts the most Xcel employees appear to remain relevant given Xcel's statements.

250. The Company did demonstrate that using a Number of Employees general allocator and adjusting for the FTE Hours methodology only in Minnesota results in a shift in allocated costs among its various operating companies and unregulated subsidiaries. The shift appears not to be a product of a shortcoming in the FTE Hours methodology, but of shortcomings in Xcel's manual accounting adjustments to meet Minnesota regulatory requirements. This does not provide a sufficient basis to determine that a different allocator should be used.

251. The Judge recommends that the Commission adopt the Department's recommendation to require Xcel to continue using the FTE allocator and the corresponding adjustment to Xcel's revenue requirement, as follows:[247]

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[244] *See* Ex. DOC-21 at 56–57 (Campbell Direct); 2011 General Allocator Order at 1–2 (eDockets No. 20113-60362-01).

[245] Ex. DOC-21 at 57 (Campbell Direct); 2011 General Allocator Order at 1–2 (eDockets No. 20113-60362-01).

[246] Xcel Initial Br. at 87.

[247] Ex. DOC-23, NAC-S-1 (Campbell Surrebuttal). The Department provided adjustment calculations for five years in the event the Commission determined to require a five-year MYRP. The Judge includes the information in this order, but for reasons discussed in section VI.E.1, above, recommends a three-year MYRP.

2022	2023	2024	2025	2026
$(5,900,000)	$(6,241,000)	$(6,613,000)	$(6,017,000)	$(6,017,000)

3. Interchange Agreement Allocators

252. In Direct Testimony, the Company included MYRP Forecast Interchange Revenue and Interchange Expenses based on 2022–2024 budget information for NSPM (Minnesota, North Dakota, and South Dakota) and NSPW (Wisconsin), consistent with the treatment of Interchange Revenue and Expenses in the Company's last three rate cases.[248]

253. Xcel uses the integrated Northern States Power (NSP) system to serve electric load of its NSPM and NSPW customers.[249] The specific generators and transmission facilities comprising the NSP System are owned by separate legal entities (NSPM and NSPW), with the ownership boundary at the Minnesota/Wisconsin border.[250] FERC approves an "Interchange Agreement" that dictates how costs are shared and revenues are allocated between NSPM and NSPW.[251]

254. When Xcel filed its rate case, it forecasted interchange revenues and expenses using forecasted budgets for NSPM and NSPW and applied forecasted allocators.[252] After this case commenced, FERC approved the 2022 Interchange Agreement between NSPM and NSPW. Xcel acknowledged that FERC's approval caused a $149,983 increase in revenue and a $1,332,358 decrease to expense in 2022 for the Minnesota jurisdiction (NSPM) due to changes in the demand rate.[253]

255. The Department recommended that the FERC approved 2022 Interchange Agreement demand allocator be incorporated into Xcel's rates.[254] The Department also recommended that the update be carried forward beyond 2022 to the future test years.[255]

256. The Company does not dispute that the Demand Allocator changed. But the Company contests the Department's proposal to update the Interchange Billings amount in the 2022–2024 revenue requirement on the grounds that the Demand Allocator is just one component of the total Interchange Billings calculation. The Company reasons that information about actual total 2022 changes to Interchange Revenue and Expenses was not available to any party before the evidentiary hearing concluded, as the hearing ended before December 31, 2022. Further, the Department has not provided evidence about the

[248] Ex. Xcel-82 at 43 (Halama Rebuttal).
[249] Ex. Xcel-79 at 64–65 (Halama Direct).
[250] Ex. Xcel-79 at 64–65 (Halama Direct).
[251] Ex. Xcel-79 at 64–65 (Halama Direct).
[252] Ex. DOC-21, NAC-D-4 at 1 (Campbell Direct) (Xcel Response to DOC IR No. 1127 part A).
[253] Ex. DOC-21, NAC-D-4 at 2 (Campbell Direct) (Xcel Response to DOC IR No. 1127 part A and Attach. A).
[254] *See* EX. DOC-21 at 21–24 (Campbell Direct); Ex. DOC-21 at 12–15 (Campbell Surrebuttal).
[255] Ex. DOC-21 at 24 (Campbell Direct); Ex. DOC-23 at 14 (Campbell Surrebuttal).

reasonableness or likely amount of total Interchange Billings, other than the change to the Demand Allocator, to rebut the Company's total Billings estimates.[256]

257. The Company further argues that even if the Department's 2022 adjustment were accepted, it should not apply to 2023–2024 (let alone 2025–2026, which are not part of the Company's case). The Company notes that it makes an annual Interchange Agreement filing with FERC, and the Demand Allocator will be updated every year based on information that is not currently known.[257] The Company also objects that the Department is not, at a minimum, applying the 2022 Demand Allocator to 2023 and 2024, but rather speculating that 2023 and 2024 Demand Allocators will further reduce the Interchange Billings beyond the 2022 level.[258] The Department is making this proposal even through the 2022 actual Demand Allocator is still higher than the 2023–2026 budgeted Demand Allocator,[259] and although the Department has not offered evidence that factual circumstances in effect in 2023 to 2026 are likely to move the Demand Allocators in the same direction or amount as the Department proposes.

258. Ultimately, the Department has not offered evidence that adjusting Interchange Billing amounts in the revenue requirement solely for the 2022 Demand Allocator change is likely to produce a reasonable estimate of total Interchange Billings for 2022, let alone 2023–2024 (or 2025 and 2026). For example, the Department does not provide evidence of the historical or typical relationship between Demand Allocators and total Interchange Billings, or about the degree to which the remaining components of the calculation are likely to change. Additionally, while it may be preferable to use actual data when available, the nature of a projected test year is that actual data may not be available for the full test year. Under those circumstances, it would be selective to update total Interchange Billings based on partial actuals for a single component of the calculation.

259. The Company has met its burden to demonstrate that its MYRP Interchange Agreement revenues and expenses are reasonable, while the Department has not shown adequate support for its recommended adjustments.

260. The Judge recommends that the Commission approve the Company's MYRP Interchange Agreement revenues and expenses.

4. Long-Term Incentive (LTI) Compensation

261. The Company seeks recovery of two components of its long-term incentive compensation program – "environmental LTI" and "time-based LTI."

262. Environmental LTI is measured by the reduction in carbon dioxide emissions below 2005 levels associated with the Company's electric service. If the

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[256] Ex. Xcel-82 at 43 (Halama Rebuttal).
[257] Ex. DOC-21 at 23 (Campbell Direct).
[258] Ex. Xcel-82 at 43-44 (Halama Rebuttal).
[259] Ex. DOC-23 at 14 (Campbell Surrebuttal).

Company does not meet its environmental goals, the environmental LTI is not paid out and the employee does not receive their full amount of market-based compensation.[260]

263. Time-based LTI requires a three-year vesting period to ensure that eligible employees engage in long-term planning for the benefit of the Company and that they remain at the Company long enough to see those plans through. Retaining employees with the knowledge and skills necessary to guide, manage, and operate a utility is a crucial component in providing a high level of service to customers and achieving operational efficiency, both of which benefit customers.[261]

264. The Company is not seeking recovery of relative Total Shareholder Return (TSR) LTI, which constituted 54% of the total LTI grant value in 2020. Relative TSR is similar to the types of LTI that the Commission has denied recovery in the past because it is aligned with shareholder interests.[262]

265. The Company argued that by offering a portion of an employee's total market-based compensation as incentive compensation, the Company provides a benefit to its customers. The Company contends that this promotes superior employee performance—by aligning compensation with results and showing employees the connection between their performance and their pay; and by reducing fixed labor costs—because base pay is tied to a variety of benefit-related expenses, if all pay was provided as base pay, benefit costs would also be higher.[263]

266. Historically, the Commission has denied utility requests to collect LTI compensation.[264] The Commission has reasoned that, because LTI programs are designed chiefly to serve shareholders' interests, shareholders should pay for the programs, rather than ratepayers.[265]

267. The Department recommended the Commission deny Xcel's request consistent with Commission past practice. The Department disagreed that these LTI programs were distinguishable from similar programs that the Commission has denied.[266]

268. XLI joined the Department's opposition to including LTI compensation costs.[267]

269. For environmental LTI, the Department argued that Xcel failed to support its claim that environmental LTI incentivized environmental achievements beyond Xcel's financial incentive to make sizable capital additions and returns it earns on its renewable

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[260] Ex. Xcel-55 at 29–30 (Lowenthal Rebuttal).
[261] Ex. Xcel-53 at 47 (Lowenthal Direct).
[262] Ex. Xcel-53 at 46 (Lowenthal Direct); Ex. Xcel-55 at 28 (Lowenthal Rebuttal).
[263] Ex. Xcel-53 at 21-24 (Lowenthal Direct).
[264] *See* Ex. DOC-21, NAC-D-6 (Campbell Direct).
[265] *See, e.g., In re Appl. of CenterPoint Energy Res. Corp. d/b/a CenterPoint Energy Minn. Gas for Authority to Increase Nat. Gas Rates in Minn.*, G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 23 (June 3, 2016) (CenterPoint 2015 Rate Case Order).
[266] Ex. DOC-21 at 24–28 (Campbell Direct); Ex. DOC-23 at 15–19 (Campbell Surrebuttal).
[267] Ex. XLI-5 at 3–4 (LaConte Rebuttal).

energy build out.[268] The Department's witness Nancy Campbell acknowledged that LTI compensation incentives are part of a market-rate compensation structure.[269]

270. Minn. Stat. § 216H.02 (2022) provides that it is the state's goal to reduce greenhouse gas emissions relative to 2005 levels, with increasing reductions over time.

271. Xcel's environmental LTI goals are more aggressive than those established in Minn. Stat. § 216H.02. For example, the statute establishes a goal of reducing emissions to 80% below 2005 levels by 2050; Xcel's goal is to reduce its carbon emissions by 80% from 2005 levels by 2030.[270]

272. However, Xcel's environmental LTI goals are not more ambitious than those established by 2023 Minn. Laws Ch. 7. The law amends Minn. Stat. § 216B.1691 to create a carbon-free standard which requires electric utilities to:

> [G]enerate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:
>
> (1) 2030 - 80% for public utilities; 60% for other electric utilities
>
> (2) 2035 - 90% for all electric utilities
>
> (3) 2040 - 100% for all electric utilities.

273. Xcel has not met its burden to show that including environmental LTI program costs in its rate base would be just and reasonable. The Company's environmental LTI compensation is directly connected to an express state policy goal and compensates employees for actions that coincide with the public interest. However, Xcel's environmental LTI incentivizes actions that are now required by law. Xcel has not demonstrated that it would be reasonable for ratepayers to pay incentives for that which the law requires.

274. Xcel acknowledged that time-based LTI is "based on the end-of-the-three performance years of Company performance," and the actual award "is increased or decreased from the target amount based on a performance goal, which is total shareholder return relative to a peer group for each individual vesting year."[271]

[268] Ex. DOC-23 at 16–18 (Campbell Surrebuttal).
[269] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 185, lines 18–25 (Campbell).
[270] Ex. Xcel-53 at 46 (Lowenthal Direct).
[271] Ex. Xcel-53 at 48 (Lowenthal Direct).

275. Xcel's description of the time-based LTI program shows that it fundamentally remains tied to achieving shareholder goals. The Commission's rationales addressing prior LTI requests remain persuasive and applicable to Xcel's time-based LTI program.

276. The Judge recommends that the Commission deny Xcel's request to recover costs for environmental and time-based LTI compensation and adopt the Department's corresponding adjustment to Xcel's revenue requirement, as follows:[272]

2022	2023	2024	2025	2026
$(7,877)	$(8,178)	$(8,531)	$(11,262)	$(11,813)

5. Annual Incentive Plan (AIP)

277. The Annual Incentive Program is Xcel's short-term compensation program, which is offered only to non-union employees. Xcel requests three specific changes to its AIP cost recovery: (1) increasing the cap on AIP compensation from 15% of base pay to 20%; (2) making the 20% cap apply to the aggregate of Xcel employees' salaries instead of on an individual basis; and (3) allowing Xcel to retain amounts not paid to employees.[273]

278. Xcel also proposed "eliminating the yearly AIP compliance filing requirement and any associated reports regarding the AIP."[274] After the Department objected, Xcel alternatively proposed several changes to its AIP reporting requirements.[275]

279. The Department and XLI oppose the Company's proposal to increase the cap from 15% to 20%.[276] The Department also opposed Xcel's other proposed changes to its AIP program and cost recovery, recommending that Xcel request and support compliance filing changes in its next AIP refund filing.[277]

280. AIP is paid only if an "affordability trigger" is reached.[278] The affordability trigger is an earnings-per-share target.[279] If the affordability trigger is reached, then AIP incentive compensation is awarded based on a combination of achievement of individual performance goals and for the Company's achievement of Key Performance Indicators (KPIs).[280] Xcel develops KPIs annually, so they can change from year to year.[281] If an

[272] Ex. DOC-23, NAC-S-1 (Campbell Direct).
[273] Ex. Xcel-53 at 33–44 (Lowenthal Direct); Ex. DOC-23 at 20 (Campbell Surrebuttal).
[274] Ex. Xcel-53 at 38 (Lowenthal Direct).
[275] Ex. DOC-23 at 24 (Campbell Surrebuttal).
[276] Ex. DOC-23 at 24 (Campbell Surrebuttal); Ex. XLI-6 at 15 (LaConte Surrebuttal).
[277] *Id.*
[278] Ex. Xcel-53 (Lowenthall Direct), Schedule 4, at 7, 18, 29.
[279] *Id.*
[280] Ex. Xcel-53 at 27–28, 30, 32 (Lowenthal Direct).
[281] Ex. Xcel-53 at 28 (Lowenthal Direct).

employee does not receive AIP, that employee's compensation will not meet market levels.[282]

i. AIP Cost Recovery Cap and Calculation

281. Since Xcel's 1992 rate case, the Commission has limited recovery for short-term incentive compensation (now called AIP) to 15% of an employee's base salary.[283] The Commission observed that earnings-per-share thresholds are an "improper transfer of risk, since ratepayers bear the risks (the costs of incentive compensation) and shareholders reap the benefits (increased earnings per share)."[284] The Commission also expressed concerns about earnings per share prioritizing short-term earnings, which could lead to short-term thinking.[285] The Commission wrote that earnings-per-share compensation thresholds "can jeopardize a utility's commitment to providing safe, reliable, economical service over the long-term by overemphasizing short-term performance."[286]

282. In its order, the Commission also expressed concern that awarding a large percentage of an individual's compensation based on shareholder interests may create concerning loyalties, noting that Xcel decisionmakers, in addition to maximizing shareholder value, "have a duty to exercise independent judgment on behalf of the Company and to give regulators their full cooperation."[287]

283. With respect to the cap applying to individual employee incentive compensation or in the aggregate, Xcel argued that "administering a pay-for-performance compensation program and calculating a refund at the individual employee level penalizes the Company for effectively differentiating pay among its incentive-eligible employees."[288]

284. The Department argued that applying the cap in the aggregate would permit Xcel to focus AIP compensation toward certain employees, creating the situation of individual employees with a large percentage of their compensation based on shareholder interests, which the Commission has sought to avoid.[289]

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[282] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 186 (Campbell).
[283] *In re Appl. of N. States Power Co. for Authority to Increase Its Rates for Elec. Serv. in the State of Minn.*, E002/GR-92-1185, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25-30 (Sept. 29, 1993) (1992 Rate Case Order) (eDockets No. 355173). The Commission originally denied Xcel's incentive compensation plan in full. After reconsideration the Commission allowed some incentive plan provisions to be recovered but imposed the 15% cap and required the Company to return any unpaid incentive compensation to ratepayers. *See* ORDER AFTER RECONSIDERATION at 7 (Jan. 14, 1994) (eDockets No. 322655).
[284] 1992 Rate Case Order at 28.
[285] 1992 Rate Case Order at 28.
[286] 1992 Rate Case Order at 28.
[287] 1992 Rate Case Order at 28–29.
[288] Ex. Xcel-53 at 41 (Lowenthal Direct).
[289] Ex. DOC-21 at 35–36 (Campbell Direct).

285. The Commission has approved a 15% cap in several of the Company's recent Minnesota rate cases, as well as recent rate case settlements by CenterPoint.[290] In a 2018 Minnesota Power rate case, the Commission approved a short-term incentive capped at 20% of individual base salaries and subject to refund of amounts not paid to employees.[291]

286. Employee compensation structures have changed since 1992, with a larger share of total market-rate compensation being performance-based.[292]

287. Between 2017 and 2021, Xcel has paid more than the allocated, approved amount in AIP to employees.[293] During this period, the Company's Minnesota Electric Jurisdiction under-recovered nearly $12.5 million below the amount approved for recovery when applying the 15% cap at the individual level after payout.[294]

288. The Department has shown that it is just, reasonable, and in the public interest to have a cap on rate-recoverable AIP compensation. AIP compensation is only paid if an earnings-per-share trigger is met. Its payment is therefore contingent upon first satisfying shareholder interests.

289. Because incentive-based market-rate compensation structures have increased since 1992, Xcel has met its burden to demonstrate increasing the cap on AIP compensation to 20% would be just and reasonable. The Commission has recently determined that a 20% cap on short-term incentive compensation, subject to refund, can be reasonable and in the public interest. Because compensation practices have evolved since the 15% cap was established in 1992, and because a 20% cap would still prevent individual employees from having their compensation too closely connected to shareholder interests, the record supports Xcel's proposed 20% cap.

290. Xcel has not met its burden to establish that calculating the cap on an aggregate rather than individual employee basis would be reasonable. The rationale supporting the individual employee calculation imposed by the Commission in 1992 has not lost persuasive value with age—aggregating the AIP cap would permit the Company to implement a compensation structure that aligns employee incentives too closely to shareholder interests and would therefore not be in the public interest.

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[290] Ex. DOC-21 at 30 (Campbell Direct).
[291] In Re: Appl. Of Minn. Power for Authority to Increase Rates for Elec. Serv. In Minn., E-015/GR-16-664, Findings of Fact Conclusions, and Order at 110 (Mar. 12, 2018) (eDockets No. 20183-140963-01) (2018 Minn. Power Rate Case Order).
[292] Ex. Xcel 53 at 36 (Lowenthal Direct).
[293] Ex. Xcel-55 (Lowenthal Rebuttal) at 19.
[294] *Id.*

ii. Refunds of Unpaid AIP Amounts

291. The Commission's 1992 Rate Case Order also reasoned that allowing Xcel to retain unpaid incentive compensation creates perverse incentives, allowing shareholders to offset losses with funds provided by ratepayers.[295]

292. The Commission reiterated the requirement than unpaid AIP be refunded in Xcel's 2012 rate case.[296] The Commission has also required these refunds for other utilities. As the Commission observed in 2020 when addressing Great Plains' request: "[T]he reasonableness of recovering incentive compensation through rates is contingent on the incentives advancing ratepayer interests. If incentives are not paid, it is reasonable to infer that the desired ratepayer advantages were not achieved."[297]

293. The Commission's basis for requiring refunds of unpaid AIP in other rate cases applies to Xcel's AIP program.

294. The Judge recommends that the Commission:

i. approve Xcel's proposal to raise the cap on AIP compensation from 15% to 20%.

ii. continue to require that the cap apply at the individual-employee level; and require Xcel to refund to ratepayers unpaid amounts.

iii. deny Xcel's proposal to modify its AIP compliance filing requirements and adopt the Department's proposal to allow Xcel to propose and support compliance filing changes in its next AIP refund filing.

6. Prepaid Pension Asset (PPA)

295. Xcel requests to earn a return on its prepaid pension asset.[298] According to the Company, the asset is funded by the Company's shareholders and federal law dictates that it can only be used for the payment of benefits and plan expenses.[299]

296. The Department and XLI opposed the Company's request.

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[295] *See* 1992 Rate Case Order at 29.
[296] *See In re Appl. of N. States Power Co. for Authority to Increase Rates for Elec. Serv. in the State of Minn.*, E-002/GR-12-961, FINDINGS OF FACT CONCLUSIONS, AND ORDER at 51 (Sept. 3, 2013) (eDockets No. 20139-90902-01) (2012 Rate Case Order).
[297] *In re Pet. by Great Plains Nat. Gas Co., a Div. of Montana-Dakota Utils., Co., for Auth. to Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 10-11 (Oct. 26, 2020) (eDockets No. 202010-167656-01) (Great Plains 2019 Rate Case Order).
[298] Ex. Xcel-57 at 59–88 (Schrubbe Direct).
[299] Ex. Xcel-57at 63 (Schrubbe Direct).

i. Pension Accounting

297. Xcel uses two methods to account for its pension costs—one for its NSPM Plan, and one for its XES Plan.[300]

298. The Company uses the Aggregate Cost Method (ACM) to account for costs under the NSPM Plan.[301]

299. FAS 87 is an accounting standard adopted by the Financial Accounting Standards Board to govern employers' accounting for pensions.[302] The Company uses this method for its XES Plan.[303]

300. The Company's annual qualified pension expense is calculated in accordance with FAS 87 and the ACM.[304] Pension expense represents an accrual for a future liability rather than the cash to pay benefits in a given year.[305] The pension expense calculation reflects an annual calculation that takes into account factors including expected salary increases, expected mortality rates, the Expected Return on Assets (EROA), the discount rate and other factors.[306]

301. The Commission has historically regarded pension expense as an operating cost and allowed recovery on that basis.[307] No party objected to Xcel recovering its pension expenses calculated using the ACM method for the NSPM Plan and using the FAS 87 method for the XES Plan.[308]

ii. Xcel's Prepaid Pension Asset

302. To determine its prepaid pension asset or liability, the Company calculates the cumulative difference between its annual pension expense amount and the annual contributions made to the qualified pension trust since it began offering the benefit.[309] An excess in contributions over the expense amount results in a positive balance that Xcel regards as its prepaid pension asset.

303. Xcel's proposed prepaid pension asset amount includes only balances associated with the NSPM Plan.[310]

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[300] Ex. Xcel-57 at 9 (Schrubbe Direct).
[301] *Id*.
[302] Ex. Xcel-57 at 25 (Schrubbe Direct).
[303] Ex. Xcel-57 at 9 (Schrubbe Direct).
[304] Ex. Xcel-57 at 60 (Schrubbe Direct).
[305] Ex. Xcel-57 at 9 (Schrubbe Direct).
[306] Ex. Xcel-57 at 10 (Schrubbe Direct).
[307] *In re Appl. of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, Docket No. G-011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS & ORDER at 11–12 (Oct. 31, 2016); *In re Appl. of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS & ORDER at 25-26 (May 1, 2017).
[308] Ex. DOC-22 at 36–38 (Campbell Direct).
[309] Ex. Xcel-57 at 60 (Schrubbe Direct).
[310] Ex. DOC-21 (Campbell Direct) at 41.

304. Over the long run, the cumulative employer contributions made to a plan in accordance with ERISA, the Pension Protection Act, and the IRC rules will be roughly equal to the cumulative pension expense recorded under both the ACM and FAS 87; but in the short and intermediate run, there can be significant differences.[311]

305. The funded status—defined as the difference between the market-related value of plan assets and the present value of future benefits—of the Company's pension plan is distinct from whether the Company has a prepaid pension asset, because the two concepts measure different things.[312] As of December 31, 2021, the NSPM Plan was underfunded by $240 million.[313]

306. Xcel asserts that the prepaid pension amount, reduced by the amount of unfunded retiree medical and other benefits and by accumulated deferred income taxes, are an asset that should be included in its rate base for which it should earn a return.[314] This amount is approximately $95 million.[315]

307. The Department opposed Xcel's recommendation for several reasons explained by the Department's utility accounting expert. The Department pointed out that the Commission has consistently denied requests to earn a return on a prepaid pension asset for other utilities.[316] The Department's accounting expert described how a "prepaid pension asset" is no longer part of Generally Accepted Accounting Principles (GAAP).[317]

308. Xcel's prepaid pension asset is fundamentally different than other prepaid assets, such as prepaid insurance expense.[318] As the Commission has observed, "pension-plan assets and benefit obligations go up and down depending on funding, market conditions, or amendments to the plan. The balances in the prepaid pension asset are temporary, and fundamentally different than typical rate-base assets on which the Company earns a return on investment."[319]

309. Even if it were similar, not all prepaid assets should be automatically included in rate base.[320] Because including the prepaid pension asset in rate base would

[311] Ex. Xcel-57 at 33 (Schrubbe Direct).
[312] Ex. Xcel-57 at 67 (Schrubbe Direct).
[313] Ex. DOC-21 (Campbell Direct) at 43 and NAC-D-15 (Campbell Direct) (Xcel's response to DOC IR No. 1007).
[314] Xcel's Initial Br. at 49–50.
[315] Ex. Xcel-57 at 63–65 (Schrubbe Direct); Xcel's Initial Br. at 50.
[316] Ex. DOC-21 (Campbell Direct) at 42.
[317] Ex. DOC-21 at 38–39 (Campbell Direct).
[318] Ex. DOC-21 at 40–43 (Campbell Direct).
[319] *In re Appl. of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-15-736, Findings of Fact, Conclusions of Law and Order at 11 (Oct. 31, 2016) (eDockets No. 201610-126124-01) (MERC 2015 Rate Case Order); *see* Ex. DOC-21 at 48 (Campbell Direct).
[320] Ex. DOC-21 at 40–43 (Campbell Direct).

earn a return on out-of-test-year expenses,[321] the Department's expert also disputed Xcel's claim that the Commission has authorized deferred accounting for the expenses.[322]

310. The Department's expert also explained that Xcel's request goes against current guidance from the Financial Accounting Standards Board (FASB) intending to address the outdated standard that allowed companies to show an asset or liability on the balance sheet that was different than the actual funded status of the pension plan.[323] The Department's expert explained that because Xcel is seeking to represent a "prepaid pension asset" when there is actually a liability, this is problematic under the current FASB standard.[324]

311. The Commission allowed Xcel to include a prepaid pension asset in its rate base in Xcel's 2013 rate case.[325] However, the Commission determined that the allowance in the 2013 case is neither persuasive nor precedential, because the issue was not specifically litigated by the parties.[326]

312. A prepaid pension asset may be recoverable to the extent that a utility can demonstrate that the amounts to be included in rate base are not supplied by ratepayers or market returns on plan assets.[327]

313. Xcel has not met its burden to demonstrate that it would be reasonable to allow Xcel to place a prepaid pension asset into its rate base. Xcel has been allowed to recover its allowable pension expense from ratepayers, and its recovery of test-year pension expenses is uncontested in this proceeding. The prepaid pension asset is defined by outdated GAAP and FASB guidance, and to the extent its value is attributable to shareholder contributions, the contributions exceeded pension expense amounts approved for rate recovery. The Commission has not approved deferred accounting for such surplus contributions, and Xcel has not met its burden to justify approval for deferred accounting here.

314. The Department has also demonstrated that because the value of the asset is determined in part by market gains and losses, there is doubt with respect to the source of the asset's value. Doubt must be resolved in favor of ratepayers.

315. The Judge recommends that the Commission deny Xcel's proposal to include a prepaid pension asset in its rate base.

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[321] Ex. Xcel-57 at 66 (Schrubbe Direct) (explaining that the prepaid pension asset arose from events occurring in 2006 and 2008).
[322] *See* Ex. DOC-21 at 44–45 (Campbell Direct).
[323] Ex. DOC-21 at 49–50 (Campbell Direct).
[324] Ex. DOC-21 at 49–50 (Campbell Direct).
[325] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 20, 98 (Finding 10) (May 8, 2015).
[326] MERC 2015 Rate Case Order at 11.
[327] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, PUC Docket No. E-15/GR-16-664, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 16-17 (Mar. 12, 2018) (explaining why a prepaid pension asset was excluded from rate base).

316. Xcel recommended that, if the Commission does not allow the prepaid pension asset to be included in rate base, the Commission should require the Company to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates.

317. Because the qualified pension expense should be correctly calculated to reflect the exclusion, the Judge recommends that the Commission require the Company to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust.

7. Accrued Liabilities for Retiree Medical and Post-Employment Benefits

318. Like its request to includes its prepaid pension asset in its rate base, Xcel sought to include in rate base accrued liabilities for retiree medical and post-employment benefits.[328]

319. The Company proposed recovery of expenses for post-retirement healthcare benefits under FASB's Statement of Financial Accounting Standard No. 106 (FAS 106), and for post-employment long-term disability (LTD) benefits under FASB's Statement of Financial Accounting Standard No. 112 (FAS 112).[329]

320. The Department opposed this request for the same reasons that it opposed Xcel's prepaid pension asset request—because these balances represent the cumulative difference between expense and payments/contributions and are not appropriate rate base assets.[330]

321. Xcel acknowledged that its request is in-line with its requested treatment of prepaid pension asset. The Company agreed with the Department that the treatment of the unfunded liabilities should be consistent with the treatment of the prepaid pension asset but argued that both the unfunded liabilities and the prepaid pension asset should be included in rate base. The Company's reasoning echoed the analysis of that regarding the prepaid pension assets.[331]

322. For the reasons provided above regarding Xcel's prepaid pension asset request, the Judge recommends that the Commission deny Xcel's request to include in rate base accrued liabilities for retiree medical and post-employment benefits.

8. Energy Supply O&M Expenses

323. The Company's Energy Supply business area is responsible for operating and maintaining the Company's non-nuclear generation portfolio in a safe, reliable, cost-effective, and environmentally-sound manner. Energy Supply is also responsible for

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[328] Ex. Xcel-57 at 33-34 (Schrubbe Rebuttal).
[329] Ex. Xcel-57 at 59 (Schrubbe Direct).
[330] Ex. DOC-23 at 35 (Campbell Surrebuttal).
[331] Ex. Xcel-58 at 33–34 (Schrubbe Rebuttal).

managing capital construction projects, overseeing environmental compliance, and supporting the coordination of generating unit dispatch with MISO.[332]

324. Energy Supply develops a five-year O&M budget of the costs to operate and maintain the Company's non-nuclear generating facilities on a day-to-day basis. Energy Supply's O&M expenses include labor, chemicals, materials, outside services, rents, land easements, and employee expenses.[333] In developing its O&M budgets, Energy Supply compares its proposed budgets to historical costs and factors in known changes such as changes to plant operating profiles, new and retiring generation, overhaul schedules, and plant improvements.[334]

325. Xcel proposed recovery of forecasted O&M expenses related to electric generation facilities for the MYRP as follows:[335]

2022	**2023**	**2024**
$154.6 million	$160.8 million	$157.7 million

326. Energy Supply's proposed average O&M budget for 2022–2024 is 13.8% higher than average O&M expenses for 2018–2020[336] and between 8.8% and 12.8% over its 2021 actual expense.[337] Mr. Capra explained that the primary drivers of this increase are new wind farm O&M contracts and land easement payments.[338]

327. The Department recommended reducing the allowed Energy Supply O&M expense by $5.3 million in each year, equal to the amount that Xcel over-collected in the Minnesota jurisdiction in the most recent year (2021).[339]

328. Xcel over-forecasted this expense category by between $6 million and 28.2 million between 2016 and 2021 and, since 2016, Xcel has collected $97.6 million more from ratepayers than it actually spent on this expense category.[340]

329. The Department disputed Xcel's stated drivers of Energy Supply O&M increases. For example, Xcel assumed a 3% increase in internal labor, although Xcel's

[332] Ex. Xcel-37 at 2 (Capra Direct).
[333] Ex. Xcel-37 at 74 (Capra Direct); Ex. Xcel-39 at 2–3 (Capra Rebuttal).
[334] Ex. Xcel-37 at 74 (Capra Direct); Ex. Xcel-39 at 2–3 (Capra Rebuttal).
[335] Ex. Xcel-80 at 53 (Halama Direct); Ex. Xcel-38 at 74–115 (Capra Direct); Ex. Xcel-82 at 37 (Halama Rebuttal); Ex. Xcel-39 at 2–12 (Capra Rebuttal).
[336] Ex. Xcel-37 at 76 (Capra Direct).
[337] These figures are Minnesota jurisdictional net of interchange allocations. *See* Ex. DOC-21, NAC-D-26 at 9 (Campbell Direct) (Xcel Response to DOC IR 163 – Attach. F) (showing $103,812,754 in 2021 actuals for the Minnesota Jurisdiction and 2022-24 MYRP Minnesota Jurisdictional forecasts ranging from a low of $113,002,174 in 2022 to a high of $117,117,086 in 2023).
[338] Ex. Xcel-37 at 76 (Capra Direct).
[339]Ex. DOC-23 at 44 (Campbell Surrebuttal) (correcting recommendation to be based on the amount of overstated 2021 costs at the Minnesota Jurisdictional level of $5.3 million).
[340] *See* Ex. DOC-21 at 74 (Table 13), NAC-26 (Campbell Direct) (Xcel's Response to DOC IR 163); Ex. DOC-23 at 45 (Campbell Surrebuttal).

employee headcount is forecasted to decrease after 2022.[341] The Department also contended that Xcel's retirement of Unit 2 of its Sherburne County Generation Facility (Sherco Unit 2) in 2023 did not appear to be sufficiently accounted for in its Energy Supply O&M in 2023 and beyond.[342]

330. Xcel argued that the Department's analysis was backward-looking and that the Department's proposed adjustment is arbitrary and does not account for increased costs. Xcel argued that cost increases were supported in the record.

331. The Company explained that Energy Supply's actual O&M expenses for 2016–2020 were lower than the amount budgeted in the Company's 2016 MYRP rate case (Docket No. E002/GR-15-826) due to generation fleet changes that occurred after the rate case budget was developed.[343] These changes included transitioning two of the Company's coal-fired generating plants, Allen S. King and Sherco Unit 2, from all-year operation to seasonal operation in 2020.[344] These changes could not have been anticipated when the Company developed its rate case budgets in 2015 and resulted in Energy Supply's actual O&M expenses being lower than the 2016 MYRP rate case budget amount.[345]

332. The Company provided evidence that the difference between Energy Supply's 2021 forecasted and actual O&M expenses was the receipt of unanticipated liquidated damage payments for its wind facilities.[346] Many of Xcel Energy's O&M service agreements with wind service providers to maintain and operate the Company's wind facilities include an "availability covenant."[347] Generally speaking, this availability covenant provides that if the wind facilities operate less than projected during a given year, the wind service providers pay liquidated damages to Xcel Energy.[348] Company witness Randy Capra explained that the Company is unable to forecast these payments in advance because the occurrence and amount of these payments are dependent on each wind facility's actual performance in a given year.[349] The Company also argued that the possibility of future availability damage payments cannot be used as a basis to support reducing Energy Supply's 2022–2024 O&M budgets as future payments will be credited back to ratepayers through the Company's Renewable Energy Standard (RES) Rider for those wind facilities recovered through that rider, which was the case for nearly all of the payments received in 2021.[350]

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[341] Ex. DOC-21 at 75 (Campbell Direct).
[342] Ex. DOC-23 at 47–48 (Campbell Surrebuttal).
[343] Ex. Xcel-39 at 4 (Capra Rebuttal).
[344] Ex. Xcel-39 at 4 (Capra Rebuttal).
[345] Ex. Xcel-39 at 4 (Capra Rebuttal).
[346] Ex. Xcel-39 at 5 (Capra Rebuttal).
[347] Ex. Xcel-39 at 5 (Capra Rebuttal).
[348] Ex. Xcel-39 at 5 (Capra Rebuttal).
[349] Ex. Xcel-39 at 5 (Capra Rebuttal).
[350] Ex. Xcel-39 at 5 (Capra Rebuttal). Borders Wind was the only wind facility that received availability damage payments in 2021, in the amount of $184,000, that was not included in the RES Rider.

333. Xcel is obliged to operate Sherco Unit 2 year-round in the 2022–23 MISO planning year, resulting in increased O&M costs that the Department did not account for in its Energy Supply O&M analysis.[351]

334. In surrebuttal testimony, the Department responded to Xcel's stated cost drivers. Regarding overhauls and inspections at certain plants, the Department described how inspections and overhauls are always occurring or in flux in a large generation fleet such as Xcel. The Department also stated that as Xcel adds new, more efficient wind to its system, there should be an expectation that less efficient, more labor-intensive fossil fuel plants would be used less. Xcel's new generation facilities should also be expected to require less O&M expense than old generation facilities—as capital costs increase, maintenance expense typically decreases.[352]

335. The Company explained that year-to-year fluctuations in Energy Supply's O&M expenses are due to the addition of new renewable generation. When new wind facilities are placed in service, the Company begins to incur additional O&M expenses to keep these facilities in proper working order and for land easement payments.[353] For instance, in 2021, several new wind facilities went into service which increased Energy Supply's O&M expenses by $13.3 million as compared to 2020.[354]

336. The Company also provided evidence that Energy Supply's 2022–2024 O&M budgets are likely understated given a number of changes that have occurred since those budgets were created in July 2021.[355] These changes include: (1) inflationary increases to several of Energy Supply's key O&M expenses, (2) wage increases for collective bargaining employees in 2023 and 2024 due to new agreements with local unions, (3) the proposed life extension for the Company's wind facilities, and (4) year-round rather than seasonal operation of the Company's King and Sherco Unit 2 facilities in 2022–2023.[356]

337. The Company has met its burden to establish that its forecasted Energy Supply O&M budget is just and reasonable. The Company has justified its budgeted amount and credibly explained the reasons for differences between its forecasted and actual expenses between 2016 and 2021. The Department's backwards-looking analysis does not, in and of itself, render Xcel's forecast in this proceeding unreasonable. The Department identifies neither specific disallowances nor, in light of the entire record, a sufficient, substantive basis to doubt the reliability of the Company's forecast on this record. Additionally, the Department's proposed $5.3 million annual reduction amount is arbitrary and unsupported by substantial evidence that the allowed expense should be reduced by that amount in each test year.

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[351] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 208–209 (Campbell).
[352] Ex. DOC-21 at 45–49 (Campbell Surrebuttal).
[353] Ex. Xcel-39 at 8 (Capra Rebuttal).
[354] Ex. Xcel-39 at 8 (Capra Rebuttal).
[355] Ex. Xcel-39 at 11-12 (Capra Rebuttal).
[356] Ex. Xcel-39 at 11-12 (Capra Rebuttal); Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 198-199 (Campbell).

338. The Judge recommends that the Commission allow Xcel to recover its proposed Energy Supply O&M Expenses, and not adopt the Department's proposed adjustment.

9. Business Systems O&M Expenses

339. The Company's Business Systems O&M budget for the MYRP is $103.2 million in 2022, $110.3 million in 2023, and $119.1 million in 2024 (exclusive of the Advanced Grid Intelligence and Security (AGIS) costs being recovered through the separate Transmission Cost Recovery rider) on an NSPM Electric basis (or $89.9 million, $96.2 million, and $103.8 million for 2022-2024, respectively, on a Minnesota Electric Jurisdiction basis, exclusive of AGIS).[357]

340. Business Systems provides information technology (IT) services across Xcel Energy.[358] The Business Systems O&M budget includes costs related to the operation and maintenance of existing IT assets such as software systems, computers, printers, phones, radio systems, and servers. It also includes annual software contract and license fees, as well as maintenance agreements, for existing software and hardware. In addition, the O&M budget includes non-capitalized costs associated with developing, enhancing, and maintaining new or existing IT systems.[359]

341. Since the Company's 2015 Rate Case, in addition to maintaining other IT capital investments, the Company's Business Systems O&M costs have increased largely due to the need to maintain the new General Ledger (GL) and Work and Asset Management (WAM) systems, which were significant undertakings in the Business Systems area, and part of the Company's Productivity Through Technology (PTT) initiative.[360]

342. The Company explained its O&M budgeting process and how it establishes a reasonable annual O&M level that allows it to complete priorities that are important to providing a reasonable level of services to the Company and its customers. The Company also explained how it may need to adjust budgeted O&M funds to adapt to changing priorities and unplanned situations, such as updates in technology, customer expectations, and operating priorities in the various business units and the finance area.[361]

343. According to the Company, its customers have benefited from lower O&M costs in previous years as the Company harvested value from current systems. The Company stated that investments and dated technology cannot be indefinitely deferred and the Company must make investments to ensure safe and reliable service for customers.[362]

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[357] Ex. Xcel-50 at 107–08 (Remington Direct); Ex. DOC-8, Attach. ALS-S-2 (Skayer Surrebuttal).
[358] Ex. Xcel-50 at 2 (Remington Direct).
[359] Ex. Xcel-50 at 105–06 (Remington Direct).
[360] Ex. Xcel-37 at 77 (Capra Direct).
[361] Ex. Xcel-50 at 110-111 (Remington Direct).
[362] Ex. Xcel-50 at 106-107 (Remington Direct).

344. The Company also testified that its investments in technology help other business areas serve customers efficiently and effectively and are intended to maintain and enhance service to customers, including in the ways customers interact with Xcel Energy. Without making these investments, the Company stated that it could not provide reliable, quality service.[363]

345. The Company explained the drivers of O&M costs in the MYRP years of this proceeding in Table 23 of Company witness Michael O. Remington's Direct Testimony.[364] Mr. Remington testified that certain categories of O&M costs, such as Software License and Maintenance and projects like the Digital Operations Factory, Customer Enhancements (including the Customer Experience or CXT program), the Core Human Resources (HR) Application project, and AGIS.[365]

346. No party to this proceeding directly challenged the reasonableness of specific IT capital investments in the Business Systems area.

347. The Department maintained that Xcel had not supported its increase and recommended an alternative increase tied to inflation.[366] The Department recommended that the Commission approve an Xcel's Business Systems O&M expense increase, assuming continued high inflation, by 7.5% from 2021 actuals in 2022, by 7.5% in 2023, and by 7% in 2024.[367]

348. The Department argued that Xcel's requested increase was not in line with either Xcel's historical expense or general growth for IT budgets.[368] The Department's expert described how Xcel's proposal differed from the typical cycle of IT O&M expenses.[369] The Department also showed that Xcel had a trend of over-forecasting its Business System O&M expense above actuals.[370] The Department's expert examined Xcel's claimed cost drivers, and concluded that they did not explain the significant increase.[371]

349. The Department's recommendations are primarily based on a "trend analysis" showing that the Company's O&M costs are increasing. The Company did not dispute that its O&M costs are increasing, but argued that the Department's analysis did not evaluate why the Company's proposed O&M budgets are higher than historical years. The Department's trend analysis neither evaluates nor challenges the reasonableness of any particular cost associated with Business Systems capital investments or O&M expense for the MYRP, and therefore, did not analyze why IT O&M expenses are increasing for the MYRP compared to previous years.

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[363] *Id*.
[364] Ex. Xcel-50 at 108 (Remington Direct).
[365] Ex. Xcel-50, Section IV (Remington Direct).
[366] Ex. DOC-8 at 28 (Skayer Surrebuttal).
[367] Ex. DOC-8 at 27–28 (Skayer Surrebuttal) (Table 3).
[368] *See* Ex. DOC-7 at 1 (Skayer Direct); Ex. DOC-8 at 21-25 (Skayer Surrebuttal).
[369] Ex. DOC-7 at 20–21 (Skayer Direct).
[370] Ex. DOC-7 at 22 (Skayer Direct).
[371] *See* Ex. DOC-8 at 21-25 (Skayer Surrebuttal).

350. In Surrebuttal Testimony, the Department assessed certain drivers of O&M cost increases, but limited that review to inflation, labor costs, and software and maintenance costs, and ultimately acknowledged that each is driving increased costs.[372]

351. In addition, the Department's analysis looked only at four individual capital projects as additional drivers and did not account for all of the illustrative new capital projects driving O&M that the Company identified. The Department's assessment considered only some drivers of O&M budget increases and did not consider that overall, O&M cost increases are due to new capital investments.[373]

352. The Department did not consider O&M cost impacts due to the Digital Operations Factory Project capital addition, which the Company discussed in Mr. Remington's Rebuttal Testimony as a driver of O&M cost increases.[374]

353. The Department's recommended increase of 7.5% for 2022 and 2023 and 7.0% for 2024 are not specifically tied to any analysis of the reasonableness of costs included in Company's proposed O&M budgets for the MYRP, and would not capture 2022 inflation or increased areas of O&M. The record does not show how particular cost amounts related to the CXT project, escalating costs for software and maintenance, and costs associated with increasing labor expenses are reflected in the Department's recommended O&M increases for the MYRP. The record also does not show how the Department's updated recommendations for 2022–2024 depicted in Attachment ALS-S-5 are calculated.

354. The Department's witness also relied article on an entitled "Gartner Forecasts Worldwide IT Spending to Grow 3% in 2022."[375] According to the witness, the Gartner "article is meant to address the large deviation between Xcel's Business System's growth for 2022 and the average growth rate of an organization's IT budget."[376] The Department included an updated publication from Gartner with Surrebuttal Testimony.[377]

355. The Department's recommended increases for 2022–2024 are not tied to or reflect any growth rate shown in the Gartner article included with the Department's Surrebuttal Testimony.[378]

356. Overall, the articles from Gartner included with the Department's testimony do not support the Department's recommendations. The Gartner articles pertain to worldwide IT spending forecasts, are not limited to U.S. utilities like the Company, and are not limited to O&M expenses. For these reasons, the articles bear little relevance to—

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[372] *See* Ex. DOC-8 at 21-28 (Skayer Surrebuttal).
[373] Ex. Xcel-50 at 106 (Remington Direct).
[374] *See* Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 111-112 (Skayer); *see also* Ex. Xcel-51 at 9 (Remington Rebuttal).
[375] Ex. DOC-7, Attach. ALS-S-5 (Skayer Direct).
[376] Ex. DOC-8 at 25-26 (Skayer Surrebuttal).
[377] Ex. DOC-8, Attach. ALS-S-7 (Skayer Surrebuttal).
[378] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 118 (Skayer).

and do not offer reliable insight into—the appropriate forecasted increases for the Company's Business Systems O&M budget.

357. The Judge concludes that the Company has met its burden to demonstrate that its proposed Business Systems O&M costs in the MYRP are reasonable. Because there is inadequate record support for the calculation of the Department's recommended 7.5% increase for 2022 and 2023 and a 7.0% increase for 2024, they lack evidentiary support and would not provide a reasonable level of O&M costs to reflect in the MYRP.

358. The Judge recommends that the Commission allow Xcel to recover its proposed Business Systems O&M Expenses, and not adopt the Department's proposed adjustment.

10. Property Tax Expense True-Up Baseline

359. The Company requested recovery of its forecasted property tax expense for the years of the MYRP. For 2022, the Company's initial forecast for property tax expense, at the Minnesota-electric-jurisdiction level, was $180 million.[379] During the pendency of this case, the Company updated its forecast to reflect new developments and data: the Company resolved its 2022 property tax valuation with the Minnesota Department of Revenue (DOR) (resulting in a substantial reduction in the DOR's valuation); it received its valuations from North Dakota and South Dakota, and the actual 2021 effective local tax rate was determined.[380] The Company's updated forecast for 2022 was $165.9 million.[381] No party disputed the use of this updated forecast figure for 2022.

360. A property tax true-up allows Xcel to surcharge or refund amounts when the actual property taxes for a given year do not match the approved baseline in this proceeding.[382] This true-up guarantees that Xcel recovers its property taxes and protects ratepayers from overpayment.[383] The reasonableness of a property tax true-up mechanism is uncontested in this proceeding, and is supported by the record.

361. The only disputed issue relating to the Company's property tax expense is the baseline amount of property tax expense to be used for 2023 and 2024.[384] The Company's initial property tax forecast, at the Minnesota-electric-jurisdiction level, was $192.6 million for 2023 and $208.1 million for 2024. During the pendency of this case, the Company updated these forecasts to $181.1 million for 2023 and $196.7 million for 2024.[385] The Company proposed to use these updated forecasts as the baseline.

362. The Department argued that Xcel did not support its updated forecast for 2023 and 2024. The Department's witness regarded Xcel's property tax forecasts to be

[379] Ex. Xcel-70 at 3 (Arend Rebuttal).
[380] Ex. Xcel-70 at 3-5 (Arend Rebuttal).
[381] Ex. Xcel-70 at 3 (Arend Rebuttal).
[382] Ex. Xcel-69 at 7 (Arend Direct).
[383] Ex. DOC-5 at 15–17 (Soderbeck Surrebuttal).
[384] Ex. Xcel-70 at 3 (Arend Rebuttal).
[385] Ex. Xcel-70 at 3 (Arend Rebuttal).

deficient for several reasons.[386] First, Xcel's updated forecast failed to fully remove the cost impacts of its unapproved EV programs as the Commission directed.[387] The update failed to factor in reductions to plant, depreciation, and income when calculating the Minnesota Allocated Value Percentage—the formula used to allocate system-wide values to Xcel's Minnesota operations—and when calculating the exclusions to the Minnesota Allocated Value.[388] And Xcel did not update the sliding scale market value exclusion, which is impacted by changes in system value, when it updated its forecast.[389]

363. The Department also showed that Xcel's property tax forecasts have historically been high.[390] From 2017–21 Xcel over-collected and subsequently refunded a total of $61.9 million in property tax expense.[391] While these amounts are refunded to ratepayers through the true-up, ratepayers are deprived of the use of the money in the meantime.[392]

364. The Department proposed an alternative property tax forecast. To determine an appropriate alternative, Ms. Soderbeck reviewed historical trends in the local property tax rate, property tax expense, and net investment and determined that a 2.5% annual increase in 2023 and 2024 was appropriate.[393] The actual five-year average increase in Xcel's property tax is only 0.77%.[394]

365. The Company argued that no "trend" is evident from the Company's actual property tax expense from 2017 to 2021.[395] The Company provided detailed explanations of the factors that affected each year's property tax expense from 2017 to 2021.[396] The detailed explanations demonstrate that each year's property tax is affected by the interplay of several factors, which often offset each other in a manner that may not be predictive of the future.

366. According to Xcel, the largest year-over-year change within the 2017 to 2021 period studied by the Department was a significant decrease from 2017 to 2018, which was the result of a new administrative appeal process, resulting from a change in a Minnesota statute.[397]

367. Using an accurate true-up baseline amount is important to avoid wide swings in rates.[398]

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[386] *See* Ex. DOC-3 at 10–24 (Soderbeck Direct); Ex. DOC-5 at 34–42 (Soderbeck Surrebuttal).
[387] Ex. DOC-5 at 38–39 (Soderbeck Surrebuttal).
[388] Ex. DOC-5 at 38–39 (Soderbeck Surrebuttal).
[389] Ex. DOC-5 at 40 (Soderbeck Surrebuttal).
[390] Ex. DOC-3 at 24 (Soderbeck Direct).
[391] Ex. DOC-3 at 24 (Soderbeck Direct).
[392] *See* Ex. Xcel-69 at 15 (Arend Direct).
[393] Ex. DOC-3 at 20–21 (Soderbeck Direct).
[394] Ex. DOC-3 at 20–21 (Soderbeck Direct).
[395] Ex. Xcel-70 at 11 (Arend Rebuttal).
[396] Ex. Xcel-70 at 11-18 (Arend Rebuttal).
[397] Ex. Xcel-70 at 11, 15-16 (Arend Rebuttal).
[398] Ex. Xcel-23 at 17 (Liberkowski Rebuttal); Evid. Hrg. Tr. Vol. 1 at 30–31 (Liberkowski).

368. Xcel's argument that it would be unreasonable to adopt the Department's method of deriving a trend from historical changes in actual property tax expense is unavailing. Xcel points to one significant decrease in 2018 as a reason to reject the comparison. However, whether or not 2018 is included or excluded, it is clear that Xcel's property tax expense did not change more than 3% in either direction between 2017 and 2021.[399] The smallest property tax increase forecast by Xcel in the MYRP is 5.01% in 2022.[400]

369. Xcel's witness stated that the Company "forecast property taxes based on the same key variables used in prior rate cases, such as investments, DOR valuation inputs, and effective tax rate."[401]

370. The Company has not met its burden to demonstrate that its property tax forecast is reasonable. Because Xcel over-recovered property tax expense each year between 2017 and 2021—collecting an excess $61.9 million from ratepayers and then returning it through the true-up—the reliability of the Company's property tax forecasting methodology is doubtful. The Company's forecasting methodology appears to favor over-recovery. That Xcel now forecasts significantly larger increases in property tax expense than have occurred in recent history must be viewed in light of the demonstrated performance of the Company's forecast methodology. The significant departure forecasted in each year of the MYRP from property tax expense changes actually experienced between 2017 and 2021 requires greater justification than has been shown on this record.

371. The Department's alternative property tax expense forecast is reasonably grounded in historical data and provides a more realistic baseline for Xcel's property tax true-up. A more accurate baseline will provide rate stability to customers by mitigating wide swings in refunds and surcharges.

372. The Judge recommends that the Commission adopt the Department's proposed property tax forecast in setting property tax expense in this proceeding, and the Department's corresponding adjustment to Xcel's revenue requirement, as follows:[402]

2022	2023	2024	2025	2026
$(14,082,000)	$(22,681,000)	$(34,107,000)	$(34,107,000)	$(34,107,000)

11. Income Tax Tracker Amortization

373. The Company concluded income tax audits with the IRS and the Minnesota Department of Revenue (DOR) for tax years ended 2010 through 2016,and paid tax and

399 Ex. DOC-3 at HS-D-11 (Soderbeck Direct).
400 *Id.*
401 Ex. Xcel-69 at 11 (Arend Direct).
402 Ex. DOC-23, NAC-S-1, line 2 (Campbell Surrebuttal).

interest on the disputed amounts.[403] Company proposed to collect these income tax costs over the course of the MYRP.[404]

374. The Department objected to Xcel's proposal because Xcel had not received deferred accounting authorization for these out-of-test-year expenses and had not shown that it had not already recovered these costs through rates.[405] Denying recovery would reduce the test year revenue requirement by approximately $2.1 to $2.5 million over the MYRP.[406]

375. To determine a utility's revenue requirement, the Commission evaluates the utility's investment in capital assets, operating revenues, and operating expenses based on a representative "test year," which is a recent or forecasted 12-month period.[407] For multi-year rate plans, although there are multiple forecasted test and plan years, the principle remains that a utility's operating expenses are limited to those expenses forecasted to be incurred in the future.

376. For a utility to recover out-of-test-year operating expenses, it must petition the Commission for deferred accounting—an exception to general accounting principles that allow utilities to record, or "track," out-of-test-year expenses.[408] Deferred accounting requests are subject to Commission discretion and the Commission grants deferred accounting requests only upon a showing of good cause.[409]

377. The Commission has historically found good cause when utilities "incur out-of-test-year expenses that, because they are unforeseen, unusual, and large enough to have a significant impact on the utility's financial condition," and when they have "incurred sizeable expenses to meet important public policy mandates."[410]

378. Reaching back in a rate case to include out-of-test-year costs generally increases intergenerational inequities, causing future ratepayers to pay costs incurred to serve ratepayers in the past. Allowing out-of-test-year costs is likely to benefit the utility—the utility has more readily available information and knowledge about which expenses had been under- or over-recovered than any intervening party.

379. The Commission denied Xcel's 1992 rate case request to establish an automatic tracker so that the Commission could retain its discretion to review for good cause credits and debits subject to deferred accounting.[411] The Commission wrote:

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[403] Ex. Xcel-79 at 90 (Halama Direct).
[404] *Id.*
[405] Ex. DOC-21 at 81–85 (Campbell Direct); Ex. DOC-23 at 53–59 (Campbell Surrebuttal).
[406] Ex. Xcel-82 at 51 (Halama Rebuttal).
[407] Ex. DOC-21 at 5–6 (Campbell Direct); Ex. DOC-23 at 54–55 (Campbell Surrebuttal).
[408] *See, e.g., In re Pet. by N. States Power Co. d/b/a Xcel Energy for Approval of Deferrals Related to Depreciation O&M and Property Tax for 2022*, Docket No. G-002/M-21-750, ORDER DENYING PETITION at 2 (Feb. 9, 2022) (eDockets No. 20222-182600-01) (Xcel Gas Deferral Petition Denial Order).
[409] *Id.*
[410] *Id.*
[411] 1992 Rate Case Order at 58.

> Because rate proceedings already are large and complex undertakings, the Commission will not permit the automatic accumulation of tax matters for review in subsequent rate cases. To maintain an element of control over the items deferred, the Commission will require that the Company petition for deferred accounting status of both tax credits and debits at the time the final decisions are received on the disputed items.[412]

380. In 1993, Xcel petitioned the Commission for deferred accounting for interest payments arising from an IRS field audit.[413] The Commission granted Xcel's requests stating that Xcel "followed the procedure established by the Commission" in Xcel's 1992 rate case.[414] The Commission also stated that its "decision does not mean that every item of expense or income associated with tax adjustments will be automatically allowed for deferred accounting" and reiterated that Xcel "must present each item at the time of its disposition and seek permission for deferral on a case by case basis."[415]

381. Between 1993 and 2005, Xcel petitioned for deferred accounting status of both credits and debits at the time it received final decisions and generally received approval for its requests.[416]

382. For the costs now at issue, Xcel has not demonstrated that it requested deferred accounting at the time it received a final decision, that the Commission has authorized these income tax costs for deferred accounting, or that the Commission has authorized the costs to be considered for recovery in this proceeding.

383. The Company argued that it was requesting recovery of the costs "at its first opportunity to do so, since the audits resulting in tracked amounts concluded between 2017 and 2020 and the Company's last electric rate case was filed in 2015."[417] The latest of these audits concluded in the second quarter in 2020.[418]

384. Xcel's argument is unpersuasive. This rate proceeding is not the Company's first opportunity to seek approval for deferred accounting. Xcel filed its first documents initiating this rate proceeding in September 2021. Xcel had more than a year to petition the Commission to approve deferred accounting for the latest-resolved of the audits, and several years for each of the other audits for which recovery is now sought. Xcel offered

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[412] *Id*.

[413] *See In re Request of N. States Power Co. for Approval of Deferred Acct. Treatment of Interest Paid on Income Tax and Sales Tax Changes*, E-002/M-93-1328, ORDER APPROVING DEFERRED ACCOUNTING at 1 (May 19, 1994) (eDockets No. 323736) (May 1994 Income Tax Deferred Accounting Order).

[414] May 1994 Income Tax Deferred Accounting Order at 3.

[415] *Id*. at 4.

[416] *See In re Request by N. States Power Co. d/b/a Xcel Energy for Approval of Deferred Acct. Treatment for Various Tax Matters*, MPUC Docket No. E-002/M-04-1605, ORDER at 12 (Jan. 18, 2005) (eDockets No. 1994819); *In re N. States Power Co. d/b/a Xcel Energy's Pet. for Approval of Deferred Acct. Treatment for Various Tax Matters*, Docket No. E-002/M-05-1471, ORDER APPROVING DEFERRED ACCOUNTING (Mar. 30, 2006) (eDockets No. 2978008).

[417] Xcel's Initial Brief at 170; Ex. Xcel-82 at 53 (Halama Rebuttal).

[418] Ex. Xcel-82 at (BCH-2), Schedule 7 (Halama Rebuttal).

no satisfactory explanation for failing to request deferred accounting "at the time the final decisions [were] received."

385. Because the Commission expressly required that Xcel request deferred accounting for these expenses outside of a rate proceeding and at the time of their disposition, Xcel has not met its burden to establish that including the costs for recovery would be reasonable. Xcel's request seeks to include out-of-test-year costs for recovery and is inconsistent with the 1992 Rate Case Order.

386. Because doing so would be inconsistent with the Commission's 1992 Rate Case Order, the Judge will not consider a deferred accounting request for these amounts in this proceeding. Doing so would deny the Commission the control over deferred accounting items that it wished to retain.

387. The Judge recommends that the Commission deny Xcel's request to recover costs arising from the income tax audits with the IRS and the DOR for tax years ended 2010 through 2016.

388. The Judge recommends that the Commission adopt the Department's corresponding adjustment to Xcel's revenue requirement, as follows:[419]

2022	**2023**	**2024**	**2025**	**2026**
$(2,492,000)	$(2,300,000)	$(2,110,000)	--	--

12. South Dakota Aurora Cost Amortization

389. In proceedings stemming from Xcel's 2010 integrated resource plan (IRP), the Commission ordered Xcel to negotiate a power purchase agreement (PPA) for the Aurora Solar project, finding it appropriate for Xcel's system.[420]

390. The Commission selected the solar project and approved a PPA between the Company and Aurora over the Company's objection.[421]

391. In a Settlement Stipulation (Settlement) negotiated with the South Dakota Public Utilities Commission (SDPUC) staff, the Company agreed that the actual costs of the Aurora Solar PPA would not be recovered from South Dakota ratepayers.[422] The Settlement limited the Company's recovery in South Dakota to an energy proxy price

[419] Ex. DOC-23, NAC-S-1 at 1, line 21 (Campbell Surrebuttal).
[420] *In re Pet. of N. States Power Co. d/b/a Xcel Energy for Approval of Competitive Res. Acq. Proposal and Cert. of Need*, E-002/CN-12-1240, ORDER DIRECTING XCEL TO NEGOTIATE DRAFT AGREEMENTS WITH SELECTED PARTIES at 4 (May 23, 2014) (eDockets No. 20145-99797-01).
[421] Ex. Xcel-22 at 38 (Chamberlain/Liberkowski Direct); Ex. Xcel-79 at 88 (Halama Direct); MPUC Docket No. E-002/CN-12-1240.
[422] Ex. DOC-21 at Schedule NAC-D-19 (Campbell Direct).

derived from the system average cost of fuel and purchased power with no capacity component.[423]

392. In this proceeding, the Company proposed recovery of a portion of the Aurora PPA cost that it cannot recover from South Dakota customers. The Company's proposal seeks to recover the difference between the PPA price and the SDPUC-approved proxy price from January 1, 2017—the date of the SDPUC denial—to January 1, 2024, to be amortized over a two-year period. The Company's proposal then requests the inclusion of this portion of the Aurora costs in the Fuel Clause Adjustment (FCA) Rider beginning January 1, 2024.[424]

393. In 2015, after the North Dakota Public Service Commission denied Xcel recovery of costs for its PPA with Aurora, Xcel requested approval to recover those costs from Minnesota ratepayers.[425]

394. In 2016, the Commission denied Xcel's request for recovery of North Dakota costs.[426] The Commission determined that it was unreasonable for Minnesota ratepayers to subsize North Dakota ratepayers' consumption of solar energy.[427] The Commission stated that Xcel "operates a single, integrated system covering portions of five states. The Aurora project was found to be a cost-effective resource addition in the context of Xcel's system as a whole."[428] The Commission found that Xcel had not provided "data to support a finding that the project is a reasonable way to meet the needs of only Minnesota ratepayers" or shown it was just and reasonable for Minnesota ratepayers to subsidize North Dakota ratepayers' solar energy consumption.[429] The Commission disagreed with Xcel's claim that the Aurora PPA was approved under Minnesota state energy policy and explained that the Aurora project was "selected because it was a cost-effective way to supply an identified capacity need—not because of a statutory mandate to promote state energy policies."[430] The Commission found that Xcel had not provided a justification to depart from "standard jurisdictional-cost-allocation practices."[431]

395. The Department opposed Xcel's request both to include costs in the MYRP and in the FCA going forward, based on the Commission's 2016 order for the North Dakota costs. The Department argued that the Commission's reasons for denying Xcel's requests for the North Dakota costs were persuasive and should also apply to South Dakota. The Department also asserted that Xcel's proposal was at odds with fundamental cost causation principles, and Xcel had failed to request deferred accounting for 2017–

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[423] *Id*.
[424] Ex. Xcel-22 at 38-39 (Chamberlain/Liberkowski Direct); Ex. Xcel-79 at 88 (Halama Direct).
[425] *In re Pet. of N. States Power Co. d/b/a Xcel Energy for Approval of Cost Recovery of the Aurora Power Purchase Agreement*, MPUC Docket No. E-002/M-15-330, ORDER DENYING RECOVERY OF NORTH DAKOTA RELATED PURCHASED-POWER COSTS at 4 (Apr. 13, 2016) (eDockets No. 20164-120018-01) (North Dakota Aurora Costs Order).
[426] North Dakota Aurora Costs Order at 8.
[427] *Id*. at 6.
[428] *Id*.
[429] *Id*.
[430] *Id*. at 7.
[431] *Id*. at 5.

2021 costs it sought to include.[432] Last, the Department pointed to the fact that Xcel had agreed in a settlement to forgo the South Dakota costs.[433]

396. The Company argued that the Commission's 2016 denial of North Dakota-related cost recovery should not be a basis for denying recovery of its proposed South Dakota-related recovery. It pointed to a detail in the North Dakota Aurora Costs Order: Xcel had agreed with Aurora that, in exchange for waiving Xcel's termination right, Aurora would reimburse Xcel if neither the North Dakota nor the Minnesota commissions allowed recovery of the North Dakota costs.[434] There is no evidence that the Company has a market-based means to recover the South Dakota costs in the event of denial in this proceeding.

397. Although the Commission acknowledged the Xcel–Aurora North Dakota reimbursement agreement in its description of Xcel's petition for cost recovery, the Commission did not include the agreement among its reasons for denying cost recovery from Minnesota ratepayers.[435] The Judge regards the omission of the reimbursement agreement from the Commission's reasoning as material—the Commission's denial rested upon its determination that the project was cost effective for Xcel's system as a whole, and that it would be unreasonable to require Minnesota ratepayers to subsidize ratepayers in another state. The Commission's reasoning in the North Dakota Aurora Costs Order can be applied directly to the South Dakota costs now proposed for recovery from Minnesota ratepayers.

398. Accordingly, for the reasons cited by the Commission in its North Dakota Aurora Costs Order, Xcel has not met its burden to demonstrate that recovering from Minnesota ratepayers costs attributable to South Dakota ratepayers would be just and reasonable. Xcel has not shown that jurisdictional-cost-allocation principles or practices have fundamentally changed, or that the Aurora solar project is a reasonable way to meet the needs of only Minnesota ratepayers.

399. In addition, Xcel has not established that its South Dakota settlement was consistent with Minnesota ratepayers' interests, or that it reflects a just and reasonable cross-jurisdictional allocation of system costs for the Aurora project. Denial of recovery of a portion of Aurora costs in South Dakota came not as a litigated result, but from a negotiated settlement agreement. The South Dakota Commission approved Xcel's *agreement* to relieve South Dakota customers of those costs. Xcel's decision to enter the agreement in South Dakota was voluntary and—because it now serves as a basis for Xcel's seeking recovery from Minnesota ratepayers in this proceeding—likely not made with the interests of Minnesota ratepayers in mind. Xcel settling the issue of recovery in South Dakota provides an independent basis to conclude that Xcel has not met its burden to establish the reasonableness of recovering South Dakota costs from Minnesota ratepayers.

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[432] Ex. DOC-21 at 61–63 (Campbell Direct).
[433] Ex. DOC-21 at 61 (Campbell Direct).
[434] North Dakota Aurora Costs Order at 4.
[435] *Id*. at 5–7.

400. The Judge recommends that the Commission deny Xcel's South Dakota Aurora cost recovery proposal.

401. The Judge recommends that the Commission adopt the Department's recommended adjustment to Xcel's revenue requirement, as follows:[436]

2022	2023	2024	2025	2026
$(2,857,000)	$(2,689,000)	--	--	--

13. Business Incentive and Sustainability (BIS) Rider Amortization

402. In December 2020, the Commission approved changes to its Business Incentive and Sustainability (BIS) rider as part of Xcel's Pandemic and Civil Unrest Recovery Program. Specifically, the Commission allowed Xcel to offer business and industrial customers that could show they lost substantial business as a result of the COVID-19 pandemic "a 25 percent credit or discount on basic charges (excluding customer charges) after the application of voltage discounts."[437] The Commission, however, denied Xcel's request to automatically recover the cost of this BIS pandemic discount through its sales true-up.[438] The Commission instead ordered that:

> [I]n its next general rate case, Xcel may seek recovery of the cost of the credits issued in this Pandemic and Civil Unrest Recovery Program; at that time, Xcel shall demonstrate the reasonableness of any cost recovery and provide a cost-benefit analysis including the full amount of the credits given and the sales revenue stimulated and retained; and Xcel may defer the cost of these credits until its next general rate case.[439]

403. Xcel requested recovery of the BIS Rider Discounts. Specifically, the Company incurred costs of $2,613,616, and proposed recovery of these costs over the three-year MYRP period.[440]

404. The Department initially opposed Xcel's request because Xcel had not provided the requisite cost-benefit analysis and had not otherwise demonstrated reasonableness.[441]

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[436] Ex. DOC-23, NAC-S-1 at 1, line 15 (Campbell Surrebuttal).
[437] *In re Pet. by N. States Power Co. for Approval to Provide Relief for Com. and Indus. Customers that Had Peak Monthly Loads of Less than 100kW Before the COVID-19 Pandemic and Civil Unrest*, MPUC Docket No. E-002/M-20-662, ORDER APPROVING PANDEMIC AND CIVIL UNREST RECOVERY PROGRAM WITH MODIFICATIONS at 2 (Dec. 7, 2020) (eDockets No. 202012-168847-01) (BIS Rider Changes Final Order).
[438] I*n re Pet. of N. States Power Co. for Approval of Revisions to the Bus. Incentive and Sustainability (BIS) Rider Tariff*, MPUC Docket No. E-002/M-20-436, ORDER APPROVING PROPOSED CHANGES WITH MODIFICATIONS at 7 (July 27, 2020) (eDockets No. 0207-165290-01) (BIS Rider Changes Initial Order).
[439] BIS Rider Changes Final Order at 5.
[440] Ex. Xcel-79 at 89 and Sched. 12 at 1, line 41 (Halama Direct).
[441] Ex. DOC-21 at 77–80 (Campbell Direct).

405. Xcel acknowledged that the cost-benefit analysis was inadvertently excluded from its direct testimony.[442] After intervenor direct testimony was filed, Xcel provided a cost-benefit analysis as a supplemental response to a previously issued information request.[443]

406. The Department requested that Xcel explain how the BIS discount was not already recovered through the Company's sales true-up.[444] Xcel explained:

> The sales true-up is measured as the difference between 1) test year base revenues and 2) actual revenues calculated from actual sales and customer counts. In both the test year base revenue calculation and the actual revenue calculation, the revenues were calculated using standard base rates. The company did not include this line item credit rate when calculating the revenues for the sales true-up, and therefore the discounts for these programs were not included in our sales true-up results.[445]

407. Company witness Lisa Peterson[446] testified that the discounts were not recovered through the sales true-up, and provided the following explanation:

> Retained sales that occurred via the Pandemic and Civil Unrest Program were priced out at full tariff rates, and no Pandemic and Civil Unrest credits were included in the actual revenue calculations for the Sales True-up. Therefore, these discounts were not recovered through the Sales True-up process.[447]

408. The Department regarded Xcel's explanation as too general and therefore insufficient.[448] The Department remained opposed to recovery of the BIS Rider Discounts.

409. Based on the evidence in the record and the prior Commission orders, the Company has demonstrated that it provided more than $2 million in discounts to small businesses to assist those customers during the pandemic and periods of civil unrest consistent with prior Commission orders. The Commission provided for the Company to seek recovery of those expenses in this case and not in the sales forecast true-up; the Company provided testimony and additional evidence that it addressed these discounts accordingly. The Commission required Xcel to provide a cost-benefit analysis in this proceeding; the Company provided the required cost-benefit analysis.

410. Ms. Peterson's testimony is credible and, together with the Company's supplemented response to information request 1130, is sufficient to support a conclusion

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[442] Ex. DOC-23, NAC-S-2, at 2 (Campbell Surrebuttal) (Xcel Supp. Response to DOC IR 1130 dated Oct. 18, 2022).
[443] Ex. DOC-23, NAC-S-2 (Campbell Surrebuttal).
[444] Ex. DOC-23, NAC-S-2, at 1 (Campbell Surrebuttal).
[445] Ex. DOC-23, NAC-S-2, at 2 (Campbell Surrebuttal).
[446] Nicholas Paluck's written testimony was sponsored and adopted at the evidentiary hearing by Lisa Peterson. Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 215, lines 21–24 (Peterson).
[447] Ex. Xcel-90 at 11 (Paluck/Peterson Rebuttal).
[448] Ex. DOC-23 at 50–53 (Campbell Surrebuttal).

that the Company did not recover the BIS Rider Discounts through the sales true-up. Accordingly, the reasonableness of Xcel's recovery of these discounts is supported by substantial record evidence. The Department has offered only speculation to contradict Xcel's evidence or to provide support for its theory of potential double recovery.

411. The Judge recommends that the Commission allow recovery of the BIS Rider Discounts.

412. The Department argued in its Initial Brief that the Company did not establish why the costs should be recovered from the classes that benefitted from the discount.[449] However, the Company is not requesting to recover the discount credits from all classes, but rather from the demand classes, as agreed to in the BIS Rider Docket.[450] Accordingly, in any relevant compliance filing in this proceeding, the Company should ensure that the developed revenue requirement and revenue allocation account for recovery of these discounts solely from the demand classes.

14. Other Amortization Expenses: Rate Case Expenses; LED Deferrals; Deferred Pension Expenses

413. With respect to rate case expense, deferred pension expense, and LED street light deferral amortizations, the parties appear to agree that the appropriate amortization period is the term of the MYRP.[451] The Company has indicated it is not seeking to implement an MYRP of longer than three years.[452]

414. Matching the amortization period to the term of the MYRP will ensure the Company will recover its expenses fairly over the period of the MYRP.[453]

415. The Judge recommends that the Commission approve amortization periods for rate case expense, deferred pension expense, and LED street light deferral that match the term of the MYRP approved by the Commission.

15. Luverne Wind2Battery Removal Costs

416. The Luverne Wind2Battery System is a one megawatt (MW) wind energy battery-storage system that was installed in December 2009 in Luverne, Minnesota and was connected to a nearby 11 MW wind farm.[454] It was one of the first utility-scale batteries installed anywhere in the country.[455] The project was an experimental pilot program taken on by the Company to assess the utilization of battery storage in

[449] DOC Initial Br. at 81.
[450] BIS Rider Order at 3 ("Xcel proposes to seek to recover the amount of the credits from other commercial and industrial customers."); *see also* Xcel Energy Reply Br. at Section IV.B.8.
[451] Ex. Xcel-79 at 193 (Halama Direct); Ex. DOC-3 at 32–36 (Soderbeck Direct); Ex. DOC-5 at 3–4 (Soderbeck Surrebuttal); Ex. SRA-3 at 11 (Bride Surrebuttal).
[452] Ex. Xcel-82 at 38 (Halama Rebuttal); Ex. Xcel-23 at 12 (Liberkowski Rebuttal).
[453] Ex. DOC-5 at 3–4 (Soderbeck Surrebuttal).
[454] In 2019, the wind farm was sold to a third party who severed the connection to the battery. Ex. Xcel-37 at 72 (Capra Direct).
[455] Ex. Xcel-37 at 71 (Capra Direct).

conjunction with wind production facilities to store output from the facilities and discharge those batteries to stabilize output.[456]

417. The project was decommissioned in 2019, years after the pilot study had been completed and as the battery was approaching the end of its useful life. The battery's manufacturer informed the Company at that time that the battery was entering legacy status, and they would not be manufacturing replacement parts. The Company explored several options for future use of this asset, but ultimately determined that removal of the battery was the best course of action.[457]

418. The Company has proposed to perform a reserve reallocation to recover the estimated costs for the Luverne Wind2Battery removal project.[458] The Company's proposed reallocation would shift $5.6 million of reserves from the remaining Other Production plants and move it to the battery, then reallocate the reserves back to the groups it came from in a future docket in the event disposal costs turn out to be lower than $5.6 million.[459]

419. The Department and OAG oppose any reserve reallocation or recovery of costs for removal of the Wind2Battery asset. They argue that recovering removal costs from ratepayers following the battery's retirement would result in intergenerational inequities because current ratepayers no longer benefit from the battery.[460] Further, they argue that recovery would be unjust because Xcel had the opportunity to recover estimated removal costs during the battery's useful life and failed to do so.[461]

420. In 2009, when the battery was placed in service, Xcel proposed a net salvage value of 0%, representing that there would be no net disposal costs.[462] Xcel acknowledged that its 2009 estimate was not made with "a strong basis" and stated it expected "to conduct an in-depth review of the Wind2Battery System in our 2010 demolition study."[463] The initial salvage value was based upon the conclusion that "the net cost of disposal would approximate the value of materials recovered from the battery and there would be no material net cost [f]or removal resulting from the end-of-life removal and disposal of the battery."[464]

421. Since that time, the Company performed three comprehensive dismantling studies: 2010, 2015, and 2020.[465] Xcel did not update the salvage value or provide supporting documentation for removal costs following a more in-depth review in either its

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[456] Ex. Xcel-37 at 70-71 (Capra Direct); Ex. Xcel-65 at 39 (Moeller Direct).
[457] Ex. Xcel-37 at 72 (Capra Direct).
[458] Ex. Xcel-65 at 45 (Moeller Direct).
[459] Ex. Xcel-65 at 45-46 (Moeller Direct); Ex. Xcel-39 at 17-19 (Capra Rebuttal).
[460] Ex. OAG-2 at 20 (Lee Direct); Ex. DOC-7 at 4–11 (Skayer Direct); Ex. DOC-8 at 12–18 (Skayer Surrebuttal).
[461] Ex. OAG-2 at 22 (Lee Direct); Ex. DOC-7 at 8 (Skayer Direct); Ex. DOC-8 at 12–15 (Skayer Surrebuttal).
[462] *See* Ex. DOC-7 at 5 (Skayer Direct).
[463] *In re N. States Power Co. d/b/a Xcel Energy Pet. for Annual Review of Remaining Lives, Depreciation, for Elec. and Gas Storage for 2009,* E,G-002/D-09-160, PETITION at 7, 8 (Feb. 17, 2009) (eDockets No. 5771187).
[464] Ex. Xcel-66 at 42 (Moeller Direct).
[465] Ex. Xcel-66 at 42 (Moeller Direct).

2010 its 2015 dismantling studies.[466] The 2010 dismantling study was completed in December 2009, the same month the Wind2Battery project went into service.[467]

422. The Company excluded the battery from its 2015 dismantling study because Xcel maintained the same assumption that disposal cost and salvage from recycling would offset one another, and it considered the cost of estimating the net salvage value was too large relative to the battery's value.[468]

423. The Company provided no updated estimates for dismantling the Wind2Battery during its in-service life.[469]

424. When the battery's vendor told Xcel that it would no longer be servicing the battery in 2018, Xcel did not update its decommissioning cost estimate or complete a dismantling study.[470] Xcel stated that it only "began investigating removal cost once it learned that the battery was entering legacy status."[471]

425. The Company's 2020 Remaining Lives and Depreciation Study updated the net salvage value to -135.6%.[472]

426. Eleven years after the battery was placed into service, Xcel sought recovery of decommissioning costs through a reserve reallocation in its 2020 remaining lives docket.[473] However, Xcel did not provide a dismantling study to support its $5.6 million estimation.[474] Instead, it stated that its $5.6 million estimate was based on a manufacturer's representation.[475] Xcel's witness acknowledged that this figure relied on "preliminary discussions with vendors which represented a significant amount of uncertainty."[476]

427. The Commission determined that the issue should be resolved in this rate case,[477] seeking "[d]evelopment of a fuller record" on the reallocation of a reserve balance "including on the prudence of costs [to] facilitate a clearer understanding of the Company's claimed costs and the steps it took to manage them."[478]

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[466] Ex. Xcel-66 at 42 (Moeller Direct); Ex. DOC-7 at 8 (Skayer Direct); Ex. OAG-2 at 23 (Lee Direct).
[467] Ex. Xcel-66 at 42 (Moeller Direct).
[468] Ex. Xcel-66 at 42 (Moeller Direct).
[469] Ex. DOC-7 at 8 (Skayer Direct).
[470] Ex. DOC-7 at 8 (Skayer Direct).
[471] Ex. Xcel-67 at 13 (Moeller Rebuttal).
[472] *In re Pet. of N. States Power Co. for Approval of Its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study*, MPUC Docket No. E,G-002/M-19-723, PETITION, Attachment A at 7 (Aug. 18, 2020) (eDockets No. 20208-165992-01). *In re Pet. of N. States Power Co. for Approval of Its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study*, MPUC Docket No. E,G-002/M-19-723, Order Approving Petition in Part at 3 (Sept. 2, 2021) (eDockets No. 20219-177671-01).
[473] *See, generally, In re Pet. of N. States Power Co. for Approval of Its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study*, MPUC Docket No. E,G-002/M-19-723.
[474] Ex. Xcel-65 at 43 (Moeller Direct).
[475] *See* Ex. Xcel-66 at 41 (Moeller Direct); Ex. Xcel-68 at 13 (Moeller Rebuttal).
[476] Ex. Xcel-39 at 19 (Capra Rebuttal).
[477] Wind2Battery Rate Case Referral Order at 2 (eDockets No. 20219-177671-01).
[478] *Id*. at 4.

428. In Rebuttal Testimony filed in October 2022, Xcel submitted a dismantling cost study.[479] But Xcel proposed that the results of the study do not modify its $5.6 million reserve reallocation request.[480]

429. The dismantling cost study is a technical memorandum from an engineering firm prepared in October 2022.[481] The firm estimated that the "expected total" for decommissioning Wind2Battery was $2.14 million.[482] The firm also provided an upper bound range, that it described as the "worst case," of $5.26 million. The upper bound range "assumes that there is some damage or leakage of the batteries requiring special handling prior to transport and that there is an increase in the recycling cost."[483] The breakdown of costs also shows that the upper bound costs assumes increased bonds/insurance (+$30,000), "Owners Costs" (+$80,000), and contingency (+$1.14 million).[484]

430. Depreciation expense, including estimated removal costs, is normally collected while an asset is in service. This practice ensures that, if there are removal costs, they are collected from the same ratepayers that benefit from the asset.[485]

431. Conversely, recovering removal costs after an asset's retirement is contrary to standard depreciation practices and would create intergenerational inequities by burdening ratepayers who did not benefit from the asset when it was in service.[486]

432. The Company explained that it worked with the initial vendor to establish a dismantling estimate of $0 due to assumptions about the salvage value of the components of the battery.[487]

433. With respect to intergenerational inequities, the Company argued that the concern ignores the findings of the Commission and the Company's Renewal Development Fund report that demonstrate the project's research value. Company witness Mr. Capra explained that these benefits were the purpose of the pilot program, and that current customers receive benefits from the research.[488]

434. The Company has not met its burden to establish the reasonableness of a reserve reallocation of $5.6 million for decommissioning the Luverne Wind2Battery System. The dismantling cost study provided by the Company establishes that the "probable" cost is expected to be $2.14 million, with a possible "worst case" upper bound

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[479] Ex. Xcel-39, RAC-R-2 (Capra Rebuttal).
[480] Ex. Xcel-67 at 16 (Moeller Rebuttal); Ex. Xcel-39 at 19 (Capra Rebuttal).
[481] Ex. Xcel-39, RAC-R-2 (Capra Rebuttal).
[482] The expected total assumes the batteries are intact and are not damaged or leak prior to transport but assumes a $360,000 contingency. See Ex. Xcel-39, RAC-R-2 at 2 (Capra Rebuttal).
[483] Ex. Xcel-39, RAC-2 at 2 (Capra Rebuttal).
[484] Ex. Xcel-39, RAC-2 at 2 (Capra Rebuttal).
[485] Ex. OAG-2 at 20 (Lee Direct).
[486] Ex. OAG-2 at 20 (Lee Direct).
[487] Ex. Xcel-67 at 12 (Moeller Rebuttal).
[488] Ex. Xcel-37 at 71 (Capra Direct); See Ex. Xcel-67 at 10-11 (Moeller Rebuttal); Ex. Xcel-65 at 40-41 (Moeller Direct).

of $5.26 million. Neither the Department nor the OAG meaningfully challenge the dismantling cost study's cost estimate.

435. The Company has met its burden to demonstrate that $2.14 million is a reasonable cost to dismantle the system. The actual cost may exceed that amount, but the prudence of any amount above the dismantling cost study's "expected total" has not been established here. Exceeding the expected total could occur if there is damage or leakage of the batteries, and there is no way to determine on this record, in advance, if such damage or leakage, should it occur, might be the result of imprudence. The "upper bound total" in the dismantling cost study also includes unexplained departures from assumptions in the "expected total," such as a doubled percentage reserved for contingency.

436. However, the Company has not met its burden to establish that it would be reasonable to recover removal costs from ratepayers. The Department and the OAG have established that Xcel failed to update the system's salvage value once during the course of its ten-year useful life. Xcel has an obligation to provide the Commission with five-year updates on salvage rates.[489]

437. The Company argued that its initial, incorrect dismantling estimate of $0 was reasonable based, in part on the novelty of the technology involved in the project.[490] The project's novelty—and status as a pilot—should have prompted Xcel to be *more* diligent about evaluating, revisiting early assumptions, and revising the salvage costs of the project during its useful life. Instead, the Company skipped a 2015 reassessment and relied on assumptions it had made when first placing the new, experimental technology into service.

438. Xcel has not provided an adequate justification for not acting sooner to estimate and recover removal costs. Xcel's failure to confirm the reasonableness of its 2009 assumptions in 2015 undermines its position that this experimental pilot offered learning opportunities for the industry and the public that now justify continued recovery.

439. Xcel's argument that the pilot's research benefit to ratepayers justifies recovering the removal costs from ratepayers is unpersuasive. The rationale is unsupported by typical ratemaking principles or generally accepted utility accounting practice, which strive to provide for recovery for depreciation of utility property while it is "used and useful in rendering service to the public."[491] The Luverne Wind2Battery System, as utility property, is no longer used or useful in rendering service. The insights gained from the pilot are distinct from the asset, have not been quantified, and do not justify ongoing recovery for the asset from ratepayers.

[489] Minn. R. 7825.0700 (2021).
[490] Ex. Xcel-67 at 12 (Moeller Rebuttal).
[491] Minn. Stat. § 216B.16, subd. 6.

440. The Judge recommends that the Commission disallow the requested reserve allocation for the Luverne Wind2Battery removal project, and adopt the Department's proposed adjustment to Xcel's revenue requirement as follows:

2022	2023	2024	2025	2026
$(217,000)	$(182,000)	$(156,000)	$(142,000)	$(121,000)

441. The Judge also recommends that the Commission adopt the OAG's recommendation to disallow the associated depreciation expense of $300,000 (MN jurisdiction) in the 2022 test year and amounts to be identified by the Company in the 2023 and 2024 plan years.[492]

442. Alternatively, should the Commission disagree and find that it is reasonable to allow the proposed reserve reallocation, the Judge believes it would be appropriate to authorize a reserve reallocation of $2.14 million and require the Company to perform the proposed "inverse reverse allocation" of reallocated amounts if actual costs are lower than the amount reallocated.

16. Beginning of Year Test Year Plant Balance

443. The term "rate base" generally refers to capital expenditures for plant, equipment, etc. reduced by amounts recovered from depreciation and accumulated deferred income taxes (ADIT).[493] Because rate base fluctuates as new investments are made, and older investments fully depreciate or stop being "used and useful," the average of the beginning of year (BOY) and end of year (EOY) balance is used for each test year.[494] For the MYRP, the EOY for 2022, becomes the BOY for 2023, and so on.[495]

444. Because this case was filed in early November of 2021, the actual end of year balance for 2021/beginning of year balance for 2022 was not yet known. This estimate was ultimately approximately $42 million more than the actual 2022 BOY test year rate base.[496]

445. Company's actual beginning of year plant balance for 2022 was $9,835,166,100 compared to the Company's anticipated beginning balance of $9,877,494,000 (a difference of approximately 0.4%).[497]

[492] Ex. OAG-9 at 36 (Lee Surrebuttal).
[493] Ex. Xcel-79 at 30–31 (Halama Direct).
[494] *See* Ex. Xcel-79 at 31–33 (Halama Direct).
[495] Ex. Xcel-79 at 33–34 (Halama Direct).
[496] Ex. DOC-3 at 43, HS-D-20 at 4 (Soderbeck Direct).
[497] Ex. DOC-3 at Schedule HS-D-20, p. 1-2 and 5 (Soderbeck Direct); Ex. DOC-5 at Schedule HS-S-8 (Soderbeck Surrebuttal). As indicated in the cited schedules, these beginning and end of year net plant balances exclude Other Rate Base, which (as noted above) consists primarily of secondary calculations such as Cash Working Capital that would be updated based on the overall determinations of the Commission. The parties' total average rate base proposals include Other Rate Base; thus, the average

446. Relying on the actual information available for the beginning of the test year, the Department recommended updating the 2022 BOY test year rate base to match the actual 2022 amount.[498] The Department recommendation incorporated the resulting changes in CWIP, ADIT, and net plant balances.[499]

447. As of mid-year, Xcel's updated forecast for EOY balance remained below the original forecast.[500] Xcel's EOY test year rate base would need to exceed its original forecast for the underachievement of BOY rate base to be offset by averaging.

448. Updating the BOY test year rate base to account for actual rate base when available is consistent with past Commission decisions and guiding principles.[501] Until recently, utilities generally agreed to update BOY rate base balance to actuals and the update was incorporated into the Commission's determination as a resolved issue.[502]

449. Using actual, accurate data is preferable to estimates for BOY rate base and Xcel has not shown that its EOY rate base will exceed its initial forecast and offset the under-forecast of its BOY rate base.

450. The Judge recommends that the Commission adopt the Department's recommendation to adjust the 2022 beginning of year rate base to reflect actual amounts, and the corresponding adjustment to the revenue requirement, as follows:

2022	**2023**	**2024**	**2025**	**2026**
$(2,005,000)	--	--	--	--

17. Construction Work in Progress (CWIP)

451. Xcel's proposed rate base includes the following "major items:"[503]

- Net Utility Plant;
- Construction Work in Progress (CWIP);
- Accumulated Deferred Income Taxes (ADIT);
- Pre-Funded Allowance for Funds Used During Construction (AFUDC); and

net plant balance data will be smaller than the total average rate base under either the Company's or Department's proposal.

[498] Ex. DOC-3 at 43 (Soderbeck Direct).

[499] Ex. DOC-3 at 45 (Soderbeck Direct).

[500] Ex. DOC-5 at 27 (Soderbeck Surrebuttal) (corrected).

[501] *See* CenterPoint 2015 Rate Case Order at 17-18; *In re Pet. Interstate Power Co. for Auth. to Change Certain of its Elec. Rate for Retail Cust. in the State of Minn.*, MPUC Docket No. E-001/GR-78-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 11 (Sept. 27, 1979) (finding that test year should reflect a cost change that is "known and measurable;" and that "[t]here is no dispute as to the certainty and magnitude of the change").

[502] *See* MERC 2017 Rate Case Order at 30–31; Great Plains 2019 Rate Case Order at 33.

[503] Ex. Xcel-79 at 31 (Halama Direct).

- Other Rate Base.

452. The Commercial Group recommended not allowing inclusion of the Company's construction work in progress (CWIP) in the Company's rate base. Commercial Group witness Steve Chriss claimed that inclusion of CWIP in rate base charges customers for assets not yet placed in service, thereby shifting risk from shareholders to customers. Alternatively, Mr. Chriss recommends that if CWIP remains in rate base, then the Company's ROE should be accordingly decreased.[504]

453. No other party opposed including CWIP in the Company's rate base.

454. The Commercial Group did not offer evidentiary support for any particular ROE adjustment.[505]

455. The Commission is required to give due consideration to construction work in progress when determining a utility's rate base.[506] The Commission has historically allowed CWIP to be included in rate base.[507]

456. Under Xcel's proposal, CWIP is included with an offset to the calculated return on rate base by including the Allowance for Funds Used During Construction (AFUDC) amount as a reduction to the revenue requirement. This offset negates the return-on-rate-base impact of CWIP.[508]

457. Additionally, the cost of short-term debt is included in the calculation of the return on rate base. Removing CWIP from the rate base without a corresponding adjustment to AFUDC and the inclusion of short-term debt from the overall return calculation would result in an imbalance and would not reasonably allow for the Commission to give due consideration to construction work in progress as required by statute.

458. The inclusion of AFUDC as an offset, and the cost of short-term debt in the overall rate of return calculation avoids inappropriately placing costs on, or shifting risks to, ratepayers.[509]

459. For these reasons, the Judge recommends that the Commission approve the inclusion of CWIP in the Company's rate base and not adopt the Commercial Group's proposal to adjust the Company's return on equity based upon CWIP's inclusion.

18. Fault Location Isolation and Service Restoration (FLISR)

460. Fault Location, Isolation, and Service Restoration (FLISR) is a form of distribution automation that involves deployment of automated switching devices that

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504 Ex. CG-1 at 9-11 (Chriss Direct).
505 Ex. Xcel-26 at 12 (Johnson Rebuttal).
506 Minn. Stat. § 216B.16, subd. 6.
507 Ex. Xcel-67 at 20 (Moeller Rebuttal).
508 *Id*.
509 Ex. Xcel-26 at 12 (Johnson Rebuttal).

work to detect feeder mainline faults, isolate them, and restore power to un-faulted sections – decreasing the duration and number of customers affected by any individual outage.[510] FLISR's purpose is to use automation to more quickly restore customer service following an outage.[511]

461. Xcel states that FLISR will provide reliability improvements for customers. According to the Company, FLISR will allow it to reduce the number of customers that experience sustained outages, shorten the duration of sustained outages, and more efficiently restore power to customers.[512] Specifically, Xcel estimates that the number of customers who experience a sustained outage because of a fault can be reduced by two-thirds.[513]

462. Between 2022 and 2024, Xcel proposes to add about $19 million capital costs to its rate base and incur about $1 million in related O&M costs to install FLISR on approximately 208 feeders in Minnesota.[514]

2022-2024 FLISR Costs[515]

	2022	2023	2024
Capital	$3,400,000	$7,800,000	$7,800,000
O&M	$300,000	$300,000	$400,000
Total	$3,700,000	$8,100,000	$8,200,000

i. Xcel's FLISR Cost-Benefit Analysis

463. As directed,[516] Xcel performed a cost-benefit analysis to evaluate whether FLISR will produce net benefits for Minnesota ratepayers.[517] Cost-benefit analysis is a systematic approach for assessing the cost-effectiveness of proposed spending.[518] Xcel's

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[510] Ex. Xcel-40 at 100 (Bloch/Mensen Direct).
[511] Ex. Xcel-40 at 100–101 (Bloch/Mensen Direct); Ex. DOC-12 at 32–33 (Havumaki Direct).
[512] Ex. Xcel-40 at 103 (Bloch/Mensen Direct).
[513] Ex. Xcel-40 at 102–103 (Bloch/Mensen Direct).
[514] Ex. Xcel-40 at 102 (Bloch/Mensen Direct).
[515] Ex. Xcel-40, KAB-D-4 (Bloch/Mensen Direct); Ex. Xcel-40 at 138 (Bloch/Mensen Direct).
[516] *See In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor*, Docket No. E002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019) at 11, 14 (requiring a cost benefit analysis for Advanced Grid Intelligence and Security (AGIS) investments.
[517] Ex. Xcel-40 at 100 (Bloch/Mensen Direct).
[518] Tr. Vol. 1 at 133–34 (Quirk).

cost-benefit analysis quantified the reliability benefits of deploying FLISR on 208 feeders as compared to the cost of this deployment.[519]

464. The Company identified and analyzed benefits and costs, as follows:

i. *Benefits.* To calculate benefits of FLISR deployment, Xcel estimated "the improvement in customer restoration times from our FLISR proposal in the form of reduced customer minutes out (CMO)."[520] Xcel multiplied this estimate by the value of these outage minutes according to the Lawrence Berkeley National Lab Interruption Cost Estimate (ICE) calculator.[521] The Berkeley Lab's methodology involved a meta-analysis of customer value of service studies and a two-part regression model to estimate "customer interruption costs per event by season, time of day, day of week, and geographical regions within the U.S. for industrial, commercial, and residential customers."[522]

ii. *Costs.* Xcel's benefit-cost analysis estimates the total net present value of FLISR costs through 2041.[523] This figure includes FLISR asset costs (specifically asset cost, installation, project management, and vendor), distribution communication, and ADMS FLISR integration and testing. It also contains O&M costs corresponding to deployment and ongoing support and communications, including project management, vendor, and network communication costs.

iii. *Results.* Based on the expected benefits and costs, Xcel estimated that benefits will likely exceed the costs.[524]

465. The Department concluded that Xcel's benefit-cost analysis was reasonable because it relied on sound assumptions and methodologies.[525] The Company's analysis produced a narrow range of benefit-cost ratio results that suggest that Xcel's FLISR program is likely to produce net benefits.[526]

466. CEO argued that Xcel's cost-benefit analysis includes outlier data with multiple major storms, resulting in an inflated estimate of FLISR benefits.[527] They argued that the Commission should order Xcel to perform a revised cost-benefit analysis that

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[519] Ex. Xcel-42, Sch. 4 (Bloch/Mensen Direct); Ex. DOC-12, Sched. BH-D-5 (Havumaki Direct).
[520] Ex. DOC-12, BH-D-4 (Havumaki Direct) (DOC IR No. 49).
[521] Ex. DOC-12, BH-D-5 (Havumaki Direct) (DOC IR No. 29).
[522] Michael J. Sullivan et al, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States* at 15, LAWRENCE BERKELEY NATIONAL LABORATORY (Jan. 2015), *available at* https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf [hereinafter *Berkeley Nat'l Lab. Report*].
[523] Ex. Xcel-40, KAB-D-4 (Bloch/Mensen Direct).
[524] Ex. Xcel-40 at 109 (Bloch/Mensen Direct).
[525] *See* Ex. DOC-12 & 13 at 18–21 (Havumaki Direct) (discussing Xcel's cost-benefit analysis).
[526] Ex. DOC-12 & 13 at 20 (Havumaki Direct).
[527] Ex. CEO-3 at 15 (Volkmann Direct).

excludes the June 2013 data as an outlier, and cap FLISR recovery at the value of benefits in the revised CBA.[528]

467. The Company argues that all outage data, including data from the June 2013 storm event and other major storms, should be included in the cost-benefit analysis to have a complete view of the reliability benefits of FLISR.[529] While the outage restoration benefits of FLISR may be reduced during major storm events depending on the extent of the damage, FLISR may still provide benefits such as fault location identification.[530]

468. Xcel's cost-benefit analysis is reasonable. It relies on sound assumptions and methodologies, and the inclusion of 2013 data has not been shown to unreasonably inflate the benefit of FLISR investments. The number of extreme weather events has been increasing in recent years.[531] It is appropriate to include the June 2013 major storm in the FLISR cost-benefit analysis since there is insufficient evidence to assume that FLISR would not have provided reliability improvements to customers during that event or other future major storm events.

469. The Judge recommends that the Commission find Xcel's FLISR cost-benefit analysis reasonable and not adopt the CEO's FLISR-related proposals.

ii. The Department's Recommended FLISR Proposal Modifications

470. The Department supports the Company's request to recover the costs for FLISR for 2022–2024 subject to three modifications: (1) 97% of the costs should be allocated to the Commercial and Industrial class of customers with the remaining 3% allocated to the Residential class;[532] (2) the Company be required to report on certain reliability performance metrics and that cost recovery should be partly contingent on achievement of performance targets;[533] and, (3) the Company prioritize deployment of FLISR based on the cost-effectiveness of each circuit.[534]

471. One issue related to FLISR was resolved between Xcel and the Department through testimony and briefing. The Department initially recommended that Xcel prioritize FLISR deployment to feeders "where it is most cost-effective, i.e., where it will deliver the greatest . . . benefits for the money spent on it."[535] Xcel responded that it agreed cost-effectiveness was an important consideration but should not be the sole consideration.[536] The company explained because "FLISR functions in groups . . . there will be situations where it is deployed on a group of feeders that have had a higher number of mainline

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[528] CEO's Initial Brief at 2.
[529] Ex. Xcel-43 at 39 (Mensen Rebuttal).
[530] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 56 (Volkmann).
[531] Ex. Xcel-43 at 9, 39 (Mensen Rebuttal).
[532] Ex. DOC-12 at 24-25 (Havumaki Direct).
[533] Ex. DOC-12 at 24-25 (Havumaki Direct).
[534] Ex. DOC-12 at 40 (Havumaki Direct).
[535] Ex. DOC-12 at 26 (Havumaki Direct).
[536] Ex. Xcel-43 at 37 (Mensen Rebuttal).

feeder outages with feeders that have had a lower number of mainline feeder outages."[537] Given this explanation based on the nature of the equipment involved, the Department no longer pursued this recommendation in surrebuttal or briefing.[538]

472. Xcel proposed to recover FLISR costs based on the following allocation:

Estimated Cost Allocation Through Base Rates[539]

Year	Residential	SCI Non-Demand	Demand	Lighting
2022	65.8%	5.2%	27.9%	1.1%
2023	68.5%	5.1%	25.2%	1.2%
2024	70.7%	5.1%	23.2%	0.9%

473. The Department argued that the economic cost of outages, and thus the benefit of reducing outages, overwhelmingly benefits demand classes relative to residential customers.[540] The Department noted, according to the Berkeley Lab, "on both an absolute and normalized basis, residential customers experience the lowest costs as a result of power interruption."[541] The cost of a one-hour outage for a residential customer in the United States is around $5, versus nearly $18,000 per hour for a medium or large commercial-industrial customer.[542] Using Berkeley Lab's Interruption Cost Estimate calculator, with adjusted inputs to match Xcel Minnesota's recorded system average interruption duration and frequency indices in 2020,[543] the Department calculated company-specific results that showed on a weighted average basis, residential customers represent about 2.5% of the total cost per outage.[544]

474. The Company disagreed with the Department's recommendation to allocate 97% of the costs of FLISR to the Commercial and Industrial class. The Company noted that FLISR is a reliability program that aims to improve the reliability for all customer classes and to deliver those benefits as widely as possible.[545] Company witness Christopher Barthol testified that current cost allocation methods are based on cost causation and that there are no established ratemaking methods to allocate utility costs based on benefits as recommended by the Department.[546] Mr. Barthol also testified that it would be impractical to allocate FLISR costs based on benefits given that FLISR

[537] Ex. Xcel-43 at 38 (Mensen Rebuttal).
[538] *See generally* Ex. DOC-14 (Havumaki Surrebuttal); DOC Initial Br. at 96–98; DOC Reply Br. at 19–21.
[539] Ex. DOC-12, BH-D-6 at 3 (Havumaki Direct) (DOC IR No. 35) (Table 4).
[540] Ex. DOC-12 at 21 (Havumaki Direct).
[541] *Berkeley Nat'l Lab. Report* at xii.
[542] Ex. DOC-12 at 22 (Havumaki Direct).
[543] These indices are commonly known and referred to in the record as SAIDI and SAIFI.
[544] Ex. DOC-12 at 22–23 (Havumaki Direct).
[545] Ex. Xcel-43 at 35 (Mensen Rebuttal).
[546] Ex. Xcel-87 at 25 (Barthol Rebuttal).

involves many different types of distribution equipment (switches, reclosers, sensors, relays).[547]

475. The Department disagreed with Xcel's view of cost allocation principles as applied to FLISR cost recovery. The Department noted that the Regulatory Assistance Project's Electric Cost Allocation Manual, for example, explains that a "costs follow benefits" approach is "usually, but not always, the superior principle" for cost allocation.[548] The Department argued that because FLISR costs would be incurred ostensibly to attain the expected benefits, and the benefits identified by Xcel primarily accrue to commercial and industrial customers, the costs should be primarily allocated to the demand classes.[549] The Department's witness stated that if the Department's proposed allocation were not approved, his alternative recommendation would be to deny recovery of the costs.[550]

476. The Department further supported its recommendation based on its determination that the FLISR investment is "entirely elective. It is not needed for the safe, reliable delivery of electricity."[551]

477. The Judge agrees with Xcel that it would represent a "significant shift"[552] in the fundamental practice of ratemaking to adopt the Department's proposal to carve out a specific distribution investment and to allocate its cost based on benefits—rather than apply standard ratemaking principles to establish a comprehensive rate design based upon the utility's entire revenue requirement and in light of all of the "many countervailing" relevant rate design considerations, including cost causation.[553] The rate-making process as it has been applied by the Commission has a long track record and is well established as resulting in fair and reasonable rates across customer classes. Even if it were assumed the Department's proposal would result in just and reasonable rates, adopting the proposal could significantly compound the complexity of future rate cases and future rate designs. It is unclear what principle would govern whether an investment cost would be allocated based on an untested economic benefits analysis rather than asset functionalization. The record lacks adequate support to determine that a departure of traditional ratemaking practice would be reasonable.

478. In addition, the Department's argument that a unique treatment of FLISR cost allocation is warranted because the FLISR investment is not needed is unavailing. The Department's argument is unpersuasive in part because Xcel has established that its proposed FLISR investment would result in a net benefit—which the Department does not dispute—and in part because the Department's own alternative analysis and

[547] Ex. Xcel-87 at 25 (Barthol Rebuttal).
[548] Ex. DOC-14, BH-S-1 at 3 (Havumaki Surrebuttal) (Jim Lazar et al, Electric Cost Allocation for a New Era: A Manual 18 (2020), www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf).
[549] Ex. DOC-12 at 24–25 (Havumaki Direct); Ex. DOC-14 at 4–5 (Havumaki Surrebuttal).
[550] Ex. DOC-14 at 5 (Havumaki Surrebuttal).
[551] Ex. DOC-14 at 4 (Havumaki Surrebuttal).
[552] Ex. Xcel-87 at 25 (Barthol Rebuttal).
[553] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).

proposed cost allocation depends in part on SAIDI and SAIFI, which are reliability measures. The FLISR investment provides a net benefit because it is expected to improve reliability.

479. Xcel has met its burden to establish that it would be just and reasonable to allocate FLISR cost recovery based upon the investments' functionalization as distribution assets. The Department has not shown that it would be reasonable to apply its proposed allocation.

480. With respect to reporting, the Department recommended that the Commission require the Company to track and report on reliability performance for circuits equipped with FLISR and compare those results with the average reliability data from the previous eight-year period before FLISR was installed.[554] The Department recommends that the Company should report System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) metrics on an annual basis.[555] The Department also recommends that the Company report on any differences between forecasted costs and actuals for FLISR.[556]

481. The Company contended that additional reporting on FLISR would be duplicative of other reporting and premature to require. Xcel has committed to continue to report on reliability metrics as part of the Company's Annual Service Quality Reports and to continue to provide reliability information in the Company's Performance-Based Ratemaking reports (Docket No. 13 E002/CI-17-401).[557] The Company also stated that it will continue to report on FLISR costs, comparing forecasts to actuals, in the Company's Integrated Distribution Plan (IDP) filings.[558]

482. The Department disagreed that its reporting recommendations would be duplicative or unhelpful to the Commission and stakeholders. The Department argued that its recommendations would, in fact, amount to a modest modification of the company's existing reporting obligations in Docket No. E002/M-20-406, where the company is required to annually compare its SAIDI, SAIFI, CAIDI, and MAIFI reliability results "for feeders with grid modernization investments such as Advanced Metering Infrastructure or Fault Location Isolation and Service Restoration to the historic five-year average reliability for the same feeders before grid modernization investments."[559]

483. The Department has established that it would be reasonable to modify Xcel's reporting requirements. Given that the reporting is largely an extension of Xcel's current obligations, it should not be unduly burdensome. The information, moreover, may

[554] Ex. DOC-12 at 31 (Havumaki Direct).
[555] Ex. DOC-14 at 5-8 (Havumaki Surrebuttal).
[556] Ex. DOC-12 at 31 (Havumaki Direct).
[557] Ex. Xcel-43 at 42 (Mensen Rebuttal).
[558] Ex. Xcel-43 at 42 (Mensen Rebuttal).
[559] Ex. DOC-14 at 7–8 (Havumaki Surrebuttal); *In re Xcel Energy's Annual Report on Safety, Reliability, and Service Quality for 2019; and Petition for Approval of Electric Reliability Standards for 2020*, Docket No. E-002/M-20-406, ORDER ACCEPTING REPORTS, REQUIRING ADDITIONAL FILINGS, & ESTABLISHING WORKSHOPS at 4 (Dec. 18, 2020) (eDockets No. 202012-169158-02).

help inform the Commission, stakeholders, and the Company of the efficacy of grid modernization spending going forward.

484. Based upon these findings, the Judge recommends that the Commission approve Xcel's proposed recovery of FLISR costs based upon the investments' functionalization as distribution assets, not adopt the Department's alternative cost allocation proposal, and adopt the Department's proposed FLISR reporting requirements.

485. The agreement between the Company and the Department concerning FLISR deployment is reasonable and should be adopted.

19. Other Distribution Capital Additions

486. CEO and JSC each objected to cost recovery for categories of distribution-asset capital additions. Their objections concerned these categories: Asset Health and Reliability, the Cable Replacement Program, and the Grid Reinforcement Program. Each of these issues is addressed below.

20. Asset Health and Reliability

487. Asset Health and Reliability is Distribution's largest capital budget category. Generally, this budget category includes programs and projects that to address the age and condition of the Company's distribution facilities.[560] Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment including transformers and breakers that have reached the end of their lives.[561] This budget category also captures replacements due to storms and public damage.[562]

488. Xcel's proposed capital investment for Asset Health and Reliability is $554.5 million in 2022–2024.[563]

489. CEO noted that Xcel's proposed AH&R budget had significantly increased from previous years. The CEOs recommended that the Company be required to develop a cost-benefit analysis for its planned Asset Health and Reliability investments and that the Company's investments be capped at the expected level of benefits.[564]

490. The Company is required to comply with Commission orders; the Company's investments in one of its Asset Health and Reliability programs—the Company's Community Solar Garden (CSG) Recloser program—is in response to a

[560] Ex. Xcel-40 at 37 (Bloch/Mensen Direct).
[561] Ex. Xcel-40 at 14 (Bloch/Mensen Direct).
[562] Ex. Xcel-40 at 14 (Bloch/Mensen Direct).
[563] Ex. CEO-3 at 5 (Volkmann Direct).
[564] Ex. CEO-3 at 7 (Volkmann Direct).

Commission order.[565] The CEOs clarified that they only sought cost-benefit analyses for discretionary spending.[566]

491. The CEOs describe Asset Health and Reliability spending as "discretionary" because Xcel can decide "when, where and how much to spend in this category."[567]

492. Disputing the characterization of this category as "discretionary" spending, Company witness Marty Mensen stated that most of the Company's Asset Health and Reliability investments address aging assets and assets in poor condition. Without replacements, the system would be at greater risk for outage events due to equipment failures.[568] The Company acknowledged that it has "some flexibility" with respect to replacement timing for end-of-life assets that haven't yet failed.[569]

493. The Company's witness explained that the increased investment in this category over previous years is a result of the age and condition of key assets, including transformers that are already past their anticipated service life.[570]

494. As a public utility, Xcel has an obligation to provide reliable electric service to its customers, even if the costs of those investments exceed their quantifiable financial benefits.[571] Additionally, assigning monetary values to certain types of benefits can be difficult as such benefits may not be quantifiable.[572]

495. The Company provided testimony that, even though a cost-benefit analysis would not be an appropriate way to determine the investments levels for the Asset Health and Reliability category, the Company has a thorough budgeting process for each program that ensures the proper level of investments within its Asset Health and Reliability budget category.[573] Xcel's budgeting process includes consideration for the age and condition of end-of-life assets to be proactively replaced before they fail, as well as forecasting the need for replacements required as a result of unanticipated failure or damage, including storm damage.[574]

496. The Company also provided testimony that requiring cost-benefit analyses for these kinds of investments would be impractical and costly. The Company stated that the Asset Health and Reliability is the Distribution area's largest budget category and includes over a hundred different subprograms and projects during the MYRP.[575]

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[565] Ex. Xcel-40 at 62-63 (Bloch/Mensen Direct) ("This is a new program in response to the Commission's May 26, 2021 Order requiring the Company to propose a plan to reduce the frequency and duration of planned outages that require CSGs to be disconnected from the system . . . .").
[566] CEO Initial Brief at 31 n. 125.
[567] Ex. CEO-3 at 6 (Volkmann Direct).
[568] Ex. Xcel-43 at 3 (Mensen Rebuttal).
[569] Id at 3–4.
[570] Ex. Xcel-43 at 8 (Mensen Rebuttal).
[571] Ex. Xcel-43 at 5-6 (Mensen Rebuttal).
[572] Ex. Xcel-43 at 6 (Mensen Rebuttal).
[573] Ex. Xcel-40 at 17-20; 37-79 (Bloch/Mensen Direct); Ex. Xcel-43 at 7 (Mensen Rebuttal).
[574] Ex. Xcel-40 at 18 (Bloch/Mensen Direct).
[575] *See* Ex. Xcel-40, Sched. 2 (Bloch/Mensen Direct).

497. For these reasons, Xcel has demonstrated that its budgeting process for Asset Health and Reliability expenditures is reasonable and that it would not be reasonable to require that Asset Health and Reliability investments be justified on the basis of a cost-benefit analysis.

498. The Judge recommends that the Commission approve Xcel's Asset Health and Reliability costs and not adopt the recommendation of the CEOs to require cost-benefit analyses for this category of costs.

21. Cable Replacement Program

499. The Company is seeking recovery of capital additions of $32.7 million in 2022, $34.3 million in 2023, and $35.4 million in 2024 for its cable replacement program.[576] The Company developed its cable replacement budget based on historical failure/fault rates for both mainline and underground residential distribution (URD) cable.[577]

500. Within its Asset Health & Reliability Program, Xcel's cable replacement program "replaces cable that is either damaged beyond repair or that has failed more than once in a two year period."[578] The largest portion of its program budget is for "reactive cable replacement," that is, "replacing cable after it has already failed," and is based on historical failure/fault rates.[579] Xcel's budget also includes "additional funds to make proactive cable replacements for both mainline and URD . . . cable more achievable in years when failure rates are lower than projected."[580] As Xcel explained, "if reactive failures are lower than forecasted, the Company utilizes the remaining budget to perform proactive replacements of cable that has a history of poor reliability."[581]

501. The Minnesota portion of the NSPM distribution system has over 1,600 miles of underground mainline cable and over 8,600 miles of URD cable.[582] Mainline cable is typically larger, multi-phase cable that originates from the substation and that then supplies the Company's smaller cable feeder system.[583] URD cable is smaller cable that is constructed in a loop arrangement, segmented by distribution transformers, to serve individual customers.[584]

502. The cable replacement program replaces both mainline and URD cable that is either damaged beyond repair or has failed more than once in a two-year period.[585]

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576 Ex. Xcel-40 at 49 (Bloch/Mensen Direct).
577 Ex. Xcel-40 at 48 (Bloch/Mensen Direct).
578 Ex. Xcel-40 at 47 (Bloch/Mensen Direct).
579 *Id*. at 48.
580 *Id*. at 47.
581 *Id*. at 53.
582 Ex. Xcel-40 at 46 (Bloch/Mensen Direct).
583 Ex. Xcel-40 at 46-47 (Bloch/Mensen Direct).
584 Ex. Xcel-40 at 47 (Bloch/Mensen Direct).
585 Ex. Xcel-40 at 47 (Bloch/Mensen Direct).

503. Cable failures are a main contributor to outages for customers who are served by underground facilities and accounted for approximately 65% of the CMO on the Company's underground system from 2016 to 2020.[586]

504. The Company acknowledges that its cable replacement program budgets for 2022–2024 are higher than prior years' budgets. According to Xcel, there are four primary reasons: (1) a rise in cable failures in 2019 and 2020, (2) a transition to conduit construction for mainline cable replacements, (3) inflationary increases in labor and materials, and (4) funding to replace mainline cables after their first rather than their second failure and to replace entire half loop segments of URD cable after the first failure of a segment.[587]

505. The Company provided evidence to support each of these reasons for the increase in the cable replacement program budget.[588]

506. The Company explained that the rise in mainline cable failures in 2019 and 2020 and in URD failures in 2020 resulted in an increase in the Company's cable replacement budget for 2022–2024.[589] This increase in the budget was needed to make certain the Company would have adequate funding to make all necessary replacements based on recent failure trends.[590]

507. The Company stated that the transition to conduit construction for mainline cable in 2022 is another reason for the budget increase in 2022–2024.[591] In 2022, Xcel Energy began placing mainline cable in a conduit as opposed to direct burying this cable.[592] While more costly, conduit installation results in improved reliability as compared to direct-bury installation. This is because cable placed in conduit is protected from the elements and wildlife.[593]

508. The final reason for the increase in the cable replacement program budget in 2022–2024 provided by the Company was to provide funding to replace mainline and URD cable after its first failure rather than after its second failure.[594] The Company explained that will only perform these types of replacements if there is sufficient funding available in a given year which will depend on the number of other types of cable replacements performed each year.[595]

509. Currently, the Company typically repairs mainline cable after its first failure but then replaces cable after its second failure in a two-year period.[596] In 2022, the

[586] Ex. Xcel-40 at 47 (Bloch/Mensen Direct).
[587] Ex. Xcel-40 at 49 (Bloch/Mensen Direct).
[588] Ex. Xcel-40 at 49 (Bloch/Mensen Direct).
[589] Ex. Xcel-40 at 49 (Bloch/Mensen Direct).
[590] Ex. Xcel-40 at 50 (Bloch/Mensen Direct).
[591] Ex. Xcel-40 at 52 (Bloch/Mensen Direct).
[592] Ex. Xcel-40 at 52 (Bloch/Mensen Direct).
[593] Ex. Xcel-40 at 52 (Bloch/Mensen Direct).
[594] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).
[595] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).
[596] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).

Company proposes to replace mainline cable after its first failure.[597] By replacing cable that has already failed once, the Company will be able to avoid emergency replacements.[598] Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages when additional failures occur.[599]

510. With regard to URD cable, Xcel Energy currently makes half loop replacements after two failures on the same half loop in a two-year period.[600] During the MYRP, Xcel Energy plans to make replacements of half loops, as funding is available, to perform half loop replacements after one failure in two years or where there has been a history of failures.[601] Once a failure occurs on a segment, replacing the half loop of the segment benefits the customers on that entire loop by avoiding future failures of other segments.[602] Company witness Mr. Mensen testified that since cable loops are installed at the same time and using the same type of cable, once a failure occurs on that loop, additional failures follow in quick succession.[603] Mr. Mensen testified that proactive replacement of these half loop sections will avoid future failures.[604]

511. JSC objected to the replacement of URD cables after the first failure. Xcel's proposal reflects a change in its approach and funding level for such proactive cable replacements.[605] JSC argues that the change in practice and related cost increase is not justified because Xcel has not conducted a benefit-cost analysis for the proactive replacements.[606]

512. JSC recommended that the Commission "reject any increase in the total cable replacement budget driven by proactive replacements until the Company has conducted a reliability-driven cost/benefit analysis of its proactive cable investments to demonstrate that such investments are reasonable and cost-effective."[607] JSC also recommends that the Company be required to track its planned and actual spending on "reactive and proactive cable replacements."[608]

513. Company witness Mr. Mensen explained that a cost-benefit analysis would not be able to accurately quantify the reliability benefits of the Company's change to replacing cables after their first failure because there are multiple factors that impact the Company's reliability performance in a given year.[609] Mr. Mensen also testified that given the increase in cable failures in recent years, replacing cables after their first failure may

[597] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).
[598] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).
[599] Ex. Xcel-40 at 53 (Bloch/Mensen Direct).
[600] Ex. Xcel-43 at 13 (Mensen Rebuttal).
[601] Ex. Xcel-43 at 13 (Mensen Rebuttal).
[602] Ex. Xcel-40 at 55 (Bloch/Mensen Direct).
[603] Ex. Xcel-43 at 14 (Mensen Rebuttal).
[604] Ex. Xcel-43 at 14 (Mensen Rebuttal).
[605] Ex. JSC-4 at 39 (Davis Direct).
[606] Ex. Xcel-40 at 40 (Bloch/Mensen Direct).
[607] Ex. JSC-7 at 16-17 (Davis Surrebuttal).
[608] Ex. JSC-7 at 16-17 (Davis Surrebuttal).
[609] Ex. Xcel-43 at 12 (Mensen Rebuttal).

not produce immediate reliability benefits but only allow the Company to maintain its current reliability performance.[610]

514. The Company's proposal to modify its cable replacement program to replace mainline cable after one failure and to replace the entire half-loop of a URD cable after the failure of one segment is reasonable and prudent. A cost-benefit analysis would be inappropriate for a cost of this nature. The Company provided evidence that it is difficult to quantify the benefits of this change but that there will be reliability benefits in terms of avoiding future failures and outages for customers.[611] Reliable service is an essential component of a public utility's provision of service.[612] The Company also provided evidence that this change will avoid emergency cable replacements that can lead to lengthy outages when additional failures occur.[613]

515. The Company has provided evidence to support the reasonableness of its plan to make proactive cable replacements in 2022–2024 as funding is available. The Company has met its burden to establish that its 2022–2024 cable replacement budgets are reasonable.

516. The Judge recommends that the Commission approve Xcel's proposal to recover its cable replacement program costs,

517. It is reasonable to require the Company to track and report its planned and actual spending on reactive and proactive cable replacements. Xcel's budget reflects a shift in its approach to cable replacement that, during this MYRP, will increase costs recovered from ratepayers. While Xcel has explained the basis for the increased cost, it would be appropriate for regulators and the public to have an opportunity to review the Company's use of the increased budget in detail. The information will provide transparency, and the tracking and reporting requirement would not be unduly burdensome to the Company.

518. The Judge recommends that the Commission adopt JSC's recommendation to require Xcel to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate case filing.

22. Grid Reinforcement Program

519. Xcel proposes approximately $12 million in capital additions over the MYRP to enable its distribution system to handle increased load associated with increased electric vehicle (EV) adoption and electrification of other sectors of the economy.[614] The Company refers to these projects as a "Grid Reinforcement Program."[615] The Grid

[610] Ex. Xcel-43 at 12 (Mensen Rebuttal).
[611] Ex. Xcel-43 at 12 (Mensen Rebuttal).
[612] Minn. Stat. § 216B.01.
[613] Ex. Xcel-43 at 12 (Mensen Rebuttal).
[614] Ex. Xcel-40 at 83 tbl.22, 87 (Bloch/Mensen Direct).
[615] *See* Xcel-40 at 83 tbl.22, 87 (Bloch/Mensen Direct).

Reinforcement Program would replace distribution-system infrastructure in areas where new load could at some point overload distribution equipment and cause outages.[616]

520. Xcel currently handles distribution-equipment upgrades to accommodate increases in customer loads through two budget categories: Routine Capacity Reinforcements and New Business.[617] Routine Capacity Reinforcements support reliability by addressing known capacity constraints such as undersized transformers or conductors.[618] New Business projects extend electric service to new customers or support increased loads in response to customer requests.[619]

521. The types of upgrades that would be made under the Grid Reinforcement Program are similar to Routine Capacity Reinforcements and New Business projects: "upgrades to service transformers, poles, primary conductors, and secondary conductors."[620] The main difference between these existing programs and the Grid Reinforcement Program is that, instead of targeting equipment or customers with an existing capacity need, the Program would focus on locations that Xcel determines are likely to experience an overload in the future because of anticipated EV load or other new electrification.[621]

522. The Company testified that it would replace transformers and conductors under the program based on forecasted load growth, forecasted EV adoption rates, and transformers that are at high risk of failure. Specifically, based on this forecast, the Grid Reinforcement Program targets replacement of overhead residential service transformers rated 25 kVA or less that have the highest risk of failure based on this forecast.[622] The Company's requested budget would allow the Company to replace 200 service-level transformers in 2022, 400 service-level transformers in 2023, and 800 service-level transformers in 2024.[623]

523. OAG and JSC recommend rejection of the Grid Reinforcement Program.[624] They argue that Xcel has not justified the program's $12 million price, particularly when the Company is not proposing any reduction to its Routine Capacity Reinforcements or New Business budgets if the Grid Reinforcement Program is approved.[625] The OAG also argues that capacity constraints related to EV load may be able to be avoided entirely if Xcel can shift EV charging away from times of peak demand.[626]

524. There may be some benefits to the proactive planning associated with the proposed Grid Reinforcement Program, particularly for avoiding transformer-related

[616] Ex. Xcel-40 at 87 (Bloch/Mensen Direct).
[617] Ex. JSC-4 at 34 (Davis Direct).
[618] Ex. JSC-4 at 34 (Davis Direct).
[619] Ex. Xcel-40 at 79 (Bloch/Mensen Direct).
[620] Ex. Xcel-40 at 87 (Bloch/Mensen Direct).
[621] Ex. Xcel-40 at 87 (Bloch/Mensen Direct).
[622] Ex. Xcel-43 at 16-17 (Mensen Rebuttal).
[623] Ex. Xcel-43 at 17 (Mensen Rebuttal).
[624] OAG Initial Br. at 21–24; JSC Initial Br. at 57–60.
[625] Ex. JSC-4 at 38 (Davis Direct); Ex. OAG-6 at 17 (Twite Rebuttal).
[626] Ex. OAG-6 at 17 (Twite Rebuttal).

problems associated with EV growth and other load growth.[627] However, Xcel has several means of avoiding such problems without spending $12.08 million on a new program.

525. Specifically, both the New Business and Routine Capacity Reinforcement Programs are designed to identify transformer upgrade needs, and customer enrollment in EV programs should also inform the Company regarding where upgrades may be necessary.[628]

526. Further, the Program is intended to address EV load growth, but EVs are among the most flexible of all electric loads.[629] The need for system upgrades to address EV load may be avoided entirely by shifting or shaping EV charging demand.[630] The technology to do so already exists, and Xcel is piloting it in other jurisdictions.[631]

527. Xcel argued that the size of EV charging load, however, is significantly higher than any other non-industrial load (such as microwaves and dishwashers) such that, even during off-peak hours, if a large number of EVs begin charging simultaneously, the off-peak demand can increase significantly.[632] There also are customers who cannot, or choose not to, modify their EV charging in response to price signals.[633]

528. However, the concern that the Company intends to address is speculative and depends on the confluence of multiple contingencies—a sufficient concentration or breadth of EV adoption during the MYRP, unavoidable synchronization of EV charging loads, and inelastic EV-charging demand—which *could* lead to a new peak demand on some equipment and cause system impacts during what had been off-peak periods. This alignment of events has not been shown to be more likely than not to justify the proposed $12.08 million revenue requirement increase. In addition, Xcel's budget request relies on forecasts and an analysis the reliability of which have not been established for this purpose.

529. Before committing to replace infrastructure that is not yet overloaded, Xcel can explore rate design and managed charging to encourage EV load patterns that avoid the need for new distribution investments. Proactively shaping EV load has the potential to unlock greater benefits for ratepayers than accelerating infrastructure buildout.[634]

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[627] Ex. JSC-4 at 36 (Davis Direct).
[628] Ex. JSC-7 at 18-19 (Davis Surrebuttal).
[629] Ex. OAG-6 at 17 (Twite Rebuttal).
[630] Ex. OAG-6 at 17 (Twite Rebuttal).
[631] *See* Ex. OAG-6 at 19 (Twite Rebuttal); Ex. OAG-10 at 9 (Twite Surrebuttal); Ex. OAG-11, sched. AT-S-1 attach. B at 33–34 (Twite Surrebuttal Schedules) (finding that "centralized" management of EV charging minimizes line loading).
[632] *See* Ex. OAG-11, Sched. AT-S-1 at 7-8 (Twite Surrebuttal) ("The large magnitude of EV loads and their possible synchronization (e.g., nearly all EVs charging immediately when the lowest price TOU period begins) could lead to significant EPS [Electric Power System] impacts, even during 'off-peak' periods when non-EVs loads are smaller.").
[633] *See* Ex. OAG-11, Sched. AT-S-1 at 7 (Twite Surrebuttal).
[634] *See* Ex. OAG-6 at 19 (Twite Rebuttal); Ex. OAG-10 at 9 (Twite Surrebuttal); Ex. OAG-11, sched. AT-S-1 attach. B at 33–34 (Twite Surrebuttal Schedules) (finding that "centralized" management of EV charging minimizes line loading).

530. The Judge recommends that the Commission adopt OAG's and JSC's recommendation to exclude the Grid Reinforcement Program costs from Xcel's revenue requirement.

23. Distributed Intelligence (DI) Capital Additions and O&M Costs

531. The Company initially presented its Distributed Intelligence (DI) budget in its Supplemental Direct Testimony, at which time the Company indicated an update would be provided in Rebuttal Testimony to reflect a more detailed allocation of the DI costs to the NSPM Electric jurisdiction.[635]

532. In this proceeding, the Company proposes to recover in relation to its DI program $33 million in capital additions, beginning with the last year of the MYRP (2024), and $3.6 million total O&M expenses for 2022–2024 (on a Minnesota Electric Jurisdiction basis), as follows:[636]

2022–2024 Distributed Intelligence Costs
State of MN Electric Jurisdiction[637]

	2022	2023	2024
Capital	$0	$0	$33,000,000
O&M	$300,000	$1,500,000	$1,800,000
Total	$300,000	$1,500,000	$34,800,000

533. According to the Company, the updated budget includes allocators revised to reflect that DI costs should be allocated based on an electric-only allocator (instead of an allocator based on both electric and gas meters),[638] and a new shared asset accounting structure that will facilitate allocation of costs to Xcel Energy's operating companies.[639] The Company asserted that these changes better align with current information about when customers will receive benefits from DI in each jurisdiction.[640]

i. DI Introduction

534. According to the Company, Distributed Intelligence (DI) generally refers to the computer processing and analytics capabilities of localized distribution grid devices and platforms.[641] DI is a relatively new technology that enables the Company to extract precise, instantaneous insights that it can use for grid operations or to communicate

[635] Ex. Xcel-44 at 8 (Remington Supplemental Direct).
[636] Ex. JSC-7 at 18 (Davis Surrebuttal).
[637] This table is a combination of information contained in tables 3 and 4. Ex. Xcel-47 at 8 (Quirk Rebuttal).
[638] Ex. Xcel-47 at 24 (Quirk Rebuttal) and Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 239-242 (Lee).
[639] Ex. Xcel-47 at 24 (Quirk Rebuttal).
[640] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 123 (Quirk).
[641] Ex. Xcel-44 at 11-12 (Remington Supplemental Direct).

usage data directly to customers to allow them to make real-time decisions impacting energy usage.[642]

535. Xcel proposes to procure DI software and associated computer hardware intended to leverage advanced meter data to offer new services to customers and help the utility more efficiently manage its distribution system.[643] Advanced meters, often referred to as advanced metering infrastructure (AMI), have embedded computer processors that can collect and process customer usage data in real time.[644]

536. DI applications are software developed and installed directly on a meter to allow the Company to carry out certain computer processing at the meter to support one or more DI "use cases." DI use cases may be either (1) customer-facing, meaning customers interact directly with the DI application, for example, through a smartphone application that has been developed for that purpose; or (2) grid-facing, meaning the Company interacts with the DI application to improve the performance of the grid.[645]

537. The Company assessed DI technology over several years as it considered procurement and deployment of its new AMI meters.[646] The Company also conducted customer research to inform its DI deployment plans[647] and developed a roadmap for staged deployment of DI capabilities.[648]

538. Xcel identifies several initial uses for its proposed DI program: energy analysis, home area network connectivity, EV detection, outage and voltage fluctuation detection, and a connectivity pilot.[649] Xcel also indicated that it would likely introduce additional uses for DI in future years.[650]

539. During 2022 and 2023, the Company plans to develop and deploy three customer-facing DI used cases: (1) Home Area Network (HAN) connectivity, allowing customers to connect to the meter on their premises using Wi-Fi and providing customers real-time access to energy usage information;[651] (2) Energy Analysis, which relies on the DI load disaggregation application, providing customers information on energy usage of specific appliances and on those appliances' monthly bill impacts;[652] and (3) EV Detection – Customer, also relying on the load disaggregation application, which will detect a customer's EV charging, quantify the EV-specific energy consumption profile over time,

[642] Ex. Xcel-44 at 13-14 (Remington Supplemental Direct).
[643] Ex. Xcel-84, MAP-D-2 at 2 (Peppin Direct); Ex. DOC-12 at 32–33 (Havumaki Direct); T. Tr. Vol. 1 at 128:5–11 (Quirk).
[644] Ex. Xcel-44 at 2 (Remington/Quirk Supp. Direct).
[645] Ex. Xcel-44 at 5 (Remington Supplemental Direct).
[646] Ex. Xcel-44 at 17-20 (Remington/Quirk Supplemental Direct).
[647] Ex. Xcel-44 at 20, 25, 26 (Remington/Quirk Supplemental Direct); Ex. Xcel-47 at 15-16 (Quirk Rebuttal).
[648] Ex. Xcel-44 at 20-21 (Remington/Quirk Supplemental Direct).
[649] Ex. Xcel-44 at 23, 34 (Remington/Quirk Supp. Direct).
[650] Ex. Xcel-47 at 35 (Quirk Rebuttal).
[651] Ex. Xcel-44 at 24-26 (Remington Supplemental Direct).
[652] Ex. Xcel-44 at 26-29 (Remington Supplemental Direct).

and provide the Company a channel to introduce customers to EV programs and rates that best suit their needs.[653]

540. The Company's proposal in this case includes costs to implement the foundational software architecture necessary to enable DI capabilities and to develop and deploy initial customer- and grid-facing DI use cases.[654] The Company also plans for additional deployment of grid-facing DI in 2024, including broader deployment of the grid-facing pilots introduced in 2022 and 2023, and potentially including development of other applications that are not currently available for deployment; the Company's rate case budget includes projected costs for this additional work.[655]

ii. The Company's DI Cost-Benefit Analysis

541. To demonstrate the cost-effectiveness of its proposed DI spending, Xcel provided a cost-benefit analysis for the energy analysis use. The energy analysis use would provide real-time, appliance-by-appliance energy usage data to participating customers. Xcel stated participating customers would then use this information to adjust their usage and become more efficient.[656]

542. According to the Company, the cost-benefit analysis was conservative in that it included all costs during the MYRP period but only included the portion of the benefits that the Company could quantify at this time with sufficient certainty.[657] All costs and benefits included in the cost-benefit analysis were separate from and incremental to AMI meter costs and benefits.[658]

543. The cost-benefit analysis was updated in Rebuttal to reflect budget updates, an updated service life projection for DI assets, and the most current general non-labor rate and estimated AMI deployment. The updated cost-benefit analysis also provided additional analysis around projected participation rates.[659] The updated DI cost-benefit analysis results show an expected benefit-to-cost ratio (BCR) of approximately 1.44 under the base scenario. Considering all sensitivities, there is 95% certainty that the BCR would result in a value greater than 0.98, with a minimum of 0.98 and maximum of 2.33.[660]

544. According to the Company, the primary benefit of DI is the potential to provide information to customers, allowing them to change their behavior in ways that promote energy efficiency and demand response, save on their energy bills, and facilitate a reduction in carbon emissions.[661] Xcel also provided testimony that DI analytics will also extend the Company's advanced capabilities for the distribution grid to enable more

[653] Ex. Xcel-44 at 29-30 (Remington Supplemental Direct).
[654] Ex. Xcel-44 at 21 (Remington Supplemental Direct).
[655] Ex. Xcel-44 at 40-41 (Remington Supplemental Direct).
[656] Evid. Hrg. Tr. Vol. 1 at 129:1–4 (Quirk).
[657] Ex. Xcel-44 at 58-60 (Remington Supplemental Direct).
[658] Ex. Xcel-47 at 9-10 (Quirk Rebuttal).
[659] Ex. Xcel-47 at 29 (Quirk Rebuttal).
[660] Ex. Xcel-47 at 35-37 (Quirk Rebuttal).
[661] Ex. Xcel-44 at 14 (Remington Supplemental Direct).

precise monitoring and control at the edge of the grid, enabling greater reliability and lower costs to customers for managing the system.[662]

545. Unlike Xcel's FLISR cost-benefit analysis, the Department identified a variety of concerns with Xcel's cost-benefit analysis for its proposed DI spending. The Department objected to the benefits measure that Xcel used and several of the assumptions baked into the model.

i. *Benefits Measure*. To quantify the benefits, Xcel used estimated customer bill savings for participating customers.[663] The company estimated that participating customers would save about $61 million between 2024 and 2028.[664] The Department objected to Xcel's reliance on participating customer bill savings for several reasons.

(1) First, the Department asserted that reliance on participating customer bill savings violated the principle of benefit-cost analysis that benefit-cost analyses should be "forward-looking, long-term, and incremental to what would have occurred absent the [distributed energy resource investment]."[665] According to the Department, "Using bill savings as a benefit violates this principle because they [rely on] prices [derived from] historical costs that cannot be avoided by the utility investment."[666]

(2) Second, the Department noted that customer bill savings only accrue to actively participating customers. Thus, according to the Department, even assuming Xcel's assumptions are correct, "there's a risk that participating customers who save money may do so at the expense of other non-participating customers absent an evaluation of avoided costs."[667]

(3) Third, the Department's witness testified that customer bill savings are likely a ceiling on benefits.[668] The Department stated, "Bill savings arguably represent a high-end limit on the potential of avoided costs in that they represent the utility's vetted costs."[669] Given that billing savings may be the high-end limit, the Department argued that Xcel's present analysis is more likely to be a best-case scenario. To produce

[662] Ex. Xcel-44 at 14-15 (Remington Supplemental Direct).
[663] Ex. Xcel-44 at 59 (Remington/Quirk Supp. Direct).
[664] Ex. Xcel-47 at 33 (Quirk Rebuttal).
[665] Ex. DOC-12 at 36 (Havumaki Direct) (quoting National Energy Screening Project, National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources at 16 (Aug. 2020), *available at* www.nationalenergyscreeningproject.org/national-standard-practice-manual).
[666] Ex. DOC-12 at 36 (Havumaki Direct).
[667] Ex. DOC-14 at 10–11 (Havumaki Surrebuttal).
[668] Ex. DOC-12 at 36–37 (Havumaki Direct).
[669] T. Tr. Vol. 2 at 155:3–14 (Havumaki).

methodologically reliable results, the Department stated that Xcel should have estimated the avoided utility costs of its DI proposal. Both the Department and Xcel agreed that estimated avoided utility costs is the “standard utility practice” for these types of cost-benefit analyses.[670]

ii. *Modeling Assumptions*. To produce its cost-benefit analysis, Xcel had to test various variables that could impact the results. To ascertain the most probable results, Xcel also had to identify the likely or most reasonable assumptions for these variables.[671] The Department argued that several of Xcel’s assumptions relating to participation rate, churn rate, and advanced meter deployment were unreasonable.

iii. *Participation Rate.* The Department asserted that Xcel’s assumed participation rate was unreasonably high for two reasons:

(1) First, the Department stated that Xcel overly relied on “My Account” login data as a proxy for participation. According to the company, “My Account is Xcel Energy’s largest digital engagement product . . . .” As a result, “[it is] a reasonable proxy for customers viewing mobile or web platforms for current energy efficiency and demand management best practices and/or engage in new best practices.”[672] The Department stated this is unreasonable because, by Xcel’s own admission, “[t]he primary reasons customers log into My Account are to view and pay bills.”[673] The Department also noted, 83% of My Account usage in 2021 was for bill delivery, bill payment, and bill information viewing.[674] The Department further pointed to the experience of Detroit-based DTE Electric Company, which started a similar program several years ago. In DTE’s case, out of about two million total residential customers, only 82,000 customers had downloaded the mobile phone application while only 59,000 had installed “energy bridge” hardware necessary for home internet routers to communicate directly with meters.[675]

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670 Ex. Xcel-47 at 11 (Quirk Rebuttal); Ex. DOC-12 at 36 (Havumaki Direct).
671 T. Tr. Vol. 1 at 134:19–135:10 (Quirk).
672 Ex. DOC-27 at 2 (DOC IR No. 94).
673 T. Tr. Vol. 1 at 138:7–10 (Quirk).
674 Ex. DOC-28 at 2 (DOC IR No. 11(e)).
675 Ex. DOC-12 at 38 (Havumaki Direct); *In re Appl. of DTE Elec. Co. for Auth. to Increase Its Rates, Amend Its Rate Schds., & Rule Governing the Distrib. & Supply of Elec. Energy, & For Misc. Acct. Auth.*, Case No. U-18014, PROPOSAL FOR DECISION at 125 (MI PSC ALJ Rept. Nov. 21, 2016); *In re Appl. of DTE Elec. Co. for Auth. to Increase Its Rates, Amend Its Rate Schds., & Rule Governing the Distrib. & Supply of Elec. Energy, & For Misc. Acct. Auth.*, Case No. U-18014, ORDER at 23 (MI PSC Jan. 31, 2017).

(2) Second, given that Xcel proposes to auto-enroll customers, the Department asserted that the company's approach to distinguishing between active participation and passive customers – adjusting active My Account usage (i.e., one log-in in six months) based on selected market research[676] – was inadequate.

iv. *Market Research.* The Department also took issue with the market research Xcel used to adjust the My Account-based participation rate: churn rate and customer interest:

v. *Churn Rate.* Churn rate refers to the percentage of enrolled customers annually leaving the program.[677] Xcel assumed an annual churn rate of 12.71% which it derived from "general market research" for digital products.[678] The Department pointed out that the market research Xcel used actually was a marketing blog post and that none of the underlying data was accessible to Xcel.[679] The Department also asserted that Xcel's use of the highest churn rate was self-serving and not conservative as the company claimed because the benefit-to-cost ratio for DI improved as annual churn increases.[680]

vi. *Customer Interest.* Xcel used a value of 80% based on customer concept testing. The Department asserted that there was little actual support for this figure because the Company only provided a single survey question asking how "interested" respondents would be in downloading an "app to allow you to understand your energy usage."[681] The Department argued that generalized interest is not a reasonable proxy for actual action, pointing to DTE's recent experience with a similar program.[682]

vii. *Meter Deployment.* Finally, the Department challenged Xcel's advanced meter deployment assumptions. The Company stated that "the deployment of meters per year affects both the costs and benefits associated with the [Distributed Intelligence] program." Xcel also acknowledged that the highest U.S. inflation rate since the 1980s is creating supply chain issues, affecting meter availability.[683]

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[676] Ex. Xcel-47 at 15 (Quirk Rebuttal).
[677] T. Tr. Vol. 1 at 142–143 (Quirk).
[678] T. Tr. Vol. 1 at 143 (Quirk); Ex. DOC-29 at 2 (DOC IR No. 95(b)).
[679] T. Tr. Vol. 1 at 145 (Quirk).
[680] Ex. Xcel-44 at 66 (Remington/Quirk Supp. Direct).
[681] Ex. DOC-27 at 3 (DOC IR No. 94).
[682] *In re Appl. of DTE Elec. Co. for Auth. to Increase Its Rates, Amend Its Rate Schds., & Rule Governing the Distrib. & Supply of Elec. Energy, & For Misc. Acct. Auth.*, Case No. U-18014, PROPOSAL FOR DECISION at 125 (MI PSC ALJ Rept. Nov. 21, 2016). The Department acknowledged that its initial brief mistakenly described both the mobile phone application and the required "energy bridge" hardware as free of cost but asserted that its argument was unaffected by the error. DOC Initial Br. at 102; DOC Reply Br. At 19.
[683] Ex. Xcel-23 at 4 (Liberkowski Rebuttal); Ex. Xcel-47 at 33 (Quirk Rebuttal).

> As a result, in its benefit-cost analysis, Xcel revised its meter deployment assumptions for 2022 from 250,000 to 90,000 meters. Xcel did not change its assumptions for 2023, leaving the assumed deployment at 670,000 meters.[684]

546. As a result of these asserted deficiencies with the benefits measure and model assumptions, the Department stated that Xcel's benefit-cost analysis for DI was not reliable.

547. The Department also expressed concern with the results produced by Xcel's benefit-cost analysis. Xcel stated the benefit-cost ratio for DI is likely to fall within the range of 0.98 to 2.33, with a mean of 1.57.[685] The Department argued that this large range of possible results—in contrast to the narrow band for FLISR—reflected the significant risk associated with Xcel's current proposal.[686] The Department's witness testified, "[Distributed Intelligence] is barely cost effective even when bill savings are (incorrectly) used as the quantified benefit."[687]

548. The Department additionally asserted that Xcel's proposal required further development. The Department noted that Xcel's argument in favor of Distributed Intelligence suggested that its analysis was conservative because the Company planned to introduce additional uses in 2024.[688] The Department argued these additional uses were too speculative to rely upon, given that Xcel lacked estimates of participation and estimates of the associated avoided costs.[689]

549. Finally, the Department objected to Xcel's rebuttal proposal to add $37.8 million in capital to its 2024 plan year rate base. This is an approximately $14.3 million increase from its original recommendation.[690] The Company stated that the enterprise-wide budget has not changed. Instead, the cost change arose from Xcel's proposal to change DI from an enterprise-wide owned shared asset to a NSPM-owned asset.[691] Xcel's other utilities such as Public Service Company of Colorado would then pay licensing fees to NSPM to use the DI technology.[692] The Department argued that this would unreasonably shifts business risk from shareholders to NSPM customers because it assumes that Xcel's other jurisdictions will timely adopt DI programs and therefore pay licensing fees.[693]

550. The OAG did not expressly oppose recovery for any DI costs, but shared the Department's concern relating to Xcel's rebuttal testimony changes to the DI accounting structure. The OAG argues that the changes shift costs to NSPM without

[684] Evid. Hrg. Tr. Vol. 1 at 142 (Quirk).
[685] Ex. Xcel-47 at 35 (Quirk Rebuttal).
[686] DOC Initial Br. at 105.
[687] Ex. DOC-14 at 10–11 (Havumaki Surrebuttal).
[688] Ex. Xcel-44 at 59 (Remington/Quirk Supp. Direct).
[689] Ex. DOC-24 at 1 (DOC IR No. 92); Evid. Hrg. Tr. Vol. 1 at 133 (Quirk).
[690] Ex. Xcel-47 at 26–27 (Quirk Rebuttal).
[691] Ex. Xcel-47 at 25 (Quirk Rebuttal).
[692] DOC Initial Br. at 106; Ex. Xcel-47 at 25-26 (Quirk Rebuttal).
[693] DOC Initial Br. at 106.

adequate explanation or sufficient detail to allow parties to evaluate the new accounting structure.[694] The OAG further argued that the costs for the DI asset do not reflect any credits from other operating companies for their use of the asset and that this will result in Minnesota ratepayers paying more than their fair share of DI costs in 2025 and beyond.[695] Finally, the OAG contends that Xcel has not explained why the accounting changes need to be reflected in the current rate case since the DI asset will not be in-serviced until the last month of 2024[696] and because Xcel claims that "the allocator update does not have a material impact on the overall DI budget allocated to NSPM through 2028."[697]

551. The OAG argued that the changed accounting structure not being disclosed until rebuttal heightened the need for Xcel to provide detailed cost information supporting the changes, and that the Company's providing the information only in rebuttal testimony hindered Intervenors' ability to thoroughly vet the proposal.[698]

552. Finally, the OAG argued that the Company had not explained why an accounting change that, according to the Company, would have no "material impact" on NSPM's budget until 2028 needs to be reflected in the MYRP. The OAG urged that the Commission decline to approve the budget and allow Xcel to seek approval of the revised budget and accounting structure in a future proceeding with a more robust record.[699]

553. The OAG recommended that, if the Commission grants recovery of DI expenses in this case, it should require Xcel to use the accounting structure the Company proposed in supplemental direct testimony. This would mean removing \$3.1 million (MN jurisdiction) in rate base, and \$303,000 (MN jurisdiction) in O&M expenses in the 2022 test year; \$12.1 million (MN jurisdiction) in rate base, and \$1,528,000 (MN jurisdiction) in O&M expense in the 2023 plan year; and \$24.6 million (MN jurisdiction) in rate base, and \$1.7 million (MN jurisdiction) in O&M expense in the 2024 plan year.[700]

554. The CEOs supported Xcel's requested recovery for DI, noting that Xcel had significantly reduced the cost of its DI program from its initial proposal in the IDP docket.[701]

555. The CEOs requested that Xcel agree to implement the program consistent with the terms of a Settlement Agreement signed by Xcel's affiliate in Colorado for implementation of a similar program.[702] Xcel's explanation of its planned implementation

[694] Ex. OAG-9 at 27–30 (Lee Surrebuttal).
[695] Ex. OAG-9 at 29 (Lee Surrebuttal).
[696] Tr. Vol. 1 at 237 (Lee).
[697] Ex. Xcel-47 at 24 (Quirk Rebuttal).
[698] Ex. OAG-9 at 28 (Lee Surrebuttal).
[699] OAG Initial Br. At 29.
[700] Ex. OAG-9 at 36–37 (Lee Surrebuttal).
[701] Ex. CEO-3 at 16 (Volkmann Direct).
[702] Ex. CEO-3 at 18 (Volkmann Direct).

terms in briefing satisfied CEOs' concerns, and in their reply brief, the CEOs fully supported Xcel's DI request.[703]

556. For the reasons identified by the Department and the OAG, Xcel has not met its burden to establish that its proposed cost recovery for DI in this proceeding would be just and reasonable. There appears to be broad agreement that grid modernization technologies like DI have the potential to deliver customer benefits. But in this instance, Xcel has not sufficiently developed its proposal before seeking cost recovery.

557. The Department identified significant shortcomings with the cost-benefit analysis provided by Xcel. Because the cost-benefit analysis only narrowly found a net benefit, genuine doubts about the methodology and the reliability of its conclusions are sufficient to conclude that the analysis did not meet the Company's burden to show the costs to be reasonable, more likely than not. Doubts about reasonableness must be resolved in favor of ratepayers.

558. The Department and the OAG have also raised legitimate concerns about the increased risk and uncertain benefits to Minnesota ratepayers implicit in the Company's revised DI accounting structure. The revision was presented at a stage in the proceeding that did not allow intervenors an opportunity to develop a full analysis and well-developed record on the proposal.

559. Accordingly, the Judge recommends that the Commission deny cost recovery for Xcel's DI proposal, without prejudice to the Company to seek recovery in a future proceeding.

560. Alternatively, if the Commission finds that the DI cost-benefit analysis meets the Company's burden of proof and authorizes DI cost recovery, the Judge recommends that the Commission adopt the OAG's alternative proposal to use the accounting structure the Company proposed in supplemental direct testimony by removing $3.1 million (MN jurisdiction) in rate base, and $303,000 (MN jurisdiction) in O&M expenses in the 2022 test year; $12.1 million (MN jurisdiction) in rate base, and $1,528,000 (MN jurisdiction) in O&M expense in the 2023 plan year; and $24.6 million (MN jurisdiction) in rate base, and $1.7 million (MN jurisdiction) in O&M expense in the 2024 plan year.

24. Production Tax Credits (PTC)

561. Production tax credits (PTCs) are per-kWh federal tax credits that are earned from the generation of electricity using qualified renewable energy resources, such as wind generation facilities.[704] PTCs impact Xcel's revenue requirement by reducing its income tax expense and increasing operating income.[705]

[703] CEOs' Reply Brief at 17.
[704] Ex. Xcel-79 at 61 (Halama Direct); *see also* 26 U.S.C. § 45(a).
[705] Ex. Xcel-79 at 61 (Halama Direct).

562. Because PTCs vary year to year, Xcel proposed creating a PTC Tracker account in its Renewable Energy Resources (RES) rider to annually refund or surcharge the dollar value of the difference between actual PTCs received and the baseline set in this rate case.[706]

563. In the current rate case, the Company proposed that the PTCs to be generated from wind facilities that begin production in 2022 would be recovered through the RES Rider.[707] The Company further proposed that the RES Rider would act as a true-up mechanism for the PTCs related to projects already in service and included in base rates as a part of the 2022 test year.[708] No party opposed the Company's request to use the RES Rider to true-up PTCs.

564. The Department agreed that continuing the PTC Tracker account in the RES rider was reasonable but disagreed on the appropriate baseline.[709]

565. In its initial filing, the Company forecasted that it would generate PTCs totaling $190.169 million for 2022, $192.916 million for 2023, and $193.385 million for 2024.[710] Xcel's initial filing included a forecasted PTC baseline based on federal law at that time, which included a phase-out of PTCs for some windfarms and was calculated at the federal MWh rate at the time.[711]

566. In August 2022, the Inflation Reduction Act (IRA) expanded the renewable generation facilities eligible for PTCs, no longer requiring Xcel to phase out PTCs; increased the eligible percentage of PTCs for existing renewable facilities from 60% or 80% to 100%; and increased the MWh rate for new and repowered renewable facilities.[712] These changes significantly affected the amount of PTCs that Xcel could expect to receive throughout the MYRP.[713] Xcel also updated its wind generation forecast to incorporate the most recent information by windfarm and the expected energy production, which impacts the amount of PTCs earned.[714]

567. The Department recommended that Xcel use its updated PTC forecast, which incorporates both the IRA's impacts and updated energy production forecast, to set the baseline for its proposed PTC true-up mechanism.[715] The Department also agreed to corrections to the updated forecast that Xcel provided in rebuttal testimony.[716] After

[706] *See* Ex. Xcel-79 at 62 (Halama Direct).
[707] Ex. Xcel-79 at 62, 109 (Halama Direct).
[708] Ex. Xcel-79 at 62, 97, 109 (Halama Direct).
[709] Ex. DOC-3 at 6 (Soderbeck Direct).
[710] Ex. Xcel-79 at 62 (Halama Direct).
[711] Ex. DOC-3 at 6–7 (Soderbeck Direct).
[712] Ex. DOC-3 at 6-7, HS-D-4 (Soderbeck Direct) (Xcel Response to DOC IR No. 1138).
[713] *See* Ex. DOC-4, HS-D-4 (Soderbeck Direct – Not Public Version) (Xcel response to DOC IR No. 1138, Attach. A). Xcel designated its PTC forecast as Trade Secret.
[714] Ex. DOC-5 at 22 (Soderbeck Surrebuttal).
[715] *See* Ex. DOC-3 at 6–8 (Soderbeck Direct).
[716] Ex. DOC-5 at 22 (Soderbeck Surrebuttal).

that issue was corrected, the Department-supported updated PTC forecast is $217.753 million for 2022, $194.204 million for 2023, and $194.738 million for 2024.[717]

568. The Department argued that this updated PTC forecast should be used to set base rates because an "accurate estimate ensures ratepayers are not subject to dramatic changes in rates as the amount is trued-up."[718] The Department further explained that setting an appropriate baseline is important because although ratepayers may receive a refund of any overpayments "significant time will have passed."[719]

569. As with other issues relating to forecasts adjusted during the proceeding, the Department and Xcel agree that setting as accurate a baseline as possible is important for true-ups to provide rate stability by minimizing the extent of future surcharges or refunds,[720] and to send appropriate price signals.[721]

570. Xcel maintained that it should continue using its original PTC forecast that was created before the IRA was passed and did not incorporate Xcel's updated wind generation forecast.[722] Xcel stated that it did not believe it was necessary to update the PTC forecast because it was waiting for further guidance from the IRS on IRA implementation and that updating the baseline was not necessary because the updated forecast may not be more accurate than the initial forecast, and because it would be trued-up in the RES rider.[723]

571. The Company also argued that the 2022 PTC true-up was already approved, and that adjusting the forecast in this proceeding would result in confusion and potentially either double counting or a need for an additional true-up.[724]

572. The principles identified by the Department for updating true-up baselines to reflect the best information available at the close of the evidentiary record support the reasonableness of the Department's proposal. It is more reasonable to rely upon the updated forecast than the initial forecast. The Company's arguments against updating the baseline are not sufficient to overcome the benefits to ratepayers of setting the baseline using the most up-to-date forecast available in the record.

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[717] Ex. DOC-5 at 24 (Soderbeck Surrebuttal).
[718] Ex. DOC-5 at 23 (Soderbeck Surrebuttal).
[719] Ex. DOC-5 at 23 (Soderbeck Surrebuttal).
[720] Ex. Xcel-23 at 17 (Liberkowski Rebuttal).
[721] Evid. Hrg. Tr. Vol. 1 at 30–31 (Liberkowski).
[722] *See* Ex. Xcel-82 at 29–30 (Halama Rebuttal).
[723] *See* Ex. Xcel-82 at 29–30 (Halama Rebuttal).
[724] Evid. Hrg. Tr. Vol. 1 at 182 (Halama).

573. The Judge recommends that the Commission adopt the Department's recommended baseline PTC update, and the corresponding adjustment to the revenue requirement, as follows:

2022	**2023**	**2024**	**2025**	**2026**
$(27,584,000)	$(1,288,000)	$(1,353,000)	--	--

25. Nuclear Carbon Free Power Project (CFPP)

574. Company witness Peter Gardner described the involvement of four people from the Company's Nuclear organization that are working on the Carbon Free Power Project (CFPP), a project by the Utah Association of Municipal Power Systems to develop a small modular reactor nuclear plant. The individuals have been transferred to Xcel Energy Services to ensure that their time can be properly billed for their work on the project, and costs and revenues associated with this work will be treated as non-utility going forward. The Company updated its budget in Rebuttal Testimony by reflecting a $774,000 reduction in its revenue requirement.[725]

575. Company witness Mr. Halama's Rebuttal Testimony indicated that there were three, rather than four, employees transferred.[726] The revenue requirement adjustment provided in Schedules 3a-3c of Mr. Halama's Rebuttal Testimony was provided by the Company's Nuclear organization.[727] At the evidentiary hearing, Mr. Halama could not confirm if the adjustment was for three or four employees.[728]

576. The Department recommended that Xcel provide information in a compliance filing to ensure that the adjustment was correctly calculated to reflect the transfer of four employees.

577. The Judge agrees that Xcel should make a compliance filing to show how it arrived at its $774,000 Nuclear CFPP O&M adjustment, or a different amount if the adjustment was based on an inaccurate number of employees.

578. The Judge recommends that the Commission approve a revenue requirement adjustment calculated to reflect the transfer of four employees.

26. Load Flexibility Program Costs

579. In Docket No. E002/M-21/101 (the Load Flexibility Docket),[729] the Company requested approval of deferred accounting for costs related to a load flexibility pilot

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[725] Ex. Xcel-35 at 11-13 (Gardner Rebuttal).
[726] Ex. Xcel-82 at 18 (Halama Rebuttal).
[727] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 194 (Halama); Ex. Xcel-82, Sched. 3a at 2; Sched. 3b at 2; Sched. 3c at 2 (Halama Rebuttal).
[728] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 189 (Halama).
[729] I*n the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, MPUC Docket No. E-002/M-21-101.

program. The Company initiated the docket on February 1, 2021.[730] The Load Flexibility Docket was underway at the time of Xcel's initial filings in this proceeding.[731] In March 2022, the Commission approved deferred accounting for a portion of load flexibility pilot program costs, but limited the expenses eligible for deferral.[732] The Commission found that the pilot programs present "important opportunities to study various demand-response offerings and their potential value to customers, to Xcel's system, and to broader state energy policy goals."[733]

580. However, the Commission adopted the Department's recommendation to limit authorization for deferred accounting after the Department argued that "the remaining categories [of costs] appear to be labor costs already included in base rates."[734]

581. The categories of pilot program costs that the Commission excluded from deferred accounting treatment are: Program Administration (including Labor), Advertising & Promotions, Measurement and Verification, and Product Development & Research.[735]

582. In Rebuttal Testimony the Company updated the cost of service in this case to include the portion of load flexibility pilot program costs that were not approved for deferred accounting in the Load Flexibility Docket, totaling $870,000 in 2023 and $1.1 million in 2024 (for the Minnesota Electric Jurisdiction).[736] These are the same cost amounts presented in detail in the Load Flexibility Docket, as updated in an April 2022 compliance filing.[737]

583. The OAG opposed Xcel's rebuttal request because, it argued, the Commission determined that Xcel is already recovering these costs.[738] The OAG also asserted that Xcel's claim that these costs are incremental cannot be verified because the Company did not provide any detailed cost information that could be used to determine whether these costs are already included in base rates.[739] And the OAG argued that Xcel made its request too late to allow Intervenors to scrutinize the proposal and ensure it would not result in double recovery.[740]

584. The Company disagreed with the OAG's recommendations for several reasons. First, the Company provided Rebuttal Testimony that none of the load flexibility

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[730] Load Flexibility Docket, LOAD FLEXIBILITY PILOT PROGRAMS AND FINANCIAL INCENTIVE MECHANISM (Feb. 1, 2021).
[731] Ex. Xcel-82 at 15 (Halama Rebuttal).
[732] Ex. Xcel-82 at 15 (Halama Rebuttal); *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, MPUC Docket No. E-002/M-21-101, ORDER APPROVING MODIFIED LOAD-FLEXIBILITY PILOTS AND DEMONSTRATION PROTECTS, AUTHORIZING DEFERRED ACCOUNTING, AND TAKING OTHER ACTION at 25, 30 (Mar. 15, 2022).
[733] *Id*. at 25.
[734] *Id* at 25.
[735] Id. at 25, 30.
[736] Ex. Xcel-82 at 15 (Halama Rebuttal).
[737] Ex. Xcel-82 at 15 (Halama Rebuttal); Compliance Filing (Apr. 14, 2022) (eDockets No. 20224-184776-01).
[738] Ex. OAG-9 at 32–33 (Lee Surrebuttal).
[739] Ex. OAG-9 at 34 (Lee Surrebuttal).
[740] Ex. OAG-9 at 34 (Lee Surrebuttal).

pilot expenses requested for deferral were included in the originally filed cost of service in this case.[741] Second, the Company argued that the timing of the movement of these costs from the Load Flexibility Docket to the rate case was a function of the timing of the Commission's decision in the load flexibility docket.[742] Finally, the Company argued that excluding the costs from recovery in this proceeding would effectively strand the costs, leaving the Company without the ability to recover the costs.[743]

585. The Commission's March 15, 2022, decision in the Load Flexibility Docket neither expressly directed that the costs denied for deferred accounting be reviewed in this proceeding nor expressly based its denial upon a determination that the costs were being doubly recovered. The Commission limited the expenses eligible for deferred accounting "[t]o protect customers,"[744] but did not conclusively determine that the ineligible costs were already included in base rates.[745]

586. Xcel's request, updated in Rebuttal Testimony, is distinct from the question presented to the Commission in the Load Flexibility Docket. The Company is not requesting deferred accounting, it is requesting rate recovery for specific costs within the 2023 and 2024 plan years, the base rates for which are subject to determination in this proceeding. The Commission's denial of deferred accounting for the costs, in and of itself, does not provide a compelling reason to deny recovery in this proceeding.

587. The issue presented is whether Xcel has established by a preponderance of the evidence that rate recovery of the load flexibility pilot program costs is reasonable.

588. Xcel introduced its evidence on the issue at its earliest opportunity after the Commission issued its decision in the Load Flexibility Docket. No party has identified any load flexibility pilot program cost that duplicates an expense already included in the Company's initial request.

589. Because the Commission has approved deferred accounting for some load flexibility pilot program costs upon a finding that the programs serve important ratepayer and policy interests, and because evidence that the costs are incremental has not been substantively rebutted, it is reasonable to include the costs in the Company's rate base in this proceeding.

590. The Judge recommends that the Commission approve rate recovery of the Company's Load Flexibility Program Costs as set forth in its rebuttal testimony.

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[741] Ex. Xcel-82 at 15 (Halama Rebuttal).
[742] Xcel's Initial Br. At 173.
[743] *Id*.
[744] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, MPUC Docket No. E-002/M-21-101, ORDER APPROVING MODIFIED LOAD-FLEXIBILITY PILOTS AND DEMONSTRATION PROTECTS, AUTHORIZING DEFERRED ACCOUNTING, AND TAKING OTHER ACTION at 25 (Mar. 15, 2022).
[745] *Id*.

27. Integrated Volt-Var Optimization (IVVO)

591. In its initial filing, Xcel included capital additions $0.2 million in 2023 and $3.7 million in 2024 for Integrated Volt-Var Optimization (IVVO).[746] At the same time, Xcel stated that it no longer planned to deploy any portion of IVVO in 2023 or 2024.[747] Because the Company's decision not to deploy IVVO was made between the budget preparation and filing of the case, the Company noted its intention to remove budgeted amounts of capital and O&M costs for IVVO from the case in Rebuttal Testimony.[748]

592. The Department concurred with the need for this adjustment.[749] The Department recommended in direct testimony that Xcel provide the revenue requirement impacts for 2022 through 2026 related to IVVO so that these costs would be clearly removed from the test years.[750]

593. Company witness Mr. Halama provided, in his Rebuttal Testimony, a revenue requirement adjustment limited to 2024 when IVVO was originally planned to be placed in service.[751]

594. In Surrebuttal Testimony, the Department questioned whether the Company had removed the full amount of IVVO from the cost of service, as Company witness Mr. Mensen identified capital budget amounts to be removed from the case that differ from Mr. Halama's revenue requirement adjustment.[752]

595. In response, Company witness Mr. Halama explained that the amounts Mr. Mensen identified were budgeted for IVVO for 2023 and 2024, whereas the approximately $0.2 million amount budgeted for 2023 was placed in service in 2022 and was not specific to IVVO. Specifically, Mr. Halama stated that "there [were] expenditures that occurred prior to the project being cancelled that were considered used and useful . . . . This adjustment does not remove those components."[753]

596. Further, for 2024 Mr. Mensen referenced the total budgeted capital addition amount for the test year ($3.7 million); however, capital additions are placed in service on a 13-month average basis.[754] Because these IVVO capital costs were budgeted to be placed in service during 2024, the revenue requirement adjustment reflects the average of the amounts included in service at the beginning of the year versus the amount at the end of the year, which is $1.8 million rather than $3.7 million. (In other words, the

[746] Ex. Xcel-40 at 98–99 (Bloch/Mensen Direct).
[747] Ex. Xcel-40 at 98–99 (Bloch/Mensen Direct).
[748] Ex. Xcel-43 at 29 (Mensen Rebuttal).
[749] Ex. DOC-5 at 19 (Soderbeck Surrebuttal).
[750] Ex. DOC-3 at 52 (Soderbeck Direct).
[751] Ex. Xcel-82 at 14 and Sched. 3a-c, page 2, row 84, column 10 (Halama Rebuttal).
[752] Ex. DOC-5 at 19-20 (Soderbeck Surrebuttal).
[753] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 185 (Halama).
[754] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 186-187 (Halama).

adjustment would only total $3.7 million if this capital addition amount was in service for the full 12 months of 2024).[755]

597. In its initial brief, the Department recommended that the Commission require removal of all costs associated with IVVO as it was unclear that had been accomplished.[756] The Department also argued that Xcel did not provide information identifying the capital additions for replacement services and, therefore, that the Company had not established that the items were used and useful for the provision of utility service.

598. The cancellation of a project does not, by itself, require the Company to forego recovery of actual capital investments deployed to complete the project or for the combined purpose of planned and existing projects.[757]

599. The Company's explanation for the $1.8 million in 2024 is sufficient to establish that its adjustment to the 2024 rate base would be more reasonable than a $3.7 million reduction. The amount is a correctly calculated adjustment to 2024 net plant in service reflecting the average net plant in service during the year.

600. The $0.2 million amount for 2023 was not specific to IVVO and so its removal is not required only as a consequence of not deploying IVVO. However, the Company's explanation for continuing to include the amount in its rate base is insufficient to meet its burden. The Company's witness stated that the amount was placed in service, and considered used and useful, in 2022.[758] The Company provided no detail about the nature of the capital additions, except to claim that they were for "replacement service."[759] There is no ability, on this record, for a regulator to confirm that the capital additions were used and useful in the provision of utility service.

601. The Judge recommends that the Commission adopt Xcel's proposed rate base reductions to remove IVVO together with the Department's recommendation to require that Xcel ensure that the removal includes the $0.2 million rate base addition in 2023.

28. Insurance Premium Expenses

602. The Company estimated its insurance premium expense at the Minnesota Electric Jurisdiction basis as $20.7 million, $22.4 million, and $25.2 million in 2022, 2023,

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[755] Evid. Hrg. Tr. Vol. 1 (Dec. 13, 2022) at 186-187 (Halama).
[756] *See* DOC Initial Br. at 95–96.
[757] *See, e.g., Northern States Power Co. v. Minnesota Public Utilities Commission*, 344 N.W.2d 374, 378 (Minn. 1984) ("In general, regulators have allowed recovery of investment and cancellation costs of abandoned projects through rates."); *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-001/GR-10-276, FINDINGS OF FACT CONCLUSIONS AND ORDER at 33 (Aug. 12, 2011) ("The Commission concludes that there is no public interest or regulatory benefit to be gained by disallowing costs prudently incurred in good-faith to meet future need. And there is much to be lost by potentially chilling a utility's diligence in developing resources and in promptly withdrawing from projects when experience shows that they will no longer serve ratepayers' best interests.").
[758] Evid. Hrg. Tr. Vol. 1 at 185–186 (Halama).
[759] *Id*.

and 2024, respectively.[760] These amounts are net of budgeted distributions from mutual insurance and captive insurance providers. The amounts do not include the costs associated with workers' compensation coverage.[761]

603. Company witness Robert Miller explained that insurance costs are impacted by the insurance market conditions and the Company's exposure metrics that are evaluated annually. To determine insurance market conditions, the Company consults with insurance brokers to identify if markets will be trending up, trending down, or staying flat. The Company then evaluates its exposure metrics, such as number of employees, miles of pipes and wires, and changes to the value of insurable assets.[762]

604. The amounts for insurance expense in the test years are significant increases from actual expenses incurred in 2021. The increase from 2021 to 2022 is particularly pronounced.[763] All test-years percentage increases are also significant compared to Xcel's historical actual expense from 2017 to 2021.[764]

605. Xcel's test year insurance budget is generally based on insurance premiums paid in the prior two years, which are then adjusted to account for the identified trends in insurance market conditions and the Company's exposure metrics. The budget also accounts for distributions from mutual insurance pools and captive insurers, which can fluctuate year-to-year.[765]

606. Xcel's primary explanation for the cause of the substantial increases was that "Year over year variances . . . occur for numerous reasons, including overall market conditions, inflation, and actual expense."[766] Xcel's Director of Hazard Insurance, Robert Miller, testified that the current insurance market is "hard" and that "increase in premiums will continue due to adverse industry loss experience."[767]

607. Mr. Miller explained that a hardening market means that insurance capacity is reducing, which allows insurance companies to increase premiums pursuant to basic supply and demand principles. This hardening in the insurance market impacted the Company's 2022 premiums and is projected to continue.[768]

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760 Ex. Xcel-62, RLM-D-3 (Miller Direct).
761 Ex. Xcel-62 at 17 (Miller Direct).
762 Ex. Xcel-62 at 18 (Miller Direct).
763 Ex. DOC-4 at 26, HS-D-15 (Soderbeck Direct) (Not Public Version) (data from Ex. Xcel-62, RLM-D-3 (Miller Direct) & Xcel's Response to DOC IR 1113). Because Xcel designated much of its insurance premium expense as Not Public Trade Secret information, this report does not include specific amounts and figures but instead provides a general analysis. However, the Administrative Law Judge recommends the Commission review the specific figures, which are informative. *See* Ex. Xcel-62, RLM-D-3 (Miller Direct) (Not Public Version); Ex. DOC-4 at 24–32, HS-D-13–15 (Soderbeck Direct) (Not Public Version); Ex. DOC-6 at 29–34 (Soderbeck Surrebuttal).
764 Ex. DOC-4 at 26, HS-D-15 (Soderbeck Direct) (Not Public Version) (data from Ex. Xcel-62, RLM-D-3 (Miller Direct) & Xcel's Response to DOC IR 1113).
765 Ex. Xcel-62 at 18-19 (Miller Direct).
766 Ex. DOC-3, HS-D-13 at 1 (Soderbeck Direct) (Xcel Response to DOC IR 1113).
767 Ex. Xcel-64 at 4 (Miller Rebuttal).
768 Ex. Xcel-62 at 20 (Miller Direct).; Ex. Xcel-64 at 4 (Miller Rebuttal).

608. Mr. Miller also explained that there is a general upward trend in claim experience across the industry with respect to Primary Casualty Insurance. This trend is driven by the increase in catastrophic events such as hurricanes and wildfires.[769]

609. The Company's insurance premium forecasting process was an accurate predictor of 2022 insurance premium costs, and the Company's Total Xcel Energy insurance premium expense forecast is just $289,000 under budget, a variance of only 0.4%.[770]

610. The Department argued that Xcel had failed to show that the increased insurance expenses were reasonable. The Department recommended an alternative forecast that reduced the significant increase from 2021 to 2022 but maintained Xcel's percentage increase from 2022 to the 2023 and 2024 plan years.[771]

611. The Department did not identify specific concerns with the Company's process of forecasting its insurance premiums. Department witness Ms. Soderbeck did not dispute during the evidentiary hearing that the Company's 2022 forecast was "quite accurate," that she had no basis to disagree with Mr. Miller's statements regarding the hardening of the insurance market, that she had no basis to disagree with Mr. Miller's statement regarding the upward trend of industry losses, that she had not undertaken an investigation of her own into insurance trends, and that the Department's recommendation results in a reduction of over $9 million for 2022 alone.[772]

612. The Company has met its burden to establish the reasonableness of its proposed insurance premium expenses in the MYRP. The record in this proceeding demonstrates the accuracy and thoroughness of the Company's insurance premium expense forecasting methodology. The validity of the Company's forecasting method is supported by the small variance between the forecast and actual expenses in 2022. Company witness Mr. Miller credibly explained the reasons for the predicted upward trend in the Company's insurance premiums.

613. Although recommendations to use historical data in lieu of doubtful forecasts can be a reasonable alternative to complete disallowance in circumstances where a utility has not met its burden, that is not the case here.

614. The Judge recommends that the Commission approve the Company's proposed Insurance Premium Expense amounts and not adopt the Department's proposed adjustment.

[769] *See* Ex. Xcel-62 at 12, 29, 46 (Miller Direct).
[770] Ex. Xcel-64 at 4 (Miller Rebuttal).
[771] *See* Ex. DOC-3 at 29–30 (Soderbeck Direct).
[772] Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 90-92 (Soderbeck).

29. Organizational Dues

615. The Company's rate request included certain dues that the Company pays to be a member of certain utility associations and Chambers of Commerce (collectively, these dues are referred to as "organizational dues").[773]

616. OAG opposes Xcel's request to recover dues for two organizations—the Edison Electric Institute (EEI) and the American Gas Association (AGA)—arguing that Xcel has not proven that membership is reasonable and necessary for the provision of electric service.[774] The OAG also recommends that Xcel only be allowed to recover 50% of the dues it incurs to be a member of state, regional, or local chambers of commerce because these organizations engage in economic-development activities that benefit Xcel's shareholders.[775]

617. The parties also dispute whether these organizational dues are "employee expenses" subject to Minn. Stat. § 216B.16, subd. 17 (2022) (the Employee Expenses Statute), and the legal standard that applies to review of those expenses.

i. Legal Standard

618. Under the Employee Expenses Statute, "[t]he commission may not allow as operating expenses a public utility's travel, entertainment, and related employee expenses that the commission deems unreasonable and unnecessary for the provision of utility service."[776]

619. The statute requires utilities to file with a general rate case petition a schedule separately itemizing "all travel, entertainment, and related employee expenses as specified by the commission, including but not limited to the following categories: . . . (6) dues and expenses for memberships in organizations or clubs."[777]

620. OAG cites a 1982 Commission Statement of Policy on Organization Dues.[778] Among other things the policy statement recommends that a utility seeking recovery for organizational dues should provide testimony explaining the primary purpose of the organization and other information relevant to evaluating the connection between the expense and reasonable and reliable utility service.[779] The policy statement does not have the force and effect of law; it instead describes "the starting point of the Commission's decision, but the final decision will depend on the facts of the case."[780]

[773] Ex. Xcel-79 at 75 (Halama Direct) (referring to workpapers for "Assn Dues" and "Chamber of Commerce Dues"); Ex. Xcel-8 at 2 of 3, VIII A2 and A4 (Application, Vol. 4, MYRP Workpapers) (containing detailed information concerning utility association dues and Chamber of Commerce dues).
[774] OAG's Initial Br. at 30.
[775] OAG's Initial Br. at 39.
[776] Minn. Stat. § 216B.16, subd. 17.
[777] *Id*.
[778] Ex. OAG-2, sched. SL-D-1 (Lee Direct).
[779] *Id*. at 1–2.
[780] *Id*. at 1.

621. The Commission's Statement of Policy on Organization Dues relies upon "basic standards of utility regulation" that have not been shown on this record to have changed since the statement was issued.

622. The OAG has previously raised Minn. Stat. § 216B.16, subd. 17, when analyzing recoverability of individual and corporate organizational dues.[781] The OAG recommends that the Commission:

> [C]larify that corporate dues are costs that fall under section 216B.16, subdivision 17, and require the Company to continue providing the information required under the statute for all dues costs for which it seeks recovery, regardless of the membership level or type of membership—including corporate dues, Chambers of Commerce dues, and individual professional-association dues.[782]

623. The Commission recently affirmed that, where a utility has not clearly established how membership dues connect to the provision of utility service or that service would be impaired without those dues, dues are not recoverable from ratepayers.[783]

624. The Company disagrees that the Employee Expenses Statute applies to the disputed organizational dues. It argues that the statute only refers to *employee* memberships. The Company provided an example: a Company employee who is an engineer might be a member of the American Society of Mechanical Engineers (ASME), pay a few hundred dollars each year to remain in good standing as a member of the ASME, and if appropriate, be reimbursed for that expense.[784]

625. The organizational dues at issue are not incurred by individual employees. Rather, the EEI, AGA, and Chamber dues are paid directly by the Company to the organizations.[785]

626. The Company argues that the recoverability of the Company's request for the EEI, AGA, and Chamber of Commerce dues should be analyzed not under the Employee Expenses Statute, but under "the normal legal standard that governs all expenses in rate cases: rates must be just and reasonable, with a balance between the interests of the utility, its shareholders, and its customers."[786]

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[781] Ex. Xcel-74 at 10–11, n.10 (Cash Rebuttal).
[782] Ex. OAG-9 at 37 (Lee Surrebuttal); OAG's Initial Br. at 35.
[783] *See In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 24–25 (Feb. 1, 2022) (2022 Otter Tail Order).
[784] Ex. Xcel-74 at 4 (Cash Rebuttal); Xcel's Initial Br. at 106 (citing Minn. Stat. § 216B.16, subd. 4; *In re Interstate Power Co. for Authority to Change its Rates for Gas Service in Minnesota*, 574 N.W.2d 408, 411 (Minn. 1998).
[785] Ex. Xcel-74 at 3–5 (Cash Rebuttal).
[786] Xcel's Initial Br. at 106.

627. The parties' dispute about applicability of the Employee Expenses Statute is largely academic because it focuses on a distinction without a material difference for either the standard or burden of proof on this issue. [787] The Employee Expenses Statute requires that the Commission disallow expenses that are unreasonable and unnecessary for the provision of utility service. This standard is consistent with the standard applied to expenses by the Commission, generally, under Minn. Stat. § 216B.16.

628. Utility rates must be just and reasonable.[788] A rate based in part upon an unreasonable expense would itself be unreasonable. And rates must give due consideration to "the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service."[789] That is, there must be a connection between an identified expense and a utility-service-related need.

629. The Commission routinely examines the need for and reasonableness of utility expenses outside the context of the Employee Expenses statute.[790] Utilities have also described the ordinary standard under Minn. Stat. § 216B.16 as allowing recovery for "reasonable and necessary expenses[.]"[791]

630. Additionally, under Minn. Stat. § 216B.16, subd. 19 (the Multiyear Rate Plan Statute), rates "must be based only upon the utility's reasonable and prudent costs of service."

631. The Employee Expenses Statute chiefly establishes statutory filing requirements for certain expense categories to assist the Commission in evaluating the need for and reasonableness of those expenses. Whether or not the Employee Expenses Statute's filing requirements apply to a given expense, the Company bears the burden to establish the rate recoverability of its claimed expenses by a preponderance of the evidence.[792] The Company therefore bears the risk, if it does not adequately support the need or reasonableness of its expenses, of having those expenses denied rate recovery.

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[787] The filing requirement aspect of subdivision 17 is discussed below; however, the Commission has already determined that the Company's initial rate case filing "substantially complies" with § 216B.16. ORDER ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIMELINE at 2 (Dec. 23, 2021).
[788] Minn. Stat. § 216B.16, subds. 4, 6.
[789] *Id*.
[790] *See, e.g.*, 2022 Otter Tail Order at 21 (discussing economic development expenses), 23 (discussing spending for "ground line inspection"); CenterPoint 2015 Rate Case Order at 12–13 (determining a pipeline safety and integrity management project to be necessary and reasonable); 2018 Minn. Power Rate Case Order at 21 (requiring utilities to demonstrate the necessity and reasonableness of recovery for capital costs), 22–23 (approving recovery for capital additions because the amount was reasonable and the utility demonstrated necessity).
[791] *See, e.g.*, CenterPoint 2015 Rate Case Order at 66 (discussing CenterPoint's position relating to "recovery of its reasonable and necessary expenses and capital investments").
[792] *See* Minn. R. 1400.7300 ("The party proposing that certain action be taken must prove *the facts at issue* by a preponderance of the evidence" (emphasis added)).

632. Utilities can be required to file information supporting an expense in a manner and with sufficient time to give parties an adequate time to review the expenses proposed for rate recovery.[793]

633. Whether Minn. Stat. § 216B.16, subd. 17, applies to the Company's organizational dues expenses has not been shown to materially affect the analysis of rate recovery for the expenses in this proceeding. Accordingly, the Judge does not reach the question.

634. The Judge recommends that the Commission determine that rate recoverability of corporate organizational dues expenses will be evaluated on a case-by-case basis in light of the facts of the case.

635. The Commission may impose specific filing requirements relating to organization dues for the Company's next general rate case filing that it deems necessary to evaluate the recoverability of the expenses.

ii. Edison Electric Institute (EEI) Dues

636. Edison Electric Institute is a trade organization that represents all U.S. investor-owned electric companies.[794] The Company's request for EEI dues is estimated at $1.02 million for 2022, $1.01 million for 2023, and $1.01 million for 2024.[795]

637. EEI lobbies on behalf of its members.[796] Xcel does not dispute that it would be unreasonable for ratepayers to fund EEI's lobbying activities.

638. Each year, EEI issues an invoice to the Company stating the total amount of dues to be paid (for the entire Company), and also stating the percentage of those dues that is attributable to lobbying.[797] As it pays the dues, the Company assigns the lobbying portion to a general ledger account for lobbying, which is accounted for "below-the-line" (meaning it is not part of the Company's rate request).[798]

639. EEI's calculation of the lobbying portion of its dues based upon a federal IRS definition of lobbying.[799]

[793] *See* 2018 Minn. Power Rate Case Order at 21 (discussing the showing required for capital project expenses).
[794] Ex. Xcel-74 at 9 (Cash Rebuttal).
[795] Ex. Xcel-74 at 8-9 (Cash Rebuttal).
[796] Ex. OAG-2, sched. SL-D-1 (Lee Direct).
[797] Ex. Xcel-74 at 6, 8, Scheds. 2 and 3 (Cash Rebuttal).
[798] Ex. Xcel-74 at 6, 8 (Cash Rebuttal).
[799] Ex. OAG-2 at 8 (Lee Direct).

640. The Company's process in this proceeding is consistent with the Company's practice in the last several rate cases, which the Commission has found to be reasonable in the past.[800]

641. OAG argued that removing dues for activities that EEI identified as meeting the IRS definition of "lobbying" does not establish that the remaining dues are recoverable from ratepayers.[801] It contends that the IRS definition was developed for a different purpose than ratemaking and, accordingly, removing expenses that meet this definition does not prove that all the remaining expenses are reasonable and necessary for the provision of utility service.[802]

642. The OAG highlighted developments since the Company's 2015 rate case that supported its request for closer scrutiny of EEI dues expenses.[803]

643. OAG pointed to a recent decision by the Kentucky Public Service Commission (KPSC) as supporting its argument. The KPSC disallowed EEI dues in their entirety because the utility seeking recovery failed to provide sufficient detail about EEI's activities. The utility provided only a letter from EEI stating that "the amount identified by EEI for 'lobbying and political activities' is calculated pursuant to Section 162I of the [Internal Revenue Code]" and that "EEI does not separately account for activities that could be described as 'regulatory advocacy, and public relations.'"[804] The KPSC found the letter insufficient to justify dues recovery, reasoning that a utility has an "affirmative burden of proof as to the reasonableness of expenses."[805] The KPSC further reasoned that "[m]erely identifying a portion of costs incurred that a utility does not seek recovery of does not meet the threshold of reasonableness as to the remainder of expenses."[806]

644. OAG also cited a recent rate case involving Otter Tail Power (OTP), in which the Commission concluded that dues should be removed from rates if "it is unclear how the membership dues connect to the provision or improvement of utility service" and denied OTP's request for dues for the Utility Air Regulation Group (UARG) and the Lignite Energy Council (LEC).[807]

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[800] S*ee, e.g., In re Application of Minn. Power for Auth. To Increase Rates for Elec. Serv. in Minn.*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 40 (Mar. 12, 2018) ("By using the organizations' invoices to subtract the portion of its membership dues attributable to lobbying, the Company has reasonably accounted for any non-recoverable lobbying expenses.").
[801] Ex. OAG-2 at 9 (Lee Direct).
[802] Ex. OAG-2 at 8–9 (Lee Direct).
[803] Ex. OAG-2 at 9 (Lee Direct).
[804] *In the Matter of Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, ORDER at 25–26 (June 30, 2021), *available at* https://psc.ky.gov/order_vault/Orders_2021/202000349_06302021.pdf.
[805] *Id*. at 28.
[806] *Id*.
[807] Ex. OAG-3 at 9 (Lee Direct) (*citing In re Application of Otter Tail Power Co. For Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 24–25 (Feb. 1, 2022).

645. The Company argued that there is no practical way for it to review EEI's activities, specifically to determine if any of the remaining dues are used for lobbying.[808] The Company also argued that the KPSC decision cited by OAG is "based on a different record and by a different regulatory body, about a Kentucky utility has next to no relevance in this proceeding."[809]

646. At issue is whether the Company has established the reasonableness of rate recovery for the portion of EEI dues that it did not exclude from its request as lobbying expenses.[810]

647. Membership in EEI provides benefits to the Company and its consumers, such as public policy leadership, strategic business intelligence, and essential conferences and forums.[811] The importance of the services provided to electric utilities, and thus to consumers, through membership in EEI has been recognized in prior rate cases.[812]

648. However, the Company did not rebut evidence that EEI does not separately account for activities that could be described as "regulatory advocacy, and public relations." The Company instead argued that it cannot practically determine what portion of non-lobbying dues to EEI might otherwise constitute a non-recoverable expense. However, it is the Company's burden to establish that its dues expenses should be recovered from ratepayers. Although Xcel has shown that EEI dues provide ratepayer benefits, it has not shown that EEI's method of distinguishing recoverable and nonrecoverable expenses is sufficient to rely upon as a basis to conclude that the remaining dues expense is fully recoverable.

649. The Commission has, in another proceeding, required that a utility account for subscription expenses attributable to legal activities, including billing-hour details.[813] If EEI's accounting to its members is inadequate for its members and their regulators to distinguish dues amounts eligible for rate recovery, that shortcoming and the resulting uncertainty should fall on the Company and not ratepayers.

650. That the Commission has approved recovery for the non-lobbying portion of EEI dues in the past does not preclude it from excluding them from recovery in this

[808] Ex. Xcel-74 at 11 (Cash Rebuttal).
[809] Xcel Initial Br. at 110.
[810] *See* OAG Initial Br. at 10 (stating that "the Commission should scrutinize the remaining portion of the EEI dues and require the Company to meet its statutory burden to show that the remaining "non-lobbying" amount is reasonable and necessary for the provision of utility service.").
[811] Ex. Xcel-74 at 9 (Cash Rebuttal).
[812] *See, e.g.*, *In re Application of Minn. Power for Auth. To Increase Rates for Elec. Serv*., MPUC Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 15 (Nov. 7, 2017) ("The work of three of the organizations Applicant is seeking recovery of dues for—Edison Electric Institute [and two other organizations not at issue here]—is reasonable, appropriate, and provides indirect benefit to [Minnesota Power's] customers"); *In re Otter Tail Power Co*., MPUC Docket No. E-017/GR-10-239, Findings of Fact, Conclusions, and Order at 34 (Apr. 25, 2011) ("The dues to EEI [and another organization not at issue] do benefit ratepayers by providing information and expertise the Company could not acquire on its own without higher cost").
[813] 2022 Otter Tail Order at 24–25.

proceeding. The Commission's prior decisions allowing recovery were based on a different record.

651. For these reasons, the Company has not established the reasonableness of recovery of the non-lobbying portion of EEI dues.

652. The Judge recommends that the Commission adopt the OAG recommendation to remove $1,021,000 (MN jurisdiction) from the 2022 test year, $1,011,000 (MN jurisdiction) from the 2023 plan year, and $1,012,000 (MN jurisdiction) from the 2024 plan year for EEI dues.

iii. AGA Dues

653. The AGA is an industry association for companies that engage in activities associated with or affiliated with the natural gas industry.[814] The Company's request for AGA dues is estimated at $365,000 for 2022, $361,000 for 2023, and $362,000 for 2024.[815]

654. The Company provided a lengthy description of the benefits that come from its membership in the AGA, such as forums, training, and other vehicles through which Company employees exchange information with peers; resources that the Company could not create on its own, such as operating manuals; and information related to managing natural gas supplies for generation facilities.[816]

655. The OAG argues that because Xcel's customers in this rate case receive electric service from Xcel, not gas service, they should not have to pay the cost of AGA dues.[817] The OAG contends that its position finds support in the Commission's decision in a recent rate case where the Commission disallowed a gas utility's request to recover EEI dues because the utility did not provide sufficient evidence of how its membership in EEI was reasonably related to providing safe and reliable natural gas service.[818]

656. The Company provided a credible description of how membership in the AGA provides significant benefits to the Company's electric operations and electric customers.[819] First, membership in the AGA helps the Company manage its procurement of natural gas for its natural gas electric generation facilities.[820] Second, membership in the AGA assists with properly and safely handling the location of gas and electric lines.[821]

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[814] Ex. Xcel-74 at 13 (Cash Rebuttal).
[815] Ex. Xcel-74 at 14 (Cash Rebuttal).
[816] Ex. Xcel-74 at 13-15 (Cash Rebuttal).
[817] Ex. OAG-2 at 15 (Lee Direct).
[818] *In the Matter of the Petition by Great Plains Natural Gas Co. for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 9 (Oct. 26, 2020).
[819] Ex. Xcel-74 at 14-15 (Cash Rebuttal).
[820] Ex. Xcel-74 at 14 (Cash Rebuttal).
[821] Ex. Xcel-74 at 14-15 (Cash Rebuttal).

Finally, the AGA is a leader in the development of hydrogen technology, which is an important element of the Company's decarbonization vision for electricity generation.[822]

657. Unlike the Great Plains matter, Xcel has provided sufficient and detailed evidence demonstrating how membership in the AGA benefits the Company's electric operations and customers.

658. The Company has demonstrated the reasonableness of its requested AGA dues.

659. The Judge recommends that the Commission approve recovery for the requested AGA dues.

iv. Chamber of Commerce Dues

660. The Company requests $156,286 for dues to 68 different Chambers of Commerce for the 2022 test year, and the same amount for the 2023 and 2024 plan years.[823] Xcel's request is separate from specifically identified economic development contributions, which are accounted for elsewhere and for which the Company sought only 50% recovery.[824]

661. Under Minn. Stat. § 216B.16, subd. 13, the Commission "may allow a public utility to recover from ratepayers the expenses incurred for economic and community development." The Commission's traditional practice has been to allow utilities to recover half of their economic development costs though rates, leaving utility shareholders to bear the other half. This practice reflects the Commission's judgment that, since shareholders benefit from the increased economic activity that results from this spending, they also should share in the costs.[825]

662. It is undisputed that only 50% of economic development costs should be recovered in rates.[826] The OAG asserts that the chambers of commerce dues should be treated as economic development costs and therefore the Company's request should be halved.[827]

[822] Ex. Xcel-74 at 15 (Cash Rebuttal).
[823] Ex. Xcel-74 at 17 (Cash Rebuttal); Ex. OAG-2 at 5, 16 (Lee Direct).
[824] Ex. Xcel-74 at 18 (Cash Rebuttal).
[825] *See In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21 (Feb. 1, 2022) ("Shareholders as well as customers benefit from economic development activities, because increased economic activity in the Company's service territory is likely to result in increased energy usage to fuel these activities. Because only a portion of the activity's benefit accrues to customers, it is appropriate for the Company to only recover a portion of the total economic development cost.").
[826] Ex. OAG-3 at 18 (Lee Direct); Ex. Xcel-74 at 18 (Cash Rebuttal).
[827] Ex. OAG-3 at 17 (Lee Direct).

663. To support its request, the Company provides the mission statements for each chamber.[828] More than 58 of the chambers of commerce, or over 85%, indicate that their mission is to further business and economic activity.[829]

664. However, chambers of commerce play roles in their communities beyond economic development.[830] By paying dues to be a member of a Chamber of Commerce, the Company demonstrates to that Chamber's community that the Company is a part of, and a supporter of, that community.[831] Chamber activities also provide a vehicle for the Company to interact with and hear from customers in those communities, so that it can provide better service.[832] By paying Chamber dues, the Company "gains opportunities, information, and resources beyond economic development."[833]

665. The Company has met its burden to show the reasonableness of its requested recovery for Chamber of Commerce dues. The Company has demonstrated that the dues provide a ratepayer benefit over and above the benefit of economic development.

666. The Judge recommends that the Commission allow the recovery of Chamber of Commerce dues and not adopt the OAG's recommended adjustment.

30. Advertising Costs

667. Xcel requests $317,439 in each year of the MYRP for certain advertising expenses.[834]

668. Consistent with past rate case precedent, the Company included for recovery advertising expenses related to providing information on safety, customer information, and general non-program specific conservation messages. The Company included samples of its advertising in its Initial Filing as requested by the Commission's June 14, 1982 Statement of Policy on Advertising.[835]

669. In its initial filing, Xcel identified FERC Account 912 as "Economic Development," and included costs for "Customer Program – Advertising."[836]

670. The OAG argued that advertising done for the purpose of economic development is properly treated as an economic-development expense and recovered at 50%.[837]

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828 Ex. OAG-2 at 16 (Lee Direct).
829 Ex. OAG-2 at 17 (Lee Direct).
830 Ex. Xcel-74 at 18 (Cash Rebuttal).
831 Ex. Xcel-74 at 18 (Cash Rebuttal).
832 Ex. Xcel-74 at 18 (Cash Rebuttal).
833 Ex. Xcel-74 at 18 (Cash Rebuttal).
834 Ex. OAG-2 at 2 (Lee Direct).
835 Ex. Xcel-5, Vol. 3, Section III.1 (Initial Filing).
836 Ex. Xcel-5, Vol. 4, MYRP Workpapers, VIII A1 (Initial Filing) (eDockets No. 202110-179109-01).
837 Ex. OAG-2 at 5 (Lee Direct).

671. The Company continues to recommend full recovery of recoverable advertising costs included in its Initial Filing.

672. The OAG had the opportunity to review the Company's provided examples of advertisements and did not identify any advertising samples that, in its view, are related to economic development.

673. According to the Company, if the costs at issue were associated with economic development, the Company would have included these costs in the Economic Development Administrative adjustment and limited these costs to 50% cost recovery.[838]

674. FERC Account 912 is defined as "Demonstrating and Selling Expenses."[839]

675. The Judge finds credible and persuasive the testimony that the Company mislabeled FERC Account 912 in its workpaper, and that amounts attributed to FERC Account 912 are recoverable advertising expenses rather than economic development expense.

676. The costs at issue, reflected in FERC Account 912 and the General Ledger Account as Customer Program – Advertising and Customer Program – Promotion, are correctly included as recoverable advertising costs and are not related to economic development costs, and more particularly, mostly originate from renewable and choice program business areas.[840]

677. The Judge finds that the costs shown in the Company's Initial Filing for advertising expenses reflect a reasonable level of advertising costs to include in final rates for 2022–2024.

678. The Judge recommends that the Commission approve Xcel's proposed advertising expenses and not adopt the OAG's recommendation.

B. 2023 and 2024 Sales Forecast

679. Test year sales volumes—including numbers of customers and energy sales—are important factors in calculating a utility's likely revenue deficiency and, thus, its revenue requirement. Additionally, sales volumes also are used to allocate costs in the Class Cost of Service Study and in rate design.[841]

680. Because the Commission must establish rates for sales that take place after Xcel filed its rate case, it must rely on forecasts of future sales volumes in setting rates. An essential part of the Commission's review of Xcel's rate request is to review Xcel's proposed sales forecasts to determine whether they are reasonable.[842]

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838 Ex. Xcel-82 at 34-35 (Halama Rebuttal).
839 Ex. Xcel-82 at 34 (Halama Rebuttal).
840 Ex. Xcel-82 at 34-35 (Halama Rebuttal).
841 Ex. DOC-9 at 2 (Shah Direct).
842 Ex. DOC-9 at 2 (Shah Direct).

681. In its rebuttal testimony, Xcel submitted updated sales forecasts for 2023 and 2024.

682. Xcel's updated sales forecast was developed in June 2022 using updated regression models with actual sales and customer data through May 2022 and the June 2022 IHS Markit economic outlook in the forecasting models.[843] This updated sales forecast removed the impact of IVVO on the sales forecast in 2024.[844]

683. Xcel recommends that the updated sales forecasts for 2023 and 2024 be used for purposes of setting rates in this proceeding and to serve as a baseline for the company's decoupling proposal.[845]

684. The Department recommends that, if the Commission decides to continue Xcel's sales true-up mechanism subject to the consumer protections the Department has proposed, that the Commission use, for rate-making purposes, Xcel's sales forecasts as initially filed with its rate case, and updating the sales volumes for the 2022 test year with up-to-date actual sales data for 2022.[846]

685. The Department offered the following reasons for its recommendation: (1) a properly designed decoupling mechanism provides Xcel a reasonable opportunity to recover the allowed revenue, regardless of the reasons for the variance in actual revenue; (2) economic uncertainty increases the potential downside risk of the updated forecasts, thus increasing the likelihood of a surcharge; (3) Xcel was unable to provide all of the data necessary for the Department to develop an alternative forecast; and (4) given that Xcel's forecasts have been overstated, using the initial forecast represents the more conservative approach.[847]

686. The Company's updated sales forecasts for 2023 and 2024 rely on the same regression models and methodologies as the Company's initially-filed sales forecasts.[848] The only difference is that these updates sales forecasts incorporate more recent sales and economic data.[849] The Company provided evidence to demonstrate that sales forecasts produced closer in time to the forecasted period provide more accurate results.[850]

687. The Department's reasons in support of its recommendation are unpersuasive. As the Department has argued in this proceeding, it is generally more reasonable to use updated forecasts when they are available, unless specific methodological shortcomings or other reasons for increased unreliability are identified.

[843] Ex. Xcel-77 at 8–9 (Goodenough Rebuttal).
[844] Ex. Xcel-77 at 8 (Goodenough Rebuttal).
[845] Ex. Xcel-77 at 8 (Goodenough Rebuttal).
[846] Ex. DOC-10 at 11 (Shah Surrebuttal).
[847] Ex. DOC-10 at 11–14 (Shah Surrebuttal).
[848] Ex. Xcel-77 at 8-9 (Goodenough Rebuttal).
[849] Ex. Xcel-77 at 8-9 (Goodenough Rebuttal).
[850] Ex. Xcel-75 at 11 (Goodenough Direct) (The Company's 1-year ahead forecasts were, on average, 1% higher than actual sales whereas the Company's 5-year ahead forecasts were, on average, 5.7% higher than actual sales.).

The Department does not provide a reason to conclude that the updated forecast is more unreliable than the initially-filed forecast, it only asserts that if the forecast proves unreliable, there may be a greater likelihood of a surcharge true-up adjustment.

688. The Department's evidence relevant to whether the updated forecast may be based upon a more unstable economic environment was inconclusive.[851]

689. The Company's updated sales forecasts are based on sound statistical methodologies and provide a reasonable estimate of 2023 and 2024 MWh sales and customer counts. These updated sales forecasts for 2023 and 2024 also reflect more recent sales and economic data. The Department, in contrast, has not established that the initially filed forecasts, based on older data, are more reasonable or reliable.

690. The Judge recommends that the Company's updated forecasts be used for purposes of setting rates and as a baseline for the Company's revenue decoupling proposal.

C. Cost of Capital

1. Return on Equity (ROE)

i. Introduction and Legal Standard

691. The only remaining cost of capital issue in this proceeding concerns the return on equity (ROE) to be allowed.

692. Public utilities must be able to obtain funds in the capital markets sufficient to offer safe, reliable electric service at reasonable rates. To secure these funds, the Commission must allow a return that is commensurate with the returns expected elsewhere for investments of equivalent risk.[852]

693. Acknowledging the necessity of a commensurate return, Minn. Stat. § 216B.16, subd. 6, states:[853]

> 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.

[851] Ex. DOC-10 at 12–13 (Shah Surrebuttal) ("there are indications of differing interpretations on levels of economic activity").
[852] Ex. Xcel-27 at 7–8 (D'Ascendis Direct).
[853] Minn. Stat. § 216B.16, subd. 6.

694. The United States Supreme Court established the hallmarks of a reasonable return on capital, including a reasonable rate of return on common equity, in the landmark cases of *Bluefield* and *Hope*.[854] The Court has stated, "What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts."[855]

695. The Court has also stated that:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By this standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[856]

696. The Minnesota Supreme Court has adopted the *Bluefield* and *Hope* requirements, including *Bluefield*'s command that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[857]

697. The *Hibbing* Court further described the establishment of a rate of return as a quasi-judicial function which involves a factual determination of "a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk,"[858] and stated that "[t]o peg an established rate to a rate advocated by any one of several expert witnesses is an arbitrary delegation of that duty."[859]

698. The Commission has observed that "[s]etting the cost of equity is a fact-intensive and record-specific judgment."[860] The Commission considers the record as a

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[854] *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679, 43 S. Ct. 675 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281 (1944).
[855] *Bluefield*, 262 U.S. at 692, 43 S. Ct. at 679.
[856] *Hope*, 320 U.S. 591 at 603, 64 S. Ct. at 288 (citation omitted).
[857] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980), citing *Bluefield*, 262 U.S. at 690, 43 S. Ct. at 678.
[858] *Hibbing*, 302 N.W.2d at 9–10 (quoting *Northwestern Bell Telephone Co. v. State*, 299 Minn. 1, 5–6, 216 N.W.2d 841, 846 (1974)).
[859] *Hibbing*, 302 N.W.2d at 11.
[860] *In re Appl. of Minn. Energy Res. Corp. for Auth. to Increase Rates for Nat. Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-17-563, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 26 (Dec. 26, 2018) (eDockets No. 201812-148702-01) (MERC 2017 Rate Case Order).

whole, with the objective of establishing a reasonable return based on the record in its entirety.[861]

699. To determine a recommended reasonable return, the Commission has historically relied on expert witnesses' analytical modeling methods, as well as the application of judgment, applied to comparable (or "proxy") companies, to identify a range of reasonable ROEs and, ultimately, determine an allowed ROE.[862]

700. A reasonable ROE helps maintain the Company's earnings and cash flows, thereby supporting its credit ratings and allowing the Company to access capital at reasonable rates.[863] Strong credit ratings, in turn, keep borrowing costs low.[864]

701. The allowed ROE has a substantial financial impact on the utility's revenue requirement and, therefore, on what consumers must pay. In this case, each additional basis point of authorized ROE adds approximately $810,000 to Xcel's revenue deficiency.[865]

702. Xcel's most recently approved ROE is 9.06%. In adopting this ROE in connection with its review of Xcel's 2017 Transmission Cost Recovery rider petition, the Commission ordered that this ROE remain in place until Xcel's next rate case.[866]

ii. Summary of the Parties' Positions

703. The parties' recommended ROEs are summarized as follows:

Xcel	10.20%
The Department	9.25%
CUB	8.80%–9.0%
XLI	9.16%

704. In Direct Testimony, Xcel Energy recommended an ROE of 10.20% within an indicated range of 9.65% to 11.65%.[867] In Rebuttal Testimony, the Company continued to recommend an ROE of 10.20% after updating its models with more current data, resulting in a higher indicated range of 10.05% to 12.05%.[868] The Company provided a

[861] MERC 2017 Rate Case Order at 26.
[862] Ex. Xcel-27 at 13 (D'Ascendis Direct).
[863] Ex. Xcel-24 at 28 (Johnson Direct).
[864] Ex. Xcel-22 at 14–15 (Chamberlain/Liberkowski Direct).
[865] Ex. DOC-1 at 48 (Addonizio Direct).
[866] *See In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor,* MPUC Docket No. E-002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS at 7-8 (Sept. 27, 2019) (e-Docket No. 201991-156134-01) (Xcel 2017 TCR Order).
[867] Ex. Xcel-27 at 4, Table 1 (D'Ascendis Direct).
[868] Ex. Xcel-28 at 7, Table 2 (D'Ascendis Rebuttal).

set of analyses, including a Constant Growth Discounted Cash Flow (DCF) model, a Two-Growth DCF model, two Capital Asset Pricing Models and two RPM analyses.[869]

705. The Department recommended an ROE of 9.25%.[870] The Department provided a set of analyses, including a Constant Growth DCF model, a Two-Growth DCF model, and a CAPM, but stated that it "anchored" its analysis using a Multi-Stage DCF model in support of its recommendation.[871] As discussed below, the Department urged the Commission to distinguish Xcel's cost of equity from its authorized return on equity as part of its analysis.[872]

706. In Direct Testimony, XLI recommended an ROE of 9.17%.[873] In Surrebuttal Testimony, XLI recommended an ROE of 9.16%.[874] XLI provided a set of analyses, including a Constant Growth DCF model, a Two-Growth DCF model, three CAPM analyses, and an RPM analysis.[875]

707. CUB recommends an ROE in the range of 8.80% to 9.00%.[876] CUB's recommendation is not based in utility risk or financial models, as CUB argues that ROE should be based on public policy analysis.[877]

iii. Proxy Groups

708. One standard method for estimating the cost of equity of a private company like Xcel is to develop a proxy group of publicly-traded companies that pose similar risks to equity investors as the non-public company and then apply cost models to the members of the proxy group to infer the non-public company's cost of equity.[878]

709. A reasonable proxy group should be established to meet the requirement of *Hope* that the return on equity should be comparable to returns on investments with similar risks.[879]

710. Xcel's ROE witness, Dylan D'Ascendis, proposed a list of regulated utilities as a proxy group, which the Company referred to as its "Utility Proxy Group." For his Utility Proxy Group, Mr. D'Ascendis used eight different screening criteria to develop a proxy group of thirteen vertically-integrated electric utilities that are most analogous to the

[869] Ex. Xcel-27 at 25–52 (D'Ascendis Direct).
[870] Ex. DOC-2 at 2 (Addonizio Surrebuttal).
[871] Ex. DOC-1 at 53 (Addonizio Direct).
[872] CUB's witness Dr. Steve Khim shared this view. Ex. CUB-2 at 6–7 (Khim Direct).
[873] Ex. XLI-4 at 25–26 (LaConte Direct).
[874] Ex. XLI-6 at 9–12 (LaConte Surrebuttal).
[875] Ex. XLI-4 at 15 (LaConte Direct).
[876] Ex. CUB-2 at 49 (Kihm Direct).
[877] Ex. CUB-2 at 49 (Kihm Direct).
[878] Ex. DOC-1 at 11 (Addonizio Direct); Ex. XLI-4 at 17 (LaConte Direct).
[879] Ex. XLI-4 at 19 (LaConte Direct).

Company. Mr. D'Ascendis updated his proxy group in his Rebuttal Testimony, excluding two companies and adding one, for a final list of twelve proxy companies.[880]

711. Xcel's final Utility Proxy Group comprises: Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Duke Energy Corporation; Edison International; Entergy Corporation; Evergy, Inc.; IDACORP, Inc.; NorthWestern Corporation; OGE Energy Corporation; and Portland General Electric Company; and Xcel Energy, Inc.[881]

712. Xcel's ROE recommendations also rely on a Non-Price Regulated Proxy Group, including such well-known and diverse companies as Alphabet, Inc., Lockheed Martin, and Pfizer. Xcel's ROE witness contended the group presented comparable risk to the Utility Proxy Group.[882]

713. As described in his Direct Testimony, Mr. D'Ascendis' Non-Price Regulated Proxy Group consisted of 50 companies.[883] In his rebuttal testimony, Mr. D'Ascendis added some companies to the list and dropped others, resulting in a new list of 39 companies that comprised his Non-Price Regulated Proxy Group.[884]

714. To develop an appropriate proxy group for estimating Xcel's cost of equity, the Department first compiled a list of all U.S. companies categorized as electric utilities by Value Line, a well-known investor service.[885] The Department then applied various screens designed to make sure the proxy group companies were reasonably comparable to Xcel.[886] Eliminating companies from the proxy group as a result of these screens produced a list of 16 companies.[887]

715. In its Surrebuttal Testimony, the Department removed one company from the proxy group and adding another to account for developments since the filing of direct testimony.[888]

716. The Department's final proxy group included the following companies: ALLETE, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power

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[880] Ex. Xcel-27 at 25–29 (D'Ascendis Direct); Ex. Xcel-28 at 4–6 (D'Ascendis Rebuttal). Mr. D'Ascendis excluded Otter Tail Corporation because it no longer met his screening criteria and Pinnacle West Capital Corporation because of a major development involving its main subsidiary. Ex. Xcel-28 at 4–5 (D'Ascendis Rebuttal). Mr. D'Ascendis added American Electric Power Company, Inc. because it met all of his screening criteria based on 2021 fiscal year data. *Id.* at 6.
[881] Ex. Xcel-27 at 17 (D'Ascendis Direct).
[882] Ex. Xcel-28 at Schedule 1, p. 33 (D'Ascendis Surrebuttal).
[883] Ex. Xcel-27 at Schedule 8, pp. 1, 3 (D'Ascendis Direct).
[884] Ex. Xcel 28 at Schedule 1, pp. 31, 33 (D'Ascendis Surrebuttal).
[885] Ex. DOC-1 at 11 (Addonizio Direct).
[886] Ex. DOC-1 at 12–13 (Addonizio Direct); see also Ex. DOC-1, CMA-D-2 (Addonizio Direct) (detailing the Department's proxy group screening process).
[887] Ex. DOC-1 at 11–14 (Addonizio Direct).
[888] Ex. DOC-2 at 4 (Addonizio Surrebuttal). Mr. Addonizio excluded Pinnacle West Capital Corporation because it no longer had two positive-earnings-growth rates from equity analysts. He added American Electric Power Company, Inc., which had initially been excluded due to merger activity; Mr. Addonizio was no longer concerned about the merger activity's distortive effects. *Id.*

Company, Inc.; Avista Corporation; CMS Energy Corporation; Duke Energy Corporation; Entergy Corporation; Evergy, Inc.; IDACORP, Inc.; NextEra Energy, Inc.; NorthWestern Corporation; OGE Energy Corporation; Otter Tail Corporation; Portland General Electric Company and the Southern Company.[889]

717. XLI's analyses used a proxy group of twelve utilities.[890] Twelve of the thirteen companies in Mr. D'Ascendis's initial Utility Proxy Group are in XLI's proxy group.[891]

718. Unlike the Company, XLI excluded Xcel's parent company from its proxy group, regarding its inclusion as circular.[892] Department witness Mr. Addonizio states that his practice is to exclude the parent company from the proxy group, but that Mr. D'Ascendis's is "far from alone" in including it and there is not a clear answer on the question.[893]

719. XLI's proxy group included the following companies: Alliant Energy Corporation; Ameren Corporation; Duke Energy Corporation; Edison International; Entergy Corporation; Evergy, Inc.; IDACORP, Inc.; NorthWestern Corporation; OGE Energy Corporation; Otter Tail Corporation; Pinnacle West Capital Corporation; and Portland General Electric Company.[894]

720. CUB used a proxy group comprising 38 electric utilities by applying its analyses to all electric utility stocks in the Value Line Investment Survey.[895] CUB's witness explained that he regarded the practice of carefully selecting a proxy group to be "often counterproductive," for two reasons: (1) "all firms in the same industry have about the same cost of capital;" and (2) a larger proxy group is superior for statistical reasons.[896]

iv. Proxy Groups Analysis

721. The Department and XLI opposed the use of a proxy group of non-price-regulated companies for determining an approved ROE on the basis that the companies do not reflect a comparable risk to investors.[897]

722. The Company asserted that the non-price regulated proxy group is similar in risk to the electric utility proxy group and therefore provides relevant information.[898] More precisely, the Company contended that the *aggregate* risk of the Non-Price

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[889] *See* Ex. DOC-1 at 14 (Addonizio Direct) (listing initial proxy group); Ex. DOC-2 at 4 (Addonizio Surrebuttal) (listing and explaining proxy group modifications); Ex. DOC-2, CMA-S-1 (Addonizio Surrebuttal) (detailing the Department's proxy group screening process, as updated).
[890] Ex. XLI-4 at 18–19 (LaConte Direct).
[891] *Id*. at 19.
[892] *Id*.
[893] DOC-1 at 69 (Addonizio Direct).
[894] Ex. XLI-4 at 18–19 (LaConte Direct).
[895] Ex. CUB-2 at 10–13 (Kihm Direct).
[896] *Id*.
[897] Ex. DOC-2 at 70-71 (Addonizio Surrebuttal); Ex. XLI-4 at 20 (LaConte Direct).
[898] Ex. Xcel-28 at 79-80 (D'Ascendis Rebuttal).

Regulated Proxy Group is similar to the Company's risk "even though individual risks may vary."[899]

723. The Company's Non-Price Regulated Proxy Group is of limited probative value for the exercise of determining "a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk."[900] The non-regulated companies have dramatically different businesses from Xcel and from one another and, as the Company acknowledges, as individual businesses their risks have not been shown to be comparable to Xcel's risk.[901]

724. Xcel has failed to show that the companies making up its proposed Non-Price Regulated Proxy Group present investment risks comparable to those of Xcel or that this group should be used to estimate Xcel's cost of equity.

725. The Judge recommends that the Commission give the Company's Non-Price Regulated Proxy Group little weight in determining a fair ROE.

726. CUB has failed to establish the reasonableness of its proxy group. Attributes besides sharing an industry are unquestionably relevant to comparing the relative risk of two companies.[902] There are material differences in business and financial risk among utilities.[903] Dr. Khim's testimony that firm-specific risk factors are irrelevant for developing a reasonable proxy group and that only systematic, macroeconomic risks affect a utility's cost of equity is inconsistent with credible testimony in this proceeding that factors in addition to a business's industry are relevant for determining a reasonable proxy group.

727. The Judge recommends that the Commission give CUB's proxy group little weight in determining a fair ROE.

728. The Judge credits Mr. Addonizio's testimony that there is no "clear answer" with respect to whether a parent company should be excluded from a proxy group for these purposes. On this record, it is no more reasonable to exclude Xcel Energy, Inc., from an appropriate proxy group than to include it.

729. Although they differ slightly, the investment risk of the regulated-utility proxy groups used by the Company, the Department, and XLI to develop their ROE recommendations are reasonably comparable to Xcel's. Each party offered reasonable explanations for including or excluding a particular company from its proxy group.

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[899] Ex. Xcel-28 at 80 (D'Ascendis Rebuttal).
[900] *Hibbing*, 302 N.W.2d at 9–10 (quoting *Northwestern Bell Telephone Co. v. State*, 299 Minn. 1, 5–6, 216 N.W.2d 841, 846 (1974)).
[901] Ex. DOC-2 at 70-71 (Addonizio Surrebuttal); Ex. Xcel-28 at 80 (D'Ascendis Rebuttal).
[902] *See* Ex. Xcel-28 at 128 (D'Ascendis Rebuttal) (discussing risk-relevant dissimilarities between Xcel and members of the CUB proxy group).
[903] See *Id*. (discussing risk-relevant dissimilarities among utilities).

730. Differences between the Department's and the Company's lists of proxy regulated utilities are not material.[904]

731. However, XLI's proxy group remained unchanged despite Pinnacle West Capital Corporation no longer having positive earnings growth rates from two equity analysts, which was among XLI's screening criteria.[905] XLI's witness acknowledged that Xcel has positive growth forecasts and that it is important for proxy group companies to have similar growth prospects.[906]

732. Because Xcel's and the Department's proxy groups and analyses were updated during the course of the proceeding, they reflect more current information and therefore are more reliable than XLI's proxy group and analysis.[907]

v. Financial Models

733. There are various methodologies that may be used to estimate a reasonable ROE.

734. In this proceeding, parties offered cost of equity calculations based on the following models: Discounted Cash Flow (DCF), Capital Asset Pricing (CAPM), Risk Premium, and Residual Income.

735. The DCF model is a cost equity model that is commonly used to estimate a company's cost of equity. The DCF model is based on the financial theory that the current price of a stock equals the present value of all expected future dividends in perpetuity discounted by the appropriate cost of equity (i.e., the compensation for the risks associated with owning the stock).[908]

736. The DCF model estimates a company's cost of equity using a company's known stock price and its most recent dividend, which are directly observable, and the company's expected future growth rate.[909] The DCF model postulates that the current price of a stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return.[910]

737. The DCF methodology has been widely used in regulatory proceedings for decades.[911]

[904] Ex. DOC-1 at 69 (Addonizio Direct).
[905] *See* Ex. XLI-4 at 17–18 (LaConte Direct) (listing screening criteria); Ex. XLI-6, Schedule 1 (LaConte Surrebuttal) (listing proxy group members); Ex. DOC-2 at 4 (stating that Pinnacle West Capital Corporation no longer had two positive earnings growth rates from equity analysts).
[906] Ex. XLI-4 at 18 (LaConte Direct).
[907] *See* Ex. Xcel-28 at 8–9 (discussing the importance of current market information for ROE analysis).
[908] Ex. DOC-1 at 8-10 (Addonizio Direct).
[909] Ex. DOC-1 at 8-15 (Addonizio Direct).
[910] Ex. DOC-1 at 8 (Addonizio Direct).
[911] Ex. DOC-1 at 10 (Addonizio Direct); Ex. XLI-4 at 15 (LaConte Direct); Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 34–35 (LaConte).

738. There are three DCF models in this record: constant growth, two-growth or two-stage, and multi-stage. Constant growth DCF is used where dividends are expected to grow at a constant rate over time.[912] Two-stage DCF uses growth forecasts to model dividend growth in years one through five, and then applies a different growth rate for years six and beyond.[913]

739. The Department's multi-stage DCF assumes dividends initially grow at one rate for five years (the first stage), then transition (through the second stage) to a final growth rate, which is sustained in perpetuity (the third stage). The Department applied the model twice: once with a second stage of ten years, and once with a second stage of 20 years.[914]

740. CAPM's basic premise is that through diversification, investors can effectively eliminate the effects of any company-specific risks. Therefore, the only risk that matters for the purpose of estimating cost of equity is the systematic risk of the stock, or the stock's tendency to move in tandem with the market as a whole.[915]

741. While the CAPM is theoretically sound, empirical studies have shown it does a poor job explaining equity returns.[916] The Commission has recognized the diminished reliability of the CAPM for estimating a reasonable ROE.[917]

742. The Risk Premium model is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk.[918] According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity.[919]

743. Models that develop cost of equity estimates based on prior return on equity decisions, such as the Risk Premium model, are circular and do not provide information about the returns investors require.[920]

744. The Commission has historically relied on the Risk Premium method less heavily, as the model is backward-looking and more prone to volatile and unreliable outcomes.[921]

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[912] Ex. DOC-1 at 9 (Addonizio Direct).
[913] Ex. DOC-1 at 24 (Addonizio Direct).
[914] Ex. DOC-1 at 10 (Addonizio Direct).
[915] Ex. DOC-1 at 29 (Addonizio Direct).
[916] Ex. DOC-1 at 30 (Addonizio Direct).
[917] *See In re Pet. By Great Plains Nat. Gas Co., a Division of Montana-Dakota Utilis., Co., for Auth. to Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 17 (Oct. 26, 2020) (eDockets No. 202010-167656-01).
[918] Ex. Xcel-27 at 30 (D'Ascendis Direct).
[919] Ex. Xcel-27 at 31 (D'Ascendis Direct).
[920] Ex. CUB-2 at 7–8 (Khim Direct).
[921] *In re Pet. By Great Plains Nat. Gas Co., a Division of Montana-Dakota Utilis., Co., for Auth. to Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-004/GR-19-511, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 15 (Oct. 26, 2020) (eDockets No. 202010-167656-01).

745. The Residual Income model is a method of determining a cost of equity using the current stock price, the book value of equity (per share), return on equity, and long-run sustainable growth.[922]

vi. Xcel's Proposed ROE

746. Xcel recommended a ROE of 10.20%.[923]

747. To reach this recommendation, Company witness Mr. D'Ascendis developed two proxy groups, a utility proxy group and a non-price regulated proxy group.[924]

748. Mr. D'Ascendis applied the following analytical models to his two proxy groups:

(1) Constant Growth DCF, which posits that investors buy stocks for an expected total return rate, derived from cash flows received from dividends and market price appreciation.[925]

(2) Two-Growth DCF, which moderates the effect of substantially high or low near-term growth estimates on the DCF result.[926]

(3) Predictive RPM (PRPM), which uses historical volatility to predict future volatility, which can then be translated to an equity risk premium.[927]

(4) Total Market Approach RPM, which develops three different equity risk premiums, using different measures for those premiums.[928]

(5) CAPM, which adds a risk-free rate of return to a market risk premium, adjusted to reflect the systematic risk of the individual security relative to the market, as measured by the Beta coefficient.[929]

(6) Empirical CAPM (ECAPM), which recognizes that low-beta securities earn returns somewhat higher than CAPM would predict and high-beta securities earn somewhat less than predicted.[930]

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[922] Ex. CUB-2 at 21 (Kihm Direct).
[923] Ex. Xcel-28 at 7-9 (D'Ascendis Rebuttal).
[924] Ex. Xcel-27 at 13 (D'Ascendis Direct).
[925] Ex. Xcel-27 at 25–29 (D'Ascendis Direct).
[926] Ex. Xcel-27 at 29–30 (D'Ascendis Direct).
[927] Ex. Xcel-27 at 30–35 (D'Ascendis Direct).
[928] Ex. Xcel-27 at 34–48 (D'Ascendis Direct).
[929] Ex. Xcel-27 at 48–55 (D'Ascendis Direct).
[930] Ex. Xcel-27 at 49–52 (D'Ascendis Direct).

749. The results of Company witness Mr. D'Ascendis' initial analysis and recommendation were:[931]

Model/Analysis	Result, Adjustment Amount, or Range
Discounted Cash Flow Models	8.78%
Risk Premium Models	10.95%
Capital Asset Pricing Models	12.53%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.24%
Indicated Range of Common Equity Cost Rates Before Adjustments[932]	9.65% – 11.65%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.13%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	9.65% – 11.65%
Recommended Cost of Common Equity	**10.20%**

750. Over a year passed between the filing of this case and the filing of Rebuttal Testimony. During this period, dramatic changes in the market environment occurred, such as a significant increase in inflation as measured by the Consumer Price Index, which statistical analysis shows has a strong correlation to authorized ROEs for electric companies.[933]

[931] Ex. Xcel-27 at 4, Table 1 (D'Ascendis Direct).
[932] The Company's indicated range "is equal to 100 basis points above and below the midpoint of the Company's four model results." Ex. Xcel-27 at 4, n.4 (D'Ascendis Direct). However, the mean of the four models in the table is 11.13% not 10.65%. 10.65% is the result if one takes the mean of *five* numbers: (1) Constant Growth DCF; (2) Two-Growth DCF; (3) Risk Premium; (4) CAPM; and (5) an aggregate result of those same models for the Company's Non-Price Regulated Proxy Group. Ex. Xcel-27 at 59 (D'Ascendis Direct).
[933] Ex. Xcel-28 at 9–12, 17 (D'Ascendis Rebuttal).

751. Mr. D'Ascendis updated the modeling in Rebuttal Testimony which resulted in the following:[934]

Model/Analysis	Result, Adjustment Amount, or Range
Discounted Cash Flow Models	9.30%
Risk Premium Models	11.65%
Capital Asset Pricing Models	12.06%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.91%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.10% – 12.10%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.18%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	10.05% – 12.05%
Recommended Cost of Common Equity	**10.20%**

752. As shown in the above table, to be conservative, Mr. D'Ascendis maintained a recommendation of 10.20% despite an increase in the indicated range of common equity rates.[935]

753. Removing the non-price regulated proxy group from Mr. D'Ascendis' models still results in an Indicated Range of Common Equity Cost Rates after Adjustment of 9.66% to 11.66%.[936]

754. Xcel relied on an average of the mean and median results of its two-growth DCF results to arrive at a conclusion for the two-growth DCF-indicated common equity cost rate for the Utility Proxy Group.[937] The updated two-growth DCF results for the Company's Utility Proxy Group were 9.83% (mean) and 9.75% (median) to yield a two-growth DCF-indicated common equity cost rate of 9.79% (average of mean and median).[938]

[934] Ex. Xcel-28 at 7, Table 2 (D'Ascendis Rebuttal).
[935] Ex. Xcel-28 at 7, Table 2 (D'Ascendis Rebuttal).
[936] Ex. Xcel-28 at 79-80 (D'Ascendis Rebuttal).
[937] Ex. Xcel-27 at 30 (D'Ascendis Direct).
[938] Ex. Xcel-28 at DWD-2, Schedule 1 at 3 (D'Ascendis Rebuttal).

755. The Company's 9.79% two-growth DCF-indicated common equity cost rate does not include a flotation cost adjustment.[939] The Company asserts that an adjustment of 0.08% is necessary to reflect flotation costs applicable to the Utility Proxy Group.[940]

vii. The Department's Proposed ROE

756. The Department recommended an ROE of 9.25%.[941]

757. The Department estimated Xcel's cost of equity by applying a multi-stage Discounted Cash Flow analysis to its proxy group.

758. The Department's multi-stage DCF has three stages. In the first stage—years one through five—the model assumes that dividends grow at the forecasted growth rates predicted by equity analysts for the proxy group companies. In the second stage, a proxy company's dividend growth rate moves linearly from the equity analyst growth rate to projected growth of GDP (i.e., the value of the total output of goods and services in the national economy).[942] In the third stage, the model assumes that dividends for the proxy group companies grow at the same rate as GDP. The Department used two different intervals for the second stage transition period: 10 years and 20 years.[943]

759. In surrebuttal testimony, the Department updated the stock prices, dividends, and forecasted growth used as modeling inputs to reflect changes in market conditions. The table below summarizes the Department's updated multi-stage DCF analysis, which includes a flotation cost adjustment (*i.e.,* costs to issue new shares of common stock, such as legal fees and costs of underwriting):[944]

Summary of Updated Multi-Stage DCF Results
Adjusted for Flotation Cost

	Mean Low ROE	Mean Avg. ROE	Mean High ROE
Multi-Stage DCF with 10-year 2nd stage	7.83%	8.50%	9.66%
Multi-Stage DCF with 20-year 2nd stage	8.03%	8.74%	9.82%

760. In addition to the multi-stage DCF discussed above, Mr. Addonizio supplemented the record with results from three of the cost models that Xcel's expert

[939] Ex. Xcel-27 at 73 (D'Ascendis Direct).
[940] Ex. Xcel-27 at 73 and DWD-1, Schedule 12 (D'Ascendis Direct).
[941] Ex. DOC-2 at 2 (Addonizio Surrebuttal).
[942] Ex. DOC-1 at 20 (Addonizio Direct).
[943] Ex. DOC-1 at 20, 23-24 (Addonizio Direct).
[944] Ex. DOC-1 at 28 (Addonizio Direct); Ex. DOC-2 at 5 (Table 3) (Addonizio Surrebuttal).

relied on: a constant growth DCF analysis, a two-stage DCF analysis,[945] and a Capital Asset Pricing Model (CAPM) analysis.[946]

761. Mr. Addonizio relied primarily on the multi-stage DCF model rather than the constant growth and two-growth versions of the DCF model because he concluded that the constant growth and two-growth DCF used unsustainable growth rates.[947]

762. The range of results of the Department's cost-of-equity models—multi-stage, constant growth DCF, two-growth DCF, and CAPM—incorporating the most up-to-date inputs, are shown in the table below:

Range of Department's Cost of Equity Model Results –
All Figures Adjusted to Include Flotation Costs

Model	Mean Low	Mean Average	Mean High
Multi-Stage DCF w/10-year 2nd Second Stage[948]	7.83%	8.50%	9.66%
Multi-Stage DCF w/20-year 2nd Stage[949]	8.03%	8.74%	9.82%
Constant Growth DCF[950]	9.04%	9.94%	10.68%
Two-Growth DCF[951]	9.09%	9.88%	10.52%
CAPM w/10-Year Growth Transition Period[952]	6.39%	6.75%	7.63%
CAPM w/10-Year Growth Transition Period[953]	7.13%	7.43%	8.16%

763. In addition to the results of equity cost models, Mr. Addonizio also considered other cost-of-equity evidence as part of his analysis. These additional "real

[945] Ex. DOC-1 at 15–19, 25 (Addonizio Direct).
[946] Ex. DOC-1 at 29-34 (Addonizio Direct).
[947] Ex. DOC-1 at 19-20, 25 (Addonizio Direct).
[948] Ex. DOC-2 at 5, Table 2 (Addonizio Surrebuttal).
[949] Ex. DOC-2 at 5, Table 2 (Addonizio Surrebuttal).
[950] Ex. DOC-2 at 5, Table 3 (Addonizio Surrebuttal).
[951] Ex. DOC-2 at 5, Table 3 (Addonizio Surrebuttal).
[952] Ex. DOC-2 at 6, Table 4 (Addonizio Surrebuttal).
[953] Ex. DOC-2 at 6, Table 4 (Addonizio Surrebuttal).

world" data points confirmed the general reasonableness of the Department's multi-stage DCF analysis.[954] This additional evidence included:

i. Reports of various equity research firms and investment banks regarding cost of equity for Xcel's parent company, Xcel Energy. These reports reflected an estimated cost of equity that was substantially below the authorized ROEs for other electric utilities during the same general timeframe.[955]

ii. Long-term return estimates for U.S. equities from well-known, highly regarded investment managers; a well-known annual survey of professors, analysts, and corporate managers; and a survey conducted by the Richmond Federal Reserve Bank of Chief Financial Officers.[956] These estimates were for U.S. equities generally and not specific to utility stocks. Because utility stocks are generally considered less risky, on average, these estimates likely exceed the expected returns for utility stocks.[957]

iii. Xcel's expected return on its pension trust investments.[958]

764. The Department does not recommend setting Xcel's authorized ROE equal to its multi-stage DCF results in this proceeding. The Department relies upon an analysis of the market-to-book ratio of the Department's proxy group over the past 20 years suggesting a persistent practice on the part of regulators of setting ROEs above the cost of equity.[959]

765. Mr. Addonizio compared ROE determinations in recent fully-litigated rate cases with estimates of the proxy group's average cost of equity and the yield on 30-year U.S. Treasury bonds.[960]

766. Based on this comparison, Mr. Addonizio recommended an ROE of 9.25%, which is significantly above Xcel's estimated cost of equity (as estimated by the Department's multi-stage DCF results) and at the lower end of the range of recent decisions.[961]

viii. XLI's Proposed ROE

767. XLI initially recommended an ROE of 9.17% in Direct Testimony.[962]

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[954] Ex. DOC-1 at 35–36 (Addonizio Direct).
[955] Ex. DOC-1 at 35 (Addonizio Direct).
[956] Ex. DOC-1 at 35-36 (Addonizio Direct).
[957] Ex. DOC-1 at 36 (Addonizio Direct).
[958] Ex. DOC-1 at 36 (Addonizio Direct).
[959] Ex. DOC-1 at 41-42 (Addonizio Direct).
[960] Ex. DOC-1 at 48-50, Figure 2 (Addonizio Direct).
[961] Ex. DOC-1 at 51 (Addonizio Direct).
[962] Ex. XLI-4 at 25–26 (LaConte Direct).

768. XLI ultimately recommended an ROE of 9.16% in Surrebuttal Testimony.[963]

769. XLI witness Billie LaConte applied to her proxy group the Constant Growth DCF (developing low, mean, and high results) and Two Growth DCF models, along with three different CAPM analyses and a Risk Premium analysis. Ms. LaConte agrees with the Company that these models "are standard methods that have been used for years to determine the appropriate ROE for utilities."[964]

770. The results of XLI's initial analysis and recommendation were:[965]

	Low	Mean	High
Constant Growth DCF	7.23%	8.60%	10.28%
Two-Stage DCF		8.55%	
CAPM Historical MRP		9.91%	
CAPM Proj. VL MRP		14.46%	
CAPM Proj. S&P MRP		8.32%	
Risk Premium Model		9.42%	

771. In Surrebuttal Testimony, Ms. LaConte did not update her analyses with more current financial information. Therefore, XLI's low, mean and high Constant Growth DCF, Two Growth DCF, RPM and two of her three CAPM results remained identical and do not reflect the most current financial market conditions.[966]

772. Ms. LaConte testified that her recommended ROE range, based on quantitative and qualitative analysis was 8.55% – 10.28%. To arrive at that range, she excluded the Constant Growth DCF low result because it is based on growth assumptions that were unreasonably low,[967] and relied on the Two-Stage DCF to set the lower end of the range, and the Constant Growth DCF high result for the upper end.

773. Ms. LaConte then applied a 25-basis point downward adjustment "to recognize [the Company's] reduced financial risk" compared to the utilities in her proxy group due to its decoupling mechanism and the MYRP to arrive at a final ROE recommendation of 9.17% in her Direct Testimony.[968]

[963] Ex. XLI-6 at 9–12 (LaConte Surrebuttal).
[964] Ex. XLI-4 at 15 (LaConte Direct); Evid. Hrg. Tr. Vol. 2 (Dec. 14, 2022) at 34–35 (LaConte).
[965] Ex. XLI-4 at 15 (LaConte Direct).
[966] *Cf*. Ex. XLI-4 at 15, Table 2 (LaConte Direct) and Ex. XLI-6 at 7, Table 2 (LaConte Surrebuttal).
[967] XLI-4 at 16 (LaConte Direct).
[968] Ex. XLI-4 at 25-26 (LaConte Direct).

774. Ms. LaConte acknowledged an error in her initial forecast market risk premium CAPM analysis that, when corrected, raised the result of that analysis from 8.32% to 11.66%. This raised her recommended ROE, prior to adjustments, by 24 basis points to 9.66%. Ms. LaConte then doubled her financial risk downward adjustment to 50-basis points, resulting in a final recommended ROE of 9.16%; one basis point lower than her original recommendation.[969]

ix. CUB's Proposed ROE

775. CUB recommended an ROE in the range of 8.80% to 9.00%.[970]

776. Dr. Kihm applied a Residual Income Model, which he asserted is essentially an algebraic re-expression of the DCF model, to all 38 electric utility stocks in the *Value Line Investment Survey*, resulting in a 7% cost of equity estimate; and applied a CAPM to the same list of 38 stocks, resulting in a cost of equity of 7.4%.[971]

777. Dr. Kihm's Residual Income model assumes that growth does not exceed the GDP growth rate.[972]

778. Despite these results, Dr. Kihm recommends an ROE of 8.80% to 9.00%, an increase over the cost of equity results based upon an analysis that a "fair return on equity typically lies above the cost of equity," and that a reasonable return for Xcel should be lower but that gradualism supported a result between 8.80% to 9.00% in this case.[973]

779. To reach this recommendation, CUB witness Dr. Kihm indicated "determining the degree to which [an allowed] return should lie above the cost of equity has nothing to do with utility risk or financial models. It is a subjective call based on public policy analysis, not corporate finance."[974] Dr. Kihm further explained that "[m]y recommendations are based on my judgment, which is the only way we can proceed when mixing a strict finance variable . . . with a fairness-based policy variable . . . .."[975]

x. Flotation Cost Adjustments

780. Flotation costs are the costs of issuing new shares of common stock, and include compensation for the investment banks underwriting the issuance, legal fees, a registration fee paid to the United States Securities and Exchange Commission, etc.[976]

781. XLI contended that a flotation cost adjustment is not necessary because Xcel is not publicly traded and only Xcel's parent company incurs flotation costs.[977]

[969] Ex. XLI-6 at 7–12 (LaConte Surrebuttal); Evid. Hrg. Tr. Vol. 1 (Dec. 14, 2022) at 35 (LaConte).
[970] Ex. CUB-2 at 49 (Kihm Direct).
[971] Ex. CUB-2 at 21-28 (Kihm Direct).
[972] Ex. CUB-2 at 22 (Kihm Direct).
[973] Ex. CUB-2 at 49 (Kihm Direct).
[974] Ex. CUB-2 at 17 (Kihm Direct).
[975] Ex. CUB-2 at 50 (Kihm Direct).
[976] Ex. DOC-1 at 26 (Addonizio Direct).
[977] Ex. XLI-4 at 38 (LaConte Direct).

782. A flotation cost adjustment is necessary to fairly compensate investors for flotation costs incurred in all past equity issuances. Flotation costs are permanent, meaning an adjustment is required for flotation costs incurred for all past issuances; otherwise investors will not receive their required return. Flotation costs have long been explicitly included in the Company's cost of debt issued in the past, and the same principle applies to the Company's issuance of common equity.[978]

783. The Company provided the data necessary to compute the Company's historical flotation cost.[979]

784. The Company and the Department applied eight-basis-point flotation cost adjustments when calculating their recommended ROEs.[980]

xi. Other Adjustments to Model Results

785. All parties offering ROE recommendations arrived at their recommended ROEs by including other adjustments from their model results, based on things such as business or financial risk,[981] bond rating,[982] and historical authorized ROEs.[983]

786. The parties offered reasons for making these adjustments, however, the analytical bases for these adjustments were disputed in the record.[984]

787. The purpose of applying models to a proxy group of companies is to estimate a reasonable ROE based on the investment risk of reasonably comparable companies.[985] Doing so is generally accepted as a method of determining an ROE that is consistent with the requirements of the Constitution and the law.[986]

It is not necessary to conduct a "relative risk analysis" of the proxy group or to make other adjustments to an analytically derived ROE based on a reasonable proxy group.[987] Such comparisons are themselves subject to judgment calls about the relative risks, and the exercise of estimating the cost of equity is too imprecise to reliably estimate such small differences.[988]

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978 Ex. DOC-1 at 27 (Addonizio Direct).
979 Ex. DOC-1 at 28 (Addonizio Direct).
980 *Id*.
981 Ex. XLI-4 at 26 (LaConte Direct) and XLI-5 at 10–11 (LaConte Surrebuttal) (adjusting for financial risk); Ex. Xcel-28 at 8 (D'Ascendis Rebuttal) (adjusting for relative business risk).
982 Ex. Xcel-28 at 8 (D'Ascendis Rebuttal).
983 Ex. DOC-1 at 50–51 (Addonizio Direct).
984 See Ex. DOC-1 at 93–97 (Addonizio Direct) (contesting Xcel's adjustments); Ex. Xcel-28 at 31–33 (contesting the Department's adjustments), 116–119 (contesting XLI's adjustments), and 124–126 (contesting CUB's adjustments) (D'Ascendis Rebuttal).
985 Ex. Xcel-27 at 13 (D'Ascendis Direct).
986 Id. (citing *Bluefield* and *Hope*).
987 Ex. DOC-1 at 57 (Addonizio Direct).
988 Ex. DOC-1 at 57–58 (Addonizio Direct).

xii. Analysis

788. For the following reasons, the Judge regards the two-stage DCF methodology as the most reliable methodology in the record for determining a fair rate of return.

789. The Commission has generally regarded the two-stage DCF methodology as the most relevant and reliable method for determining an authorized return on equity.[989] In its 2022 Otter Tail Power Company rate case decision, the Commission wrote that "DCF modeling continues to offer analytically rigorous, substantial evidence to support a determination of the Company's cost of equity," particularly when the reasonableness of results are checked by other analytical approaches, such as CAPM and Risk Premium.[990]

790. The Commission has, on previous occasions, favored the two-stage DCF over a multi-stage DCF—most recently when determining Otter Tail Power's ROE because the projected growth rate used in the analysis was lower than the record supported.[991]

791. Gross Domestic Product (GDP), which the Department's multi-stage DCF uses, is not a market measure, but rather a measure of the value of the total output of goods and services, excluding inflation, across all private industry and government sectors. The relevant financial literature establishes that projected growth in earnings per share (EPS) is a superior measure of growth in a DCF model. EPS is incorporated into the Constant Growth DCF and Two Growth DCF models.[992]

792. The Department has rejected use of GDP forecasts in a Multi-Stage DCF model in the past because there was "no basis to believe that the growth in GDP would be comparable" to the growth of regulated utilities.[993]

793. GDP is the sum of all private industry and government output in the United States, and its growth is an average of the value of those components of the economy.[994] Between 1947 and 2021, seven industries, including utilities, grew faster than the overall GDP.[995]

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[989] *See, e.g.*, 2022 Otter Tail Order at 34 (Feb. 1, 2022).
[990] *Id*.
[991] *Id*.
[992] Ex. Xcel-28 at 39 (D'Ascendis Rebuttal).
[993] *In the Matter of the Application of CenterPoint Energy Minnesota Gas, a Division of CenterPoint Energy Resources Corp., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G008/GR-05-1380 at 31 (Nov. 2, 2006).
[994] Ex. Xcel-28 at 39–40 (D'Ascendis Rebuttal).
[995] Ex. Xcel-28 at 40 (D'Ascendis Rebuttal).

794. GDP growth forecasts primarily rely on productivity growth assumptions.[996] Assumptions about productivity growth used for the GDP growth forecasts are unreliable, particularly for the purpose of forecasting growth of a specific industry, in perpetuity.[997]

795. Although the GDP measure proposed by the Department is constituted of transparent, public-record data, the Department has not established that using a GDP growth forecast as a cap on utility growth rates is reasonable for this purpose. That the Department has opposed GDP growth forecasts' use for this purpose in the past diminishes the credibility of opinions that it should be used here, and suggests that proposals to use GDP growth are driven by the results derived therefrom.

796. Accordingly, the Commission should give greater weight to the two-stage DCF analyses in this record than to the Department's multi-stage DCF.

797. The CAPM has flaws that make it an unreliable tool when viewed in isolation. As the Commission has recognized, the CAPM "requires expert judgment at nearly every turn—determining the term of the risk-free, interest-bearing investments used as a benchmark, determining the time frame for calculating growth rates, determining the beta that represents market volatility, determining the historical periods over which to measure returns." This reliance on the analysts' judgment is unlike the DCF as "none of these inputs [in the CAPM] are simple matters of fact and public record."[998] The subjectivity of these judgments means there can be significant variation between analysts in their estimations of several inputs, which is compounded when the inputs are combined in the CAPM.[999]

798. The Company's and XLI's recommended ROEs are derived from a blend of models which includes the CAPM and Risk Premium Models. That is, the Company and XLI do not use these models as a check for reasonableness but include them as a part of their recommendations' computation. As a consequence, their ROE recommendations embed the subjective judgments and backwards-looking influences of the CAPM and Risk Premium models.

799. The Department and CUB both recommended that the Commission calculate the Company's cost of equity using methods that the Commission has disfavored, and then adjust the results of those methods upward by adding an unspecified adjustment factor to arrive at an approved return on equity.[1000] The lack of a clear principle for determining the adjustment amount leaves any such adjustment without adequate support in the record.

800. The arguments of the Department and CUB notwithstanding, the Commission's ROE determination requires a factual determination of "a fair rate of return

[996] Ex. Xcel-28 at 42 (D'Ascendis Rebuttal).
[997] *See* Ex. Xcel-28 at 42–44 (D'Ascendis Rebuttal) (discussing the reliability of productivity growth assumptions).
[998] MERC 2017 Rate Case Order at 25; s*ee also* Great Plains 2019 Rate Case Order at 17.
[999] Ex. DOC-1 at 30 (Addonizio Direct).
[1000] Ex. DOC-2 at 37 (Addonizio Surrebuttal); Ex. CUB-2 at 17 (Kihm Direct).

which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk."

801. To remain consistent with the requirements of *Hope* and *Bluefield*, the Commission should decline the invitation to develop an ROE that is not based upon record evidence. The Department's and CUB's recommended ROEs rely on methodologies that have not been shown on this record to accurately estimate a fair rate of return, plus a subjective adjustment factor that has no substantial support in the record.

802. The Department's and CUB's recommendations to set an approved ROE *above* the ROE established by their model and empirical analyses would be inconsistent with the requirements of *Hope* and *Bluefield*. If the Commission agrees that either model results in an ROE sufficient to provide earnings to investors comparable to businesses of similar risk, that ROE should be approved without adjustment.

xiii. ROE: Summary Conclusion, and Recommendation

803. The parties have offered a considerable array of methodologies for the Commission to choose from as a basis for the Company's authorized ROE. In addition, the parties' recommended ROEs are further derived from their own hand-picked blend of those methodologies and additional adjustments.

804. To heed the Court's caution in *Hibbing*, the Commission must provide an analysis based on facts in the record and must determine a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk.[1001]

805. As discussed in more detail above, the following findings inform the state of the record:

i. The Company's Non-Price Regulated Proxy Group and CUB's proxy group of 38 electric utilities have diminished probative value relative to proxy groups comprising companies shown to be more similar in investment risk to Xcel.

ii. Because they were not updated, XLI's proxy group and ROE recommendation have diminished probative value relative to the updated utility proxy groups and analyses of the Company and the Department.

iii. The Department's and CUB's ROE recommendations rely on growth rate assumptions that have not been established as reliable on this record.

[1001] "To peg an established rate to a rate advocated by any one of several expert witnesses is an arbitrary delegation of [the Commission's] duty." *Hibbing*, 302 N.W.2d at 11.

iv. The Department's and CUB's ROE recommendations require the Commission to compute the company's cost of equity using historically disfavored methods and then apply a subjective adjustment that lacks substantial record support.

v. The Company's and XLI's ROE recommendations rely on a blend of models, including CAPM and Risk Premium, which have doubtful reliability for establishing a reasonable ROE.

vi. It is reasonable to include a flotation cost adjustment of eight basis points.

vii. A reasonable ROE can be determined through an analytically rigorous method applied to a reasonable proxy group and it is not necessary to apply other adjustments such as for relative risk; doing so is more likely than not an exercise in false precision.

806. For these reasons, the Judge does not find any ROE recommended by a party to be sufficiently reliable to recommend its adoption.

807. The most reasonable, reliable methodology for determining a fair ROE in this record is the two-growth DCF methodology when applied to a reasonable proxy group of representative regulated utilities.

808. The Company's updated two-growth DCF results as applied to its Utility Proxy Group indicated a common equity cost rate of 9.79%, without a flotation adjustment. Adding the Company's recommended 0.08% flotation-cost adjustment results in a 9.87% ROE.[1002]

809. The Department's updated two-growth DCF results as applied to its proxy group, including a flotation adjustment, indicated a mean expected ROE of 9.88%.[1003]

810. That these results are within one basis point of one another, and within the Company's indicated range of common equity cost rates after adjustment (excluding its Non-Utility Proxy Group analyses), confirms the reliability of the method and reinforces the value of the two-growth DCF methodology as tool for estimating a reasonable return that minimizes reliance on subjectivity embedded within the other models and analyses.

811. The Judge recommends that the Commission find that the updated two-growth DCF results for the Company's Utility Proxy Group, with a flotation-cost adjustment, will result in a reasonable return on equity based on the record in its entirety, and authorize an ROE of 9.87%.

[1002] Ex. Xcel-27 at 73 and DWD-1, Schedule 12 (D'Ascendis Direct).
[1003] Ex. DOC-2 at CMA-S-9 (Addonizio Direct).

3. ROE Adjustment Mechanism

812. Xcel has proposed a mechanism that would automatically adjust its ROE in each year of the MYRP based on changes in interest rates on long term utility bonds.[1004]

813. The ROE adjustment mechanism would function by allowing the Company to increase its ROE for the 2024 plan year consistent with a proposed ROE adjustment methodology if financing rates increase significantly during the term of the MYRP, or requiring the Company to decrease its ROE for the 2024 plan year if financing rates decrease significantly during the term of the MYRP.[1005]

814. The Company's witness, Timothy S. Lyons, described the proposed ROE adjustment methodology as follows:[1006]

> . . . [T]he Company will track the deviations in Moody's Long-Term Utility Bond Yield for Aa-rated utilities against a Benchmark yield. The Benchmark yield is 2.89%, which is based on the average Moody's Aa utility bond yield for 12 months' ending September 2021 period.
>
> . . . [T]he Company will file in October 2023 a compliance filing that will include:
>
> 1. a comparison between the most recent October 2022 through September 2023 average Moody's Aa utility bond yield and the Benchmark yield,
>
> 2. adjustment to the Company's authorized 2024 ROE (if any) under the proposed ROE adjustment mechanism, and
>
> 3. the Company's updated 2024 rates to reflect the adjusted ROE (if applicable).
>
> If the deviation in October 2022 through September 2023 average yield does not exceed 100 basis points compared to the Benchmark yield, there will be no adjustment to the authorized ROE for 2024. Conversely, if the deviation in October 2022 through September 2023 average yield exceeds 100 basis points compared to the Benchmark yield, the authorized ROE for 2024 would be adjusted by 50.00% of the deviation between current yield and the Benchmark yield.

815. Mr. Lyons explained that the Company's recommended ROE adjustment mechanism is consistent with similar mechanisms for utilities in other states in that it is designed with several principles in mind, including that it:

[1004] Ex. Xcel-29, *passim* (Lyons Direct).
[1005] Ex. Xcel-29 at 13–14 (Lyons Direct).
[1006] *Id*.

- Tracks changes in economic and financial market conditions;
- Demonstrates a strong relationship with utility financial markets;
- Triggers ROE adjustments when there is a significant change in the financial market conditions and conversely does not trigger ROE adjustments when there is little to no changes in the financial market conditions;
- Tempers ROE adjustments to reflect only a portion of the changes in financial market conditions while avoiding volatility; and
- Streamlines the ROE adjustment process in a manner that relies on third-party financial data, is transparent, non-controversial, and easily replicated.[1007]

816. The Department, XLI, CUB, and the Commercial Group opposed the Company's proposed adjustment mechanism.

817. The opposing parties noted that the proposed adjustment baseline "all but assured" an upward adjustment if implemented.[1008] CUB witness Mr. Nelson testified that, "based on the design of the mechanism (e.g., a benchmark reflecting 2020 and 2021 interest rates and the trending inflation), the probability is skewed towards an ROE increase, and therefore, a shift of risk on to ratepayers."[1009] Department witness Mr. Addonizio raised similar concerns, noting that, had the mechanism been in place in 2022, it would have resulted in a 75-basis point ($65 million) rate increase.[1010]

818. The Company did not explain whether or how an upward adjustment in its ROE triggered by the proposed ROE true-up mechanism would allow for meaningful, timely consideration of customers' ability to pay for a corresponding rate increase resulting from that adjustment.

819. CUB argued that, in light of the above, the proposed ROE true-up mechanism would be inconsistent with the Supreme Court's requirement that authorized returns on equity balance the interests of a utility's investors and ratepayers and should be denied.[1011]

[1007] Ex. Xcel-29 at 12-13 (Lyons Direct).
[1008] Commercial Group's Initial Br. at 6; Ex. DOC-1 at 101 (Addonizio Direct).
[1009] Ex. CUB-3 at 6-7 (Nelson Surrebuttal).
[1010] Ex. DOC-1 at 98-101 (Addonizio Direct).
[1011] CUB Initial Brief at 27.

820. The Commission has stated that “[w]hen the Commission establishes a utility’s return on equity in a rate case involving a multiyear rate plan, the Commission will rely on that figure when setting rates throughout the rate plan.”[1012]

821. If the Commission were to approve the mechanism, the Department recommended two modifications to the Company’s proposal: (1) the benchmark should be recalculated using data from “roughly the same time period as the final ROE calculations,” and (2) it should only be approved to adjust the authorized ROE in 2024, and not be authorized to make adjustments after the term of the MYRP.[1013] The Department’s witness reasoned that “[r]epeated, annual use of the mechanism would likely increase the potential for . . . misalignment and allowing only a single use of the proposed mechanism would be a reasonable guard-rail to protect ratepayers, particularly the first time the Commission approves such a mechanism.”

822. Xcel has presented no evidence that it needs its proposed automatic adjustment mechanism to continue to have access to capital on favorable terms.

823. The Company has failed to meet its burden to show the ROE true-up mechanism is reasonable, necessary, or that it adequately balances the interests of the Company's ratepayers and investors. The chosen baseline favors the Company, and any benefits of a formulaic adjustment of the Company’s ROE are insufficient to justify the potential consequences for ratepayers of an ROE that is not “established in a fact-driven ratemaking process built on a substantial evidentiary record.”[1014] The Company’s proposal also departs from the Commission’s statement that it would not adjust a utility’s ROE during the term of a MYRP.

824. The Judge recommends that the Commission deny the proposed automatic ROE adjustment mechanism.

825. If the Commission approves the mechanism, the Judge recommends that the Commission adopt the Department’s proposed modifications for the reasons provided by the Department.

VIII. Class Cost of Service Study (CCOSS)

826. After determining a utility’s revenue requirement, which establishes the amount to be recovered from ratepayers, the amount must be divided among the various ratepayer classes.[1015] Prior to establishing a rate design, utilities perform a Class Cost of Service Study (CCOSS) to provide insight into the actual costs of serving particular

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[1012] *In the Matter of the Minnesota Office of the Attorney General – Antitrust and Utilities Division’s Petition for a Commission Investigation Regarding Criteria and Standards for Multiyear Rate Plans under Minn. Stat. § 216B.16, subd. 19*, MPUC Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans at 7 (June 17, 2013) (MYRP Order) (eDockets No. 20136-88242-01).
[1013] Ex. DOC-1 at 101–02 (Addonizio Direct).
[1014] MYRP Order at 7 (explaining why the Commission would not approve multiyear rate plans that rely on formula rates).
[1015] Ex. DOC-17 at 2–3 (Bahn Direct).

customer classes. These study results can then be used inform decisions about revenue apportionment and, ultimately, the rates that customers pay for utility service.[1016]

827. According to the National Association of Utility Commissioners, creating a CCOSS has three steps: (1) cost functionalization, (2) cost classification, and (3) cost allocation. In the first step, costs are typically separated by function: (a) production or purchased power-related, (b) transmission-related, (c) distribution-related, (d) customer service and facility-related, and (e) administrative. In the second step, once costs are separated by function, they are divided, or "classified," based on the utility service components facilitated by that cost. At this stage, the relevant inquiry is whether the cost: (a) is demand-related, (b) is energy-related, or (c) is customer-related. In the third step, these functionalized and classified costs are "allocated" to specific customer classes using specific parameters known as "allocation factors."[1017]

828. One of the most contentious aspects of performing a CCOSS is the classification of distribution facilities. To classify its distribution plant, Xcel employed three different methodologies. The Minimum System and Zero Intercept methods classify distribution plant as primarily customer-related costs with the remainder as demand-related.[1018] The Basic Customer method, by contrast, classifies distribution plant as primarily demand-related and partially as energy-related.[1019]

829. Because these different methodologies can produce widely different results, the Commission has taken a holistic approach and indicated a preference for reviewing multiple methods for classifying distribution plant.[1020] The Commission has explained, "No single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data."[1021]

A. CCOSS – General

830. Three parties submitted CCOSSes in this matter: the Company, XLI, and OAG.

831. The Company prepared 2022, 2023, and 2024 CCOSS[1022] in this proceeding.[1023] The Company updated these CCOSS models in rebuttal to reflect the Company's rebuttal revenue requirement.[1024] The CCOSS models developed by the Company in this proceeding uses the same methods that were approved by the

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[1016] Ex. DOC-15 at 2 (Collins Direct).
[1017] Ex. DOC-15, SC-D-1 at 27–32 (Collins Direct).
[1018] Ex. DOC-15 at 5 (Collins Direct).
[1019] Ex. OAG-4 at 10 (Twite Direct).
[1020] Ex. DER-15 at 4 (Collins Direct); *In re Appl. of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 44-45 (June 12, 2017) (eDockets No. 20176-132748-01) (Xcel 2015 Rate Case Order).
[1021] 2022 Otter Tail Order at 44.
[1022] These Findings use "CCOSS" to refer to a single study or multiple studies.
[1023] Ex. Xcel-84 at 5 (Peppin/Barthol Direct).
[1024] Ex. Xcel-87 at 2 (Barthol Rebuttal).

Commission in the Company's last electric rate case (Docket No. E002/GR-15-826).[1025] The only change is that the Company updated the allocators using more recent system data, and updated the Minimum System/Zero Intercept study for classification and allocation of distribution costs.[1026]

832. The Department concluded that Xcel's Minimum System, Zero Intercept, and Basic Customer method derived results were sufficient reference points for the Commission's eventual decision in this matter.[1027] The Department also did not object to Xcel's decision to use the Stratification (also known as the "Equivalent Peaker") method for classifying fixed production plant costs. The Stratification method assumes any fixed production plant costs beyond what would be needed simply to meet peak demand are incurred due to energy requirements and are therefore energy related.[1028] The Department deemed this assumption to be reasonable and consistent with Commission decisions dating back to the 1970s.[1029]

833. XLI, OAG, CEO, JSC, and SRA opposed some or all of Xcel's CCOSS, as discussed below.

834. The OAG sponsored three CCOSS.[1030] The OAG's CCOSS reflect the following changes from Xcel's preferred CCOSS: First, each OAG CCOSS reflects one of the three methods the Commission has used for classifying distribution costs—the Minimum System Method, the Basic Customer Method, and the Peak & Average Method.[1031] Second, all three CCOSSes do the following:

- classify the costs of Xcel's transmission lines as 70% demand-related and 30% energy-related;[1032]

- allocate demand-related transmission costs based on the classes' contributions to Xcel's 12 monthly peaks (i.e., using a "12CP" allocation factor);[1033] and

- calculate Xcel's "D10S" allocation factor, which the Company uses to allocate demand-related production costs (among others), based on the midwestern grid's regional peak rather than Xcel's system peak.[1034]

[1025] Ex. Xcel-84 at 5 (Peppin/Barthol Direct).
[1026] Ex. Xcel-84 at 5 (Peppin/Barthol Direct).
[1027] Ex. DOC-15 at 5 (Collins Direct).
[1028] Ex. DOC-15 at 8 (Collins Direct).
[1029] Ex. DOC-15 at 9 (Collins Direct); Ex. DOC-16 at 3–4 (Collins Surrebuttal); *See, e.g.*, *In re Appl. of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 62 (May 8, 2015) (noting that Xcel has used the "plant stratification" method to classify fixed production-plant costs since the 1970s).
[1030] Ex. OAG-4 at 12 (Twite Direct).
[1031] Ex. OAG-4 at 12 (Twite Direct).
[1032] Ex. OAG-4 at 12 (Twite Direct).
[1033] Ex. OAG-4 at 14–15 (Twite Direct).
[1034] Ex. OAG-4 at 15 (Twite Direct).

835. The OAG argues that its assumptions better reflect the drivers of Xcel's costs than the Company's CCOSS and yield a more reasonable allocation of Xcel's production, transmission, and distribution costs than the Company's study.

836. XLI argued that the Company CCOSS should be replaced by a CCOSS using the Average and Excess – Four Coincident Peak (AED-4CP) methodology and prepared two CCOSS of its own.

B. CCOSS – Classification and Allocation of Production Costs

837. Fixed production plant revenue requirements arise from a utility's investments in power plants.[1035]

838. In this proceeding, Xcel used the "Stratification" method, also known as the Equivalent Peaker Method, to classify fixed production costs into capacity versus energy-related sub-functions.[1036] Xcel has used the Plant Stratification method since the late 1970s.[1037]

839. Under the Stratification method, the capacity-related portion of the fixed costs of Company-owned generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost and the highest operating cost).[1038] The percent of total generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized as energy-related.[1039] These costs are in excess of the capacity-related portion, and as such, were not incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce.[1040]

840. The Company stated that the Stratification method appropriately recognizes that a significant portion of fixed costs of baseload and intermediate plants are incurred to obtain fuel savings that more than offset the higher costs, thereby minimizing total costs.[1041]

841. While the Department and the OAG support the Stratification method, XLI opposes this method, arguing that the prevalence of renewable energy on the Company's system has rendered it obsolete.[1042] XLI takes issue with the fact that Stratification classifies wind and solar plant as primarily energy-related even though they are incapable of generating energy in all 8,760 hours of the year.[1043] OAG witness Andrew Twite testified that it is more reflective of cost causation to classify the costs of wind production

[1035] Ex. DOC-15 at 8 (Collins Direct).
[1036] Ex. DOC-15 at 8 (Collins Direct); Ex. Xcel-84 at 17 (Peppin/Barthol Direct).
[1037] Ex. Xcel-84 at 17 (Peppin/Barthol Direct).
[1038] Ex. Xcel-84 at 18 (Peppin/Barthol Direct).
[1039] Ex. Xcel-84 at 18 (Peppin/Barthol Direct).
[1040] Ex. Xcel-84 at 18 (Peppin/Barthol Direct).
[1041] Ex. Xcel-84 at 18 (Peppin/Barthol Direct).
[1042] Ex. DOC-15 at 12 (Collins Direct); Ex. OAG-6 at 26 (Twite Rebuttal).
[1043] XLI-1 at 9-10 (Pollock Direct).

plant as energy-related rather than demand-related due to the low capacity accreditation for wind and solar resources.[1044]

842. XLI's argument against the Stratification method does not reflect the realities of Xcel's system. Xcel has procured significant amounts of wind generation to provide low-cost energy.[1045] The decision to build wind generation involves the same tradeoffs as the decision to build a baseload plant with high fixed costs and low variable costs.[1046] Moreover, XLI's claim that renewable resources are entirely different from baseload plants because they are incapable of providing energy in every hour of the year is misplaced. No individual power plant—whether renewable or fossil fueled—provides energy in every hour of the year, but in the aggregate, renewable resources (particularly wind) do provide energy in every hour of the year.[1047]

843. Instead of the Stratification method, XLI proposes the AED-4CP method for allocating production costs.[1048] Under this method, the classification between energy-related costs and demand-related costs is determined by the Company's system load factor.[1049] Specifically, the system load factor determines the amount of fixed production costs that is allocated with each class's Average Demand (or energy usage).[1050] The remaining costs are then allocated with each class's share of excess demand.[1051]

844. The Company and the OAG disagreed with XLI's recommendation to use the AED-4CP method for allocating production costs.

845. Company witness Mr. Barthol testified that the AED-4CP method is flawed because it uses coincident peaks (CP) instead of non-coincident peaks (NCP) for calculating excess demand.[1052] Mr. Barthol also testified that when the Company analyzed seven different methods of classifying and allocating fixed production costs in the Company's 2012 rate case (Docket No. E002/Gr-12-961), the Stratification method fell in the middle of the seven methods while the AED-4CP method allocated the most costs to the Residential class.[1053]

846. OAG witness Mr. Twite testified that the AED-4CP method is problematic because of its use of "excess demand" that is not relevant to integrated resource planning or MISO Resource Adequacy.[1054] The OAG noted that utilities procure generation resources to meet the cumulative energy and peak demand needs of their customers in all hours of the year and that the relationship between individual classes' average and

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[1044] Ex. OAG-6 at 23 (Twite Rebuttal).
[1045] Ex. OAG-10 at 22 (Twite Surrebuttal).
[1046] *See* Ex. OAG-10 at 23–24 (Twite Surrebuttal).
[1047] Ex. OAG-10 at 22 (Twite Surrebuttal).
[1048] Ex. XLI-1 at 12 (Pollack Direct).
[1049] Ex. Xcel-87 at 10 (Barthol Rebuttal).
[1050] Ex. Xcel-87 at 10 (Barthol Rebuttal).
[1051] Ex. Xcel-87 at 10 (Barthol Rebuttal).
[1052] Ex. Xcel-87 at 12 (Barthol Rebuttal).
[1053] Ex. Xcel-87 at 13 (Barthol Rebuttal).
[1054] Ex. OAG-4 at 27 (Twite Rebuttal).

peak usage are irrelevant in resource planning.[1055] Mr. Twite also testified that the AED-4CP method produces results that are not consistent with cost causation because, by relying on excess demand, the customer class with the largest energy usage is allocated the smallest share of costs.[1056]

847. The Stratification method is more reflective of cost-causation than the AED-4CP method because this method "appropriately reflects the fact that Xcel [Energy] builds baseload plants to meet both demand and energy needs."[1057]

848. The Stratification method is a reasonable method for classification of fixed production plant costs that recognizes that Xcel Energy has procured its specific generation mix to meet its customers' energy usage and peak demand.

C. CCOSS – Peak Demand (D10S) Allocator

849. Xcel allocates the demand-related portion of its fixed production plant using the "D10S" allocation factor.[1058] Historically, Xcel has calculated the D10S allocation factor using each class's forecasted loads that were in the same hour as Xcel's system peak.[1059] In Xcel's last rate case, the Commission ordered the Company to "base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak."[1060] In other words, Xcel was to calculate class allocation factors based on classes' relative share of Xcel's system load at the time of the MISO peak.

850. Because MISO did not publish its peak hour for 2022, the Company looked at the hour that MISO's Local Resource Zone 1 (LRZ1) peaked for each of the last 12 years.[1061] Virtually all of the Company's load is included in MISO's LRZ1.[1062]

851. Accordingly, Xcel did not calculate the D10S allocation factor based on MISO's peak hour but instead calculated it using forecasted class loads during the six highest Xcel system peak hours.[1063] The Company contends that "using forecast class loads for the six highest NSP System peak hours for the D10S allocator would encompass the MISO peak hour."[1064]

[1055] Ex. OAG-4 at 27 (Twite Rebuttal).
[1056] Ex. OAG-4 at 28 (Twite Rebuttal).
[1057] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 64 (May 8, 2015).
[1058] Ex. Xcel-84 at 20 (Peppin/Barthol Direct). The D10S allocator is Xcel's main peak demand allocation factor. Ex. OAG-4 at 15 (Twite Direct).
[1059] Ex. Xcel-84 at 20 (Peppin/Barthol Direct).
[1060] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 46 (June 12, 2017).
[1061] Ex. Xcel-84 at 21 (Peppin/Barthol Direct).
[1062] Ex. Xcel-84 at 20 (Peppin/Barthol Direct).
[1063] Ex. OAG-4 at 15 (Twite Direct).
[1064] Ex. Xcel-84 at 22 (Peppin/Barthol Direct).

852. The Department concluded that the Company's method to determine the D10S allocator was reasonable given that this rate case uses forecasted test and plan years using normalized weather data.[1065]

853. The OAG argues that Xcel's D10S allocator does not comply with the Commission's order and does not reflect cost causation because Xcel's resource-adequacy requirements are based on MISO's system peak, not Xcel's system peaks or MISO's Zone 1 peak.[1066] Accordingly, the OAG's CCOSS use a D10S allocator calculated using class loads during MISO's system peak.[1067]

854. Xcel criticizes the OAG's D10S allocator for not using weather-normalized class loads.[1068]

855. The Company's calculation of the D10S allocator using LRZ1 peaks is reasonable. MISO's peak hour was not available for Xcel to use in its calculation, and the Company's basis for using the LRZ1 peaks is supported by the record.

D. CCOSS – Classification and Allocation of Other Production O&M

856. Other Production O&M costs include non-fuel expenses associated with operating and maintaining the Company's power plants as well as regional market expenses to support the Company's participation in the MISO wholesale market.[1069]

857. The Company's CCOSS classifies Other Production O&M costs that vary directly with energy usage as energy-related and classifies the remaining Other Production O&M that originates from a specific generator cost based on the type of production plant associated with the costs.[1070] This method is referred to as the location method.[1071] The location method uses the same cost classification as derived from Stratification for each specific generating resource.[1072]

858. XLI opposes the Company's classification of Other Production O&M expenses due to its objection to use of the Stratification method and the fact that regional market expenses and corporate expenses are not tied to any one resource type.[1073]

859. XLI proposes that regional market expenses and labor-related production O&M be classified as demand-related and the remaining O&M expenses be classified with an energy allocator.[1074]

[1065] Ex. DOC-15 at 11 (Collins Direct).
[1066] Ex. OAG-4 at 15–17 (Twite Direct).
[1067] Ex. OAG-4 at 15 (Twite Direct).
[1068] Xcel Initial Br. at 181.
[1069] Ex. XLI-1 at 17 (Pollock Direct).
[1070] Ex. Xcel-84 at 28 (Peppin/Barthol Direct); Ex. Xcel-87 at 21 (Barthol Rebuttal).
[1071] Ex. Xcel-87 at 21 (Barthol Rebuttal).
[1072] Ex. XLI-1 at 18 (Pollock Direct).
[1073] Ex. XLI-1 at 18 (Pollock Direct).
[1074] Ex. XLI-1 at 19 (Pollock Direct).

860. The Company and the OAG defended the Company's classification and allocation of Other Production O&M. Both parties explained that allocating Other Production O&M costs in the same proportion as their corresponding generation plant best corresponds to the causes of those costs.[1075] The Company and the OAG also noted that the Commission affirmed these methods in the Company's 2013 rate case.[1076]

861. The Company's classification and allocation of Other Production O&M costs is reasonable. As Other Production O&M costs are incurred as a result of the specific generation resources that the Company has procured, it is reasonable to align the classification and allocation of these costs with the underlying generation investments that caused them.

E. CCOSS – Classification and Allocation of Transmission Costs

862. To the extent transmission plant can be directly assigned to a customer, the Company does so.[1077] The remaining transmission plant is classified as 100% demand-related and the costs are allocated with the D10S allocator, which is calculated from Xcel Energy's system peak coincident with the MISO LRZ1 peak.[1078]

863. The OAG argues that it would be more reasonable to classify a portion of Xcel's transmission costs as energy-related because transmission lines are built both to meet peak demands and to lower energy costs.[1079] The OAG also argues that it would be more reasonable to allocate demand-related transmission costs using a "12CP" allocation factor to align with the way Xcel actually collects demand-related transmission costs.[1080] Accordingly, the OAG's CCOSS all classify Xcel's transmission lines as 70% demand and 30% energy and allocate the demand-related portion using a 12CP allocator.

864. Xcel and XLI object to treating any portion of the transmission system as energy-related, arguing that doing so violates cost-causation principles.[1081] However, their arguments fail to establish that transmission costs are driven solely by peak demand, and the evidence establishes that a portion of the cost of Xcel's transmission lines is energy-related.[1082]

865. Xcel is a member of the Midcontinent Independent System Operator (MISO), which sets the compensation structure for the Company's transmission infrastructure.[1083] Several of Xcel's transmission lines were constructed as MISO Multi-Value Projects (MVPs), which are expressly designed to provide economic value by

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[1075] Ex. Xcel-87 at 22 (Barthol Rebuttal). Ex. OAG-4 at 30 (Twite Rebuttal).
[1076] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 68-69 (May 8, 2015).
[1077] Ex. Xcel-84, Sched. 2 at 7 (Peppin/Barthol Direct).
[1078] Ex. Xcel-84, Sched. 2 at 5 (Peppin/Barthol Direct); Ex. Xcel-87 at 15 (Barthol Rebuttal).
[1079] Ex. OAG-4 at 12 (Twite Direct).
[1080] Ex. OAG-4 at 15 (Twite Direct).
[1081] Ex. Xcel-87 at 16 (Barthol Rebuttal); Ex. XLI-2 at 2 (Pollock Rebuttal).
[1082] Ex. OAG-4 at 12–14 (Twite Direct).
[1083] Ex. OAG-4 at 12–13 (Twite Direct).

enabling the dispatch of the lowest-cost generation resources.[1084] Approximately 36% of Xcel's test-year net transmission plant was constructed entirely or in part to incorporate low-cost renewable energy and/or to lower energy market prices.[1085] The OAG's proposal to classify Xcel's 30% of Xcel's transmission costs as energy-related and 70% as demand-related therefore reflects cost causation.[1086]

866. Xcel claims that transmission costs are driven solely by peak demand.[1087] Xcel's claim, however, is inconsistent with the NARUC Manual and fails to acknowledge the fact that transmission costs are incurred in part to lower energy costs.[1088] A passage from the NARUC Manual quoted in Xcel's own CCOSS testimony states that the same factors that drive production costs tend to drive transmission costs.[1089] Xcel classifies its production costs as 48% energy-related[1090] but none of its transmission costs as energy-related. The OAG's recommendation to classify only 30% of Xcel's transmission costs as energy-related is more consistent with the NARUC Manual.

867. XLI argues that "costs should be classified and allocated according to the manner for which they were incurred," that "meeting peak demand is the single most important consideration in designing, building, and operating a utility's transmission system," and that "a transmission system that lowers energy costs but does not meet peak demand fails to fulfill its objective."[1091]

868. Xcel collects demand costs from other load-serving entities (LSEs) that use its transmission network using demand charges that are based on an LSE's cumulative peak in each month, rather than on a single yearly peak.[1092] The OAG's CCOSS' use of a "12CP" allocation factor, which reflects the classes' coincident peaks in each month of the year, would be reasonable for allocating demand costs with the way Xcel collects demand-related transmission costs.[1093]

869. Nevertheless, the 12CP method gives equal weight to all 12 monthly peaks despite the high summer peak demand months (i.e., July and August) driving transmission investment costs.[1094] The Company's allocation of transmission costs using the D10S allocator is also reasonable as it reflects the fact that system peaks trigger transmission investment. The D10S allocator is also used by the Company to allocate demand-related production costs and given that the transmission system is an extension

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[1084] Ex. OAG-4 at 13 (Twite Direct).
[1085] Ex. OAG-4 at 13–14 (Twite Direct).
[1086] Ex. OAG-4 at 14 (Twite Direct).
[1087] Ex. Xcel-87 at 16 (Barthol Rebuttal).
[1088] Ex. OAG-10 at 15 (Twite Surrebuttal).
[1089] *See* Ex. Xcel-87 at 16 (Barthol Rebuttal). The RAP MANUAL, moreover, is clear that a portion of transmission facilities should be classified as energy-related. See Ex. OAG-10 at 16 (Twite Surrebuttal) (quoting manual).
[1090] Ex. OAG-10 at 15 (Twite Surrebuttal).
[1091] Ex. XLI-2 at 19 (Pollock Rebuttal).
[1092] Ex. OAG-4 at 14–15 (Twite Direct).
[1093] Ex. OAG-4 at 15 (Twite Direct).
[1094] Ex. XLI-2 at 19-20 (Pollock Rebuttal) "Xcel Energy is a summer-peaking utility." Ex. Xcel-87 at 17 (Barthol Rebuttal).

of the production system it is reasonable to use the same allocator for both of these types of costs.[1095]

F. CCOSS – Classification and Allocation of Distribution System Costs

870. The classification of distribution costs has been one of the most controversial elements of utility cost allocation for more than a half century.[1096] In recent Minnesota rate cases, the Commission has considered three methods of classifying distribution costs: the Basic Customer, Peak & Average, and Minimum System methods,[1097] finding all of them to be "useful tools" for apportioning revenue.[1098]

871. The Basic Customer Method classifies distribution equipment that serves a single customer or a single multiuse building (e.g., service lines and meters) as customer-related.[1099] The method classifies all shared distribution equipment (e.g., transformers, poles and towers, primary and secondary conductors, substation equipment) as demand-related.[1100]

872. The Peak & Average Method classifies the shared distribution system as both energy- and demand-related, reflecting the fact that a portion of the system is needed to serve a regular amount of energy usage at all times, while additional costs are incurred to "up size" the system to meet the cumulative local peak demand.[1101]

873. The Minimum System Method "assumes there would be costs to connect customers to a minimum-sized distribution system, even if this shared distribution system served little or no load."[1102] The Minimum System Method therefore attempts to estimate the cost of a hypothetical distribution system with little or no load. It then classifies the cost of this hypothetical minimum-sized system as customer-related and the remaining costs as demand-related.[1103] There are multiple ways to estimate the costs of a hypothetical minimum system, including the Minimum Size and the Zero Intercept approaches.[1104]

874. Xcel's CCOSS uses a "hybrid," or blend, of two Minimum System approaches. Its Zero-Intercept study uses statistical regression analysis to estimate the cost of a distribution system with zero load.[1105] Xcel's Minimum Size study, which the Company refers to as a "Minimum System" study, attempts to determine the smallest-

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[1095] Ex. Xcel-87 at 16 (Barthol Rebuttal).
[1096] Ex. OAG-4 at 3 (Twite Direct) (Quoting RAP MANUAL at 145, excerpted in Ex. OAG-5, sched. AT-D-2 (Twite Direct Schedules)).
[1097] Ex. OAG-4 at 3 (Twite Direct).
[1098] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 63 (May 1, 2017).
[1099] Ex. OAG-4 at 4 (Twite Direct).
[1100] Ex. OAG-4 at 4 (Twite Direct).
[1101] Ex. OAG-4 at 4 (Twite Direct).
[1102] Ex. OAG-4 at 4 (Twite Direct).
[1103] Ex. OAG-4 at 4 (Twite Direct).
[1104] Ex. OAG-4 at 4 (Twite Direct).
[1105] Ex. Xcel-84 at 37–38 (Peppin/Barthol Direct).

sized equipment of each type installed throughout the Company's distribution system and uses the unit cost of that equipment to calculate the cost of a system with all components sized consistent with the smallest actual equipment.[1106]

875. XLI opposed consideration of both the Minimum System and Zero-Intercept methods, arguing that combining them "is totally arbitrary and fails to give proper weight to the results of both studies."[1107]

876. The OAG opposes classifying the distribution based on the Minimum System Method alone. It argues that the Minimum System Method is the least reliable of the three methods and that the best practice for classifying distribution costs is to (1) use the Basic Customer Method to determine customer-related distribution costs and (2) classify the remaining shared distribution-system costs as both demand- and energy-related (using, for example, the Peak & Average Method).[1108] The OAG, however, acknowledges that the Commission's historic approach is to consider all three methods and concedes that that approach is also reasonable.[1109]

877. Xcel and XLI support classifying distribution costs based solely on the Minimum System Method.[1110] They oppose considering the Basic Customer Method because of their belief that a portion of the costs of the shared distribution system—beyond customer-specific facilities—is incurred merely to connect customers to the system without delivering electricity.[1111] And they contend that none of the costs of the shared distribution system are energy-driven, rendering the Peak & Average Method inappropriate.[1112]

878. The Basic Customer Method is widely used by regulatory commissions and is described by the Regulatory Assistance Project's (RAP) cost-allocation manual as "by far the most equitable solution for the vast majority of utilities."[1113] The RAP Manual indicates that methods like the Minimum System Method that classify shared distribution facilities as customer-related, by contrast, are "frequently unfair and wholly unjustified" because they "vastly overstate[] the portion of distribution that is customer-related."[1114]

[1106] Ex. Xcel-84 at 36 (Peppin/Barthol Direct).
[1107] Ex. XLI-1 at 22–23 (Pollock Direct).
[1108] Ex. OAG-4 at 5–7, 10 (Twite Direct).
[1109] Ex. OAG-4 at 11 (Twite Direct).
[1110] *See* Ex. OAG-4 at 5 (Twite Direct) (noting that Xcel favors the Minimum System approach); Ex. Xcel-84, sched. 2 at 5–6 (Peppin/Barthol Direct) (describing Company's CCOSS as using Minimum System methods); Ex. Xcel-89 at 9 (Paluck/Peterson Direct) (stating that "starting point" for Company's revenue apportionment was Peppin's CCOSS); Ex. XLI-1 at 31–32 (Pollock Direct) (arguing for revenue apportionment based on Xcel's CCOSS).
[1111] *See* Ex. Xcel-84 at 6 (Peppin/Barthol Direct); Ex. XLI-2 at 7–8 (Pollock Rebuttal).
[1112] *See* Ex. XLI-2 at 8 (Pollock Rebuttal). Xcel does not expressly contest the OAG's claim that its distribution system contains energy-related costs. Rather, the Company criticizes claimed errors in the Peak & Average CCOSS that Xcel prepared in response to an OAG information request. These errors and their impact, or lack thereof, on the CCOSS results are discussed in greater detail below.
[1113] x. OAG-5, sched. AT-D-2 at 6 (Twite Direct Schedules) (excerpting JIM LAZAR ET AL., RAP, ELECTRIC COST ALLOCATION FOR A NEW ERA: A MANUAL at 146–47 (Jan. 2020) (RAP MANUAL).
[1114] Ex. OAG-5, sched. AT-D-2 at 7 (Twite Direct Schedules).

879. Xcel and XLI characterize the Basic Customer Method as not being widely accepted[1115] or even "extreme."[1116] These claims are unsupported for at least two reasons: First, as noted earlier, the Commission has historically relied on the Basic Customer Method to inform its revenue-apportionment decisions.[1117] Second, the OAG surveyed utility cases from across the country and found that the Basic Customer Method is the most commonly used method in the upper Midwest, and one of the most commonly used methods nationwide.[1118]

880. Xcel claims that the Basic Customer Method is "extreme." When cross-examined on this point, the Company's CCOSS witness clarified that the Basic Customer Method was not "extreme" in the sense of being unusual, exceptional, or drastic, but rather in the sense that it classifies the fewest distribution costs as customer-related of any method in the record.[1119]

881. The Peak & Average Method appropriately reflects that Xcel incurs costs to reduce energy losses in its distribution system.[1120] Since Xcel's distribution system has been designed with both peak demand and energy usage in mind, the costs of the shared distribution system can reasonably be classified as both demand- and energy-related.[1121]

882. XLI argues that the Peak and Average Method is inconsistent with cost causation and has no basis in accepted ratemaking principles.[1122] However, XLI fails to refute record evidence that Xcel plans its distribution system with energy needs in mind.[1123] XLI also fails to engage or refute the RAP Manual's explanation of how energy needs infuse the distribution system.[1124] Since XLI fails to refute this countervailing

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[1115] Ex. XLI-2 at 11 (Pollock Rebuttal).
[1116] Ex. Xcel-87 at 20 (Barthol Rebuttal).
[1117] *See* 2022 Otter Tail Order at 44; *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-011/GR-17-563, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Dec. 26, 2018); *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 71 (Mar. 12, 2018); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 45 (June 12, 2017); *In the Matter of the Application of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 53 (June 3, 2016).
[1118] *See* Ex. OAG-4 at 8–9 (Twite Direct); Ex. OAG-10 at 17 (Twite Surrebuttal). XLI conducted its own survey of distribution-classification practices. Ex. XLI-2, sched. 1 (Pollock Rebuttal). XLI's survey, however, omits relevant information that undermines its conclusions. *See* Ex. OAG-10 at 22–24 (Twite Surrebuttal) (noting that XLI's survey examines utility approaches rather than commission approaches, focuses almost exclusively on northeastern states, and omits relevant information about the three upper Midwest cases it does include).
[1119] Tr. Vol. 1 at 201 (Barthol).
[1120] Ex. OAG-4 at 10–11 (Twite Direct).
[1121] Ex. OAG-4 at 11 (Twite Direct).
[1122] Ex. XLI-2 at 2 (Pollock Rebuttal).
[1123] Ex. OAG-10 at 19–20 (Twite Surrebuttal). Further, XLI's argument that line losses are inevitable misses the point. The relevant consideration for cost allocation is whether Xcel incur costs to reduce line losses, and the Company's discovery responses show that it does. Ex. OAG-10 at 20 (Twite Surrebuttal).
[1124] *See* Ex. OAG-5, sched. AT-D-2 at 9–10 (Twite Direct Schedules) (excerpting RAP MANUAL).

evidence, its assertion that the distribution system lacks any energy-related costs is not reliable.

883. Further, XLI's basis for opposing the Peak & Average Method conflicts with its support of the Minimum System Method.[1125] In opposing classification of distribution costs as energy-related, XLI argues that "distribution plant must be sized to meet peak demand" and that a system "sized only to meet the customer's average load [i.e., the customer's energy needs] . . . would not be sufficient to meet the customer's power needs."[1126] XLI concludes that energy usage is therefore not a driver of system costs.[1127] In other words, XLI's reasoning is that none of the costs of the shared distribution system are energy-related because the system must be sized to meet peak demand. Yet XLI claims that the distribution system has significant customer-related costs even though a system sized only to connect customers (i.e., the "minimum system") would also be insufficient to meet customers' power needs.[1128] XLI's testimony on distribution-cost causation is thus internally inconsistent and its criticisms of the Peak and Average method are given little weight.

884. XLI's second argument is that classifying distribution costs as energy-related has no basis in accepted ratemaking principles.[1129] But the Commission has relied on the Peak & Average Method, which classifies distribution costs as energy-related, in several recent rate cases.[1130] Moreover, the RAP Manual recommends classifying shared distribution facilities as both energy- and demand-related, describing this as a "best practice."[1131] XLI asserts that "NARUC, through its published Electric Cost Allocation manuals has stated unequivocally that there is no energy component to distribution system costs."[1132]

885. The NARUC Manual's treatment of distribution costs is not as clear cut as XLI asserts. XLI is correct that the NARUC Manual states that "there is no energy component of distribution-related costs."[1133] But the NARUC Manual at other points contemplates that there are energy-related distribution costs.[1134] Thus, the manual does

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[1125] The Minimum System Method is discussed below.
[1126] Ex. XLI-2 at 8 (Pollock Rebuttal).
[1127] Ex. XLI-2 at 8 (Pollock Rebuttal).
[1128] *See* Ex. XLI-2 at 7 (Pollock Rebuttal) (asserting that a "grid connection with facilities sized [only] to provide voltage support" is "clearly related to the existence of a customer").
[1129] Ex. XLI-2 at 2 (Pollock Rebuttal).
[1130] *See* 2022 Otter Tail Order at 44; *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-011/GR-17-563, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 33 (Dec. 26, 2018); *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, MPUC Docket No. E-015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 71 (Mar. 12, 2018); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 45 (June 12, 2017); *In the Matter of the Application of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 53 (June 3, 2016).
[1131] Ex. OAG-4 at 10 (Twite Direct) (citing RAP Manual).
[1132] x. XLI-2 at 11 (Pollock Rebuttal).
[1133] Ex. DOC-15, sched. SC-D-1 at 100 (Collins Direct).
[1134] *See* Ex. OAG-10 at 21 (Twite Surrebuttal).

not unequivocally settle the question, particularly in light of the evidence in this record that Xcel's distribution costs are in part driven by energy needs.

886. Xcel and XLI also identify two technical concerns with the OAG's Peak & Average CCOSS.[1135] First, XLI argues that the Peak & Average CCOSS results in double-counting "because the class peak demand allocator is also included in the energy allocator."[1136] OAG witness Mr. Twite testified, however, that the impact of the peak hour on the energy allocator is negligible.[1137] Second, XLI and Xcel claim that the CCOSS mistakenly assigns distribution costs to customers that take transmission-level service.[1138] Neither party, however, offers any evidence of the impact this mistake may have had.[1139] And there is no indication that the error was material or impacted the results in a way that would have altered the patterns the OAG identified among its three CCOSS.[1140]

887. The Minimum System Method is a commonly used method for determining the percentage of distribution plant that is customer-related.[1141] However, it is generally understood to overstate customer-related distribution costs.[1142] This is because the method assumes that distribution costs vary directly with the number of customers, yet "[m]uch of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number."[1143] Further, "[s]erving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering," and "[a]dding customers without adding peak demand or serving new areas does not require any additional poles or conductors."[1144] In other words, contrary to the theory behind the Minimum System Method, the costs of the shared distribution system are more directly influenced by factors such as customer usage

[1135] In addition to the two concerns discussed below, XLI claims that the OAG's Peak & Average CCOSS inappropriately uses a 12CP allocation factor to allocate demand-related distribution costs. Ex. XLI-2 at 16 (Pollock Rebuttal). Here, however, XLI is mistaken: the OAG's CCOSS allocate demand-related production and distribution costs using a single peak hour. Ex. OAG-10 at 24 n.58 (Twite Surrebuttal).
[1136] Ex. XLI-2 at 17 (Pollock Rebuttal).
[1137] Ex. OAG-10 at 24–25 (Twite Surrebuttal).
[1138] Ex. XLI-2 at 16–17 (Pollock Rebuttal); Ex. Xcel-88 at 11 (Barthol Surrebuttal).
[1139] *See* Ex. XLI-2 at 16–17 (Pollock Rebuttal); Ex. Xcel-88 at 11 (Barthol Surrebuttal). *See also See* Tr. Vol. 1 at 201–04 (Barthol) (unable to quantify impact).
[1140] *See* OAG Reply Br. at 12–13. Xcel also claims that the Peak & Average CCOSS mistakenly "allocates secondary distribution costs to customers who take service at primary voltages and do not use the secondary portion of the system." Xcel Initial Br. at 186. Xcel did not identify this effect until the evidentiary hearing, nor did the Company quantify its impact. *See* Tr. Vol. 1 at 213 (Barthol). Accordingly, the Administrative Law Judge assigns Xcel's claim little weight.
[1141] Ex. Xcel-84 at 32 (Peppin/Barthol Direct).
[1142] *See* Ex. OAG-4 at 5–7 (Twite Direct) (citing RAP MANUAL at 146–47); Ex. DOC-17 at 48 (Bahn Direct) (stating concern that Xcel's Minimum System CCOSS "has over-classified distribution plant costs as customer related"). The Commission itself has recognized the flaws in the Minimum System approach. In a 2016 decision, it agreed with the OAG that "minimum-system studies over-allocate distribution costs to the customer component," and that "the over-allocation to the customer component may be significant." *In the Matter of the Application of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 53 (June 3, 2016).
[1143] Ex. OAG-4 at 6 (Twite Direct).
[1144] Ex. OAG-4 at 6–7 (Twite Direct).

patterns and the physical layout of a utility's service territory than the number of customers.[1145]

888. The OAG also raised concerns with the way Xcel conducted its Zero Intercept study.[1146] Xcel relied on work orders for distribution projects completed in 2007–2020, but the Company excluded 91% of the work orders from that period from its analysis.[1147] The OAG argues that, because Zero Intercept studies are very sensitive to changes in the underlying statistical methods used, Xcel's omission of significant amounts of data undermines the credibility of the results.[1148] Xcel contends that it needed to exclude any work orders involving more than one type of equipment.[1149] Regardless, excluding a large number of work orders increased the potential for bias in the results.

889. The Judge recommends that the Commission continue its practice of considering all three distribution-system classifications methods when apportioning revenue in this case. All three methods have their benefits and limitations, and it is reasonable to consider them together when determining a cost-causation starting point for rate design.

G. CCOSS – Conclusion

890. A comparison of the different CCOSS offered in this proceeding are summarized in the table below:

[1145] Ex. OAG-10 at 17–18 (Twite Surrebuttal).
[1146] Xcel's Minimum System CCOSS is a "hybrid" of the Minimum Size and Zero Intercept methods. See Ex. Xcel-84, sched. 2 at 5 (Peppin/Barthol Direct) (describing Company's CCOSS methodology).
[1147] Ex. OAG-4 at 7 (Twite Direct). Specifically, Xcel used data from just 3,837 of a possible 42,660 distribution work orders over this period. *Id.*
[1148] Ex. OAG-4 at 7 (Twite Direct).
[1149] Ex. Xcel-87 at 20 (Barthol Rebuttal).

2022 CCOSS Results[1150] Comparison - Deficiency %[1151]

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG	Peak & Avg	-1.1%	1.9%	21.5%	24.5%
OAG	Basic Customer	5.0%	1.3%	17.4%	26.4%
OAG	Hybrid	12.1%	7.5%	12.3%	27.2%
Xcel Energy	Hybrid	15.8%	6.4%	9.9%	22.7%
XLI	Minimum System	19.2%	3.9%	7.7%	30.7%
XLI	Zero Intercept	19.2%	3.9%	7.7%	31.0%

891. The Company has shown that its 2022, 2023, and 2024 CCOSS provides reasonable results consistent with cost causation. However, each of the parties' CCOSS have strengths and weaknesses, as identified and discussed above. Accordingly, the Judge recommends that the Commission consider the CCOSS sponsored by the parties in light of those strengths and weaknesses.

H. Future Changes to CCOSS

892. The OAG also recommends that the Commission require Xcel Energy, in its next rate case, to file CCOSS using the following methods for classifying shared distribution costs: Basic Customer, Peak and Average, and Minimum System.[1152] The Company opposes the this recommendation on the grounds that the Company should not be required to file CCOSS that it does not support and that it believes do not reflect cost causation.[1153] The Company does not oppose other parties introducing additional CCOSS into the proceeding and is agreeable to conducting additional CCOSS for other parties during discovery.[1154]

893. The Judge recommends that the Commission take no action on OAG's recommendation. The practice of parties introducing their own CCOSS has allowed parties to develop a full record on the issue in this proceeding, and the Company's

[1150] Ex. Xcel-88 at 10, Table 2 (Barthol Surrebuttal).
[1151] CCOSS results in the table are shown at the overall revenue deficiency presented by the Company in Direct Testimony. While the Company has reduced its deficiency in Rebuttal Testimony, parties utilized the Company's original deficiency when presenting the results of their proposed CCOSSs. The table provides an apples-to-apples comparison of the impact of different CCOSS methodologies in this rate case.
[1152] Ex. OAG-4 at 12 (Twite Direct).
[1153] Ex. Xcel-87 at 21 (Barthol Rebuttal).
[1154] Ex. Xcel-87 at 21 (Barthol Rebuttal).

willingness to conduct additional CCOSS during discovery should adequately provide a means for parties to introduce alternative CCOSS.

IX. Rate Design

894. 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 designed to recover those costs from customers.

895. Revenue apportionment describes the assignment of the utility's approved revenue requirement to the various customer classes. Put differently, if setting the revenue requirement is like determining the size of the pie, then revenue apportionment is akin to cutting the slices.[1155]

896. Rate design, in contrast to the determination of the revenue requirement, is a quasi-legislative function.[1156] This step of the ratemaking process largely involves policy decisions to be made by the Commission.[1157] Rate design requires the application of judgment to synthesize a range of objective and subjective factors.[1158]

897. The rate design process "is one requiring both technical expertise on the one hand and a careful balancing of many complimentary and competing interests on the other."[1159] That is, rate design is not a formulaic process, but involves balancing many factors.[1160]

898. In apportioning revenue responsibility and designing rates, the Commission must balance competing principles and policies.[1161] Rates should offer utilities a reasonable opportunity to earn their revenue requirements.[1162] They should promote efficiency and conservation.[1163] They also should promote renewable energy use.[1164] And they must not unreasonably discriminate against any customer class.[1165] In balancing these priorities, the Commission must resolve any doubts in favor of consumers.[1166]

899. The Commission has historically considered a variety of cost and non-cost factors when designing rates including: cost of service; economic efficiency; ability to pay;

[1155] Ex. DOC-21 at 7 (Campbell Direct).
[1156] *St. Paul Area Chamber of Commerce v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357, 312 Minn. 250, 260 (Minn. 1977).
[1157] *St. Paul Area Chamber,* 251 N.W.2d at 357.
[1158] *See* Ex. OAG-4 at 19 (Twite Direct) (describing CCOSS analysis, which arguably is the most empirically grounded factor in rate design, as itself subjective).
[1159] *St. Paul Area Chamber*, 251 N.W.2d at 354.
[1160] *See St. Paul Area Chamber*, 251 N.W.2d at 357 (stating that after the revenue requirement is established "many countervailing considerations come into play.").
[1161] Ex. DOC-17 at 4–5 (Bahn Direct).
[1162] Minn. Stat. § 216B.16, subd. 6 (2022).
[1163] Minn. Stat. §§ 216B.03–.04 (2022).
[1164] Minn. Stat. § 216C.05, subd. 1 (2022).
[1165] Minn. Stat. §§ 216B.03, .07 (2022).
[1166] Minn. Stat. § 216B.03 (2022).

continuity with prior rates;[1167] ease of understanding; ease of administration; promotion of conservation; and ability to bear, deflect, or otherwise compensate for additional costs.[1168]

900. Continuity with prior rates is relevant because setting a rate based only on the cost of service without considering the established rate design could result in sudden dramatic rate increases, or “rate shock.”[1169]

901. The Commission has noted that establishing interclass revenue apportionments based on anticipated circumstances presents unique challenges and complications.[1170] In addition, each class’s share of total revenues during a MYRP can vary from apportionments set in a rate case based upon factors such as actual sales.[1171] The Commission expressed a preference for setting rates using fixed apportionments that remain in effect until the utility’s next rate case.[1172]

A. Revenue Apportionment

902. Xcel proposed to annually apportion approximately $3.5 to $3.7 billion in test-year revenues to its customers between 2022 and 2024. To apportion this revenue, Xcel proposed to move customers 50% closer to cost each year based on the results of its Hybrid method derived CCOSS results.[1173]

903. Xcel explained that its proposed class revenue apportionment differs from the apportionment established in its 2015 rate case.

904. The Department partially disagreed with Xcel. The Department agreed that it was appropriate to move customers 50% closer to cost for the 2022 test year based on Xcel’s Hybrid method results. The Department, however, disagreed with making additional movements toward cost in 2023 and 2024 due to rate shock concerns and to be consistent with past Commission decisions.

905. The Department asserted that using a single revenue apportionment throughout the life of the MYRP reduces the risk of rate shock from the cumulative movements towards cost that Xcel proposed.[1174] In support of its position, the Department stated that moving customers 50% to cost each year as the revenue requirement increases would mean even greater revenue responsibility for residential customers than applying the 2022 responsibilities to the 2023 and 2024 revenue requirements.

[1167] OAG described this as the principle of gradualism. Ex. OAG-4 at 20 (Twite Direct).
[1168] Xcel 2015 Rate Case Order at 36.
[1169] Ex. OAG-4 at 20 (Twite Direct).
[1170] *In re Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E002/GR-15-826, Findings of Fact, Conclusions, and Order at 56 (Jun. 12, 2017).
[1171] Ex. Xcel-90 at 4–5 (Paluck/Peterson Rebuttal).
[1172] *Id*.
[1173] Ex. Xcel-90 at 7 (Paluck/Peterson Rebuttal).
[1174] DOC Initial Br. at 119–121.

906. The Department also maintained that using the same fixed revenue apportionments for the entire multi-year rate plan period is consistent with past Commission decisions.[1175] The Department further pointed to Xcel's testimony that "rates should be set on the basis of an approved apportionment and that the Company should not reset rates over the term of the MYRP on the basis of any different apportionment" as support for using a fixed apportion for the duration of the multi-year rate plan.[1176]

907. The OAG recommended class increases using patterns identified in its three CCOSS to inform the relative magnitude of the increase assigned to each class.[1177] If all three CCOSS showed that a class is currently paying less than its share of costs, for example, the OAG would assign that class a relatively larger increase.[1178] The OAG chose increases based on the magnitude of the difference between the amount a class is currently paying and the cost-share patterns identified in its CCOSS, while moderating increases where the CCOSS indicated that a class is currently paying substantially less than its cost-based share.[1179]

908. OAG recommends, if the final revenue apportionment in any test year is lower than the amount Xcel requests, that the Commission determine the final class increases by multiplying the Commission's approved total Company revenue increase for that test year by the ratio of the OAG's recommended class increase to Xcel's proposed Total Company increase.[1180]

909. XLI argued that the revenue allocation in this proceeding should move customers closer to cost of service under a valid CCOSS. It disputed that Xcel's proposed allocation moved rates "50% closer to cost."[1181] It recommended that the Commission adopt its proposed revenue allocation based on its AED-4CP CCOSS.[1182] XLI opposed the recommended class revenue allocations of DOC, OAG and ECC.[1183]

910. XLI argued that Xcel's Commercial and Industrial (C&I) class rates are uncompetitive and inconsistent with the state policy goal to maintain retail electric rates for each customer class at 5% below the national average.[1184] It argued that rates should be designed to address this by moving the C&I class closer to the class's cost of service.[1185]

911. ECC recommended that the Commission limit the residential rate increase to 6.4%.[1186]

[1175] Ex. DOC-20 at 15 (Bahn Surrebuttal).
[1176] Ex. Xcel-90 at 6–7 (Paluck/Peterson Rebuttal).
[1177] Ex. OAG-4 at 20–21 (Twite Direct).
[1178] Ex. OAG-4 at 21 (Twite Direct).
[1179] Ex. OAG-4 at 21 (Twite Direct).
[1180] Ex. OAG-6 at 4–5 (Twite Rebuttal).
[1181] Ex. XLI-1 at 32–33 (Pollock Direct).
[1182] XLI Reply Br. at 22.
[1183] Ex. XLI-3 at 20.
[1184] *See, e.g.,* Tr. Vol. 1 at 226:8-17 (Peterson); Minn. Stat. § 216C.05, subd. 2(4) (2022).
[1185] Ex. XLI-1 at 31 (Pollock Direct).
[1186] Ex. ECC-1 at 5–8 (Fair Direct).

912. The Commercial Group advocated for setting rates based on the cost of service, and did not oppose Xcel's proposal to move class rates at least 50% toward cost as determined by the Company's CCOSS.[1187] It recommended that if the Commission approves a smaller revenue requirement than the Company proposed, it should use the reduced requirement to further move classes toward their cost of service, subject to no class receiving an increase greater than that initially proposed by the Company.[1188]

913. Apples-to-apples comparisons of the parties' proposed revenue allocations is challenging on this record because each has presented the information in a slightly different manner.

914. XLI compared the proposed revenue allocations according to their "movement to cost," as determined by XLI's CCOSS.[1189]

915. OAG described its proposed revenue allocation, if the Commission does not approve Xcel's initially proposed revenue requirement, as a formula:[1190]

> If the final approved revenue requirement in any test year is lower than the amount Xcel requests, the ALJ and the Commission should determine the final class increases by multiplying the Commission's approved Total Company revenue increase for that test year by the ratio of the OAG's recommended class increase to Xcel's proposed Total Company increase.

916. The proposed class apportionments of Xcel and DOC are reproduced below:

Proposed Revenue Apportionments - Xcel

Customer Class	2022[1191]	2023[1192]	2024[1193]
Residential	39.29%	39.57%	39.92%
C&I Non-Demand	3.31%	3.31%	3.30%
C&I Demand	56.55%	56.26%	55.92%
Lighting	0.86%	0.86%	0.86%
Total	100%	100%	100%

1187 Commercial Group Initial Br. at 11; Ex. CG-1 at 22 (Chriss Direct).
1188 Ex. CG-1 at 22 (Chriss Direct).
1189 Ex. XLI-2, Schedule 3 (Pollock Rebuttal) (citing Ex. XLI-1, Schedule 10 at 2 (Pollock Direct)).
1190 Ex. OAG-6 at 4–5 (Twite Rebuttal); OAG Initial Br. at 65 n.317.
1191 Ex. DOC-20 at 14 (Bahn Surrebuttal).
1192 Ex. DOC-20 at 14 (Bahn Surrebuttal).
1193 Ex. DOC-20 at 14 (Bahn Surrebuttal).

Proposed Revenue Apportionments - DOC[1194]

Customer Class	2022	2023	2024
Residential	39.29%	39.29%	39.29%
C&I Non-Demand	3.31%	3.31%	3.31%
C&I Demand	56.55%	56.55%	56.55%
Lighting	0.86%	0.86%	0.86%
Total	100%	100%	100%

917. For the following reasons, the Judge regards the Department's proposed class revenue apportionment to be the most reasonable of the parties' proposals.

918. It is reasonable to consider multiple CCOSS methods as factors when determining a fair and reasonable rate design.[1195]

919. The Company, DOC, and OAG each proposed class apportionments based upon multiple CCOSS.

920. The Judge gives less weight to XLI's proposed class revenue allocation because it is inconsistent with Commission's practice of considering multiple CCOSS, and because it is premised on cost causation determined by the AED-4CP allocation of production costs rather than the Stratification method. AED-4CP's shortcomings, as identified by Xcel and OAG, require that at a minimum, the shortcomings of XLI's CCOSS should be balanced by considering other CCOSS when determining the cost-causation rate design factor.

921. ECC's proposal to limit the residential rate increase to 6.4%—without consideration of the effect of the decision on other customer classes—lacks adequate support in the record. ECC reasoned that the Commission found exigent circumstances to limit the interim rate increase to 6.4% and that the basis for the exigency still applies.[1196] However, the standard for setting final rates in a rate proceeding is different from the standard for finding interim rate increase exigency. ECC's proposal to limit the size of the increase to one customer class without respect to the proposed limitation's effect on other classes would not satisfy the requirements of Minn. Stat. § 216B.03 to establish rates that are not "unreasonably preferential, unreasonably prejudicial, or discriminatory."

922. The starting point for the Company's proposed class revenue apportionment is the cost responsibility for each customer class as determined by the Company's CCOSS, which the Company stated is consistent with Commission decisions and with the Company's pricing objectives.[1197]

[1194] Ex. DOC-20 at 19 (Bahn Surrebuttal).
[1195] Ex. OAG-4 at 19 (Twite Direct).
[1196] Ex. ECC-1 at 5–8 (Fair Direct).
[1197] Ex. Xcel-89 at 9 (Paluck/Peterson Direct).

923. Rates that give significant weight to cost causation provide stabilization of utility earnings and provide economically efficient and appropriate usage incentives.[1198]

924. In this case, the Company proposed a 50% movement to cost for all customer classes as a basis for the proposed class apportionment. This movement toward cost, as determined by the Company's CCOSS, constitutes the relative position between a class increase set at the average retail increase and a class increase set directly at class cost.[1199]

925. Competitive and economic forces make cost-based rates for business customers an important goal for class revenue apportionment, as noted by XLI. Testimony by XLI witness Mr. Pollock that C&I electric rates are inconsistent with a state policy goal for competitiveness went unrebutted. The Company's proposed revenue apportionment takes these goals into account by proposing a 50% movement toward costs coupled with rate movement moderation.[1200]

926. The Department's proposal improves upon Xcel's balance of the relevant considerations. The Department's proposal begins with the Company's proposal but would establish a single class revenue allocation to remain in effect until the Company's next rate case. This is consistent with the Commission's decision in Xcel's 2015 rate proceeding.

927. The Company's proposal to modify the class revenue apportionment in each year of its MYRP would change the interclass revenue allocation without evidence of the classes' cost of service in those years.

928. Finally, the Department's recommendation better achieves the objective of rate movement moderation, to mitigate rate shock. The Department's recommendation would make residential customers responsible for 39.29% of Xcel's proposed $3.713 billion proposed revenue requirement for 2024, or $1.459 billion.[1201] By contrast, Xcel's 39.92% apportionment would make residential customers responsible for $1.482 billion.[1202] This amounts to an approximately $23 million difference.

929. The Judge recommends that the Commission adopt the Department's recommended apportionment of revenue responsibility. The Department's recommendation reasonably moves customers to cost, but more gradually than proposed by Xcel. This approach reasonably balances the goals of economic efficiency, competitive rates, and avoiding rate shock. It also is consistent with prior Commission decisions to use fixed revenue apportionment.

[1198] Ex. Xcel-90 at 7 (Paluck/Peterson Rebuttal).
[1199] Ex. Xcel-89 at 10-11 (Paluck/Peterson Direct).
[1200] Ex. Xcel-90 at 3 (Paluck/Peterson Rebuttal).
[1201] Ex. Xcel-90 at 7 (Paluck/Peterson Rebuttal); Ex. DOC-20 at 19 (Bahn Surrebuttal).
[1202] Ex. Xcel-82, BCH-R-2 at 4 (Halama Rebuttal); Ex. DOC-20 at 19 (Bahn Surrebuttal).

B. Residential Customer and Small General Service Charges

930. After revenues are apportioned to classes, rates must still be designed for each class. Particularly, for non-demand billed classes (residential and small general service customers), Xcel's rates establish an amount to be recovered through a "fixed" or "customer" charge and an amount to be recovered through a "variable" or "energy" charge. Revenues allocated to a class that are not recovered through a fixed charge must be recovered through a variable charge.[1203]

931. Intra-class rate design is a zero-sum endeavor: the same amount of revenue is recovered from the class, but the Commission must determine the relative proportion of the revenue amount recovered through fixed and variable charges.[1204]

932. While the Company initially proposed a $1.50 increase in the fixed monthly charge for both residential and small general commercial customers,[1205] the Company subsequently simplified its proposed customer charges for residential customers and now recommends a customer charge of $9 for all Residential customers, which reflects a $1 increase for residential customers and which eliminates the incremental $2 fixed monthly customer charges for space-heating customers, customers with underground service, and those customers on Residential Time of Day service.[1206]

933. The Department (supported by the CEOs), OAG, JSC, and ECC recommended alternatives to Xcel's proposed increase to the residential customer charge.

934. ECC, which "promote[s] more affordable utility service for low- and fixed-income Minnesotans," stated that it could agree to a $1 increase in the monthly fixed charge for residential customers if the Company agreed to ECC's proposed low-income discount program, which the Company stated it supports.[1207]

935. Although there are modest variations in their arguments and proposals, DOC, OAG, JSC, and CEOs agree that Xcel should decrease its residential customer charge and that the decrease for multifamily customers should be larger.[1208]

936. The Department and the OAG advocate for reducing both Residential and Small General Service customer charges by $3, setting it at $6.[1209] They also recommend

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[1203] *See* Ex. DOC-17 at 46 (Bahn Direct).
[1204] *Id*.
[1205] Ex. Xcel-89 at 20 (Paluck/Peterson Direct). This proposal applied to the following rate schedules: Residential Service, Residential Time of Day Service, Small General Service, and Small General Time of Day Service.
[1206] Ex. Xcel-90 at 10 (Paluck/Peterson Rebuttal).
[1207] Ex. ECC-1 at 1, 10-12 (Fair Direct); Ex. Xcel-90 at 8, 12-13 (Paluck/Peterson Rebuttal).
[1208] Ex. JSC-5 at 52-74 (Rábago Direct); Ex. JSC-10 at 5-10 (Rábago Surrebuttal); Ex. OAG-4 at 24-37 (Twite Direct); Ex. OAG-6 at 8-12 (Twite Rebuttal); Ex. OAG-10 at 9-13 (Twite Surrebuttal); Ex. DOC-17 at 46-56 (Bahn Direct); Ex. DOC-20 at 19-24 (Bahn Surrebuttal); Ex. CEO-5 at 12-16 (Nelson Rebuttal).
[1209] The Department recommends that all single-family Residential customers as well as Small General Service customers receive a customer charge of $6, a $3 reduction from Xcel's proposed simplified charge.

that Xcel establish a new customer charge for Residential customers in multifamily dwellings that would be $1 lower than the standard Residential charge, setting it at $5.[1210] The Clean Energy Organizations and JSC likewise support the recommendation to reduce single-family Residential customer charges by $3 and multifamily Residential customer charges by $4.[1211]

937. Xcel disagreed with the customer-charge-reduction proposal, arguing that it relies too heavily on the Basic Customer Method for distribution cost classification and is inconsistent with the Department's recommended revenue apportionment, which relied on multiple CCOSS models.[1212]

938. According to the Company, the parties' recommended decreases to the residential and small commercial customer charges could lead to undesired consequences as fewer costs are recovered through the fixed charge and more through the variable energy charge. Specifically, increasing the portion of costs on a customer's bill recovered through the energy charge may unfairly require households with large families (or customers with higher-than-average monthly electric usage), as well as households who have or are planning to switch to electric space heating via heat pumps and other electric household appliances for cooking and clothes drying, to pay for more customer-related costs.[1213]

939. Finally, the Company objected to the proposal to set distinct customer charges for single- and multi-family dwellings because it cannot currently identify residential customers by dwelling type.[1214]

940. For the reasons set forth below, the Judge regards the Department's proposal, as the most reasonable of the parties' recommendations.

941. Although economic efficiency is not the only relevant consideration, rates are most economically efficient when they reasonably reflect the cost of serving that customer class.[1215]

942. Xcel acknowledged that customers residing in duplexes, condominiums, and apartments impose fewer fixed costs on its system.[1216] Xcel's marginal cost study showed that multi-unit dwellings impose about 60% less cost than single-family dwellings

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See Ex. DOC-20 at 24 (Bahn Surrebuttal). The OAG indicates that it does not oppose Xcel's proposal to simplify Residential customer charges and agrees with the Department that a simplified charge should be set at $6. Ex. OAG-10 at 10 (Twite Surrebuttal).

[1210] *See* Ex. OAG-10 at 27 (Twite Surrebuttal) (recommending that fixed charges for Residential customers in multifamily dwellings be reduced by $4); Ex. DOC-20 at 24 (Bahn Surrebuttal) (recommending $5 multifamily Residential customer charge, or $4 less than Xcel's proposed $9 simplified charge).

[1211] *See* Ex. CEO-5 at 16 (Nelson Rebuttal); Ex. JSC-10 at 11–12 (Rábago Surrebuttal).

[1212] *See* Ex. DOC-17 at 54 (Bahn Direct) (stating that "the basic customer method is more appropriate for informing customer charge decisions within each customer class.").

[1213] Ex. Xcel-90 at 9 (Paluck/Peterson Rebuttal); Ex. Xcel-91 at 3 (Paluck/Peterson Surrebuttal).

[1214] Ex. Xcel-89 at 22 (Paluck/Peterson Direct).

[1215] DOC Initial Br. at 124; Ex. Xcel-89 at 8–9 (Paluck/Peterson Direct).

[1216] *Id.*; Ex. JSC-5 at 56 (Rábago Direct).

impose on the system.[1217] This differential exists because customers in a multi-unit dwelling often share secondary distribution system facilities (e.g., meters, poles, conductors, cable) while each single-family residence requires its own connection to Xcel's system.

943. It is reasonable to reflect the difference in fixed service costs for single- and multi-family dwelling customers with a difference in their fixed customer charges.

944. The record establishes that the Company has a reasonable means to begin identifying multi-unit-dwelling residential customers. The Company can begin by applying the multi-unit customer charge to customers in dwellings with apartment numbers or who can be identified using other indirect means—approximately 270,000 customers.[1218]

945. The Company argued that if fixed customer costs are not recovered using the fixed customer charge, customers who have greater-than-average electricity use could pay a portion of customer costs through the variable portion of their rates.[1219] Customers with greater-than-average electricity use can include large families, customers who cannot invest in energy efficiency improvements, and customers engaging in "beneficial electrification," by shifting their energy usage to electricity from another energy source (e.g., natural gas).[1220]

946. However, when non-customer-specific costs are removed from the Company's Basic Customer CCOSS, the cost-based customer charges fall below $5 for Residential and below $6 for Small General Service customers.[1221]

947. It is reasonable to rely most heavily on the Basic Customer Method when determining customer charge decisions within a customer class.[1222]

948. Because the Department's proposed customer charges reasonably compare to the fixed costs identified in the Company's Basic Customer CCOSS, relevant fixed costs will likely be recovered through the customer charge.

949. State policies favoring energy conservation and renewable energy use support reducing, not increasing, Residential and Small General Service customer charges.[1223] Any increase or decrease to the customer charge must be offset by a decrease or increase in a class's volumetric rate so that overall class revenue remains the same. Thus, any increase to the customer charge lowers the value of each kWh saved, which reduces the incentive to conserve energy.[1224] Conversely, reducing residential and small general service customer charges would increase the incentive for customers in these classes to conserve energy and pursue renewable generation. An

[1217] Ex. DOC-18 at 49 (Bahn Direct); Ex. Xcel-89, NNP-D-7 at 4 (Paluck/Peterson Direct).
[1218] Ex. DOC-20 at 22–23 (Bahn Surrebuttal).
[1219] Ex. Xcel-91 at 3 (Paluck/Peterson Surrebuttal).
[1220] *Id.*
[1221] Ex. OAG-4 at 26 (Twite Direct).
[1222] Ex. DOC-17 at 54 (Bahn Direct).
[1223] Ex. OAG-4 at 28–29 (Twite Direct).
[1224] Ex. OAG-4 at 28–29 (Twite Direct).

increase to the fixed charge would also lengthen the payback period for investments in energy efficiency such as building insulation or more efficient appliances.[1225] Decreasing the class's fixed charge would have the opposite effect. The same considerations apply to customer incentives to adopt distributed renewable energy, like rooftop solar photovoltaic installations.[1226]

950. The Commission is required to set rates to encourage energy conservation and renewable energy use to the "maximum reasonable extent."[1227]

951. Customer-charge reductions are not unprecedented. For example, in the most recently concluded electric rate case in Minnesota, the Commission approved a reduction for three customer classes, including a 57% reduction for one class.[1228]

952. Waiting for further study to perfect the method of identifying qualifying customers would delay establishing a differentiated customer charge—which is strongly supported by this record—for years. Implementing the rate would incentivize Xcel to improve its methods for identifying qualifying customers more quickly than delay for further study.

953. Because (1) multi-unit-dwelling customers can be served at a lower fixed cost than single-unit residential or small general service customers; (2) the Department's proposed customer charges are supported by the Company's Basic Customer CCOSS; (3) reducing the customer charge will reasonably incentivize energy conservation and advance other state energy policy goals; and (4) the Company can reasonably identify a significant number of qualifying ratepayers.

954. The Judge recommends that the Commission adopt the Department's recommended customer charge of $6 for all single unit-dwelling residential customers and small general service customers, and $5 for residential customers in multi-unit dwellings.

955. If the Commission adopts Xcel's proposal to simplify Residential customer charges, that charge should be set at $6 per month, or $3-less than Xcel's proposed simplified charge.[1229]

C. Commercial and Industrial (C&I) Demand Class – Customer Charge, Demand Charge, and Energy Rates

956. The term "commercial and industrial demand classes" refers to non-residential customers other than small general class customers. Unlike residential and small general service customers, these customers take service under a three-part

[1225] Ex. OAG-4 at 29 (Twite Direct).
[1226] Ex. OAG-4 at 29 (Twite Direct).
[1227] Minn. Stat. § 216B.03.
[1228] *See* 2022 Otter Tail Order at 72 (approving a reduction in the Standby Service (Secondary) customer charge from $242.24/month to $105.32/month as well as customer-charge reductions for the Large General Service (Time of Day–Secondary) and Lighting (Metered) customer classes).
[1229] Ex. OAG-10 at 10, 27 (Twite Surrebuttal).

rate.[1230] Their rates include a fixed customer charge and a volumetric energy usage charge like other classes. Their rates also include a demand charge.[1231] The demand charge is calculated based on the maximum amount of electricity demanded at any moment during the billing period.[1232]

957. The Company proposed multiple changes to C&I demand class rate design in this case.[1233]

958. First, the Company developed energy and demand rates that would primarily maintain a similar ratio between demand and energy rates, as is currently the case, to limit rate design changes.[1234]

959. Second, the Company proposed certain changes to interruptible service, including a moderate increase to the interruptible service discount that in general reinstates the discount levels to what they were prior to the Federal Tax Cut and Jobs Act.[1235] The following table compares present and proposed discounts by Tier and Performance Factor (PF) category:

Present and Proposed Interruptible Discounts
NSPM-Minnesota Electric Jurisdiction

Tier-PF	2-C	2-B	2-A	1-C	1-B	1-SN
Present	$4.58	$4.06	$3.04	$5.36	$4.77	$5.83
Proposed	$4.80	$4.26	$3.13	$5.61	$4.98	$6.11
Increase	$0.22	$0.20	$0.09	$0.25	$0.21	$0.28
Increase %	4.8%	4.9%	3.0%	4.6%	4.4%	4.8%

960. The Company also proposed certain additions to rules for application of the Peak Controlled Services tariff. The first change requires customers to provide reliable contact information, an essential requirement that has been followed without formal rule, and the second change regards testing requirements required by MISO, which will provide more certainty about available load relief during MISO emergency events.[1236] Finally, the Company proposed to eliminate the Annual Minimum Demand Charge, which

[1230] Ex. Xcel-4 at 62, 66, 71, 75 (Appl. Vol. 2E – Proposed Tariffs) (General Service Class. Tariff Sheet No. 5-26; General Service Class – Time of Day. Tariff Sheet No. 5-29; Peak Controlled. Tariff Sheet No. 5-40; Peak Controlled – Time of Day. Tariff Sheet No. 5-44).
[1231] *See, e.g.*, Ex. Xcel-4 at 62 (Appl. Vol. 2E – Proposed Tariffs) (General Service Class. Tariff Sheet No. 5-26).
[1232] Ex. Xcel-4 at 64 (Appl. Vol. 2E – Proposed Tariffs) (General Service Class. Tariff Sheet No. 5-26).
[1233] A comparison of present and proposed rates for the MYRP is included at Ex. Xcel-89, Sched. 5 (Paluck/Peterson Direct).
[1234] Ex. Xcel-89 at 27 (Paluck/Peterson Direct).
[1235] Ex. Xcel-89 at 27-28 (Paluck/Peterson Direct). The only exception is the discount for the lowest value service distinction of Tier 2, Performance Factor A.
[1236] Ex. Xcel-89 at 28-29 (Paluck/Peterson Direct).

would be a customer-friendly change that would simplify and streamline the interruptible tariff for customers.[1237]

961. Third, the Company proposed to eliminate its Real Time Pricing (RTP) Service tariff.[1238]

962. Fourth, the Company proposed to revise its demand charge voltage discounts under the C&I Demand tariff based on current cost levels and to revise its energy charge voltage discounts for the proposed level of base energy and fuel charges.[1239]

963. Fifth, the Company currently has a General Time of Day (TOD) Service tariff with a two-period TOD rate design and an interruptible service counterpart called the Peak-Controlled TOD Service tariff. The Company has proposed a new three-tier TOU tariff in Docket No. E002/M-20-86, which has two pilot pricing structures, which the Commission orally approved on January 5, 2023.[1240]

964. With respect to the Company's proposal to adjust C&I rates to maintain a similar demand/energy ratio as in present rates, the Department recommended that the Commission instead require Xcel to develop rates for its commercial and industrial demand classes using the same rate design principles and CCOSS results that are applicable to residential and small general service class customers.[1241] The Department stated that Xcel declined to address the Department's direct testimony recommendation that the company present evidence-based rate proposals in rebuttal. As a result, the Department recommended the Commission require Xcel to produce this analysis in Docket No. E002/M-20-86.[1242]

965. Understating customer and demand charges for C&I Demand customers shifts cost responsibility to large, high-load-factor customers.[1243]

966. Because the Company's C&I Demand rates should be evidence-based, the Judge recommends that the Commission adopt the Department's recommendation to require Xcel to work with stakeholders and address C&I fixed customer charges, demand rates and demand-related costs, seasonal costs and rates, other DR and DER initiatives in Docket No. E002/M-20-86, which is already focused on advanced rate design.[1244]

[1237] Ex. Xcel-89 at 29-30 (Paluck/Peterson Direct).
[1238] Ex. Xcel-89 at 30-31 (Paluck/Peterson Direct).
[1239] Ex. Xcel-89 at 31, Sched. 8 (Paluck/Peterson Direct).
[1240] Ex. Xcel-89 at 31-32 (Paluck/Peterson Direct).
[1241] Ex. DOC-18 at 57–58 (Bahn Direct).
[1242] Ex. DOC-20 at 25–26 (Bahn Surrebuttal); *In re N. States Power Co.'s Pet. for Approval of General Time-of-Use Service Tariff*, Docket No. E002/M-20-86.
[1243] Ex. XLI-2 at 4 (Pollock Rebuttal).
[1244] Ex. DOC-20 at 25–26 (Bahn Surrebuttal); *In re N. States Power Co.'s Pet. for Approval of General Time-of-Use Service Tariff*, Docket No. E-002/M-20-86.

D. Low-Income, Low-Usage Discount

967. ECC witness Catherine Fair proposed implementation of a low-income, low-usage discount rate. Under the proposal, the Company would provide a 35% monthly discount on monthly electric usage of 300 kWh to all low-income residential customers that use an average of 300 kWh per month or less of electricity. Ms. Fair estimated that out of 305,000 residential customers that use 300 kWh or less, approximately 30% of those customers (roughly 92,000) would be income-eligible for the discount. ECC recommended establishing the income-eligibility threshold at 50%of state median income, the same threshold used in Minnesota to qualify for the Low-Income Home Energy Assistance Program (LIHEAP). ECC recommended that eligibility be established through receipt of LIHEAP, through categorical or income-based program participation or through an income-based self-declaration.[1245]

968. According to Ms. Fair, the low-income, low-usage customers would experience an average rate increase of less than 1%, rather than the Company's proposed 24% increase. This is important because low-income, low-usage customers have fewer opportunities to lower their bills through conservation measures, shifting to off-peak hours, or to participate in beneficial electrification opportunities.[1246]

969. Predicted impacts for customers at different usage levels are:[1247]

Average Monthly kWh	Customer Count	35% Discount on Base
0-100	81,653	-$2.12
101-200	104,248	-$7.12
201-300	118,964	-$11.72

970. The discount would impact average bills at different usage levels:[1248]

Average Monthly kWh	Average Current Bill Total	Average Bill with 2024 Rate Case Proposed Increase with Discount	Average Bill with 2024 Rate Case Proposed Increase without Discount
0-100	$15.19	$16.45	$18.46
101-200	$29.21	$29.91	$36.70
201-300	$42.09	$42.27	$53.44

[1245] Ex. ECC-1 at 12-14 (Fair Direct).
[1246] Ex. ECC-1 at 13 (Fair Direct).
[1247] Ex. ECC-1 at 14 (Fair Direct).
[1248] Ex. ECC-1 at 16 (Fair Direct).

971. The Company supported ECC's low-income, low-usage discount proposal as proposed by ECC witness Ms. Fair, regardless of the decision with respect to the Company's proposed increased customer charge. The Company identified three principal reasons for its support:

i. it helps address the housing and energy burden challenges faced by the Company's low-income customers during a time of high inflation and ongoing instability from the pandemic;[1249]

ii. it offers a practical way to address the barriers to participation that exist in energy assistance programs by leveraging enrollment in other assistance programs or through self-declaration of income;[1250] and

iii. it provides a way to counteract the potentially regressive impacts of a uniform customer service charge, which imposes a larger percentage bill increase on low-usage customers, as the proposed discount would largely offset a limited customer service charge for such customers.[1251]

972. OAG witness Andrew Twite also supported ECC's proposed discount. Mr. Twite determined that the benefits of the low-income, low-usage proposal justify the modest cost increase for other customers and recommends approval.[1252]

973. OAG and JSC argued that the Commission should consider ECC's low-income rate proposal separately from Xcel's customer charge proposal, contending that they are two unrelated policy issues.[1253]

974. JSC further argued that ECC's proposal would exclude low-income households that use more than ECC's proposed 300 kWh-per-month cap and could create a perverse incentive against beneficial electrification for qualifying households that consume energy near the 300 kWh-per-month limit.[1254] JSC therefore supported ECC's proposed discount but recommended three modifications:[1255]

i. JSC Modification Option 1: income-qualified customers that exceed the usage threshold of 300 kWh per month could apply for an exemption to the usage threshold if their premise has installed certain electric appliances (e.g., electric space heating, electric range, electric medical device, two- or four-wheel electric vehicle, electric water heater). The discount could apply to the first 300 kWh

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[1249] Ex. Xcel-83 at 39 (Martin Rebuttal).
[1250] Ex. Xcel-83 at 39 (Martin Rebuttal).
[1251] Ex. Xcel-83 at 39-40 (Martin Rebuttal).
[1252] Ex. OAG-6 at 6-7 (Twite Rebuttal).
[1253] Ex. OAG-X at 7-8 (Twite Rebuttal); *see also* Ex. JSC-X at 10 (Rabago Surrebuttal) (explicitly supporting Mr. Twite's position).
[1254] Ex. JSC-6 at 38-39 (Chan Surrebuttal).
[1255] *Id*.

of consumption in a month (or could be considered for consumption above 300 kWh). This option would mitigate the concern with the usage threshold potentially excluding certain households that have or plan to adopt certain electrification technologies.

ii. JSC Modification Option 2: all income-qualified households would qualify for a 35% discount on their first 300 kWh of monthly consumption, regardless of total consumption in the month. For customers that consume less than 300 kWh in a month, this modification would have no impact. And for customers that consume more than 300 kWh in a month, they would now receive the 35% discount on their first 300 kWh (approximately $14 per month). This option would mitigate the impact of the concern about the original proposal excluding certain structurally higher energy consumers that face energy insecurity (such as households with an above-average number of people). This option would also remove the concerns with the potential for perverse incentives around the 300 kWh per month usage threshold that might lead some households near the usage threshold to curtail load or be less likely to adopt beneficial electrification technologies.

iii. JSC Modification Option 3: all income-qualified households would receive guaranteed provision of electric service for the first 100 kWh of consumption in a month at no cost. This would be economically equivalent to receiving the approximate value of at 35% discount on 300 kWh of consumption fully in the first 100 kWh of consumption in a month. In addition to mitigating the concerns with the original proposal in a similar manner to JSC Modification Option 2, this option would also establish a universal basic level of electricity provisioning to households for their most essential energy services. This option would thereby guarantee that all customers that can afford the fixed monthly charge would be protected from disconnection (unless otherwise protected from disconnection, such as by the Cold Weather Rule or participation in an existing affordability program). This option follows similar policy adopted by other electric utilities.

975. Ultimately, JSC recommended that the Commission adopt JSC Modification Option 2.[1256] JSC estimates that the option would reach approximately 230,000 additional customers, providing them a discount on the first 300 kWh that they consume in a month.[1257]

976. JSC estimates that under its modification, the cost of the program to non-participating customers would increase to between $1.47–$2.48 per month—an increase of almost $1–$2 per month from the discount ECC originally proposed. JSC's estimate may also be low, as it is based on an estimate of 25%–50% enrollment by low-income,

[1256] Ex. JSC-6 at 49-50 (Chan Surrebuttal); JSC-10 at 12-14 (Rábago Surrebuttal).
[1257] *Id.* at 42.

non-low-usage customers.[1258] If a larger number of customers enrolled, the average cost for non-participating customers would be higher.

977. The Judge recommends adoption of the low-income, low-usage discount proposal, as proposed by ECC witness Ms. Fair. As pointed out by Company witness Mr. Martin and OAG witness Mr. Twite, the Company's residential customers are facing challenges due to inflation and effects of the COVID-19 pandemic.[1259] Although addressing the undesirable effects of the 300 kWh-per-month cap is a worthwhile goal, JSC's proposal would add significant cost to the program. OAG, which is statutorily responsible for representing the interests of residential and small business ratepayers,[1260] supports the ECC recommendation. The Judge concludes that the low-income, low-usage discount, as proposed by ECC, provides relief to the Company's most financially at-risk customers and appropriately limits the impact of the electric rate increase.

E. Business Incentive and Sustainability (BIS) Rider – Discretionary Discount

978. The Company proposed an additional, temporary discretionary discount to the off-peak base energy rate of 50%, applicable only to incremental loads of more than five MW that have a minimum load factor of 70%, to the BIS Rider tariff, which is the economic development incentive available to existing demand-metered C&I customers with new or additional load of 350 kW or greater.[1261] After a five-year discount period, the customer would pay full tariff rates.[1262] Xcel further proposed that it would file any agreements with prospective data center customers with the Commission and that the agreements would take effect after 30 days unless an objection was raised.[1263]

979. Xcel stated that the purpose of this proposal is to help the company compete for and capture large data center customers.[1264] According to the Company, this additional discretionary discount would appeal to high-load, high-load-factor customers like data centers, but would benefit all customers, and not just potential data center load, because system fixed costs would be able to be spread more broadly, among other benefits.[1265]

980. The Department expressed concern about the application of the discretionary 50% discount on off-peak energy without express Commission approval. The Department did not oppose Xcel's proposal to offer the discount but recommended that the Commission require the company to obtain express Commission approval before contracts with prospective data center customers take effect. The Department reasoned that requiring express Commission approval of the Electric Service Agreement (ESA)

[1258] Ex. JSC-6 at 46-47 (Chan Surrebuttal).
[1259] Ex. OAG-6 at 7 (Twite Rebuttal).
[1260] Minn. Stat. § 8.33, subd. 2 (2022).
[1261] Ex. Xcel-89 at 32-33 (Paluck/Peterson Direct).
[1262] Ex. Xcel-90 at 19 (Paluck/Peterson Rebuttal).
[1263] Ex. Xcel-90 at 19 (Paluck/Peterson Rebuttal).
[1264] Ex. Xcel-89 at 32–33 (Paluck/Peterson Direct).
[1265] Ex. Xcel-89 at 33-34 (Paluck/Peterson Direct).

allows parties and the Commission a greater opportunity for review and analysis to decide if the agreement is in the public interest than a 30-day negative check-off."[1266]

981. JSC argued that the Commission should require Xcel to suspend enrollments in its BIS rider, conduct a long-term, comprehensive cost-benefit analysis, and demonstrate that the net present benefits of the program outweigh its net present costs.[1267]

982. Because the Commission, or any interested stakeholder, may review the economics of agreements when they go through a 30-day negative check-off period, it would be reasonable to approve the Company's proposed discount. Requiring a stakeholder to object to an ESA within 30 days is reasonable given the purpose of the discount and would not prevent a more thorough public-interest analysis of an ESA where the public benefit is uncertain. In addition, the Company confirmed that even with the discounts under the BIS Rider tariff, revenues exceed costs of service, which highlights the incremental financial benefits for all customers for service taken under the BIS Rider tariff.[1268]

983. The Judge recommends that the Commission approve the Company's proposed BIS Rider discretionary discount.

F. EV Charging and Charging Rates

984. Under Xcel's "General Rules and Regulations" tariff, section 5.2, when a customer adds new a load that necessitates system upgrades, the Company will cover the cost of the upgrades that does not exceed 3.5 times the anticipated annual revenue from the sale of additional service, excluding the portion that represents recovery of fuel costs. The customer causing the need for the upgrade is responsible for the remaining cost. The purpose of this cost-sharing provision is to ensure that "the rendering of service to the [customer] will not cast an undue burden on other customers."[1269]

985. In response to a discovery request, Xcel disclosed that it does not apply this provision to Residential customers taking service under an EV-specific rate. Specifically, asked "whether a customer would be responsible for paying some or all of the cost for a transformer upgrade that is driven by that customer's load addition . . . [and] whether the customer's cost responsibility for a transformer upgrade would vary based on the type of load being added (e.g., Electric Vehicle (EV) charging)," Xcel responded,

> *For customers on the Electric Vehicle (EV) rates (A08, A76, A77, A80, A81, A82, A83)*. Residential customers who request/need an upgrade

[1266] Ex. DOC-20 at 27–28 (Bahn Surrebuttal).
[1267] Ex. JSC-5 at 41 (Rábago Direct).
[1268] Ex. Xcel-90 at 19 (Paluck/Peterson Rebuttal).
[1269] Xcel Energy Minnesota Electric Rate Book, Section 6, "General Rules and Regulations," sheet 26.

to the existing transformer will not be charged for the transformer upgrade costs directly related to their EV load.[1270]

986. The Company indicated, however, that other residential customers not taking service under an EV-specific rate and commercial customers remain responsible for system upgrade costs as provided under its tariff.[1271]

987. JSC supported the Company's transformer upgrade charge waiver and further recommended that the Commission require the Company, in situations where new EV load would require a distribution system upgrade, waive the customer's contribution for the upgrade and instead collect the cost from all customers regardless of whether the customer participates in one of the Company's EV charging programs.[1272]

988. Specifically, JSC's witness recommended:[1273]

> . . . the Company conduct a study to estimate the total cost of serving typical residential customer configurations which may result in a need for a transformer or service upgrade, followed by an estimate of three and a half times the expected annual revenue (using the methodology discussed within the General Extension 9 Section 5.2 of the Rate Book). This will determine if the anticipated revenue is sufficient to offset the upgrade costs of Company's EV programs. If the revenue offset is sufficient, I would recommend the Company conduct customer outreach using these results to reduce fears of cost incursion and make customers aware of the need for the Company to understand where EV charging will occur to ensure continued reliability.
>
> Second, even if the results of such a study conclude that the customer in such scenarios would be responsible for a portion of the cost, I would recommend the Company waive the customer's contribution, bear that cost instead and recover it through rates, preferably as an EV-specific budget item. Because some customers (specifically those who have existing electric services and panel sizes large enough to accommodate the load) do not have to notify the utility, they would not directly bear any related costs for any resulting transformer upgrades. This creates inherent inequality. This is especially relevant because newer and remodeled homes (which are typically more expensive) often have larger service and panel sizes, which makes the inequality inherently regressive and doubly burdens customers with older and smaller service and panel sizes.

989. OAG, conversely, opposed the Company's proposal to exempt EV-rate customers from the cost sharing provisions of the tariff. According to the OAG, Xcel

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[1270] *See* Ex. JSC-4 at 36 (Davis Direct) (citing "JSC Exhibit 16," (eDockets No. 202210-189514-05), which the Judge regards as a schedule to Ex. JSC-4).
[1271] *See* Ex. JSC-4 at 36 (Davis Direct) (citing "JSC Exhibit 16").
[1272] Ex. JSC-4 at 37–38.
[1273] Ex. JSC-4 at 37-38 (Davis Direct).

instituted this policy without obtaining authority from the Commission.[1274] The OAG also argues that Xcel's practice creates a regressive subsidy in favor of wealthier EV owners.[1275]

990. The Company's current EV programs are designed not only to promote the overall adoption of EVs to help meet the state's transportation electrification goals, but also to help encourage charging of EVs at beneficial times for our system and all Xcel customers.[1276] The Company's current EV programs generally promote off-peak charging through off-peak lower rates.[1277]

991. EV rate tariffs A08, A76, A77, A80, A81, A82, and A83 do not contain a provision to waive contributions in aid of construction under Xcel's General Rules and Regulations tariff.[1278]

992. The reasonableness of JSC's alternative proposal is unsupported by substantial evidence. JSC's proposal would result in inaccurate price signals to customers. It would also eliminate an incentive to enroll in an EV-specific rate. Customers with electric vehicles should be encouraged to participate in the Company's EV programs as these programs help the Company manage EV loads and allow customers to take advantage of lower off-peak rates.

993. The Company has established that it would be reasonable to waive distribution transformer upgrade charges for EV-rate customers—doing so incentivizes participation in the Company's EV rate offerings, helps the Company shift EV charging load through EV-specific rate design, and can reduce the cost barrier for customers who wish to undertake beneficial electrification. However, Xcel has not established that its tariff presently allows it to exclude EV-rate customers from the cost-sharing provision.

994. The Judge recommends that the Commission approve Xcel's practice to waive the cost sharing requirement for EV-rate customers and require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff.

995. Alternatively, the Judge recommends that the Commission adopt the OAG's recommendation to require Xcel to apply the cost-sharing provisions in a manner consistent with its tariffs.

996. JSC also recommended that the Commission require Xcel to study and assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods, especially in distribution areas that already have high penetrations of solar.[1279] Specifically, JSC recommended that the study include both distribution peak capacity and minimum load impacts, as well as bulk system impacts and

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[1274] OAG Initial Br. at 74.
[1275] OAG Initial Br. at 74.
[1276] Ex. Xcel-40 at 142 (Bloch/Mensen Direct).
[1277] *See* Ex. Xcel-40 at 144-146 (Bloch/Mensen Direct) (summarizing EV programs and charging options).
[1278] Initial Filing Vol. 2E, Proposed Tariffs List (eDockets No. 202110-179126-04).
[1279] Ex. JSC-4 at 31–32 (Davis Direct).

costs. The Coalition argued that shifting EV charging load to nighttime, creates an inherent misalignment between EV charging and solar DER generation.[1280] JSC further recommends that the Company coordinate with MISO to explore how these factors may change over the next few years, and explore to what extent the resulting EV charging rates may be dynamic and differentiated by location, existing solar resources, or other variables.[1281]

997. The Company opposed JSC's recommendation to require a study as outside the scope of this proceeding, and better addressed in a different forum. The Company pointed to an Integrated Resource Plan (IRP) and Integrated Distribution Plan (IDP) Policy, Technology, and Planning workshop that it hosted on November 15, 2022, as an example of a more appropriate forum to raise issues that related to system planning.[1282] The Company also argued that if the Commission determines from a policy perspective that such studies are appropriate, the decision could impact other utilities as they also develop their EV charging rates and may be required to study the potential for EV charging during high solar generation periods.

998. The Judge recommends that the Commission take no action on JSC's EV charging study proposals. There are more appropriate venues for these topics to be raised and explored in detail. Requiring additional EV charging studies could impact other utilities and stakeholders that are not party to this rate case proceeding.

G. Residential Space Heating Rates

999. According to the Company, the Commission has required it to evaluate its rate options for electric heat pumps. The Company pointed to the Commission's decision in Docket No. E002/M-21-101, where the Commission issued the following order point:[1283]

> Xcel shall review its existing electric heating rate options, including the Back-up Relief Rate Plan, to ensure that they accurately reflect the value of the additional load and additional load flexibility for customers installing an air source heat pump and maintaining an existing gas heating backup source. If existing rates do not reflect the added value of these electrified loads, the rates should be adjusted, or new rate offerings should be developed.

1000. The Company stated that it evaluated its existing electric heating rate options, and in this proceeding, the Company has proposed that customers with heat pumps receive service on the Company's residential space heating rate. In addition, the Company also proposed a modification to the residential space heating tariff rate design. The Company asserts that these changes will promote equity among all customers who

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[1280] Ex. JSC-4 at 29-30 (Davis Direct).
[1281] Ex. JSC-4 at 31-32 (Davis Direct).
[1282] Ex. Xcel-43 at 28-29 (Mensen Rebuttal).
[1283] *In re Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, MPUC Docket No. E002/M-21-101, ORDER APPROVING MODIFIED LOAD-FLEXIBILITY PILOTS AND DEMONSTRATION PROJECTS, AUTHORIZING DEFERRED ACCOUNTING, AND TAKING OTHER ACTION at 29 (Mar. 15, 2022).

have electric space heating needs so that customers on standard residential rates and customers on the space heating rate, with average usage, pay the same annual base rate revenue.[1284]

1001. More specifically, the Company proposed the following changes regarding its residential space heating rates:

i. First, consistent with its recommendation regarding its proposed monthly customer charges, the Company has proposed to eliminate the incremental $2 customer charge for residential space heating customers.[1285]

ii. Second, the Company has proposed to increase the differential from the standard Residential winter rate to 5.42 cents per kWh from 2.815 cents per kWh.

1002. The Company estimated that its proposed changes would result in annual savings of approximately $159 for a typical overhead service space heating customer and $242 for a typical underground service space heating customer. The Company estimates the savings for a customer with a heat pump to be approximately $133 annually on the heat pump usage alone.[1286]

1003. The Department and CEO recommended rejecting the Company's proposal.

1004. The Department offered no opinion on the merits of Xcel's proposed modifications. But given the timing of Xcel's proposal, made in rebuttal testimony, the Department stated it did not have enough information or time to analyze it. In addition, the Department noted there are parties who are not participating in this proceeding that may wish to review Xcel's proposal. For these reasons, the Department recommended that the Commission reject Xcel's proposal and direct the company to re-file it in Docket No. E002/M-21-101.[1287]

1005. The Judge agrees with the Department that the Commission should deny Xcel's residential space heating rate without prejudice and direct Xcel to re-file its proposal in Docket No. E002/M-21-101 to ensure there is sufficient opportunity for interested stakeholders to participate and to provide adequate time for review.

1006. CEO recommended that Xcel's proposed rate be rejected and that Xcel be required to use their proposed Time of Use (TOU) rate, which would include seasonal rates. CEO's TOU proposal is discussed in greater detail below.

[1284] Ex. Xcel-90 at 10, 17 (Paluck/Peterson Rebuttal).
[1285] Ex. Xcel-90 at 17 (Paluck/Peterson Rebuttal).
[1286] Ex. Xcel-90 at 17 (Paluck/Peterson Rebuttal).
[1287] *In re Xcel Energy's Pet. for Approval of Load Flexibility Programs & Financial Incentive Mechanism*, Docket No. E002/M-21-101.

H. Time of Use Rates

1007. In this proceeding, the Company has not proposed any changes to its residential TOU pilot rates, besides the modification for space heating customers discussed above. For the new space heating TOU category, the Company would apply the same residential TOU rates for summer on-, mid-, and off-peak period.

1008. CEO argued that the Company's TOU rate offerings for residential customers are insufficient.[1288]

1009. Currently, Xcel residential customers are only able to enroll in a two-period rate with an on-peak period from 9:00 a.m. to 9:00 p.m.[1289] Xcel developed and piloted an updated TOU rate from 2017–2022.[1290] However, the pilot has now ended and the piloted TOU rate is closed to new enrollment.[1291] Consequently, Xcel is beginning a stakeholder process to develop a full residential TOU rate.[1292] The new rate developed during this process is not expected to be available until 2025.[1293]

1010. CEO argued the existing two-period rate with a lengthy on-peak period is outdated and does not send accurate price signals to encourage conservation or load shifting.[1294] CEOs asserted the public interest requires Xcel residential customers to have access to an updated, more granular TOU rate now.[1295]

1011. CEO recommended Xcel residential customers be allowed to continue to enroll in the piloted TOU rate subject to a modification to that rate.[1296] Specifically, CEOs recommended the existing TOU pilot rate be modified to (1) continue using a three-period rate but reduce the magnitude of the non-summer on-peak charge; or (2) modify the rate to a two-period rate in the non-summer months with no on-peak period.[1297] CEO further recommended that summer rates could be increased to enable any needed cost recovery as a result of this change.[1298]

1012. A relatively high winter on-peak rate encourages EV owning customers to shift their load to the evening period when demand is lower and wind generation is plentiful.[1299]

1013. The reasonableness of the CEO TOU proposal is not supported on this record. It would not provide appropriate price signals, especially in light of anticipated EV load increases on the system, and it would not have consistent summer and winter

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[1288] Ex. CEO-1 at 31 (Nelson Direct); CEOs' Initial Brief at 11-12, n. 42.
[1289] Ex. Xcel-4 at 5-2 through 5-3 (Application Volume 2E, proposed Tariffs).
[1290] Ex. CEO-1, Schedule 2, Xcel Response to Information Request 99 (Nelson Direct).
[1291] Ex. CEO-1 at Schedule 2, Xcel Response to Information Request 99 (Nelson Direct).
[1292] Ex. CEO-1, Schedule 2-Xcel Response to Information Request 99 (Nelson Direct).
[1293] Ex. CEO-1 at 15-16 (Nelson Direct).
[1294] CEO Initial Brief at 16.
[1295] Ex. CEO-1 at 17-32 (Nelson Direct); CEOs' Initial Brief at 16-17.
[1296] Ex. CEO-1 at 31 (Nelson Direct).
[1297] Ex. CEO-1 at 28-30 (Nelson Direct).
[1298] Ex. CEO-1 at 32 (Nelson Direct).
[1299] Ex. Xcel-90 at 18 (Paluck/Peterson Rebuttal).

on-peak period pricing which could lead to customer confusion. There is a process underway for developing a full residential TOU rate. Requiring the Company to implement the CEO proposal outside of that process would deprive interested stakeholders of sufficient opportunities to participate or adequate time for review.

1014. XLI provided evidence regarding the Company's ongoing implementation of a new C&I Demand TOU Rate.[1300]

1015. XLI argued that the Company should be required to complete a more in-depth analysis of the cost of serving the C&I Demand class, and that any C&I Demand TOU rate should be evaluated within the context of a general rate case.[1301]

1016. The Company agreed that the ideal time to set rates is in a general rate case.[1302]

1017. XLI recommended that the Commission require the Company, in its next rate case, to further segment the C&I Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I TOU rate.[1303]

1018. The Judge recommends that the Commission not adopt the CEO residential TOU proposal in this proceeding.

1019. The Judge recommends that the Commission adopt XLI's proposal to require the Company, in its next rate case, to further segment the C&I Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I TOU rate.

I. Real Time Pricing (RTP) Service Tariff

1020. Xcel proposed to eliminate its existing real-time pricing service rate due to a lack of customer interest.[1304] The current RTP design was established in 2004 and has never attracted more than two customers at the same time, which may be due to the complexity of the rate.[1305]

1021. Currently, there is only one customer (with three accounts) taking service on the RTP Service tariff, who was informed prior to taking RTP service in 2018 of the Company's proposal to cancel RTP Service in the Company's next rate case filing. Given the limited attractiveness of the RTP Service, the Company has proposed to use other

[1300] Ex. XLI-1 at 47 (Pollock Direct).
[1301] XLI Initial Br. at 41–42; Ex. XLI-1 at 47 (Pollock Direct).
[1302] Ex. Xcel-90 at 19–20 (Paluck/Peterson Rebuttal).
[1303] Ex. XLI-1 at 47 (Pollock Direct).
[1304] Ex. Xcel-89 at 30–31 (Paluck/Peterson Direct).
[1305] Ex. Xcel-89 at 30-31 (Paluck/Peterson Direct); Ex. Xcel-90 at 13-14 (Paluck/Peterson Rebuttal).

rates that may be more attractive and beneficial to customers, including the Company's new three-period TOU pilot.[1306]

1022. The Department, however, recommended that the Commission require Xcel to maintain this offering. First, the Department asserted that Xcel currently lacks other similar, permanent offerings. Second, the Department stated that Xcel is currently deploying advanced meters and engaged in advanced rate discussions with stakeholders in other Commission proceedings. Given these developments, the Department concluded that Xcel's experience with the real-time pricing rates may inform these other rate designs. For these reasons, the Department recommended that Xcel be required to maintain its RTP service rate in the near term.[1307]

1023. The Judge agrees with the Company that the Department's concerns should not bar cancellation of the rate. Other rate offerings, approved or proposed, such as the new three-period C&I TOU tariff, could be more attractive to substantially more customers. The potential informational value of a RTP rate that currently has one customer, and has never had more than two concurrent customers in nearly 20 years, is not large enough to warrant requiring the Company to continue offering the rate.

1024. The Judge recommends that the Commission approve the Company's proposal to cancel its existing RTP Service tariff.

J. Street Lighting

1025. The Company's proposed rate increases for the Lighting class shown in the Company's updated class revenue apportionment reflect cost differentials among subcategories within the Lighting class.[1308]

1026. The Company's rate design for the Lighting class also reflects reduced costs from lower energy usage associated with Light Emitting Diode (LED) technology compared to other lighting sources, such as High Pressure Sodium (HPS) fixtures.[1309]

1027. The Company has completed its mass-conversion program to replace HPS fixtures with LED technology, which has resulted in estimated lighting cost reductions for the 2022 test year of $1,387,000 in energy-related costs and $826,000 in demand-related costs.[1310]

[1306] According to the Company, examples of tariffs with greater potential include the approved Peak Partner Rewards tariff for optional interruptible service in Docket No. E,G002/CIP-16-155, the proposed three-period C&I TOU tariff in Docket No. E002/M-20-86, and the now approved Peak Flex Credit Rider Pilot in Docket No. E002/M-21-101 (approved on Mar. 15, 2022). *See* Ex. Xcel-89 at 31 (Paluck/Peterson Direct); Ex. Xcel-90 at 13-14 (Paluck/Peterson Rebuttal).
[1307] DOC Initial Br. at 127; Ex. DOC-18 at 59–60 (Bahn Surrebuttal); Ex. DOC-20 at 26–27 (Bahn Surrebuttal).
[1308] Ex. Xcel-89 at 34–35 (Paluck/Peterson Direct).
[1309] Ex. Xcel-89 at 35 (Paluck/Peterson Direct).
[1310] Ex. Xcel-89 at 35–36 (Paluck/Peterson Direct).

1028. In this proceeding, the Company included all LED fixture costs in the calculation of Lighting class rates, which are direct assigned. In addition, the Company included an LED fixture deferral amount of $410,155,[1311] which is the difference between the annual revenue requirements of LED fixtures since the Company began installing them in 2016 and fixture-related revenue collected via the LED lighting rates.[1312]

1029. The Company also proposed additional LED rate options for directional lighting in the Automatic Protective Lighting Service tariff.[1313] The Commission has already approved an LED option for Area Lighting fixtures in the Automatic Protective Lighting Service tariff (Docket No. E002/M-18-729), and the Company's proposal to add an LED rate option for directional lighting would leverage the same inputs and Commission decisions from that docket.[1314]

1030. In reviewing the Company's proposed rates for the Lighting class, SRA commented on the size of the cost premium of the pricing proposed for streetlights that receive underground service compared to streetlights that receive service from overhead poles and was concerned that the Company's pricing for LED streetlights did not take into account all the efficiency of LED fixtures compared to other fixtures, such as HPS fixtures.[1315]

1031. In response, the Company noted that the rate relationship of LED and HPS streetlights was established in Docket No. E002/M-15-920, but moving forward, the Company stated that it is willing to update that price structure to reflect the efficiencies associated with LED technology more directly in rate design.[1316]

1032. In response to SRA's concern that the premium for underground streetlight service is too large (compared to overhead), the Company stated that it is willing to base the underground premium solely on the overhead and underground differential reflected in current rates, which would result in a lower underground premium of $9.90 going forward.

1033. In Surrebuttal Testimony, SRA's witness recommended four additional changes to the LED street lighting rate design: (1) further reduction to the A30 LED base fixture charge rate; (2) adjustment of the premium for underground service so overhead and underground customers share equally in the savings from LEDs; (3) change the percentage of overhead poles that are direct assigned to the street light class from 60% to 58%; and (4) update the LED deferral asset amount from $136,718 to $120,021.[1317]

1034. In surrebuttal, SRA also recommended that prior to its next rate case, the Company prepare a study comparing the costs for overhead versus underground

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[1311] Current as of Direct Testimony.
[1312] Ex. Xcel-89 at 35–36 (Paluck/Peterson Direct).
[1313] Ex. Xcel-89 at 36, Sched. 10 (Paluck/Peterson Direct).
[1314] Ex. Xcel-89 at 36-37 (Paluck/Peterson Direct).
[1315] Ex. SRA-1 at 4-13 (Bride Direct).
[1316] Ex. Xcel-90 at 14-15 (Paluck/Peterson Rebuttal).
[1317] Ex. SRA-3 at 6, 9 (Bride Surrebuttal).

service.[1318] SRA also requested that prior to filing its next rate case, the Company revise its workpapers to provide greater granularity.

1035. Regarding SRA's first recommendation, the Company argued in briefing that it cannot further reduce the A30 LED base fixture charge rate and still recover the Company's revenue requirement.[1319] However, Xcel did not rebut SRA's testimony that its proposal was revenue neutral. SRA proposed reducing the LED fixture charge with a commensurate increase in monthly charges for non-LED fixtures.[1320]

1036. It is reasonable to reduce LED fixture charges as proposed by the SRA with a commensurate increase in monthly charges for non-LED fixtures. This adjustment recognizes the efficiency benefits of LEDs and the high O&M costs of non-LED fixtures as well as sends a price signal that incentivizes further adoption of this efficient lighting technology.

1037. With regard to SRA's second recommendation, the Company argued that its proposed rate design for LED streetlights equally distributes the cost savings for LEDs between underground- and overhead-service customers but there is a premium added to underground-service customers to account for the higher costs associated with underground service.[1321] However, the Company's increase in the monthly per-fixture charge for all rate A30 customers combined with a reduction of the per-fixture rate for underground-service customers offset the cost benefit of LEDs for overhead-service lighting customers.[1322]

1038. It is reasonable to ensure that overhead-service customers experience the cost benefit of LED fixtures by increasing the underground-service premium by $0.605 per month to $10.505 (from $9.90).

1039. As to SRA's third recommendation to modify the percentage of poles assigned to the street light class, the Company agreed that this would be an appropriate modification for its next rate case.

1040. SRA argued that Xcel should adjust the percentage of pole costs in this proceeding.[1323] SRA Witness James D. Bride updated Xcel's cost allocation methodology to determine direct assigned pole costs using 58% of Streetlighting poles as lighting only instead of 60%. This update to the cost allocation methodology resulted in a reduction in pole costs that are direct assigned to the streetlighting class. Xcel's original direct assignment cost using the 300-pole sample size was $52,663,000. Xcel's updated direct-assigned costs using the 500-pole sample size resulted in a drop to 58% of Streetlighting poles as lighting only and a total of $50,907,000 in direct-assigned pole costs. The SRA

[1318] Ex. SRA-3 at 9 (Bride Surrebuttal).
[1319] Xcel Initial Br. at 218.
[1320] Ex. SRA-6 at 7–8 (Bride Surrebuttal).
[1321] *See* Ex. Xcel-90 at 15 (Paluck/Peterson Rebuttal) (discussing the overhead and underground differential).
[1322] Ex. SRA-3 at 6 (Bride Surrebuttal).
[1323] SRA Initial Br. at 8–9; SRA Reply Br. at 1.

accordingly recommended a downward adjustment of $1,756,000 to pole costs that are direct assigned to street lighting customers.[1324]

1041. In a vacuum, it would be unreasonable to assign costs to the street lighting class not attributable to the class. However, SRA's proposal to reduce the FERC 364 pole costs attributable to the street lighting class did not specify whether or how to make a corresponding revenue requirement adjustment to other classes. Reducing the revenue requirement for the street lighting class without a corresponding adjustment to other classes is unlikely to be revenue neutral and could deprive the Company of a reasonable opportunity to earn its revenue requirement. Accordingly, the SRA proposal to adjust the pole cost allocation for the street lighting class should only be adopted if there is a corresponding adjustment to the remaining classes or if it is determined that the adjustment is revenue neutral.

1042. With regard to SRA's fourth recommendation, in Rebuttal Testimony, the Company had updated the LED deferral amount to adjust for the passage of time since the Company filed its Direct Testimony.[1325]

1043. The Judge recommends that the Commission:

i. approve the LED rate option for directional lighting as a reasonable option for customers;

ii. adopt the A30 LED fixture rate-revenue-neutral rate adjustment proposed by SRA. This intra-LED customer adjustment will help ensure that the efficiency benefits of LEDs are more equitably realized by both OH and UG fed Streetlighting customers;

iii. adopt the updated pole cost allocation methodology, require a direct assignment of $50,907,000 in FERC 364 pole costs to the street lighting class, and either (1) adjust the revenue requirement and rates for all affected classes accordingly, or (2) determine that the adjustment is revenue neutral;

iv. approve the Company's LED deferral amount updated to adjust for the passage of time;

v. require Xcel to complete prior to its next rate case filing a study and report of its OH and UG distribution line cost to feed streetlighting as a component of streetlighting costs; and,

vi. encourage the Company to continue to work with the SRA regarding its concerns about costs related to overhead versus underground,

[1324] Ex. SRA-6 at 10 (Bride Surrebuttal).
[1325] Ex. Xcel-82 at 14-15 (Halama Rebuttal).

including revising its workpapers to achieve greater granularity to the extent possible.

K. Advanced Rate Design

1044. CEO recommended that the Commission open a docket for a single, overarching proceeding where advanced rate design (ARD) for Xcel could be discussed.[1326] Advanced rate design and load management programs are currently addressed in multiple different dockets.[1327]

1045. In support of their proposal for an ARD docket, CEO asserted an ARD docket would (1) be more efficient than considering rate design issues in multiple different dockets, (2) better ensure policy goals are being achieved by looking at load management across all customer segments, (3) be nimbler, allowing for more timely iteration of rates, and (4) would allow for greater participation in rate development by key stakeholders.[1328]

1046. CEO recommended an ARD docket be designed to achieve the following goals: (1) determine to what extent Xcel's portfolio of rates and load management programs is on track to achieve policy goals; (2) establish a framework for evaluating the performance of Xcel's portfolio of rate offerings and load management programs; and (3) create timelines and procedures for developing or refining rate offerings and load management programs.[1329]

1047. The scope of the CEO-proposed docket would include load management mechanisms including tariffed rates as well as programmatic offerings such as non-firm (i.e., interruptible) capacity and other forms of demand response.[1330] The proposal contemplates that the docket's procedural scope and process itself be established by the Commission after taking comments from stakeholders.[1331]

1048. The Commission required Xcel to develop a Rate Design Roadmap when it approved the Company's 2019 Integrated Distribution Plan.[1332] The Company filed a draft roadmap in October 2020.[1333] CEO argued that the roadmap is insufficient to address its ARD-related concerns, and that a proceeding is necessary.[1334]

1049. The Company disagreed with the CEO recommendation to open an ARD proceeding. The Company expressed concern about the scope of such a proceeding and

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[1326] Ex. CEO-1 at 6-17 (Nelson Direct).
[1327] *See, e.g.,* Docket No. E002/M-17-775: Time of Use Rate Design Pilot, Docket No. E002/M-20-86: General Time of Use Service Tariff, and Docket No. E002/M-19-666: Integrated Distribution Plan.
[1328] Ex. CEO-1 at 17 (Nelson Direct); CEOs' Initial Brief at 3.
[1329] Ex. CEO-5 at 3 (Nelson Rebuttal).
[1330] Ex. CEO-5 at 8 (Nelson Direct).
[1331] Ex. CEO-1 at 16–17 (Nelson Direct).
[1332] Docket No. E002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS (July 23, 2020).
[1333] Docket E002/M-19-666, DRAFT RATE DESIGN ROADMAP (Oct. 1, 2020).
[1334] Ex. CEO-1 at 13–14 (Nelson Direct).

stated that ongoing TOU pilot proceedings are best able to focus on exploring different topics and issues associated with particular customer classes.[1335]

1050. If the Commission were to open an advanced rate design docket, the Company stated that to the extent that there are any revenue impacts associated with new rates or new rate structures, those rate design changes should be implemented in the Company's next rate case so the Company has the reasonable opportunity to recover its revenue requirement.[1336]

1051. The CEO recommendation to establish a docket to consider Xcel's advanced rate design is so broad and underspecified as to contain both reasonable and potentially unreasonable aspects. The proposal identifies appealing objectives, such as adding structure and transparency to rate and program development,[1337] facilitating establishment of rate-design and program performance metrics,[1338] and ensuring that rates and programs are designed to advance policy goals.[1339]

1052. However, the proposal envisions a comprehensive, potentially wide-reaching docket that could include or touch on: all load flexibility practices including rate design and load management programs,[1340] advanced metering,[1341] grid modernization,[1342] rates for low-income customers,[1343] cost of service studies,[1344] and resource planning investment decisions.[1345] These subjects gave rise to contested issues in this proceeding. The proposal appears to contemplate implementing rates designed through the docket, outside of a general rate case.[1346] And the proposed docket has no clear end point; the proposal instead seems to describe a perpetual docket.

1053. Xcel's concerns about the potential scope of the proposed docket are reasonable. Rather than making the process more transparent and accessible, it could duplicate much of the work of a general rate case outside of a rate case, increase the burden and inaccessibility for participants when these issues are addressed or decided in other dockets, and be administratively unwieldy to manage. There is no reason that Xcel could not engage in "an iterative process to improve rates and programs," in a more informal manner through, for example, a standing stakeholder workgroup.

1054. The CEO has not shown why a separate proceeding is necessary when ongoing dockets or an alternative process could provide a forum for discussing and improving rate designs.

[1335] Ex. Xcel-91 at 4 (Paluck/Peterson Surrebuttal).
[1336] Ex. Xcel-91 at 4-5 (Paluck/Peterson Surrebuttal).
[1337] Ex. CEO-1 at 10 (Nelson Direct).
[1338] *Id.*
[1339] *Id.*
[1340] Ex. CEO-1 at 8 (Nelson Direct).
[1341] Ex. CEO-1 at 8, 11 (Nelson Direct).
[1342] Ex. CEO-1 at 11 (Nelson Direct).
[1343] Ex. CEO-1 at 11 (Nelson Direct).
[1344] Ex. CEO-1 at 11 (Nelson Direct).
[1345] Ex. CEO-1 at 11 (Nelson Direct).
[1346] Ex. CEO-1 at 11 (Nelson Direct).

1055. The Judge recommends that the Commission take no action on the CEO proposal for an advanced rate design docket.

1056. However, if the Commission were to open an advanced rate design docket, the Judge agrees with the Company that the Commission should determine that rate design changes that result from the docket will be implemented in the Company's next rate case so the Company has the reasonable opportunity to recover its revenue requirement.

X. MYRP Features

A. MYRP Term

1057. CUB recommends that the Commission require Xcel Energy to transition to a five-year MYRP term in its next rate case, based in part on the fact that Xcel Energy develops five-year capital forecasts.[1347] CUB witness Mr. Nelson argued that a five-year MYRP would align the MYRP with those forecasts and "ensure that the most accurate and up to date information is being used to inform rates."[1348]

1058. If the Commission chooses not to require a five-year MYRP, CUB alternatively argues that the Company should be required to file both three- and five-year forecasts in its next MYRP filing, and compare the costs and benefits of those options.[1349]

1059. The Company opposes CUB's recommendation. Company witness Ms. Liberkowski explained that filing a MYRP is option and can cover any period up to five years. Ms. Liberkowski also explained that mandating a five-year MYRP would achieve the opposite result to that desired by CUB, as it would set rates five years in advance, based on what may prove to become outdated information during that time period. Contrary to CUB's proposal, Xcel updates is five-year forecast every year to ensure that the forecast reflects current information.[1350]

1060. The Company's position is supported by the MYRP statute. Minn. Stat. § 216B.16, subd. 19, permits a public utility to propose a multiyear rate plan of between two and five years. The statute provides the utility with flexibility, which is an important consideration in the dynamic business environment in which the Company operates.

1061. The Company's capital forecasts are not the only forecasts that are relevant in a rate proceeding. Utilities' MYRP filings also typically forecast future years' operating expenses.[1351] Xcel's revenue decoupling mechanism depends on a sales forecast.[1352]

1062. The Judge recommends that the Commission take no action on CUB's proposal. Mandating a five-year term removes the flexibility granted to the utility in the

[1347] CUB Ex. 1 at 26-27 (Nelson Direct).
[1348] CUB Ex. 1 at 27 (Nelson Direct).
[1349] CUB Initial Brief at 28.
[1350] Ex. Xcel-23 at 13 (Liberkowski Rebuttal).
[1351] Minn. Stat. § 216B.16, subd. 19 (a)(2).
[1352] The decoupling mechanism is discussed below.

statute's plain language, could discourage utilities from requesting a MYRP, and rates set for the outer years of the plan would not be based on the most up to date information. And, because the Company has demonstrated that there is no need to require a five-year MYRP to ensure up-to-date capital forecasts, CUB has not shown a basis for requiring Xcel to file five-year forecasts in its next multi-year rate case if the Company proposes a shorter term.

B. Sales True-Up/Revenue Decoupling

1063. The Company proposes to implement a sales true-up decoupling mechanism beginning with the 2023 plan year, modeled after the true-up mechanism approved in its 2021 stay-out docket (2021 True-up) with modifications.[1353]

1064. A decoupling mechanism is "a regulatory tool designed to separate a utility's revenue from changes in energy sales."[1354] Separating sales and revenue reduces the utility's financial disincentive to promote energy efficiency, or its "throughput incentive."[1355] Decoupling reduces throughput incentive through annual rate adjustments designed to account for fluctuations in sales that would otherwise lead to over- or under-recovery of the utility's previously approved revenue requirement.[1356] State law requires that decoupling mechanisms must advance the goal of reducing throughput incentive "without adversely affecting utility ratepayers."[1357] In short, decoupling mechanisms must balance the financial interests of utilities and ratepayers while advancing conservation through reduced throughput incentive.[1358]

1065. The Company has had a sales true-up or decoupling mechanism in place since 2016, including a combination of a sales true-up (for demand customer classes) and a revenue decoupling mechanism (for other classes) as part of it 2015 MYRP.[1359]

1066. The Commission described the operation of sales true-ups or decoupling mechanisms in the Company's 2021 True-up:

> [T]he Commission has identified the share of Xcel's revenue requirement to recover from various customer classes and, based on forecasts of the amount of energy that each class would consume in a year, set rates designed to permit Xcel to recover the appropriate revenues from each class. But recognizing that forecasts are imperfect, the Commission authorized Xcel to implement a sales true-up to adjust rates for any given customer class to offset the variance. That is, when a customer class buys more energy (and therefore generates more revenue) than forecast, Xcel files an adjustment to reduce the rates for that class for the next year;

[1353] Ex. Xcel-22 at 48-49 (Chamberlain/Liberkowski Direct); Ex. Xcel-89 at 11-12 (Paluck/Peterson Direct); Ex. Xcel 23 at Sched. 1 (Liberkowski Rebuttal); MPUC Docket No. E002/M-20-743 (2021 True-up).
[1354] Minn. Stat. § 216B.2412, subd. 1 (2022).
[1355] Ex. DOC-18 at 10 (Bahn Direct).
[1356] Ex. DOC-18 at 10 (Bahn Direct).
[1357] Minn. Stat. § 216B.2412, subd. 2.
[1358] Ex. DOC-18 at 10 (Bahn Direct).
[1359] Ex. Xcel-75 at 17 (Goodenough Direct); Ex. Xcel-22 at 48 (Chamberlain/Liberkowski Direct).

likewise, when a class buys less energy (and therefore generates less revenue) than forecast, Xcel files an adjustment to increase rates for that class for the next year.[1360]

1067. Under Xcel Energy's proposed decoupling mechanism in this proceeding, in the event the Company experiences increased sales compared to the sales forecast used to set 2023 and 2024 plan year rates, customers will see a refund. If sales decrease compared to forecast, the Company will still receive revenues at the revenue requirement level approved by the Commission as necessary to maintain its service.[1361]

1068. The 2021 True-up established a rate adjustment to offset the difference in base rate revenue from actual 2021 sales, compared to base rate revenue at the sales level previously authorized by the Commission. The base revenue differences were determined in detail by CCOSS categories, meaning that the Residential class was separately calculated but several C&I rate schedules were combined into the two main categories of relatively small load non-demand (energy-only) customers and demand-billed customers. The three additional customer categories—small in comparison to the Residential and two C&I categories—were also separately calculated: metered energy-only street lighting service, public authorities and non-retail interdepartmental sales to Xcel's related gas utility. The adjustment mechanism for each customer category recognized changes in revenues due to changes in sales without weather-normalization, billing determinants related to sales such as billed demands, and the number of customers. The mechanism then calculated refund or surcharge rate factors for each applicable customer category, with no limit on refund or surcharge levels.[1362]

1069. The Company's proposed decoupling mechanism proposes three modifications to the 2021 True-up methodology:

i. to exclude the metered lighting category, which constitutes 7% of lighting class revenue;[1363]

ii. to use the C&I-Demand adjustment factor for interdepartmental sales rather than determining and applying a separate factor specific to the interdepartmental category, consistent with base rates used for the interdepartmental category;[1364] and

iii. to eliminate the sales growth adjustment that has been used for the C&I class, as the Company did not make an adjustment to its

[1360] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, MPUC Docket No. E002/M-20-743, ORDER APPROVING TRUE-UP ADJUSTMENTS at 3 (Aug. 5, 2022).
[1361] Ex. Xcel-23 at 15 (Liberkowski Rebuttal).
[1362] Ex. Xcel-89 at 12–13 (Paluck/Peterson Direct).
[1363] Ex. Xcel-89 at 13 (Paluck/Peterson Direct).
[1364] Ex. Xcel-89 at 13 (Paluck/Peterson Direct).

revenue deficiency to recognize future forecasted sales growth in the C&I class in this case.[1365]

1070. The following parties took positions on Xcel's proposal: DOC, OAG, XLI, CEO, SRA, and the Commercial Group.

1071. DOC, OAG, and CEO supported the proposal subject to their own modifications. SRA opposed a DOC-proposed modification relating to metered street lighting.

1072. XLI recommended that the decoupling/true-up mechanism be rejected, and the Commercial Group joined in XLI's opposition.

1073. Apart from the parties opposing Xcel's proposal entirely, no party opposed Xcel's proposed second and third modifications to its 2021 True-up.

1. Opposition to a Sales True-Up Mechanism

1074. XLI argued that the Company's sales true-up proposal should be rejected because it "does not function like traditional decoupling, which incentivizes conservation."[1366] According to its witness Mr. Pollock, because the sales true-up mechanism is not associated with any particular energy efficiency program, the mechanism only shields the Company from sales forecast errors "as well as variations due to weather, economic activity, business cycles, geopolitical events and changes in customer/sales mix due to evolving technology - all of which are difficult to predict," and insulates the Company from any deviations between actual and projected revenues.[1367]

1075. The Company's projected sales for commercial and industrial customers in the last rate case overestimated the actual sales that materialized, which resulted in surcharges to the C&I Demand class.[1368]

1076. Thus, XLI opposed the proposed sales true-up mechanism because it shifts risks from the utility to ratepayers and is therefore not a "properly implemented decoupling mechanism."[1369]

1077. XLI also opposed the true-up mechanism as "single-issue" ratemaking, changing rates without consideration of corresponding/offsetting cost reductions.[1370]

1078. The Commercial Group joined XLI's opposition to the proposal.[1371]

[1365] Ex. Xcel-89 at 13–14 (Paluck/Peterson Direct).
[1366] XLI's Proposed Findings at 28; Ex. XLI-1 at 38–39 (Pollock Direct).
[1367] Ex. XLI-1 at 38 (Pollock Direct), citing Xcel's Response to XLI-043.
[1368] Ex. XLI-1 at 40 (Pollock Direct).
[1369] Ex. XLI-1 at 38–39 (Pollock Direct).
[1370] Ex. XLI-1 at 40 (Pollock Direct).
[1371] Commercial Group's Initial Br. at 11–12.

1079. XLI recommended that the Commission should, instead of the Company's proposal, implement a mechanism of refunds and surcharges based on the Company's earnings relative to its authorized ROE.[1372] Or, if the Commission approves the true-up, the true-up should be applied on a system-wide rather than class-specific basis.[1373] XLI and the Commercial Group also recommended reducing the Company's authorized ROE if the proposal is adopted to "compensate customers for assuming the added risk imposed by the sales true-up."[1374]

1080. The Department and OAG specifically opposed a system-wide decoupling mechanism factor as proposed by XLI.[1375] The reasonableness of a multi-class decoupling factor has not been established on this record. Each class differs considerably from the others, and such a mechanism would not reflect each class's unique circumstances.[1376] XLI's proposal would likely insulate a class from the effects of a decrease in sales unique to that class by spreading the true-up adjustment across all classes.

1081. The Department agreed that Xcel's sales true-up mechanism should be approved because it would facilitate energy conservation policies.

1082. XLI's opposition to any decoupling mechanism is contrary to sound public policy and would make the Company an outlier compared to the proxy electric utility companies considered in this proceeding.[1377]

1083. XLI also misstates the purpose of a decoupling mechanism, which is neither to directly incentivize conservation nor to be linked to a specific energy efficiency program. The purpose of decoupling is set forth in statute as "a regulatory tool designed to separate a utility's revenue from changes in energy sales . . . to reduce a utility's disincentive to promote energy efficiency."[1378] A sales true-up mechanism, like the one proposed by the Company, matches that description.

1084. A sales true-up designed to separate the Company's revenue from changes in energy sales for the purpose described in Minn. Stat. § 216B.2412, subd. 1, is permissible whether or not it can be fairly characterized as single-issue ratemaking.

1085. For these reasons, the Judge recommends that the Commission take no action on the XLI or Commercial Group alternatives to the Company's sales true-up proposal.

[1372] Ex. XLI-1 at 41 (Pollock Direct).
[1373] Ex. XLI-1 at 42 (Pollock Direct).
[1374] Ex. XLI-1 at 42 (Pollock Direct); Commercial Group's Initial Br. at 11.
[1375] Ex. DOC-17 at 23 (Bahn Direct); Ex. OAG 6 at 14-15 (Twite Rebuttal).
[1376] Ex. DOC-17 at 23 (Bahn Direct).
[1377] *See* Ex. Xcel-28 at 116-117 and Sched. 10 (D'Ascendis Rebuttal).
[1378] Minn. Stat. § 216B.2412, subd. 1.

2. Metered Lighting Exclusion

1086. Xcel offers street lighting service to customers, typically municipalities. Most street light customers pay flat monthly rates to Xcel to provide and maintain streetlights. The amount paid by these customers is based on the number of lights.[1379] Some customers, however, provide their own streetlights and pay metered (i.e., usage-based) rates.[1380]

1087. The Company proposed to modify its 2021 True-up mechanism by excluding the metered lighting category. The Company argued that most lighting services have fixed rates per lighting unit that already effectively decouples sales and revenue. The sales revenue associated with metered lighting usage is a function of lighting hours which are consistent from year to year. Eliminating decoupling for metered lighting would provide consistency by allowing the entire lighting category to be exempt from decoupling adjustments.[1381] Xcel also asserted that decoupling is inappropriate for the metered lighting class because the company cannot directly advance energy conservation goals that decoupling is intended to facilitate.[1382]

1088. SRA supported the Company's proposal to exclude the metered lighting category from the true-up mechanism. It argued that the risk of an exposure of the class to a surcharge resulting from significant changeover to LED lighting, which could cause energy sales to fall short of Xcel forecasts and would operate as a disincentive to adopt LED lighting.[1383]

1089. The Department disagreed with Xcel's proposal. The Department argued that characteristics of the metered lighting class make it an appropriate candidate for decoupling. The Department noted that the purpose of decoupling is to "reduce a utility's disincentive to promote energy efficiency."[1384] The Department also argued that the metered lighting class's size did not impact its ability to invest in energy efficiency, or Xcel's throughput incentive. In addition, the Department asserted that Xcel does have an indirect role through the promotion of energy efficiency to these customers, as is true for almost all customer usage.[1385] According to the Department, Xcel has acknowledged that some street lighting customers still use less-efficient, high-pressure sodium bulbs. This means these customers increase Xcel's energy sales relative to other street lighting customers, and there remains energy conservation gains to be made. As a result, the Department concluded that the sales true-up mechanism is still an appropriate tool for reducing Xcel's disincentive to promote energy efficiency to these customers.[1386]

[1379] Ex. Xcel-89 at 14 (Paluck/Peterson Direct); Ex. DOC-18 at 19–20 (Bahn Direct).
[1380] Ex. Xcel-4 at 107 (Appl. Vol. 2E – Proposed Tariffs) (Street Lighting Energy Service – Metered. Tariff Sheet No. 5-78).
[1381] Ex. Xcel-89 at 13 (Paluck/Peterson Direct).
[1382] Ex. Xcel-90 at 11–12 (Paluck/Peterson Rebuttal).
[1383] SRA Reply Br. at 9.
[1384] Ex. DOC-18 at 20 (Bahn Direct); Minn. Stat. § 216B.2412, subd. 1.
[1385] Ex. DOC-20 at 15 (Bahn Surrebuttal).
[1386] Ex. DOC-18 at 20 (Bahn Direct).

1090. The Judge agrees with the Department that the class should be included in the sales true-up mechanism. Neither the class's size nor facility ownership impacts Xcel's throughput incentive. The sales true-up mechanism is intended to reduce the Company's disincentive to promote energy efficiency. There are still energy efficiency gains to be obtained within this class. Although Xcel does not control the lighting fixtures installed by these customers, it has the same ability to promote energy efficiency as it does for any customer.

1091. With respect to the argument that the sales true-up could result in an offsetting surcharge as a result of reduced sales from LED conversions, the SRA does not point to evidence in the record of the relative magnitude of any offset. The magnitude of the theorized surcharge has not been shown as likely to exceed the benefit of reduced energy consumption. Customers converting to LED fixtures may reduce Xcel's sales in the category, but all customers in the category would share in any true-up surcharge. The potential for a surcharge could just as likely encourage a customer with less-efficient fixtures to convert sooner to avoid experiencing a sales true-up surcharge—caused by other customers' conversions—on top of the greater consumption of their less-efficient fixtures.

1092. The Judge recommends that the Commission require Xcel to include the metered lighting category in its sales true-up mechanism.

3. Surcharge Cap

1093. Xcel proposed that no surcharge cap be placed on its sales true-up mechanism.[1387]

1094. CEO recommended that the Commission approve Xcel's proposal subject to a 3% soft cap. Under a soft cap, revenues exceeding the cap would remain in a deferral account for recovery in a future year.[1388]

1095. The Department, however, recommended that the Commission impose a 3% hard cap on customer surcharges.[1389] A 3% hard cap would limit annual customer surcharges meant to reduce discrepancies between actual and authorized revenues at 3% of Xcel's actual revenues.[1390] The Department argued that a hard cap was appropriate for several reasons.

1096. The Department first argued that a hard cap better balances the financial interests of the utility and ratepayers than does an uncapped decoupling mechanism because the cap more equitably splits the risk of unexpected weather and economic conditions.[1391] Such a split, in the Department's view, is appropriate because utilities are

[1387] Ex. Xcel-89 at 11–12 (Paluck/Peterson Direct).
[1388] Ex. Xcel-90 at 10 (Paluck/Peterson Rebuttal).
[1389] Ex. DOC-18 at 27 (Bahn Direct).
[1390] Ex. DOC-18 at 24–25 (Bahn Direct); Ex. Xcel-90 at 10 (Paluck/Peterson Rebuttal).
[1391] DOC Initial Br. at 109–110.

only entitled to a reasonable opportunity to earn their approved revenue requirement.[1392] The Department additionally asserted that utility investors are compensated for assuming such business risks,[1393] and pointed out that state law requires makes that decoupling must occur "without adversely affecting utility ratepayers."[1394]

1097. The Department also pointed out that a 3% hard cap would have reasonably balanced sales risk had it been in place for Xcel's proposed customer classes between 2017 to 2021.[1395] Without a 3% hard cap, Xcel's proposed customer classes would have been surcharged approximately a net total of $246 million. This burden would have been almost exclusively borne by demand class customers.[1396]

1098. The Department compared the annual and total surcharges for customer classes, with and without a 3% hard cap, between 2017 and 2021, as follows:

[1392] *See, e.g., In re Appl. of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 25 (May 14, 2012) (eDockets No. 20125-74691-01) ("The Commission must determine an appropriate rate that provides a reasonable opportunity for Xcel to recover its Commission-approved revenue requirement."); Ex. DOC-1 at 5 (Addonizio Direct); Ex. DOC-21 at 5 (Campbell Direct).
[1393] Ex. DOC-1 at 5 (Addonizio Direct).
[1394] Minn. Stat. § 216B.2412, subd. 2.
[1395] DOC Initial Br. At 110.
[1396] Ex. CEO-1, REN-D-5 at 17 (Nelson Direct) (DOC IR No. 525 – Attach. A).

Xcel Energy's Proposed Sales True-Up Classes, 2017 - 2021[1397]

Surcharge or (Credit) $1000's	Residential	Commercial	Demand	Other Pub. Auth.	Total
2017					
Surcharge or (Credit) - No Cap	$18,344	$1,254	$19,832	($269)	$39,160
Surcharge or (Credit) - 3% Cap	$18,344	$1,254	$19,832	($269)	$39,160
Difference	$0	$0	$0	$0	$0
2018					
Surcharge or (Credit) - No Cap	($26,675)	($301)	$7,274	($462)	($20,163)
Surcharge or (Credit) - 3% Cap	($26,675)	($301)	$7,274	($462)	($20,163)
Difference	$0	$0	$0	$0	$0
2019					
Surcharge or (Credit) - No Cap	$4,674	$2,506	$58,474	($318)	$65,336
Surcharge or (Credit) - 3% Cap	$4,674	$2,457	$37,002	($318)	$43,817
Difference	$0	$48	$21,471	$0	$21,519
2020					
Surcharge or (Credit) - No Cap	($42,623)	$6,471	$144,620	($3)	$108,465
Surcharge or (Credit) - 3% Cap	($42,623)	$2,457	$37,002	($3)	($3,166)
Difference	$0	$4,014	$107,617	$0	$111,631
2021					
Surcharge or (Credit) - No Cap	($66,664)	$5,094	$115,794	($255)	$53,969
Surcharge or (Credit) - 3% Cap	($66,664)	$2,457	$37,002	($255)	($27,460)
Difference	$0	$2,637	$78,792	$0	$81,429
2017-2021 Totals					
Surcharge or (Credit) - No Cap	($112,943)	$15,025	$345,993	($1,308)	$246,767
Surcharge or (Credit) - 3% Cap	($112,943)	$8,326	$138,113	($1,308)	$32,187
Total Difference	**$0**	**$6,699**	**$207,880**	**$0**	**$214,579**

1099. According to the Department, regardless of a surcharge cap, residential customers would have received about $113 million in bill credits, but demand customers would have experienced about $345 million in surcharges without a 3% cap.[1398] With a 3% hard cap, the sales decline would have been split between Xcel and demand class customers. Xcel would have been unable to recoup $207 million in lost sales, while demand customers would have been surcharged $138 million.[1399] The Department argued—based on this illustration—that a 3% hard cap is necessary to ensure that unforeseen risks are equitably shared consistent with the statutory requirement.[1400]

1100. The Department also asserted that a 3% hard cap would rarely curtail surcharges. Relying on 2017 through 2021 data, the Department stated that its proposed cap would have only curbed the size of the customer surcharge in five out of twenty

[1397] Ex. CEO-1, REN-D-5 at 17 (Nelson Direct) (DOC IR No. 525 – Attach. A).
[1398] DOC Initial Br. At 111.
[1399] DOC Initial Br. At 111; Ex. CEO-1, REN-D-5 at 17 (Nelson Direct) (DOC IR No. 525 – Attach. A).
[1400] DOC Initial Br. At 111; Minn. Stat. § 216B.2412, subd. 2 (requiring the Commission to design decoupling mechanisms to avoid "adversely affecting utility ratepayers.").

possible occasions between 2017 and 2021.[1401] According to the Department, the surcharge reduction has exceeded $5 million only three times.[1402] In addition, the Department noted that its recommendation that the Commission adopt Xcel's lower, initial sales forecast for 2023 and 2024 would make it less likely that a surcharge would be necessary.[1403]

1101. The Department next argued that a hard cap is supported by the Commission's February 2022 decision in Otter Tail Power Company's electric rate case.[1404] Otter Tail is smaller than Xcel. Otter Tail's authorized revenue requirement is about $208 million. It only has about 62,000 customers.[1405] By contrast, Xcel's proposed revenue requirements range between $3.5 and $3.7 billion, and it has more than 1.5 million electric customers.[1406] According to the Department, these differences gave Otter Tail a better argument that it required the absolute revenue stability offered by uncapped surcharges. Despite Otter Tail's argument, the Commission concluded that a 4% hard cap was appropriate.[1407] The Commission reasoned that "a hard cap would most reasonably balance the interests of the utility and ratepayers . . . without undermining conservation goals."[1408] Given that Xcel is larger and enjoys a more diversified and resilient customer base, the Department reasoned that it is better positioned to share the risks of unexpected changes in sales.

1102. In response, Xcel asserted that a surcharge cap is inappropriate because it is transitioning to time-of-use rates that could significantly reduce sales.[1409] The Department disagreed that this transition posed any significant risk. First, the Department noted that TOU rates are intended to shift but not eliminate usage.[1410] The Department stated, for example, that "TOU rates should incentivize a residential customer to do laundry late at night or early in the morning instead of during the afternoon when rates might be highest. In this way, a TOU rate shifts load as opposed to eliminating it all together."[1411] Second, the Department pointed to evidence from Xcel's own pilot programs. Specifically, Xcel's pilot program study report stated, "On average, an Eden Prairie premise enrolled for a full 12 months reduced energy consumption overall by approximately 13 kWh (0.1% of annual consumption) and a Minneapolis premise

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[1401] DOC Initial Br. At 111.
[1402] DOC Initial Br. At 111; Ex. CEO-1, REN-D-5 at 17 (Nelson Direct) (DOC IR No. 525 – Attach. A).
[1403] DOC Initial Br. At 111; Ex. DOC-10 at 11 (Shah Surrebuttal); Ex. Xcel-77 at 11 (Goodenough Rebuttal).
[1404] DOC Initial Br. At 112.
[1405] *In re Appl. Of Otter Tail Power Co. for Auth. To Increase Rates for Elec. Serv. In the State of Minn.*, Docket No. E-017/GR-20-719, ALJ FINDINGS OF FACT, CONCLUSIONS, & RECOMMENDATION ¶ 1 (Sept. 20, 2021) (eDockets No. 20219-178116-01); 2022 Otter Tail Order at 64 (Feb. 1, 2022) (eDockets No. 20222-182349-01).
[1406] Ex. Xcel-82, BCH-R-2 at 4 (Halama Rebuttal); Ex. Xcel-22 at 11 (Chamberlain/Liberkowski Direct).
[1407] DOC Initial Br. At 112.
[1408] 2022 Otter Tail Order at 61.
[1409] Xcel Initial Br. At 226; Ex. Xcel-90 at 10–11 (Paluck/Peterson Rebuttal).
[1410] DOC Reply Br. At 27; Ex. DOC-20 at 6–7 (Bahn Surrebuttal).
[1411] Ex. DOC-20 at 6 (Bahn Surrebuttal).

increased consumption overall by approximately 14 kWh per year (0.2% of annual consumption)."[1412]

1103. The Department also argued that Xcel's speculation about a possible revenue decline is broadly inconsistent with its earnings history dating back two decades.[1413] According to the Department, Xcel has only collected less revenue than the prior year five times since 2002. Only three times has the decline exceeded 3% of total annual revenue. Overall, Xcel collected 93% more revenue from Minnesota ratepayers in 2021 than in 2002—nearly double.[1414] The Department suggested that these trends demonstrate that a dramatic downward revenue swing is improbable, and a 3% hard cap would rarely be exceeded in any case.[1415]

1104. The Judge concurs with Xcel, CEOs, and Department, and recommends that the Commission approve the Company's proposal to operate a sales true-up mechanism for the duration of this multi-year rate plan. For the reasons discussed below, the Judge recommends that the Commission impose a 3% hard cap as recommended by the Department.

1105. A hard cap best balances the statutory requirements for decoupling mechanisms. It would balance the financial interests of investors and ratepayers by ensuring that financial risks of unexpected sales declines are shared. As the Department illustrated, without a hard cap ratepayers would have been surcharged a net amount of $246 million between 2017 and 2021 while investors would have been left completely whole. On the other hand, a 3% hard cap would have assigned about 60% of the sales shortfall to investors and 40% to ratepayers.

1106. The Department's proposal also addresses, at least in part, the objections of XLI and the Commercial Group by having the Company share some risk of sales falling short of forecasts.

1107. While the CEO soft cap proposal would alleviate the risk to Xcel of dramatic one-year spikes, it would fundamentally shift all sales-related business risks from the company to ratepayers. This is inconsistent with Minn. Stat. § 216B.2412, subd. 2, which requires sales decoupling mechanisms to avoid "adversely affecting utility ratepayers." It's also inconsistent with the utility regulatory framework which only ensures the Company a reasonable opportunity to recover its revenue requirement and a rate of return to compensate investors for assuming these business risks.

1108. Finally, the Commission's recent decision in the Otter Tail Power Company electric rate case is instructive. It would be unreasonable to subject a smaller, more volatile utility to a hard cap, but not a larger utility with a diverse customer base. It also

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[1412] Ex. DOC-20 at 6–7 (Bahn Surrebuttal) (quoting *In re Xcel Energy Residential Time of Use Rate Design Pilot*, Docket No. E002/M-17-775, Compliance Filing – Attach. C at 10–11 (pgs. 62–63 of pdf) (Feb. 25, 2022) (eDockets No. 20222-183193-02)).
[1413] DOC Reply Br. At 27; Ex. DOC-20 at 7 (Bahn Surrebuttal).
[1414] DOC Reply Br. At 27; Ex. DOC-20, APB-S-1 at 1 (Bahn Surrebuttal).
[1415] DOC Reply Br. At 27.

would be inequitable to Minnesota ratepayers whose exposure to surcharges may vary simply by virtue of their geographic location.

C. Compliance Filings

1109. A final matter related to the sales true-up proposal pertains to Xcel's annual compliance filings. The Department recommended that the Commission continue to require Xcel to make annual compliance filings consistent with its February 1, 2022, filing in Docket No. E-002/M-20-743.[1416] The Department also recommended that the Commission adjust the filing deadline—from February 1 to April 1—so Xcel's report could incorporate Conservation Improvement Program savings results from the prior year. To accommodate a later filing date, the Department further recommended that the Commission postpone the implementation of any sales true-up adjustments from the current date of April 1 until June 1, so that the Commission and parties have an opportunity to review Xcel's report.[1417] In terms of the procedural schedule, the Department recommended that parties be afforded 30 days to file comments on Xcel's April 1 compliance filing, and ten days for the Company to provide its reply comments.[1418]

1110. The Department's recommended adjustments to Xcel's annual compliance filings are reasonable. Given that the parties agree a sales true-up is intended to facilitate energy conservation programs, it makes sense to delay annual compliance filings to ensure that conservation data from the prior year is available. This data could be helpful to the Commission, Department, and interested stakeholders in understanding the impact of sales decoupling.

1111. The Judge recommends that the Commission adopt the Department's proposed sales true-up compliance filing requirements.

D. Other Rider Issues

1112. Special cost recovery mechanisms, including riders, "allow a utility to recover its actual costs for a specified function on a periodic basis outside the context of a formal rate case."[1419] Allowing automatic recovery for certain costs "removes them from inclusion in the overall review of costs . . . when a general rate case is ultimately filed," which can mask the full rate implications for ratepayers.[1420]

1113. The Commission noted in its 2010 Utility Rates Study that there are "concerns with [the] use" of riders, including an adverse effect on incentives.[1421] Specifically, the Commission stated that by "allowing the immediate pass-through of

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[1416] Ex. DOC-18 at 28 (Bahn Direct); *In re Pet. Of N. States Power Co. for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Compliance Filing—2021 Sales & Related Revenue Calculations (Feb. 1, 2022) (eDockets No. 20222-182320-02).
[1417] Ex. DOC-20 at 9–10 (Bahn Surrebuttal).
[1418] Ex. DOC-20 at 9–10 (Bahn Surrebuttal).
[1419] Minn. Pub. Utils. Comm'n, *Report to the Legislature: Utility Rates Study*, at 5 (Jun. 2010), available at https://mn.gov/puc/assets/012854_tcm14-5188.pdf (emphasis omitted) (PUC Utility Rates Study).
[1420] *Id*. At 8.
[1421] *Id*. At 7.

certain types of cost increases, meaningful and binding incentives to control costs could be substantially eroded." [1422] In addition, the "expanded use of [alternative rate] mechanisms can lead to reduced efficiency and increased administrative costs."[1423]

1114. The Commission has authority to grant or deny the use of riders.[1424]

1115. In its 2013 Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, the Commission ordered utilities to "achieve [the] administrative efficiencies" of multiyear rate plans by "recovering continuing, predictable costs" through base rates instead of riders.[1425] The Commission wrote that it would "direct the utility to propose consolidating as many [other riders and cost recovery mechanisms] as practical in the most reasonable manner available," and that "[o]therwise, the, the Commission will address petitions for riders and deferred accounting on a case-by-case basis as they arise."[1426]

1116. Xcel identified that it currently has seven cost recovery riders: Renewable Energy Standards (RES); Transmission Cost Recovery (TCR); Renewable Development Fund (RDF); Conservation Improvement Program (CIP); Windsource; Renewable Connect; and Fuel Clause Adjustment (FCA).[1427]

1117. The Company proposed continuing six of the riders, some with modifications, and discontinuing the Windsource Rider upon transitioning customers to the Renewable Connect Rider.[1428] The Company has identified that it intends to recover approximately $3.1 billion in rider costs throughout the course of the MYRP.[1429]

1118. The utility bears the burden of establishing that its planned investments are prudent, will result in just and reasonable rates, and that rider treatment is the appropriate avenue for cost recovery.[1430]

1119. CUB recommended that the Commission limit rider authorization to extraordinary circumstances and direct the Company to recover more costs through its rate base.[1431] CUB offered three specific rider-related recommendations: (1) establish

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[1422] *Id*.
[1423] *Id*. At 13.
[1424] *See*, *e.g.*, Minn. Stats. §§ 216B.16, subd. 7; 216B.1645, subd. 2 (providing the Commission with authority to allow rider treatment for fuel, transmission, and renewable energy standard costs).
[1425] MYRP Order at 8.
[1426] *Id*.
[1427] Xcel Ex. 79 at 105 (Halama Direct) (stating "six" but listing seven).
[1428] Xcel-79 at 105–06 (Halama Direct).
[1429] Ex. CUB-1 at 34, Table 3 (Nelson Direct); *see also* Xcel response to CUB-008, *attached to* Ex. CUB-1 as CUB-REN-3.
[1430] Minn. Stat. § 216B.16, subd. 4; *see also 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-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 5 (May 14, 2012) (noting that utilities must "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").
[1431] CUB Initial Brief at 34–36.

rider revenue caps;[1432] (2) disallow the creation of new riders during the course of the MYRP;[1433] and (3) direct the Company to propose a fuel-cost risk-sharing mechanism.[1434]

1. Rider Revenue Caps

1120. The Transmission Cost Recovery (TCR) rider allows the Commission to "approve a tariff mechanism for the automatic annual adjustment of charges for the Minnesota jurisdictional costs net of associated revenues" related to new transmission facilities, federally approved MISO tariff charges, distribution planning, and certified grid modernization investments.[1435]

1121. The Renewable Energy Standard (RES) rider provides the Commission with permissive authority to approve, or approve as modified, a rate schedule that:

> [P]rovides for the automatic adjustment of charges to recover prudently incurred investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the requirements of section 216B.1691, provided those facilities were previously approved by the commission under section 216B.2422 or 216B.243, or were determined by the commission to be reasonable and prudent under section 216B.243, subdivision 9.[1436]

1122. CUB recommended that the Commission establish revenue caps on Xcel's TCR and RES riders consistent with the Company's forecasted capital expenditures during the MYRP.[1437] CUB argued that revenue caps would simulate the cost containment incentives of the rate setting process while still allowing the TCR and RES riders to operate during the MYRP period.[1438] Applying a revenue cap based on these figures would produce budgets of $148.9 million for the TCR rider and $158.7 million for the RES rider over the course of the test and plan years.[1439]

1123. CUB argued that the ability to use riders for cost recovery between rate cases undercuts the cost containment function of the MYRP by encouraging indiscriminate use of riders without accompanying budgetary constraints.[1440]

1124. Xcel argued that any modifications to the TCR and RES riders should be evaluated within their respective dockets,[1441] and that establishing revenue caps on the

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[1432] CUB Initial Br. At 36-37; Ex. CUB-1 at 34 (Nelson Direct).
[1433] CUB Initial Br. At 42-43; Ex. CUB-1 at 34 (Nelson Direct); Ex. CUB-3 at 11 (Nelson Surrebuttal).
[1434] CUB Initial Br. At 43-51; Ex. CUB-1 at 34-36 (Nelson Direct); Ex. CUB-3 at 15 (Nelson Surrebuttal).
[1435] Minn. Stat. § 216B.16, subd. 7b.
[1436] Minn. Stat. § 216B.1645, subd. 2a.
[1437] CUB Initial Br. At 36-37; Ex. CUB-1 at 34 (Nelson Direct).
[1438] Ex. CUB-1 at 32, 34 (Nelson Direct); Ex. CUB-3 at 14 (Nelson Surrebuttal).
[1439] Ex. CUB-1 at 34, Table 3 (Nelson Direct); *see also* Xcel response to CUB-008, *attached to* Ex. CUB-1 as CUB-REN-3.
[1440] Ex. CUB-3 at 12–13 (Nelson Surrebuttal).
[1441] Xcel Initial Brief at 241; Xcel Ex. 23 at 18-19 (Liberkowski Rebuttal). As of the filing of rebuttal testimony, the Company's RES Rider filing was being considered in MPUC Docket No. E002/M-22-528, while the TCR Rider was being considered in MPUC Docket No. E002/M-21-814. *Id.* At 19.

riders would be "contrary to their very purpose – to encourage investment in renewable energy projects and transmission assets."[1442]

1125. CUB argued that project costs recovered through the TCR and RES riders generally are not large, volatile, and outside the control of the utility.[1443] Rather, renewable energy projects have become integral parts of the Company's resource portfolio,[1444] and transmission developments are necessary to provide safe, adequate, and reasonable utility service.[1445] Based on Xcel's commitments towards reaching net-zero emissions and constructing transmission buildouts, CUB argued that establishing a revenue cap on the TCR and RES riders would not prevent the Company from investing in those types of assets.

1126. CUB has not met its burden to establish that imposing its proposed revenue caps on the TCR and RES riders would be reasonable. CUB has not demonstrated that an aggregate revenue cap is a reasonable or necessary way to incentivize the Company to control the costs of projects eligible for rider recovery. The Company is required to justify the expenses proposed for rider recovery and the Commission has an opportunity to review such proposals for prudence when they are filed.[1446]

1127. The TCR and RES riders permit timely recovery for certain investments that serve important policy objectives. The timeliness can benefit ratepayers as well as the Company because ratepayers only begin paying for projects as they are placed in service.[1447] Limiting the use of the riders before the Commission has had an opportunity to consider a proposed investment could prevent investment proposals that would serve the riders' policy objectives and benefit ratepayers and the public.

1128. Contrary to CUB's argument, the TCR rider can include costs that could be large, volatile, and outside the control of the utility.[1448]

1129. Finally, this proceeding is likely not the best venue for considering a cap on TCR and RES rider revenue. The Commission considers the Company's RES Rider and TCR Rider each year, in dockets specifically devoted to them. The Commission reviews the proposed rider revenue requirements, reflecting both the capital and operating costs associated with the Commission-approved projects and, in the case of the RES rider, include true-up to actual production tax credits. Any significant change to the design or

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[1442] Xcel Initial Brief at 242; Xcel Ex. 23 at 19 (Liberkowski Rebuttal).
[1443] CUB Initial Brief at 37 (citing Ex. CUB-1 at 32–33 (Nelson Direct)).
[1444] *Id*.
[1445] Ex. CUB-1 at 37–38 (Nelson Direct)
[1446] *See* Minn. Stat. §§ 216B.16, subd. 7b(c), (d) (regarding the TCR rider), 216B.1645, subd. (b) (regarding the RES rider).
[1447] Ex. Xcel-22 at 43 (Chamberlain Direct).
[1448] *See* Minn. Stat § 216B.16, subd. 7b(a)(3) (authorizing automatic adjustment of charges for costs net associated revenues of charges incurred by a utility under a federally approved tariff that accrue from other transmission owners' regionally planned transmission projects that have been determined by the Midcontinent Independent System Operator to benefit the utility or integrated transmission system).

operation of these riders should be considered in those dockets, not in this general rate case docket.[1449]

1130. The Judge recommends that the Commission not adopt the proposal to impose revenue caps on the TCR and RES riders.

2. New Rider Prohibition

1131. CUB argued that the cost containment purposes of the MYRP and its proposed TCR and RES rider revenue caps would be reduced if the Company was able to propose and automatically recover costs through new riders during the MYRP.[1450]

1132. CUB recommended that the Commission should state in its order that the Company may not propose any new riders throughout the course of the MYRP.[1451]

1133. The Company recommended rejecting CUB's proposal to limit new riders. Company witness Ms. Liberkowski explained that the MYRP statute gives the Commission discretion to approve riders or other adjustment mechanisms during the term of the plan, and that riders are a reasonable tool for the Company and the Commission to address unanticipated events, such as new statutory requirements. Without the availability of riders, incorporating new requirements that mandate specific investments or expenditures would be frustrated and expose the Company and the Commission to recovery concerns and deferred costs.[1452]

1134. Because the Commission can impose, and has imposed, cost caps when approving projects that may be eligible for rider recovery,[1453] riders are not wholly without cost control mechanisms.

1135. Prohibiting new rider proposals during the MYRP term raises more concerns that it alleviates. It would unreasonably limit the Commission's own discretion to consider and approve a future, justified rider proposal. The Commission can determine whether to approve a new rider if and when one is proposed.

1136. The Judge recommends rejecting CUB's proposal to prohibit new riders during the course of the MYRP.

[1449] Ex. CUB-1 at 34–36 (Nelson Direct).
[1450] CUB Initial Brief at 42.
[1451] Ex. CUB-1 at 34 (Nelson Direct).
[1452] Ex. Xcel-23 at 21 (Liberkowski Rebuttal); Minn. Stat. § 216B.16, subd. 19.
[1453] *See, e.g.,* In the Matter of the Petition of Northern States Power Company for Approval of the Renewable Energy Standard Rider Revenue Requirements For 2023, and a Revised Adjustment Factor, MPUC Docket No. E-002/M-22-528, ORDER, attachment at 6 (Dec. 27, 2022) (eDockets No. 202212-191643-01).

3. Requirement to Propose Fuel-Cost Risk-Sharing Mechanism

1137. CUB recommended the Commission require the Company to propose a "risk sharing" mechanism in its separate FCA docket.[1454]

1138. CUB witness Mr. Nelson argued that an FCA risk-sharing mechanism would "more fairly share the risk of fuel price" between customers and the utility.[1455]

1139. Mr. Nelson acknowledged that the Commission's 2017 reforms to the FCA mechanism "were notable improvements to the status quo" that "moved towards more equitably balancing" utility and ratepayer interests.[1456] However, he argued that additional evaluation was warranted because the utility industry and resource costs have undergone significant changes since the Commission last acted to modify the FCA mechanism in 2017.[1457]

1140. The Company disagreed with CUB's recommendation. Company witness Ms. Liberkowski explained that the Commission, Xcel Energy, other Minnesota electric utilities, the Department, OAG, and other stakeholders recently completed an industry-wide and years-long process of exploring FCA reforms:

> That process culminated in a series of orders approving various reforms and first reflected by Xcel Energy in the Company's 2019 FCA filing, Docket No. E002/M-19-293, with the first fuel rates under this new process implemented January 1, 2020. In its December 19, 2017 Order in the 802 Docket, the Commission explained that it specifically designed these reforms to "more equitably balance the interests of a utility and its ratepayers," by setting a fuel rate and allowing a utility to petition for recovery if it incurs costs above the approved fuel rate, subject to prudence review. The Commission further stated that these reforms "will permit more effective prudence review of fuel costs, better protect consumers from potentially unreasonable rates, and increase clarity of anticipated fuel costs, enhancing a customer's ability to make meaningful choices about energy usage. And when necessary, an annual true-up mechanism will ensure that over- or under-recoveries are equitably addressed.[1458]

1141. Ms. Liberkowski also testified that the FCA reforms are at the end of a three-year pilot and an evaluation of the revised FCA process will follow.[1459] The Commission established a requirement that utilities file "lessons learned" reports three years after the implementation of FCA revisions.[1460] The three-year anniversary of FCA revision implementation was January 1, 2023.

[1454] Ex. CUB-1 at 34-36 (Nelson Direct).
[1455] Ex. CUB-1 at 35 (Nelson Direct).
[1456] Ex. CUB-3 at 24 (Nelson Surrebuttal).
[1457] *Id*. at 18–21.
[1458] Ex. Xcel-23 at 20 (Liberkowski Rebuttal).
[1459] Tr. Vol 1 at 27:17–23 (Dec. 13, 2022).
[1460] Dec. 19, 2017 FCA Order at 10.

1142. Ms. Liberkowski also argued against CUB's proposed risk-sharing mechanism by suggesting that such a mechanism is "unnecessary, would be highly contentious, and could have unintended adverse consequences."[1461]

1143. CUB's arguments and position are supported and reasonable. The timing of utilities' "lessons learned" reports provides a timely opportunity to evaluate the reasonableness and feasibility of a risk-sharing mechanism within the broader context of FCA modifications. That such a proposal may be contentious is not a reason to avoid addressing it in the course of evaluating the FCA process.

1144. The Judge recommends that the Commission adopt CUB's recommendation to require the Company to propose a risk-sharing mechanism in its lessons learned report and cross-file its proposal in its own fuel clause adjustment docket.

XI. Additional Policy Issues

A. Corporate Governance

1145. The Company is a wholly owned subsidiary of Xcel Energy, Inc. (XEI), the holding or parent company. A holding company is a company that holds the controlling stock of its subsidiaries.[1462]

1146. XEI is an investor-owned utility holding company which has publicly traded stock. XEI also issues its own debt in the form of senior unsecured bonds.[1463]

1147. XEI pays cash dividends to its shareholders on a quarterly basis which has been consistent over the many years of XEI's existence.[1464]

1148. OAG witness Brian Lebens provided testimony discussing issues related to dividend policy and corporate governance. Mr. Lebens discussed both Xcel Energy and its parent company, XEI.[1465]

1149. The Company's 10-K specifically acknowledged as an operational risk that cash requirements for the parent company could result in the parent company increasing the cash dividends that the operating company pays to the parent company.[1466] As a result, the operating company could need to seek out alternate sources of funding.[1467]

1150. OAG recommended that the Commission initiate an investigation or, in the alternative, require Xcel to convene a stakeholder group to explore a range of topics

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[1461] Ex. Xcel-23 at 20 (Liberkowski Rebuttal).
[1462] Ex. Xcel-26 at 4 (Johnson Rebuttal).
[1463] *Id.*
[1464] *Id.*
[1465] Ex. OAG-1, passim (Lebens Direct); Ex. OAG-8, passim (Lebens Surrebuttal).
[1466] Ex. OAG-1 at 12–13 (Lebens Direct); Ex. Xcel-60, sched. 10 at 11 (Baumgarten Direct).
[1467] Ex. OAG-1 at 14 (Lebens Direct); Ex. Xcel-60, sched. 10 at 12 (Baumgarten Direct).

related to dividends, their effect on the Company's cash-on-hand, and the potential impact of the relationship between dividends and liquidity on ratepayers.[1468]

1151. Company witness Paul Johnson, Vice President, Treasurer and Investor Relations, explained the relationship between the NSPM operating company's equity ratio and its payment of dividends to XEI.[1469] He explained that the equity balance for NSPM can be increased by retained earnings and by equity infusions from XEI, and reduced by dividends from NSPM to XEI and debt issuances.[1470] According to the Company, it is paying the appropriate amount in dividends to its parent company to maintain its authorized equity ratio.[1471]

1152. XEI would not require the Company to pay dividends that would cause a material departure from the equity ratio approved by the Commission.[1472]

1153. If the Company's dividends to its parent company were reduced, the result may be the loss of confidence of investors and difficulty of XEI to raise capital.[1473] It would also, in the absence of a Commission-approved change, cause the Company's equity ratio to increase beyond the Commission-approved level.[1474]

1154. The Company recommended that the Commission not expend regulatory and stakeholder resources on either a stakeholder working group or an investigation.[1475] It argued that the OAG's concern about extracting liquidity from the Company was unfounded.[1476]

1155. The Commission and interested parties have regularly reviewed the Company's financing structure and related financial practices in multiple rate cases and annual capital structure filings over the past several decades. OAG identified no error or omission in the Commission's regulatory oversight or in these past proceedings.

1156. The Company's capital structure is uncontested by any party in this proceeding.

1157. The Judge recommends rejecting OAG's proposal to require a proceeding or stakeholder group to examine the Company's corporate governance and dividend policy. The risk identified in the Company's 10-K is hypothetical and the record does not establish a likely benefit of further investigation to ratepayers.

[1468] Ex. OAG-1 at 12–14 (Lebens Direct).
[1469] Ex. Xcel-26 at 4-11 (Johnson Rebuttal).
[1470] *Id*. at 7.
[1471] *Id*. at 8
[1472] *Id* at 7.
[1473] *Id*. at 8.
[1474] *Id*.
[1475] Ex. Xcel-26 at 11 (Johnson Rebuttal).
[1476] *Id*. at 9–10.

B. Distributed Energy Resources (DER)

1158. Distributed Energy Resources, including energy sources such as photovoltaic solar and battery energy storage systems, are located near the load they serve and generally interconnect to the electrical grid at the distribution level.[1477]

1159. The Electric Power Research Institute (EPRI) defines hosting capacity as the amount of DER that can be accommodated on the existing utility system without adversely affecting power quality or reliability under existing configurations and without requiring infrastructure upgrades.[1478]

1160. Over the MYRP 2022–24 period, Xcel seeks approval for $1.63 billion in distribution capital expenditures, over $500 million per year.[1479]

1161. Xcel's distribution investment proposals in this rate case focus primarily on addressing aging assets and grid modernization.[1480]

1162. JSC and CEO recommend that the Commission adopt several DER-related requirements for the Company as discussed below. The Company generally opposed the recommendations, and argues they are outside the scope of this proceeding.[1481]

1. CEO DER Recommendations

1163. CEO recommended Xcel be required to quantify the amount of additional DER and beneficial electrification that Xcel's planned Asset Health and Reliability (AH&R) and capacity projects will accommodate, and to report this information in Xcel's next Integrated Distribution Plan.[1482]

1164. CEO argued that at the same time Xcel is seeking to make these distribution infrastructure improvements, there are other distribution system improvements that will be needed for DER interconnection that must be paid for by customers and developers.[1483] CEO expressed concern that certain distribution equipment is slated for upgrades through both paths, meaning the same distribution equipment could be replaced twice in a short period of time.[1484]

1165. Xcel does not currently consider DER interconnection capacity when it prioritizes its distribution infrastructure upgrades.[1485]

[1477] *See* Ex. Xcel-43 at 57, n.79, and 59 (Mensen Rebuttal) (discussing hosting capacity as "the amount of generation that can be accommodated on the distribution system").
[1478] Ex. Xcel-43 at 57, n.79 (Mensen Rebuttal).
[1479] Ex. Xcel-40 at 34 (Bloch Direct, adopted by Mensen) (Table 7, showing total distribution capital expenditure budgets of $524.6 million (2022), $556.9 million (2023), and $551.5 million (2024)).
[1480] Ex. JSC-4 at 5 (Davis Direct).
[1481] Ex. Xcel-43 at 49-59 (Mensen Rebuttal); Xcel's Initial Br. at 240–41.
[1482] Ex. CEO-3 at 19–23 (Volkmann Direct).
[1483] Ex. CEO-3 at 19-23 (Volkmann Direct).
[1484] Ex. CEO-3 at 19-23 (Volkmann Direct).
[1485] Ex. CEO-3 Schedule 5, Response to Information Request 64 (Volkmann Direct).

1166. It is reasonable to coordinate distribution upgrades needed for DER interconnection with upgrades planned for other reasons to ensure equipment is not replaced twice in a short period of time. This ensures spending on distribution system upgrades is reasonable and prudent, and that infrastructure investments are being made thoughtfully and efficiently.

1167. Although Xcel generally opposed this recommendation, it did not provide a basis to conclude that it would be unduly burdensome or otherwise unreasonable. The recommendation is consistent with the Company's view that issues such as these are not best resolved within this proceeding.

1168. CEO also recommended that the Commission convene the Distributed Generation Working Group's Technical Subgroup (TSG) to examine the issue of unintentional islanding, identify additional screens the Company can perform to assess the risk, and determine if there are less costly alternatives to Voltage Supervisory Reclosing to address perceived risk.[1486] The CEOs recommend the TSG should seek feedback from the Working Group during this examination and file a report with its findings and recommendations in the Interconnection docket (Docket No. E999/CI-16-521) by December 31, 2023.[1487]

1169. Unintentional islanding is when one or more DERs become isolated from the rest of the power system and inadvertently continue to serve loads separately from the utility system.[1488] This is a concern because the utility loses control of the voltage and the frequency during the islanding condition.[1489]

1170. To address this, the Company requires that DER customers seeking to pay for substation upgrades to install Voltage Supervisory Reclosing (VSR) before interconnecting to feeders where unintentional islanding is a limiting factor.[1490]

1171. CEO express concern that the perceived risk of unintentional islanding is overstated and the Company's remedy too costly for DER customers.[1491]

1172. JSC similarly recommended that Xcel be required to examine whether it could avoid unintentional islanding in a less costly manner.[1492]

1173. The Company argues that Commission should decline to adopt this recommendation because the issue of unintentional islanding is one that the Company has studied and analyzed extensively, and the Company continues to support its requirement for DER developers to install VSR to address unintentional islanding issues. It contends that the responsibility to establish technical standards, like the VSR requirement, must remain within the utility as such standards are part of the Company's

[1486] Ex. CEO-3 at 24 (Volkmann Direct).
[1487] Ex. CEO-3 at 4 (Volkmann Direct).
[1488] Ex. Xcel-43 at 56 (Mensen Rebuttal).
[1489] Ex. Xcel-43 at 56 (Mensen Rebuttal).
[1490] Ex. CEO-3 at 10-11 (Volkmann Direct).
[1491] CEO Initial Br. at 26.
[1492] Ex. JSC-4 at 11-12 (Davis Direct).

responsibility as a public utility to meet its obligation to provide safe, adequate, and reliable electric service.[1493]

1174. The Judge recommends that the Commission adopt the CEO recommendation to require Xcel to begin quantifying the incremental hosting capacity for DERs and beneficial electrification enabled by Xcel's planned distribution system investments and to report this information in Xcel's next Integrated Distribution Plan. Doing so will allow Xcel, the Commission, and interested ratepayers to better assess proposed distribution infrastructure investments and prioritize those that will also facilitate the expansion of DERs and beneficial electrification, consistent with state policy.[1494]

1175. The Judge recommends that the Commission adopt the CEO recommendation relating to examining the issue of unintentional islanding. Further investigation of potential less costly methods of addressing the risk of unintentional islanding has been shown to be reasonable and would not, in and of itself, impair the Company's ability to provide safe and reliable service. The Distributed Generation Working Group's Technical Subgroup is a reasonable venue for analysis and possible recommendations that could reduce costs and be consistent with Xcel's obligation to maintain safe and reliable service.

2. JSC DER Recommendations

1176. JSC made several additional DER-related recommendations, urging that the Commission scrutinize the Company's planned investments through an energy justice lens.[1495]

1177. JSC criticized the Company's planned distribution investments as insufficiently addressing its system's ability to integrate new renewable energy sources or to better utilize existing renewable resources,[1496] and insufficiently addressing equity concerns.[1497]

1178. Specifically, JSC recommended that the Commission require the Company to:[1498]

i. modify its prioritization for circuit breaker, recloser, and regulator replacement projects to include a prioritization element for hosting capacity increases;

ii. assess the potential hosting capacity benefits which could be achieved by encouraging EV charging during high solar generation

[1493] Xcel's Proposed Findings of Fact at 174–75.
[1494] *See* Minn. Stat. § 216.05, subd. 1; Minn. Stat. § 216B.03.
[1495] JSC Initial Br. at 42.
[1496] Ex. JSC-4 at 5–6 (Davis Direct).
[1497] Ex. JSC-4 at 10-11 (Davis Direct); Ex. JSC-5 at 26-27 (Rábago Direct).
[1498] JSC's recommendation relating to anti-islanding requirements is discussed in the preceding section.

periods, especially on distribution feeders that already have limited hosting capacity;

iii. leverage the capabilities of smart inverters by enabling Volt-VAR and Volt-Watt functions, and evaluating their ability to defer voltage-driven capital investments; and,

iv. explore the impacts of DER on its planned capacity investments, and based on that analysis, consider changing its approach to load forecasting.

1179. The Company opposed each of JSC's DER-related recommendations.

i. Circuit Breaker, Recloser, and Regulator Replacement Prioritization

1180. JSC specifically recommends that the Commission direct the Company to modify its ELR programs for circuit breakers, reclosers, and regulator replacements to include a prioritization for replacements that will increase hosting capacity.[1499] JSC argues that replacement of these components can help increase hosting capacity on the system, and that the Company ignored potential hosting capacity improvements when assessing whether to replace these components.[1500]

1181. The Company explained that its ELR programs are equipment replacement programs designed to mitigate the risk of equipment failure and service interruption to customers. Replacement is based on factors such as age, condition, and criticality of the asset, which help the Company identify which pieces of equipment are reaching end-of-life and which will have the greatest impact on customer experience if they fail.[1501]

1182. The Company also explained that because increasing hosting capacity is not the purpose of these ELR programs, it is not appropriate to require hosting capacity prioritization when determining which breakers, reclosers, or regulators need to be replaced.[1502] That said, when the Company replaces assets based on its ELR criteria with new equipment, the Company makes sure that the new equipment meets new standards and provides sufficient capacity to meet forecasted loads.

1183. The Company further explained that one of the primary reasons that Distribution's budgets for its ELR programs are increasing in 2022–2024 is due to the age and condition of Distribution's key assets.[1503] For instance, the typical life span for substation breakers is 50 years, and 300 of NSPM's approximately 1,500 breakers are 50 years old or older.[1504] The Company's 2022–2024 budget for its ELR Substation Breaker program was developed to address those breakers that are beyond their 50 year

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[1499] Ex. JSC-4 at 7 (Davis Direct).
[1500] JSC Initial Br. at 48-49.
[1501] Ex. Xcel-43 at 58 (Mensen Rebuttal).
[1502] Ex. Xcel-43 at 58 (Mensen Rebuttal).
[1503] Ex. Xcel-40 at 31-32 (Bloch/Mensen Direct).
[1504] Ex. Xcel-40 at 74 (Bloch/Mensen Direct).

life expectancy and/or are in poor condition.[1505] The Company also explained that while the budget for this program is increasing over the term of the MYRP to allow the Company to replace substation breakers closer to their expected life, replacing all substation breakers at 50 years or older would require even higher budget amounts than what is currently budgeted in 2022–2024.[1506]

1184. Given the age and condition of the Company's Distribution assets and the importance of maintaining reliability for customers—while also considering the cost impacts of these replacements to customers—it is reasonable for the Company to prioritize replacement of these assets based on age, condition, and criticality of the asset.

1185. The Judge recommends that the Commission not adopt the JSC recommendation relating to circuit breakers, reclosers, and regulator replacement prioritization.

ii. EV Charging Studies

1186. In its testimony, the Company describes several existing or planned EV pilots or programs, many of which attempt to shift EV charging energy use to time windows outside of system peaks, which typically occur during the daytime.[1507] This approach can help to minimize the overall impact of EVs on distribution system capacity and related spending on large distribution capacity investments. But JSC argues that it creates an inherent misalignment between EV charging and solar DER generation.[1508]

1187. JSC recommends that the Commission direct the Company to conduct additional studies to assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods.[1509] JSC also recommends that the Company coordinate with MISO to explore how these factors may change over the next few years, and to what extent the resulting EV charging rates may be dynamic and differentiated by location, existing solar resources, or other variables.[1510]

1188. The Company's current EV programs are designed not only to promote the overall adoption of EVs to help meet the state's transportation electrification goals, but also to help encourage charging of EVs at beneficial times for its system and customers.[1511] The Company's current EV programs generally promote off-peak charging through off-peak lower rates.[1512]

[1505] Ex. Xcel-40 at 74 (Bloch/Mensen Direct).
[1506] Ex. Xcel-40 at 74 (Bloch/Mensen). The same is true for the Company's ELR Regulator Program. *See* Ex. Xcel-40 at 74-75 (Bloch/Mensen).
[1507] Ex. Xcel-40 at 169-180 (Bloch Direct, adopted by Mensen); see also Ex. JSC-4 at 29 (Davis Direct) (discussing Xcel testimony).
[1508] Ex. JSC-4 at 30 (Davis Direct).
[1509] JSC Initial Br. at 47.
[1510] Ex. JSC-4 at 31-32 (Davis Direct).
[1511] Ex. Xcel-40 at 142 (Bloch/Mensen Direct).
[1512] Ex. JSC-4 at 29-30 (Davis Direct).

1189. The Company explained that it opposes this recommendation primarily for two reasons. First, the Company explains that JSC's recommendation relates to system planning issues that are both outside the scope of this rate case and are broader than just distribution system planning, and as such, are better addressed in another forum.[1513] The Company recommended one such forum would be the Company's Integrated Resource Plan (IRP) and IDP Policy, Technology, and Planning workshops.[1514] Second, if the Commission determines from a policy perspective that such studies are appropriate, this could impact other utilities as they also develop their EV charging rates and may be required to study the potential for EV charging during high solar generation periods.

1190. Based on review of JSC's recommendation and the Company's responses, requiring additional EV charging studies is outside of the scope of this rate case, better addressed in a system-planning related proceeding, and could impact stakeholders that are not party to this rate case proceeding, and is better addressed in a system-planning-related proceeding

1191. The Judge recommends that the Commission take no action on JSC's recommendation to require additional EV charging studies.

iii. Smart Inverters

1192. "Smart inverters" is a general term used to describe inverters that meet industry standard IEEE 1547-2018 and are certified by a national testing lab to those standards. Under the State of Minnesota DER Interconnection Process (MN DIP), Minnesota has not yet adopted the applicable IEEE standard as part of its statewide Minnesota DER Technical Interconnection and Interoperability Requirements (TIIR), such that certification is currently pending for "readily available" smart inverters.[1515] EPRI's current projection is that certified smart inverters will be available around the second quarter of 2023.[1516]

1193. The Company explained that in its most recent IDP annual update,[1517] the Company filed its smart inverter roadmap outlining three phases of in its transition to using the smart inverter capabilities in Minnesota. Phase 1, expected to be completed in the second quarter of 2023, will consist of implementing the autonomous functions that do not require communications, including Volt-VAR, Volt-Watt, frequency ride-through, and voltage ride-through. Phase 2 will include monitoring functions and will require build-out

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[1513] Ex. Xcel-43 at 28-29 (Mensen Rebuttal).
[1514] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, MPUC Docket No. E002/M-21-694; *In re: 2020-2034 Upper Midwest Integrated Resource Plan of N. States Power Co. d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368.
[1515] Ex. Xcel-43 at 54 (Mensen Rebuttal).
[1516] Ex. Xcel-43 at 54 (Mensen Rebuttal).
[1517] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, MPUC Docket No. E002/M-21-694, ANNUAL UPDATE, Attachment E (Nov. 1, 2022).

of communications capabilities. Phase 3, which includes interactive control, will require a Distributed Energy Resource Management System (DERMS).[1518]

1194. JSC recommends that the Commission require the Company to leverage the capabilities of smart inverters by enabling Volt-VAR and Volt-Watt functions, and evaluating their ability to defer voltage-driven capital investments.[1519]

1195. As the Company explained in Rebuttal Testimony, because the Company is transitioning to using smart inverter capabilities in Minnesota, it would be premature to start assuming use of smart meter capabilities in the Company's planning studies, as JSC recommends, or for the Commission to require an evaluation of their impact as part of this rate case.[1520] Additionally, use of smart inverters is already being addressed in the Company's IDP proceeding, which is the proper venue for these issues.

1196. The Judge recommends taking no action on JSC's recommendations related to the Company's use of smart inverters and the associated analysis of potential impacts on capital investments.

iv. Load Forecasting

1197. Currently, within its distribution planning load forecasting and capacity planning processes, the Company "intentionally excludes any peak load reduction effects caused by DER power injections during the peak time window for both the present year and future forecast years."[1521] Since the Company's current process involves removing DER power injections, it would be possible for it to re-incorporate them, and examine whether any capacity investments could be deferred.[1522]

1198. JSC recommends that the Company "explore the impacts of DER on its planned capacity investments and, based on that analysis, consider changing its approach to load forecasting."[1523]

1199. The Company opposed JSC's DER-impacts load forecasting recommendation.

1200. First, as the Company clarified in Rebuttal Testimony, the Company already incorporates DER forecasts into its Non-Wires Alternatives analyses that are used to evaluate certain Distribution capacity projects,[1524] and many of the capacity projects proposed in this case were evaluated in the Company's 2019, 2020, or 2021 Non-Wires Alternatives analyses (which incorporated DER forecasts).[1525] Additionally, for the smaller capacity projects (i.e., those under $2 million), the Company does not expect that DER

[1518] Ex. Xcel-43 at 55 (Mensen Rebuttal).
[1519] JSC Initial Br. at 55.
[1520] Ex. Xcel-43 at 56 (Mensen Rebuttal).
[1521] Ex. JSC-4 at 19–20 (Davis Direct).
[1522] *Id*. at 21.
[1523] JSC Initial Br. at 52.
[1524] Ex. Xcel-43 at 50 (Mensen Rebuttal).
[1525] *Id*. at 53

capacity would have any impact on the capacity projects currently planned in the 2022–2024 timeframe.[1526]

1201. Second, the Company is already evaluating how to adopt granular DER forecasts and scenario planning using the new advanced planning tool, LoadSEER, to incorporate DER into its forecasting for distribution system planning and resulting budgeting process.[1527]

1202. Third, the Company is also assessing the current treatment of DER-derived capacity in anticipation of stakeholder discussions related to prioritizing net load, intended to inform its 2023 IDP.[1528]

1203. Relatedly, JSC specifically recommends that the Commission require the Company to study the impact of using native load (the Company's current approach) versus net load (incorporating DER forecasts) in system planning.[1529]

1204. The Company explains that it disagrees with this recommendation for several reasons.

1205. First, as discussed above, the Company is already currently working on developing a method to properly incorporate DER into its load forecasts, but this work is not yet completed. Even so, as also discussed, many of the capacity projects in this case were evaluated in the Non-Wires Alternatives analyses, which did incorporate DER forecasts.[1530]

1206. Second, DER forecasts are not to the level of granularity required for distribution planning because they are developed for a much larger area than load forecasts and there is significant uncertainty as to exactly where forecasted DERs will materialize.[1531]

1207. Third, certain DERs (like solar generation) cannot be relied upon to consistently provide firm capacity reductions at system peak, which for distribution feeders is generally when solar irradiance is reduced. Other non-intermittent DERs, such as energy storage, have limited energy durations, which means they cannot be relied upon to provide capacity reductions for long periods.[1532]

1208. Fourth, while the Company discussed its use of the new LoadSEER planning tool going forward, this is new to Xcel and the overall industry, meaning its use will require refinements over time with respect to incorporation of DER and net load inputs,

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[1526] *Id.*
[1527] Ex. Xcel-43 at 50 (Mensen Rebuttal).
[1528] JSC Initial Br. at 54.
[1529] JSC Initial Br. at 53–54.
[1530] Ex. Xcel-43 at 53 (Mensen Rebuttal).
[1531] Ex. Xcel-43 at 51 (Mensen Rebuttal).
[1532] Ex. Xcel-43 at 51 (Mensen Rebuttal).

among others. The Company does not plan to use these scenario forecasts in the short-term.[1533]

1209. JSC has not demonstrated that it would be reasonable to require the Company to study changing its approach to load forecasting to further incorporate DER impacts. Xcel already incorporates DER forecasts into its Non-Wires Alternatives analyses, and is already evaluating how to adopt granular DER forecasts and scenario planning.

1210. The Judge recommends that the Commission take no action on JSC's recommendation relating to required study of DER impacts on load forecasting.

C. Grid Modernization Investments

1211. Two grid modernization projects are included in the Company's rate request in this proceeding: FLISR and Distributed Intelligence (DI).[1534]

1212. The Department provided recommendations on both FLISR and DI, but also made recommendations related to filing requirements and procedures for future grid modernization proposals.[1535]

1213. The Department recommended that the Commission require Xcel to comply with certain grid modernization filing requirements going forward. The Department argued that Xcel has pursued discretionary grid modernization proposals such as FLISR and Distributed Intelligence in a piecemeal fashion. In the Department's view, this approach makes it difficult to ascertain the true benefits of Xcel's proposals, many of which are interconnected such as advanced meters and DI.[1536]

1214. To provide the Commission and stakeholders with a complete picture, the Department reasoned that the Commission should require Xcel to include the following standardized information with all future proposals: (1) a road map with all planned and contemplated future grid modernization investments; and (2) a complete accounting of all historical grid modernization costs and all anticipated future grid modernization costs.[1537]

1215. The Company explained that it supports efforts to improve efficiency in the regulatory process, but the Department's grid modernization filing requirement recommendations should not be adopted because they go beyond the scope of this proceeding and would be applicable to all utilities, but the other affected utilities are not party this rate case.[1538] Further, the Company asserted that the specific proposals are

[1533] Ex. Xcel-43 at 52 (Mensen Rebuttal).
[1534] Ex. Xcel-40 at 100-110 (Block/Mensen Direct); Ex. Xcel-44 (Remington/Quirk Supplemental Direct).
[1535] Ex. Xcel-43 at 45 (Mensen Rebuttal).
[1536] Ex. DOC-12 at 13–15 (Havumaki Direct).
[1537] Ex. DOC-12 at 16 (Havumaki Direct).; Ex. DOC-14 at 14 (Havumaki Surrebuttal).
[1538] Ex. Xcel-43 at 49 (Mensen Rebuttal).

overly broad, may not be applicable to each and every grid modernization proposal, and in most cases would not be possible because they require speculation.[1539]

1216. Regarding filing requirement standardization, the Company also explained that the Commission has issued several orders implementing a framework for assessing grid modernization proposals and specifying filing requirements. These requirements are different for an IDP filing compared to a cost recovery filing because the Commission's determinations in an IDP proceeding are different than in a cost recovery proceeding.[1540]

1217. Additionally, the Company noted that Department's recommendations were also proposed in the "Guidance Document" related to evaluation of grid modernization proposals, submitted in the Company's 2021 IDP and 2021 Transmission Cost Recovery Rider proceeding,[1541] but the Commission declined to adopt the Guidance Document.[1542] The Commission concluded that the proposed framework was not appropriate for all proposals, and that the Commission would evaluate utility filings and proposals on a case-by-case basis.[1543]

1218. Given the interconnected nature of grid modernization technologies and the goal of cost-benefit analysis to capture the full range of costs and benefits, the Judge agrees that the information identified by the Department would facilitate informed decision-making and thoughtful program design.

1219. While the proposed filing requirements may have been included in the Guidance Document that the Commission declined to adopt, the Department's proposal here is considerably more modest. The Department proposes that Xcel include with future grid modernization proposals its investment plans and an accounting for past and future grid modernization costs. It is reasonable to require Xcel to provide this information to allow regulators and the public a clear, up-to-date overview of the Company's grid modernization efforts with each new project proposal. Contrary to the Company's argument, determining that Xcel should include this information in its future filings would not affect the filing requirements for other utilities, unless the Commission so ordered.

1220. The Judge recommends that the Commission adopt the Department's recommended grid modernization filing requirements.

D. Energy Assistance Programs

1221. JSC proposed a number of Commission actions related to energy assistance programs. JSC witness Karl Rábago recommended that the Commission direct the Company to work with other utilities and the Department to develop a strategic

[1539] Ex. Xcel-43 at 48 (Mensen Rebuttal).
[1540] Ex. Xcel-43 at 47 (Mensen Rebuttal).
[1541] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the Transmission Cost Recovery Rider Revenue Requirement for 2021 and 2022, Tracker True-up and Revised Adjustment Factors*, MPUC Docket No. E002/M-21-814, LETTER AND GUIDANCE DOCUMENT (Feb. 9, 2022).
[1542] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan,* MPUC Docket No. E002/M-21-694, ORDER DECLINING TO ADOPT GUIDANCE DOCUMENT, (Oct. 14, 2022).
[1543] *Id*. at 2.

plan for funding and delivering energy assistance to all low-wealth customers and households; to reevaluate its program budgets for low-income programs to address a significantly greater percentage of the unserved population of low-wealth customers; and to quantify the differences in the costs to serve-multi-family households versus single-family households to reflect those differences in rates.[1544] JSC also recommended that the Commission require Xcel to study how its demand response programs could minimize bill volatility, and to evaluate a permanent moratorium on disconnections.[1545]

1222. ECC witness Ms. Fair testified that JSC's testimony underestimated the Company's budget for low-income Conservation Improvement Program (CIP) and that JSC was incorrect regarding the funding levels of other low-income assistance programs.[1546]

1223. The Company identified energy burden as the first area of concern in its Energy Equity docket, Docket No. E002/M-22-266, and recommended continuing to address concerns regarding barriers to energy assistance programs with the Equity Stakeholder Advisory Group (ESAG) and through the Company's Energy Equity docket, as groundwork has already been laid in that dedicated process.[1547]

1224. The Judge recognizes the importance of the issues raised by JSC and the challenges and energy burdens faced by low-income customers. The Energy Equity docket and the ESAG are designed to give full consideration of these issues. JSC's concerns are more appropriately raised in that docket, where JSC's broader policy recommendations can be incorporated into the Company's work with the ESAG and be given full consideration.

1225. The Judge recommends that, to the extent JSC's energy equity and affordability concerns are not otherwise addressed in this proceeding,[1548] the Commission take no action on JSC's energy-assistance-related recommendations.

E. Reliability

1226. JSC recommended in its in initial brief that the Commission require the Company to conduct analysis related to locational differences in reliability and service quality, specifically related to low-income and energy justice communities, to inform its future distribution investments and planning.[1549]

1227. The Company explained in its reply brief that the work to assess locational differences in reliability and service quality has already begun and continues in the

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[1544] Ex. JSC-5 at 74-82 (Rábago Direct).
[1545] *Id.*; Ex. JSC-3 at 29–31, 36 (Chan Direct); JSC-6 at 16, 25-26 (Chan Surrebuttal); Ex. JSC-1 at 18-19 (Porter Direct).
[1546] Ex. ECC-2 at 11-15 (Fair Rebuttal).
[1547] Ex. Xcel-83 at 16 (Martin Rebuttal).
[1548] *See, e.g.,* discussion and recommendation relating to costs to serve multi-family housing, in Section IX.B. above.
[1549] JSC Initial Br. at 69.

Company's annual service quality and performance-based ratemaking proceedings.[1550] The Company is gathering and reporting baseline data, incorporating stakeholder input, and is beginning assessment of this data per the Commission direction on procedural schedules in those dockets. These dockets will also address potential future metrics and performance targets for reliability and equity measures.[1551]

1228. Based on consideration of JSC's concerns and the Company's responses, the Judge recommends that the Commission take no action on JSC's recommendations related to gathering, analyzing, and publicly presenting reliability data relating to low-income and energy justice communities. The issues are more appropriately addressed in the relevant dockets cited by the Company and should continue in those proceedings, which include ongoing opportunities for stakeholder input.

F. Procedural Justice

1229. JSC identified opportunities for procedural justice improvements during its participation in this rate case.[1552] The Coalition specifically cited the highly technical nature of the proceedings and the volume of the filings as barriers to effective public participation, among other concerns.[1553]

1230. JSC offers this definition of procedural justice: "meaningful and equitable participation and representation in energy decision making. Procedural justice focuses on ensuring equitable decision-making processes across the energy system. It is concerned with how decisions are made."[1554]

1231. JSC recommended that the Commission:[1555]

i. continue to implement procedural justice reforms, including those contained in the 2020 report by the Legislative Auditor;

ii. provide more and better resources to help the public understand the Commission's unique role and the role of the public in Commission proceedings;

iii. provide better guidance to its staff and partner agencies to ensure consistency and fairness across public participation processes;

[1550] *In the Matter of Northern States Power Company's Annual Report on Safety, Reliability, and Service Quality for 2021; and Petition for Approval of Electric Reliability Standards for 2022*, MPUC Docket No. E002/M-22-162; *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, MPUC Docket No. E002/CI-17-401.
[1551] Xcel Reply Br. at 139.
[1552] Ex. JSC-3 at 52 (Chan Direct); Ex. JSC-9 at 1-2 (Madden Surrebuttal).
[1553] Ex. JSC-3 at 52 (Chan Direct); Ex. JSC-9 at 15 (Madden Surrebuttal).
[1554] Ex. JSC-3 at 9 (Chan Direct).
[1555] Ex. JSC-3 at 54–57 (Chan Direct); *see also* JSC-5 at 46-47, 83 (Rábago Direct) (making similar suggestions for Commission action).

iv. provide more oversight of the Commission's public participation processes and better prepare for cases with significant public interest;

v. and, if necessary to adopt the JSC recommendations, communicate to the public and elected officials that the Commission requires additional resources to provide sufficient oversight and transparency on issues of significant public importance.

1232. Because JSC's recommendations on this subject relate to Commission actions, functions, and processes outside the scope of this proceeding, the Judge makes no recommendation to the Commission.

G. Company Audit of Third-Party Sales Forecast Data

1233. The Company requested that it no longer be required to audit economic and demographic information obtained from third parties used to develop the Company's test year sales forecast.[1556]

1234. In its order in the Company's 2008 electric rate case, the Commission ordered the Company to work with the Department to achieve "greater data transparency" and "to respond to any concerns regarding its data sources." Since that time, the Company has conducted an audit of this data as provided by IHS Markit databases in each of its rate cases and has filed the results as part of the Company's sales forecast pre-filing.[1557]

1235. The Company has not identified any data discrepancies at any time since its 2008 rate case.[1558]

1236. IHS Markit is an information services company that provides information and research to major corporations, financial markets, and governments. As an information provider that relies on the accuracy of its data to remain in business, IHS Markit is incentivized to ensure the accuracy of the data that it provides.[1559]

1237. The Department opposed the Company's request, claiming that there have been updates to the historical economic data used by the Company in its forecasts.[1560]

[1556] Ex. Xcel-77 at 3 (Goodenough Rebuttal).
[1557] *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*, MPUC Docket No. E002/GR-08-1065, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at Ordering para. 13 (Oct. 23, 2009) (citing finding 145 of the Administrative Law Judge's FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDATION at 39 (Aug. 24, 2009); Ex. Xcel-77 at 3 (Goodenough Rebuttal).
[1558] Ex. Xcel-77 at 4 (Goodenough Rebuttal).
[1559] Ex. Xcel-77 at 3–4 (Goodenough Rebuttal).
[1560] Ex. DOC-9 at 9–10 (Shah Direct); Ex. DOC-10 at 14–17 (Shah Surrebuttal).

The Department asserted that auditing the data would be beneficial to identify material corrections in historical economic data.[1561]

1238. The Company explained that updates to historical economic data are not updates that would be corrected as part of the Company's audit. The Company uses the most recent economic data that is available at the time its sales forecast is developed. This data is occasionally estimated preliminary data that the Company updates accordingly when actual data is reported, sometimes taking as long as two years. The Company proposed that it commits to helping the Department and other parties understand or resolve any issues with the third-party data that is identified in the Company's sales forecast, but that continued audits in each future rate case is not beneficial.[1562]

1239. The Company has demonstrated that it would be reasonable to end the requirement to audit third-party sales forecast data. IHS Markit has an incentive to provide reliable data, and the Department has not established that auditing the data would correct preliminary historical data provided by IHS Markit before actual data is reported.

1240. The Judge recommends that the Commission discontinue any requirement to audit economic and demographic information obtained from third parties used to develop the Company's test year sales forecast, and continue to require the company to work closely with the Department to respond to issues with third-party data used in the Company's sales forecast.

H. Regulatory Sandbox

1241. CEO recommended that the Commission open an investigatory docket to design a regulatory sandbox, or other expedited pilot process, for all rate-regulated utilities in Minnesota.[1563]

1242. According to CEO, a regulatory sandbox allows for the creation of a framework for utility pilot projects so the development of pilot projects is more streamlined, allowing for expedited pilot deployment within pre-established rules that ensure cost containment and oversight.[1564] Regulatory sandboxes have been used in New York, Connecticut, California, Hawaii, and Vermont.[1565]

1243. CEO asserted a regulatory sandbox is needed because innovation is not yet happening at the pace and scale needed to address climate change.[1566] CEO asserted that currently, the time required to implement a pilot program is too long

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[1561] Ex. DOC-10 at 17 (Shah Surrebuttal).
[1562] Ex. DOC-10 at 15 (Shah Surrebuttal), *citing In re the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Elec. Serv. in Minn.*, MPUC Docket E002/GR-15-826, DIRECT TESTIMONY AND SCHEDULES OF JANNELL E. MARKS at 7 (Nov. 2, 2015); Ex. Xcel-77 at 4 (Goodenough Rebuttal).
[1563] Ex. CEO-1 at 34–53 (Nelson Direct).
[1564] Ex. CEO-1 at 41–42 (Nelson Direct).
[1565] Ex. CEO-1 at 43–44 (Nelson Direct).
[1566] Ex. CEO-1 at 34 (Nelson Direct).

considering the urgent need for greater electrification and decarbonization.[1567] Moreover, pilots are not sufficiently leading to learnings, iteration, or scaled-up offerings.[1568]

1244. CEO claimed creating a regulatory sandbox in Minnesota could broaden the group of stakeholders involved in pilot development, allow stakeholders to surface new ideas (as opposed to just the utilities), improve efficiency and timeliness of pilots, reduce regulatory burden by standardizing pilot processes, increase energy sector innovation, and scale innovative clean energy offerings for ratepayers.[1569]

1245. No party opposed the CEO proposal.

1246. Ratepayers and the public would benefit from a framework for utility pilot projects by allowing for more nimble testing of ideas with greater efficiency while simultaneously ensuring cost control and facilitating increased participation of stakeholders. It would be in the public interest for the Commission to open an investigation into how a regulatory sandbox, or similar approach, could be used in Minnesota to foster innovative pilot programs. More efficient and better designed and implemented pilot programs would promote just and reasonable rates for ratepayers.

1247. The Judge recommends that the Commission initiate an investigation into creating a framework for rate-regulated utility pilot projects as recommended by CEO.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Commission has general jurisdiction over Xcel Energy under Minn. Stat. §§ 216B.01 and 216B.02. The Commission has specific jurisdiction over the rate changes requested by the Company under Minn. Stat. § 216B.16.

2. The Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. §§ 14.50 and 216B.08 (2022).

3. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48–14.62 and Minn. R. 1400.0200, et seq.

4. The public and parties received proper and timely notice of the hearing and the Commission and Xcel Energy complied with all procedural requirements of statute and rule.

5. 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.

[1567] Ex. CEO-1 at 39 (Nelson Direct).
[1568] Ex. CEO-1 at 40-41 (Nelson Direct).
[1569] Ex. CEO-1 at 49-50 (Nelson Direct).

6. 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 Minn. Stat. §§ 216B.164, 216B.241 and 216C.05 (2022).[1570]

7. The burden of proof is on the public utility to show that a rate change is just and reasonable.[1571] Any doubt as to reasonableness should be resolved in favor of the consumer.[1572]

8. The record supports the resolution of the settled, resolved, and uncontested matters set forth in Section VI, above, and in Xcel's initial filing. These matters have been resolved in the public interest and are supported by substantial evidence.

9. Rates set in accordance with this Report would be just and reasonable.

10. Any findings of fact more properly designated as conclusions of law are hereby adopted as such.

Based upon these Conclusions of Law, and for the reasons explained in the accompanying Memorandum, the Administrative Law Judge makes the following:

RECOMMENDATIONS

1. The Company is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. The text of the Findings and Conclusions should govern the mathematical and computational aspects of the Findings and Conclusions. The computations should be adjusted so as to conform to the conclusions of the Report.

3. By May 1, 2023, Xcel should make a compliance filing to show how it arrived at its $774,000 Nuclear CFPP O&M adjustment, or a different amount if the adjustment was based on an inaccurate number of employees.

4. The Commission incorporate the agreements made by the parties in the course of this proceeding into its Order.

5. The Commission adopt the recommendations set forth in the Findings above.

[1570] Minn. Stat. § 216B.03.
[1571] Minn. Stat. § 216.16, subd. 4.
[1572] Minn. Stat. § 216B.03.

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

Dated: March 31, 2023

CHRISTA L. MOSENG
Administrative Law Judge

Reported: Digitally Recorded
No transcript prepared

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. 7829.1275, .2700 (2021), 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 Minn. R. 7829.2700, subp. 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.

ATTACHMENT A: SUMMARY OF PUBLIC COMMENTS

Public hearings were held at the following times and places:

- October 4, 2022, at 1:00 p.m. at Brookview Golden Valley, Bassett Creek North Room, 316 Brookview Parkway South, Golden Valley, Minnesota;

- October 4, 2022, at 6:00 p.m. at Woodbury Central Park, Valley Creek Room A, 8595 Central Park Place, Woodbury, Minnesota;

- October 5, 2022, at 6:00 p.m. at Red Wing Ignite, 419 Bush Street, Red Wing, Minnesota;

- October 6, 2022, at 6:00 p.m. at Courtyard by Marriott, 404 W St. Germain Street, St. Cloud, Minnesota;

- October 20, 2022, at 5:30 p.m. at Rondo Community Library, 461 Dale Street North, St. Paul, Minnesota;

- October 21, 2022, at 2:30 p.m. at Minneapolis Central Library, 300 Nicollet Mall, Doty Board Room, Minneapolis, Minnesota;

- October 31, 2022, at 1:30 p.m. via WebEx;

- November 2, 2022, at 6:00 p.m. via WebEx;

- November 3, 2022, at 6:00 p.m. at Courtyard by Marriott, 901 Raintree Road, Mankato, Minnesota; and

- December 9, 2022, at 1:30 p.m. via WebEx.

Appearances:

Shubha M. Harris and Ian M. Dobson appeared on behalf of Northern States Power (NSP, Xcel Energy, or Applicant);

Craig Addonizio, Andy Bahn, Jessica Burdette, and Nancy Campbell, and Tracy Smetana, appeared on behalf of the Department of Commerce, Division of Energy Resources (Department);

Kristin K. Berkland,[1573] Peter G. Scholtz, and Joseph C. Meyer, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General (OAG);

[1573] Ms. Berkland has since withdrawn as counsel for OAG. Notice of Withdrawal (Dec. 30, 2022) (eDockets No. 202212-191727-01).

appeared on behalf of the Citizens Utility Board (CUB).

James Strommen, Kennedy & Graven, appeared on behalf of the Suburban Rate Authority (SRA);

Timothy DenHerder-Thomas, Joshua Lewis, Alice Madden, Julia Nerbonne, and Kristel Porter appeared on behalf of the Just Solar Coalition (JSC);

Jorge Alonzo, Jason Bonnett, Andrew Larson, Ashley Marcus, and James Worlobah, Public Utilities Commission (Commission) staff members.

The public comment period closed on January 6, 2023, as provided in the Notice of Public Hearings approved by the Commission on August 3, 2022.[1574] Written comments were filed in the electronic docket system.

SUMMARY

1. Over 500 written public comments were received by the January 6, 2023, deadline set by the Commission. In addition, over 40 individuals provided oral comments at the public hearings held throughout the Company's service territory.

2. All comments made at the public hearings or submitted in writing were fully considered. The description below summarizes the topics raised; however, not all persons raising a given topic are cited.

3. A considerable share of written comments—some 150 of the over 500 comments—were the same or substantially similar and focused on a specific subset of topics: economic hardship, income and racial inequity; Xcel's profits; supporting investment in distributed generation and renewable energy; and the need for programs to help customers invest in energy efficiency.[1575] These are addressed in more detail under the specific subject headings below. A number of these comments, though similar, were not identical.[1576] Variations within and among similar comments were also considered and are reflected in the summary below.

I. General Opposition to the Proposed Rate Increases

4. The vast majority of the public comments expressed concern about, or opposition to, the proposed rate increases. A large number of customers opposed any

[1574] Notice of Approval of Public Hearing Customer Notice (Aug. 3, 2022) (eDockets No. 20228-188081-01).

[1575] *See, e.g.*, Dana Blumberg (Nov. 14, 2022 email) (eDockets No. 202211-190588-01); Judy Gregg (Dec. 12, 2022 email) (eDockets No. 202212-191278-01).

[1576] *See, e.g.,* Nanette Echols (Nov. 14, 2022 email) (eDockets No. 202211-190588-01); Ellie Schmidt (Dec. 12, 2022 email) (eDockets No. 202212-191278-01).

rate increase.[1577] Others suggested that any rate increase should be smaller than that requested by the Company.[1578]

II. Economic Hardship / Unaffordability

5. A substantial number of individuals noted that the rate increase requested by the Company would impose a hardship.[1579]

6. Often, commenters explained that the requested rates would be unaffordable by specifically citing macroeconomic or individual economic circumstances affecting the affordability of electric rates. The circumstances included: recent inflation in energy and non-energy costs;[1580] the effects of the Covid-19 pandemic on both the broader economy and on individual incomes;[1581] customers and households with low-,[1582] fixed-,[1583] and/or single-incomes;[1584] and, the cost of other needs such as food, fuel, or medical expenses.[1585] Several commenters stated that the rate increase would force them or others to choose among necessities.[1586]

7. Many commenters specifically identified recent increases in energy costs as a basis of unaffordability, particularly in connection with increased natural gas costs arising from the February 2021 cold weather event resulting in an extraordinary natural gas price spike.[1587] Recent utility cost increases caused multiple commenters confusion regarding whether the requested rates at issue in this proceeding had already gone into effect.[1588] Several specifically objected to the continuing natural gas surcharge.[1589]

8. Several commenters objected to the requested increases as exceeding the general rate of consumer price inflation.[1590] Others observed that the requested increase exceeds the rate at which their wages or income are increasing.[1591] Multiple commenters argued that the requested rate of increase was unreasonable, but a smaller increase

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[1577] *See, e.g.*, Joshua Lewis (Dec. 16, 2022 email) (eDockets No. 202212-191447-01).
[1578] *See, e.g.*, Jim Lovestar (Oct. 3, 2022 letter) (eDockets No. 202210-189733-01).
[1579] *See, e.g.*, Anne Hartman (Jan. 2, 2023 email) (eDockets No. 20231-191789-01).
[1580] *See, e.g.*, Brenna Thom (Feb. 7, 2022 email) (eDockets No. 20222-182555-02); Alexis Theisen (Feb. 2, 2022 email) (eDockets No. 20222-182378-03); Jenny Winiecki-Rowe, Tr. Oct. 31 Hrg. at 25.
[1581] *See, e.g.*, Laurie Howard (Feb. 4, 2022 email) (eDockets No. 20222-182555-02).
[1582] *See, e.g.*, Richard Jantz, Jr. and Clara Bantz (Jan. 28, 2022 email) (eDockets No. 20221-182247-01).
[1583] *See, e.g.*, Kay Beams (Nov. 14, 2022 email) (eDockets No. 202211-190588-01).
[1584] *See, e.g.*, Koa Vang (Jan. 27, 2022 email) (eDockets No. 20221-182060-01).
[1585] *See, e.g.*, Alexandra Sarantos (Jan. 26, 2022 email) (eDockets No. 20221-182060-01); Erin Andretta (Feb. 1, 2022 email) (eDockets No. 20222-182369-01); Pang Mee Xiong (Feb. 4, 2022 email) (eDockets No. 20222-182573-01).
[1586] *See, e.g.*, Amanda Erickson (Jan. 25, 2022 email) (eDockets No. 20221-181998-01).
[1587] *See, e.g.*, Ken Binner (Jan. 11, 2022 email) (eDockets No. 20221-181789-01); Daphne J. Fish (Feb. 6, 2022 email) (eDockets No. 20222-182555-02).
[1588] *See, e.g.*, Jeffrey Benson (Jan. 19, 2022) (eDockets No. 20221-181772-01).
[1589] *See, e.g.*, Greg Goffinet (Jan. 29, 2022 email) (eDockets No. 20222-182834-05).
[1590] *See, e.g.*, Brad Schinkle (Oct. 25, 2022 email) (eDockets No. 202210-190109-01).
[1591] *See, e.g.*, Tara McNaughton (Nov. 4, 2022 email) (eDockets No. 202211-190477-01).

would be reasonable—generally, suggested increases fell in a range similar to the three to 6% range proposed by Linda Wagner.[1592]

III. Conservation Efforts

9. Many commenters, like Katherina Vang and Lori Belz, explained that they had engaged in efforts to conserve energy by reducing consumption, investing in energy efficiency, or both, but that their efforts had not prevented, or would not prevent, utility bill increases.[1593] Kathy Starkey, for example, wrote that "bills have doubled while I've been turning down my thermostat until I'm downright freezing and conserving everything I can."[1594] Commenters such as Robert Frank argued that the disconnect between conservation and utility bill increases would discourage people who might otherwise pursue conservation efforts.[1595]

IV. Comments by Business Customers

10. Several business owners opposed the proposed rate increase. Steve Cichosz, among others, observed that business energy costs affect the prices that consumers pay for services and goods.[1596] Other business owners highlighted that they, too, are experiencing economic hardship that would make a rate increase unaffordable.[1597]

V. Xcel Should Control Costs Rather Than Raise Rates

11. Public comments included a range of suggested categories for cost reductions that could temper the proposed increase. Cost categories proposed for possible savings included: executive and management compensation,[1598] employee compensation generally,[1599] and labor inefficiency.[1600] Jess Landgraf proposed that Xcel seek cost savings by having more employees work remotely and close office space.[1601]

12. A handful of comments contended that the Company's investments in renewable energy were driving costs.[1602] Others asserted that renewable energy is inexpensive, should be prioritized, and that the reduced energy cost should result in lower customer bills.[1603] Nancy Larkey and Paula Jelen commented that initial investment in

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[1592] *See, e.g.*, Linda Wagner (Dec. 2, 2021 email) (eDockets No. 202111-179422-01).
[1593] *See, e.g.*, Katherina Vang (Jan. 28, 2022 email) (eDockets No. 20221-182191-01); Lori Belz (Dec. 27, 2022 email) (eDockets No. 202212-191668-01).
[1594] Kathy Starkey (Jan. 27, 2022 email) (eDockets No. 20222-182327-03).
[1595] Robert Frank (Nov. 28, 2022 email) (eDockets No. 202211-190934-01).
[1596] *See, e.g.*, Steve Cichosz (Sept. 26, 2022 email) (eDockets No. 20229-189320-01).
[1597] *See, e.g.*, Nathan Redding (Jan. 29, 2022 email) (eDockets No. 20221-182192-01); Laurie Howard (Feb. 4, 2022 email) (eDockets No. 20222-182555-02).
[1598] Tim Ballman (Dec. 13, 2022 email) (eDockets No. 202212-191311-01).
[1599] Lanny Smaagard (Mar. 4, 2022 email) (eDockets No. 20223-183656-01).
[1600] Anna Rabecevich (Jan. 1, 2023 email) (eDockets No. 20231-191789-01).
[1601] Jess Landgraf (Oct. 24, 2022 email) (eDockets No. 202210-190083-01).
[1602] *See, e.g.*, Lanny Smaagard (undated email, filed Nov. 2, 2021) (eDockets No. 202111-179422-01); Linda Paulson (Oct. 12, 2022 letter) (eDockets No. 202210-189881-01).
[1603] *See, e.g.*, Matt Kuzma (Oct. 28, 2022 email) (eDockets No. 202210-190261-01).

renewable generation could result in reduced costs over time, and that the cost savings should go to reducing rates or paying for new investments.[1604]

VI. Xcel Should Reinvest Profits Rather than Raise Rates

13. Several commenters questioned the need for a rate increase in light of recent returns to equity investors in the form of stock price increases and dividend payments.[1605] Many, like Jeff Ryan, argued that Xcel should reinvest profit in infrastructure rather than giving it to shareholders and raising rates.[1606]

VII. Incentives Not Aligned to Public Interest

14. Commenters such as the Twin Cites Energy Efficiency Cohort asserted that Xcel's profit incentive does not coincide with the public interest.[1607] Benjamin Werner noted that Commission regulation is needed to ensure Xcel's incentives are aligned with the public interest.[1608]

VIII. Residential Customer Charge Increases

15. Several commenters argued against increasing the residential fixed customer charge because doing so would not incentivize conservation.[1609] Others argued that the proposed fixed customer charge increase would inequitably burden low-income households because the increase could not be avoided by reducing consumption.[1610]

16. Joshua Lewis, among others, specifically opposed the proposed residential basic customer charge in multifamily dwellings. He commented that it is unfair and results in racial inequity for households living in multifamily dwellings. He commented that multifamily-dwelling customers subsidize other residential customers because the lower cost to serve multifamily-dwelling customers is not reflected in the fixed customer charge.[1611]

[1604] Nancy Larkey (Jan. 13, 2022 email) (eDockets No. 20221-182060-01); Paula Jelen (Jan. 24, 2023 email) (eDockets No. 20231-192582-01).
[1605] *See, e.g.*, Anna Fraser (Jan. 26, 2022 email) (eDockets No. 20221-182060-01); Tom Rams (eDockets No. 202110-179264-01).
[1606] *See, e.g.*, Jeff Ryan (Feb. 11, 2022 email) (eDockets No. 20222-182719-01).
[1607] Twin Cites Energy Efficiency Cohort (undated letter, filed Jan. 9, 2023) (eDockets No. 20231-191959-01).
[1608] Benjamin Werner (Dec. 15, 2022 letter) (eDockets No. 202212-191403-01).
[1609] *See, e.g.*, Lisa Franchett (Jan. 4, 2023 email) (eDockets No. 20231-191856-01); Joan Pasiuk, Tr. St. Paul Hrg. at 29.
[1610] *See, e.g.*, Diane Krueger (Jan. 1, 2023 email) (eDockets No. 20231-191789-01).
[1611] Joshua Lewis, Tr. Oct. 31 Hrg. at 34–35.

IX. Other Customer Class Issues

17. A handful of commenters objected to subsidizing electric vehicle (EV) owners through utility investment in EV charging infrastructure.[1612]

X. Rate of Return/Return on Equity

18. Many commenters specifically objected to Xcel's proposed return on equity (ROE) or overall rate of return. Janet Pope and Drew Harper urged that return on equity increases should be connected to good performance and "defined objectives and milestones."[1613] Tim Wulling opposed an ROE increase, urged that Xcel's ROE be reduced to 8%, and opposed Xcel's proposed ROE adjustment mechanism.[1614] He stated that "[a]t a time when energy costs complicate ratepayers' finances, it seems entirely unfair to increase shareholders' benefits."[1615]

XI. Service Quality Issues

19. A handful of customers complained about unreliable electric service or poor customer service. Sally Strand of Plymouth commented that she has experienced 22 outages since 2021, and has had to replace appliances and have electrical work following power surges.[1616] Anne Gerrietts of Roseville, Todd Hanson of Rosemount, and David Gardeen of Golden Valley also complained of frequent power outages.[1617]

20. Some commenters suggested that Xcel's rate increase should depend at least in part on a demonstration of improved service quality.[1618]

XII. Xcel's Investment Plans

21. Public comments incorporated a range of proposed alternatives to Xcel's proposed investments. A plurality of comments favored increased investment focus on infrastructure investments to facilitate or promote some or all of: distributed generation,[1619] customer access to local ownership of distributed generation of renewable energy,[1620] or customer investments in energy conservation.[1621]

[1612] *See, e.g.*, Mary Davis, Tr. Golden Valley Hrg., at 23; Ernest Starkweather (Dec. 12, 2022 email) (eDockets No. 202212-191236-01).
[1613] Janet Pope, Tr. St. Paul Hrg., at 26; Drew Harper (Dec. 31, 2022 email) (eDockets No. 20231-191789-01).
[1614] Tim Wulling (Jan 5, 2023 letter) (eDockets No. 20231-191931-01).
[1615] *Id*.
[1616] Sally Strand (Mar. 11, 2022 email) (eDockets No. 20223-184102-02).
[1617] Anne Gerrietts (Jan. 21, 2022 public comment) (eDockets No. 20221-181819-01); Todd Hanson (Nov. 2, 2021 public comment) (eDockets No. 202111-179422-01); David Gardeen, Tr. Golden Valley Hrg., at 19–22.
[1618] *See, e.g.*, Anne Gerrietts (Jan. 21, 2022 public comment) (eDockets No. 20221-181819-01).
[1619] *See, e.g.*,.William Slichter (Jan. 6, 2023 email) (eDockets No. 20231-191928-01).
[1620] *See, e.g.*, Julia Nerbonne, Tr. Minneapolis Hrg. at 45–46.
[1621] *See, e.g.*, Leslie Wille (Dec. 28, 2022 email) (eDockets No. 202212-191668-01).

22. Several commenters supported Xcel's planned investments and criticized proposals to require Xcel to instead focus investment on distributed generation. They argued that increased investment in distributed generation would reduce equity and service quality.[1622]

23. Three commenters argued that Xcel should invest in nuclear generation rather than wind or solar.[1623]

XIII. Support for Xcel's Proposed Rate Increases

24. A handful of commenters supported Xcel's requested increase. Comments in support of Xcel's proposal cited benefits including "family sustaining" jobs for local workers, and the need for increased investment to update infrastructure and to transition to clean energy.[1624]

25. Some commenters specifically identified the need for reliable electric service, and expressed an interest in ensuring sufficient investment to ensure reliability.[1625]

XIV. Dissatisfaction with Public Notice or Public Hearing Schedule

26. Several commenters observed that they did not timely receive the public-hearing-schedule notice. Mary Behrens stated that she received notice of public hearings on November 7, 2022, and the last public hearing on the notice had been set for November 3.[1626] Sandra Willis commented on November 2, 2022, that she had just received the notice that day and was only able to attend because she had the day off.[1627]

27. Kristel Porter requested an additional hearing be held "in the City of Minneapolis at a more accessible time[.]"[1628]

28. Joshua Lewis commented on the difficulty in connecting with the October 31 public hearing conducted via WebEx.[1629]

29. In response to comments critical of the timing, location, and notice of in-person hearings, and to technical difficulty experienced by members of the public when attempting to connect to the October 31, 2022, WebEx hearing,[1630] an additional public hearing was scheduled for December 9, 2022, and held via WebEx. Notice of the

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[1622] *See, e.g.*, International Union of Operating Engineers Local 49 and North Central States Regional Counsel of Carpenters (Jan. 6, 2023 letter). (eDockets No. 20231-191919-01).
[1623] David Enochson (Jan. 21, 2022 email) (eDockets No. 20221-181998-01); John Chamberlain (Apr. 8, 2022 email) (eDockets No. 20224-184820-01); Keith Nystrom (Oct. 21, 2022 email) (eDockets No. 202210-190040-01).
[1624] *See, e.g.*, Stacey Karels, Tr. Mankato Hrg. at 17–20.
[1625] *See, e.g.*, Adam Harrington, Tr. Minneapolis Hr. at 29; Stacey Karels, Tr. Mankato Hrg. at 17–19.
[1626] Mary Behrens (Nov. 9, 2022 email) (eDockets No. 202211-190561-01).
[1627] Sandra Willis, Tr. Nov. 2, 2022 Hrg. at 39–40.
[1628] Kristel Porter, Tr. Minneapolis Hrg. at 44.
[1629] Joshua Lewis, Tr. Oct. 31, 2022 Hrg., at 33–34.
[1630] Tr. Oct. 31, 2022, Hrg. at 3–6.

additional public hearing was published on the Commission's website.[1631] Approximately 20 members of the public attended the December 9 hearing—more than attended several of the initially noticed in-person public hearings.[1632]

XV. Energy Justice / Equity

30. Several comments characterized the proposed increase as a form of wealth extraction, transfer, or redistribution from poor, marginalized, or underserved communities to utility executives and shareholders.[1633] A significant minority of comments concerned the disproportionate impact of a rate increase on low-income and BIPOC communities.[1634] This view often corresponded with an assertion that the Company should focus investment on those communities or take other steps to mitigate or avoid the negative effects.[1635]

XVI. Other Issues

31. Although a large number of commenters highlighted Xcel's monopoly as their electricity provider in the context of arguing that the Commission must scrutinize Xcel's rate increase proposal and protect captive customers,[1636] several commenters specifically criticized the vertically integrated monopoly model for electric utilities, and urged consideration of alternatives to Xcel's monopoly in particular.[1637] Other commenters supported the model, and opposed fundamental regulatory policy changes in this proceeding.[1638]

[1631] CALENDAR OF UPCOMING MEETINGS AND EVENTS, FRIDAY DEC. 9, 2022, *available at* https://mn.gov/puc/about-us/calendar/?trumbaEmbed=view%3Devent%26eventid%3D163194326 (last visited Feb. 2, 2023).
[1632] Tr. Dec. 9, 2022, Hrg. at 30.
[1633] *See, e.g.*, Tracy Kugler (Dec. 4, 2022 email) (eDockets No. 202212-191091-01).
[1634] *See, e.g.*, Marylee Pithian (Oct. 26, 2022 letter) (eDockets No. 202210-190171-01).
[1635] *See, e.g.*, Terri Burnor (Dec. 12, 2022 email) (eDockets No. 202212-191278-01).
[1636] *See, e.g.*, Benjamin Tsai (Dec. 9, 2022 email) (eDockets No. 202212-191236-01); Mark Helgeson, Tr. Dec. 9, 2023 Hrg. at 40.
[1637] *See, e.g.*, Joshua Lewis (Dec. 16, 2022 email) (eDockets No. 202212-191447-01); Maia Homstad, Tr. Dec. 9 2023 Hrg. at 47.
[1638] *See, e.g.*, International Union of Operating Engineers Local 49 and North Central States Regional Counsel of Carpenters (Jan. 6, 2023 letter). (eDockets No. 20231-191919-01).

MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

PO Box 64620
Saint Paul, MN 55164-0620
mn.gov/oah
PH (651) 361-7900

March 31, 2023

See Attached Service List

Re: ***In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota***

OAH 22-2500-37994
MPUC E-002/GR-21-630
MPUC E-002/M-21-748

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** in the above-entitled matter.

If you have any questions, please contact me at (651) 361-7874, michelle.severson@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,

Michelle Severson

MICHELLE SEVERSON
Legal Assistant

Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota	OAH Docket No.: 22-2500-37994

On March 31, 2023, a true and correct copy of the **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS** was served by eService, and United States mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name
Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties
Alison C	Archer	aarcher@misoenergy.org	MISO
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy
Allen	Barr	allen.barr@ag.state.mn.us	Office of the Attorney General-DOC
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