CAH 28-2500-40515
MPUC E-002/GR-24-320
MPUC E-002/GS-24-321

STATE OF MINNESOTA
COURT OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota

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STATE OF MINNESOTA
COURT OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS**

An evidentiary hearing was held before Administrative Law Judge Joseph C. Meyer on December 17 and 18, 2025, at the Public Utilities Commission, St. Paul, Minnesota in the above-captioned matter.

Public hearings were held on September 15, 2025 in Stillwater, on September 16, 2025 in St. Cloud, on September 17, 2025 in St. Paul, on September 22, 2025 in Faribault, on September 23, 2025 in Edina, on September 24, 2025 in Minneapolis, and on September 25, 2025 in Welch. Virtual public hearings were held on September 16, 2025 and September 23, 2025. Written public comments were received until December 30, 2025.

Post-hearing briefs were filed on January 28, 2026, and reply briefs and proposed findings were filed on February 25, 2026. The hearing record closed upon receipt of the last post hearing briefs on February 25, 2026.

Appearances:

Eric F. Swanson and Elizabeth H. Schmiesing of Winthrop & Weinstein, P.A.; Elizabeth M. Brama and Valerie T. Herring Taft Stettinus & Hollister LLP; Ryan P. Barlow of Moss & Barnett, P.A.; 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.

Richard Dornfeld, Katherine Arnold, Steve Melchionne, and Amrit Hundal, Assistant Attorneys General, appeared on behalf of the Department of Commerce, Division of Energy Resources (Department or DOC).

Peter G. Scholtz, Joey Cherney, and Wendy Raymond, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General Residential Utilities Division (OAG).

Brian Edstrom, Senior Regulatory Advocate; and Brandon Crawford and Olivia J. Carroll, Regulatory Advocates, appeared on behalf of the Citizens Utility Board of Minnesota (CUB).

Erica S. McConnell and Bradley Klein, Environmental Law & Policy Center, appeared on behalf of the Joint Intervenors.

Joseph L. Sathe and Samuel B. Ketchum, Kennedy & Graven, appeared on behalf of the Suburban Rate Authority (SRA).

Andrew P. Moratzka, Amber Lee, and Eden A. Fauré, Stoel Rives, LLP, appeared on behalf of the Xcel Large Industrials (XLI).

George Shardlow, Executive Director, appeared on behalf of the Energy CENTS Coalition (ECC).

Collette N. Brashears and Todd J. Guerrero, Kutak Rock, LLP, appeared on behalf of Walmart, Inc. (Walmart).

Robert Manning and Ashley Marcus appeared for the Staff of the Public Utilities Commission.

STATEMENT OF THE ISSUES

On December 30, 2024, the Commission issued a Notice of and Order for Hearing referring this matter to the Court of Administrative Hearings. The Notice of and Order for Hearing set forth the following issues to be addressed:

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

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

3. Are the Company's proposed capital structure and return on equity reasonable?[1]

4. Whether it is appropriate to use the proposed hypothetical capital structure or whether an alternate capital structure should be adopted.

5. Reasons for the significant changes of the following costs since the last rate case:

    a. Customer Accounting – $16.5 million

    b. Customer Service and Information – $34.0 million increase

    c. Administrative and General – $34.0 million increase

    d. Depreciation – $112.9 million increase

[1] The Commission specifically asked the Court to consider the impact of data centers on issues 1 through 3.

6. The increase in the distribution budget with a focus on how the increased spending will impact reliability.

7. How much Top 10 executive compensation costs should be recovered in rates?

8. What grid reinforcement program and associated costs should be approved.

9. What wildfire mitigation costs should be approved, and the impact these measures will have on other areas of Company operations, including FLISR, ADMS, vegetation management, and pole replacements.

10. Develop a full record that ensures decisions made in Docket E-002/CI-24-318 are properly reflected in the 2026 Test Year.

11. Future ADMS functionalities, lifespan, and costs.

12. The program, to be submitted in supplemental direct testimony, where interest payments and fees from late bill payments are donated to low-income customer assistance programs or are eliminated.

13. Should Xcel's proposed 2025 and 2026 sales true-ups be approved.

14. Develop a record for prepaid pension asset that, at a minimum addresses the following:

    a. The contribution amounts to pension funds required by federal law for each year of the cumulative years for which the Company claims a prepaid pension asset.

    b. The actual contributions amounts made by the Company for each of the years.

    c. The amount of pension expense recovered from ratepayers as an O&M expense each year.

    d. The amount of each of the five components of pension expense (ACM or FAS 87) for each year of the claimed asset and determine the extent to which the component:

        i. increases or decreases of the claimed prepaid pension asset for that year relative to the previous year;

        ii. whether any of the increase or decrease in the year is attributable to shareholder funding and by how much.

e. Whether the method of calculating pension expense (ACM or FAS87) affects the extent to which the asset is shareholder funded and, if so, how.

f. Determine the overall extent to which the Company has established by a preponderance of evidence that the claimed amount of the prepaid pension asset is attributable to shareholder contributions (i.e. is shareholder funded), and not the result of market returns or other attributes of pension expense under ACM and FAS 87.

15. Develop a record addressing whether the fuel to steel transition will result in intergenerational cost shifting and, if so, make recommendations addressing this issue.

16. Develop a record for insurance premium expense that, at a minimum, addresses the following:

a. Provide the forecasted and actual annual expenses for each subcategory of expenses and credits since 2017.

b. A detailed description of each subcategory and their business purpose.

c. The extent to which the Marshall Wildfire in Colorado and the 2024 Smokehouse Creek Fire Complex in Texas affect the insurance premium, rate of return, or borrowing costs for the MN jurisdiction.

d. A thorough description of each actual refund or credit the company has received for insurance premiums since 2017 and any supporting documentation explaining the source and reason for each refund or credit.

e. For all past refund and credit subcategories received between 2017 and 2024 provide a thorough description of the company's prediction for refunds or credits in their 2025 and 2026 budget including all subcategories that they may have predicted no budgeted refund or credit.

f. If refunds and credits lack sufficient predictability to ensure fair and just rates, provide proposed mechanisms by which rate payers can be appropriately reimbursed for insurance expenses refunds and credits they have paid for in base rates.

FINDINGS OF FACT

I. Summary of the Application

1. As updated in supplemental direct testimony, Xcel's two-year multi-year rate plan (MYRP) sought an approved revenue increase of $344.3 million (9.4 percent increase) in 2025 and an incremental $129.4 million increase (3.3 percent increase) in 2026.[2]

2. Over the course of the proceeding, the Company made several changes to its overall rate request, including resolving several financial issues with other parties. In Rebuttal Testimony, the Company quantified these changes and incorporated them into a revised revenue increase request of $208.4 million (5.8 percent increase) in 2025 and an incremental $156.9 million (4.2 percent increase) in 2026.[3]

3. Following Rebuttal Testimony, the Company agreed to two further adjustments to its request, related to its wildfire mitigation efforts and capacity revenues for the Prairie Island Nuclear Generating Plant (PINGP), further reducing its revenue increase request.[4]

II. The Parties

4. The Company is a Minnesota corporation that serves Minnesota customers and a subsidiary of Xcel Energy, Inc., a public utility holding company.[5]

5. The Department represents the interests of the State's ratepayers in rate proceedings.[6] Department staff reviewed the testimony and schedules filed by the Company and other parties to assure their accuracy and completeness, and filed testimony and argument addressing the reasonableness of the elements of the rate request in this proceeding.

6. The OAG represents the interests of residential and small business ratepayers. Its staff reviews the testimony and schedules filed by the Company and other parties and files testimony and argument intended to protect those interests.[7]

7. XLI is an ad hoc consortium of large industrial customers of Xcel, consisting for purposes of this proceeding of Flint Hills Resources Pine Bend, LLC; Marathon Petroleum Corporation; USG Interiors, Inc.; and Building Owners and Managers

[2] Ex. Xcel-18 at 2 (Halama Supplemental Direct).
[3] Ex. Xcel-16 at 20 (Liberkowski Rebuttal); Ex. Xcel-19 at 4-29 (Halama Rebuttal).
[4] Ex. Xcel-95 (Xcel Energy correspondence regarding wildfire issue). The capacity revenue for PINGP issue was shown as an item not in dispute on the Issue Matrix. Issue Matrix (Jan. 23, 2026) (eDockets No. 20261-227337-01).
[5] Ex. DOC-1 at 29 (Johnson Direct).
[6] Minn. Stat. § 216A.07, subd. 3 (2024); Minn. R. 7829.0800, subp. 3 (2025).
[7] Minn. Stat. § 8.33.

Association (BOMA) Greater Minneapolis. Their costs of production could be significantly affected by a rate increase.[8]

8. 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.[9]

9. 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.[10]

10. Walmart is an American multinational retail corporation that operates a 79 retail units and one distribution center in Minnesota, including 34 stores and related facilities that purchase electric service from Xcel.[11]

11. The Joint Intervenors comprise Cooperative Energy Futures, Environmental Law & Policy Center, Minnesota Interfaith Power & Light, and Vote Solar. The Joint Intervenors intervened in this proceeding to advocate for a more clean, equitable, and resilient power grid, accomplished through decentralization that offers robust opportunities for customers and communities to own distributed energy resources (DER).[12]

12. SRA is a joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, most served by Xcel.[13]

III. Procedural Background

13. The Company filed its Application for Authority to Increase Rates for Electric Service (Application or Initial Filing) in Minnesota on November 1, 2024, requesting a two-year MYRP addressing rates for 2025 and 2026.[14]

14. On November 5, 2024, the Commission issued a notice to interested parties requesting comments on three topics:

a. Does Xcel Energy's application comply with the filing requirements of Minn. Stat. § 216B.16, Minn. Rules, parts 7825.3100 to 7825.4400, other relevant Minnesota statutes and Commission rules, and relevant Commission Orders?

[8] XLI Petition to Intervene (Jan. 24, 2025) (eDockets No. 20251-214380-02).
[9] CUB Initial Comments and Petition to Intervene (Nov. 12, 2024) (eDockets No. 202411-211851-02).
[10] ECC Petition to Intervene (Jan. 22, 2025) (eDockets No. 20251-214232-01).
[11] Walmart Petition to Intervene (Apr. 29, 2025) (eDockets No. 20254-218272-02).
[12] Joint Intervenors Petition to Intervene (Apr. 30, 2025) (eDockets No. 20254-218395-01).
[13] SRA Petition to Intervene (Mar. 31, 2025) (eDockets No. 20253-217053-01).
[14] Ex. Xcel-3 (Application-Volume 1, Notice of Change in Rates and Interim Rate Petition).

b. Should this matter be sent to the Office of Administrative Hearings[15] for a contested case hearing and if so, what should be the scope of the hearing?

c. Are there other issues or concerns related to this matter?[16]

15. November 12, 2024, the Department filed initial comments recommending the Commission accept the Company's filing as complete and refer this matter to the Office of Administrative Hearings for a contested case proceeding. The Department also recommended the Commission limit the Company's interim rate recovery.[17]

16. CUB also filed initial comments recommending referral to the Office of Administrative Hearings and that the Commission limit the Company's interim rate recovery, on November 12, 2024, along with their petition to intervene in this matter.[18]

17. The OAG filed initial comments on November 12, 2024, opposing the Company's request for interim rate recovery.[19]

18. On November 18, 2024, the Department,[20] Electrify America,[21] the OAG[22] and the Company[23] filed reply comments.

19. The filing came before the Commission on December 12, 2024.[24]

20. On December 30, 2024, the Commission issued an Order accepting the Company's filing and suspending the proposed rates.[25]

21. In a separate Order, the Commission set the Company's interim rates.[26]

22. In an additional Order, the Commission referred the case to the Office of Administrative Hearings for contested case proceedings.[27]

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[15] During the pendency of this proceeding, the Office of Administrative Hearings changed its name to the Court of Administrative Hearings. Any references to the Court in this Report will use the name of the tribunal on the relevant date.
[16] Notice of Comment Period on Completeness and Procedures (Nov. 5. 2024) (eDocket No. 202411-211632-01).
[17] Department Initial Comments (Nov. 12, 2024) (eDocket No. 202411-211839-01).
[18] CUB Initial Comments and Petition to Intervene (Nov. 12, 2024) (eDocket No. 202411-211851-02).
[19] Comments of the Office of the Attorney General in Opposition to Xcel's Interim-Rate Proposal (Nov. 12, 2024) (eDocket No. 202411-211845-02).
[20] Department Correspondence (Nov. 18, 2024) (eDocket No. 202411-212074-01).
[21] Reply Comments of Electrify America (Nov. 18, 2024) (eDocket No. 202411-212053-01).
[22] Reply Comments of the OAG (Nov. 18, 2024) (eDocket No. 202411-212075-02).
[23] Reply Comments of Xcel (Nov. 18, 2024) (eDocket No. 202411-212101-01).
[24] Notice Of Oral Argument Times And Procedures (Dec. 11, 2024) (eDocket No. 202412-212899-01).
[25] Order Accepting Filing and Suspending Rates (Dec. 30, 2024) (eDocket No. 202412-213389-01).
[26] Order Setting Interim Rates (Dec. 30, 2024) (eDocket No. 202412-213390-01).
[27] Notice of and Order for Hearing (Dec. 30, 2024) (eDocket No. 202412-213391-01).

23. On January 22, 2025, the Administrative Law Judge held a prehearing conference via Microsoft Teams.[28]

24. On January 22, 2025, ECC submitted a Petition to Intervene.[29]

25. On January 24, 2025, XLI submitted a Petition to Intervene.[30]

26. On January 27, 2025, the Administrative Law Judge issued a Protective Order and Protective Order for Highly Confidential Trade Secret Data regulating the use and disclosure of nonpublic data.[31]

27. On January 31, 2025, the Administrative Law Judge issued the First Prehearing Order which established a procedural schedule for this proceeding.[32]

28. No party filed an objection to XLI's petition to intervene and on February 10, 2025, the Administrative Law Judge granted the petition.[33]

29. No party filed an objection to ECC's petition to intervene and on February 14, 2025, the Administrative Law Judge granted the petition.[34]

30. On March 17, 2025, Xcel Energy filed Supplemental Direct Testimony for Company witnesses Benjamin C. Halama, Gregory J. Robinson, Marty D. Mensen, Nora C. Lindgren, Anne Z. Sherwood, and Kelly A. Bloch.[35]

31. On March 31, 2025, SRA submitted its Petition to Intervene.[36]

32. No party filed an objection to SRA's petition to intervene and on April 15, 2025, the Administrative Law Judge granted the petition.[37]

33. On April 29, 2025, Walmart submitted its Petition to Intervene.[38]

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[28] Order on Prehearing Conference (Jan. 13, 2025) (eDocket No. 20251-213881-01).
[29] ECC Petition to Intervene (Jan. 22, 2025) (eDocket No. 20251-214232-01).
[30] XLI Petition to Intervene (Jan. 24, 2025) (eDocket No. 20251-214380-02).
[31] Protective Order and Protective Order for Highly Confidential Trade Secret Data (Jan. 27, 2025) (eDocket No. 20251-214424-01).
[32] First Prehearing Order (Jan. 31, 2025) (eDocket No. 20251-214744-01).
[33] Order Granting Unopposed Intervention Petition of XLI (Feb. 10, 2025) (eDocket No. 20252-215166-01).
[34] Order Granting Unopposed Intervention Petition of ECC (Feb. 14, 2025) (eDocket No. 20252-215402-01).
[35] *See* Xcel Exs. 18, 27, 37, 39, 48 and 79.
[36] SRA Petition to Intervene (Mar. 31, 2025) (eDocket No. 20253-217053-01).
[37] Order Granting Unopposed Intervention Petition of SRA (Apr. 15, 2025) (eDocket No. 20254-217644-01).
[38] Walmart Petition to Intervene (Apr. 29, 2025) (eDocket No. 20254-218272-02).

34. On April 30, 2025, counsel for the Joint Intervenors submitted their applications for Pro Hac Vice Admission.[39]

35. On April 30, 2025, the Joint Intervenors submitted their Petition to Intervene.[40]

36. On April 30, 2025, XLI submitted correspondence notifying the Commission, the ALJ and parties that they had incorporated a new member, BOMA Greater Minneapolis, into the consortium.[41]

37. No parties filed an objection to the petitions to intervene of Walmart or the Joint Intervenors, and on May 19, 2025, the Administrative Law Judge granted the petitions and Pro Hac Vice admission for counsel for the Joint Intervenors.[42]

38. On June 3, 2025, counsel for Walmart submitted her application for Pro Hac Vice admission.[43]

39. On June 9, 2025, the Administrative Law Judge granted the Pro Hac Vice admission of Walmart's counsel.[44]

40. On July 25, 2025, the OAG and the Department jointly filed a motion with the Court for an order to compel the Company to produce certain documents in response to an information request.[45]

41. On July 31, 2025, the Company submitted errata corrections to its Application and Direct Testimony and Schedules of Benjamin S. Levine, Marty D. Mensen, Anne Z. Sherwood, Robert L. Miller, Yen Ly and Christopher J. Barthol.[46]

42. On August 8, 2025, the Company filed its response to the OAG and the Department's motion to compel discovery.[47]

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[39] Application for Pro Hac Vice Admission of Bradley Klein (eDocket No. 20254-218401-02) (Apr. 30, 2025); Application for Pro Hac Vice Admission of Erica S. McConnell (eDocket No. 20254-218401-03) (Apr. 30, 2025).

[40] Petition to Intervene of Joint Intervenors (Apr. 30, 2025) (eDocket No. 20254-218395-01).

[41] Correspondence adding Building Owners and Managers Association of Greater Minneapolis (BOMA) to the XLI group (Apr. 30, 2025) (eDocket No. 20254-218394-01).

[42] Order Granting Unopposed Intervention Petitions of Walmart and Joint Intervenors and Applications to Appear Pro Hac Vice (May 19, 2025) (eDocket No. 20255-219070-01).

[43] Application for Pro Hac Vice Admission of Colette N. Brashears (June 3, 2025) (eDocket No. 20256-219531-02).

[44] Order Granting Application for Pro Hac Vice Admission of Colette N. Brashears (June 9, 2025) (eDocket No. 20256-219712-01).

[45] OAG and Department's Notice of Motion and Motion to Compel Discovery (July 25, 2025) (eDocket No. 20257-221445-01).

[46] *See* Ex. Xcel-11.

[47] Xcel Reply in Opposition to Motion to Compel Discovery (Aug. 8, 2025) (eDocket No. 20258-221905-01).

43. On August 19, 2025, the Administrative Law Judge held a motion hearing via Microsoft Teams.[48]

44. On August 22, 2025, SRA, CUB, the Joint Intervenors, Walmart, XLI, OAG and the Department submitted their Direct Testimony.[49]

45. On August 25, 2025, ECC submitted its Direct Testimony.[50]

46. On August 27, 2025, XLI submitted errata corrections to its Direct Testimony of Billie S. LaConte and Jonathan Ly.[51]

47. On August 29, 2025, the Administrative Law Judge issued an order granting in part and denying in part the motion to compel of the Department and the OAG.[52]

48. On September 5, 2025, the Administrative Law Judge held a prehearing conference via Microsoft Teams to discuss logistics and planning for the public hearings in this matter.[53]

49. Between September 15 and September 25, 2025, in-person public hearings were held in Stillwater, St. Cloud, St. Paul, Faribault, Edina, Minneapolis and Welch, and two virtual public hearings were held via WebEx.[54]

50. On September 29, 2025, XLI submitted errata corrections to its Direct Testimony.[55]

51. On October 1, 2025, the Company submitted correspondence regarding 2026 Interim Rates.[56]

52. On October 8, 2025, the Commission issued a notice of comment period on the Company's interim rate request setting initial and reply comment periods.[57]

53. On October 10, 2025, the SRA, the Company, XLI, Joint Intervenors, the Department, and the OAG filed Rebuttal Testimony.[58]

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[48] Order for Motion Hearing (Aug. 11, 2025) (eDocket No. 20258-221943-01).
[49] *See, e.g.*, Exs. DOC-1, OAG-5, CUB-1, JIN-1, SRA-1, WAL-1, XLI-1.
[50] Ex. ECC-1.
[51] Ex. XLI-4.
[52] Order Granting in Part and Denying in Part Motion to Compel (Aug. 29, 2025) (eDocket No. 20258-222555-01).
[53] Order for Prehearing Conference (Sept. 3, 2025) (eDocket No. 20259-222664-01).
[54] Public Hearing Notice (Jun. 13, 2025) (eDocket No. 20256-219897-01).
[55] XLI Filing Letter (Sep. 29, 2025) (eDocket No. 20259-223371-02).
[56] Xcel Letter Regarding 2026 Interim Rates (Oct. 1, 2025) (eDocket No. 202510-223492-01).
[57] Notice of Comment Period on Interim Rate Request (Oct. 8, 2025) (eDocket No. 202510-223704-01).
[58] *See, e.g.,* Exs. Xcel-16, DOC-17, OAG-6, JIN-1, SRA-2, and XLI-5.

54. On October 21, 2025, the OAG filed an objection to and motion to strike along with a memorandum of law in support of its motion to strike portions of the Rebuttal Testimony of Benjamin Halama.[59]

55. On October 24, 2025, the Company filed errata corrections to its Initial Application and Direct Testimony of Yen Ly and Richard R. Schrubbe and Rebuttal Testimony of Benjamin C. Halama and Benjamin S. Levine.[60]

56. On October 27, 2025, the Administrative Law Judge issued an order for motion hearing on the OAG objection and motion to strike portions of Benjamin Halama Rebuttal Testimony.[61]

57. On October 31, 2025, initial comments on the Company's interim rate request were filed with the Commission by the OAG,[62] ECC[63] and the Department,[64] and jointly by CUB and XLI.[65]

58. On November 4, 2025, the Company filed its comments on the OAG's objection and motion to strike portions of the Rebuttal Testimony of Benjamin Halama.[66]

59. On November 4, 2025, the Department filed its response supporting OAG's objection and motion to strike potions of Benjamin Halama's Rebuttal Testimony.[67]

60. On November 5, 2025, the Administrative Law Judge held a motion hearing via Microsoft Teams.[68]

61. On November 10, 2025, the Department[69] and the Company[70] filed reply comments to the Company's interim rate request with the Commission.

62. On November 12, 2025, the Administrative Law Judge issued an order denying the OAG's motion to strike.[71]

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[59] Objection to and Motion to Strike Portions of Rebuttal Testimony and Memorandum of Law in Support of Objection to and Motion to Strike Portions of the Rebuttal Testimony of Benjamin Halama (Oct. 21, 2025) (eDocket Nos. 202510-224157-02-03).
[60] Xcel Errata (Oct. 24, 2025) (eDocket No. 202510-224273-01).
[61] Order for Motion Hearing (Oct. 27, 2025) (eDocket No. 202510-224308-01).
[62] Comments of the OAG (Oct. 31, 2025) (eDocket No. 202510-224548-01).
[63] ECC Initial Comment (Oct. 31, 2025) (eDocket No. 202510-224517-01).
[64] Initial Comments of the Department (Oct. 31, 2025) (eDocket No. 202510-224510-01).
[65] Initial Comments of CUB and XLI (Oct. 31, 2025) (eDocket No. 202510-224520-02).
[66] Comments in Opposition to the Office of the Attorney General – Residential Utilities Division's Objection and Motion to Strike Portions of the Rebuttal Testimony of Benjamin Halama (Nov. 4, 2025) (eDocket No. 202511-224660-01).
[67] Department Response Supporting OAG's Objection and Motion to Strike Potions of the Rebuttal Testimony of Benjamin Halama (Nov. 4, 2025) (eDocket No. 202511-224653-01).
[68] Motion Hearing Tr. (Nov. 5, 2025) (eDocket No. 202511-224780-01).
[69] Department Reply Comments – 2026 Interim Rates (Nov. 10, 2025) (eDocket No. 202511-224790-01).
[70] Xcel Reply Comments – 2026 Interim Rates (Nov. 10, 2025) (eDocket No. 202511-224825-01).
[71] Order Denying Motion to Strike (Nov. 12, 2025) (eDocket No. 202511-224861-01).

63. On November 25, 2025, SRA, ECC, CUB, the Company, Joint Intervenors, the OAG, XLI, and the Department filed Surrebuttal Testimony.[72]

64. On December 4, 2025, the Company filed Public and Trade Secret errata corrections to the Direct Testimony of Marty D. Mensen, Nora Lindgren and Christopher Barthol, and Rebuttal Testimony of Christopher Barthol, Diedra Howard, Robert Miller and Yen Le.[73]

65. On December 4, 2025, the OAG filed errata corrections to the Direct Testimony of Katherine Hinderlie.[74]

66. On December 4, 2025, the Department filed errata corrections to the Direct Testimony of Eric Borden and Sachin Shah, and the Surrebuttal Testimony and Attachments of Mark Johnson and the Surrebuttal Testimony of Michael Zajicek.[75]

67. On December 5, 2025, the Company filed a notice of motion and motion to strike portions of Jonathan Ly's Surrebuttal Testimony.[76]

68. On December 8, 2025, the Administrative Law Judge ordered parties wishing to respond to the Company's motion to strike to file responses by December 12, 2025 and provided for interested parties to make oral argument on the motion to strike at the December 15, 2025 status conference.[77]

69. On December 9, 2025, the Company submitted a reconciliation filing in accordance with the September 16, 2025 Electric Rate Case Virtual Public Hearing.[78]

70. On December 11, 2025, XLI filed a response to the Company's motion to strike part of XLI witness Jonathan Ly's Surrebuttal Testimony.[79]

71. On December 11, 2025, the Company filed a motion for relief raising procedural and due process concerns.[80]

72. On December 11, 2025, the Department responded to the Company's motion for relief filed on December 11, 2025.[81]

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[72] *See, e.g.*, Exs. DOC-2, OAG-3, CUB-6, ECC-2, JIN-4, SRA-4, XLI 7.
[73] *See* Xcel Errata Filing (Dec. 4, 2025) (eDocket No. 202512-225546-01).
[74] Ex. OAG-1.
[75] Exs. DOC-2, DOC-9, DOC-15, DOC-18.
[76] Notice of Motion and Motion to Strike and Memorandum in Support of Motion to Strike (Dec. 5, 2025) (eDocket No. 202512-225566-01).
[77] Order on Status Conference (Dec. 8, 2025) (eDocket No. 202512-225611-01).
[78] Reconciliation Filing – September 16, 2025 Virtual Public Hearing (Dec. 9, 2025) (eDocket No. 202512-225673-01).
[79] Response of XLI (Dec. 11. 2025) (eDocket No. 202512-225778-02).
[80] Xcel Notice of Motion and Motion for Relief and Memorandum of Law in Support of Motion for Relief (Dec. 11, 2025) (eDocket Nos. 202512-225738-02-03).
[81] Department Correspondence (Dec. 11, 2025) (eDocket No. 202512-225770-01).

73. On December 11, 2025, the Administrative Law Judge issued an Order for Procedure on Motion for Relief and ordered parties wishing to respond to file a written response in advance of the status conference scheduled for December 15, 2025.[82]

74. On December 12, 2025, the Company filed correspondence regarding the Company's position on wildfire-related costs in the 2025 test year and 2027 plan year.[83]

75. The Administrative Law Judge heard oral argument on the Company's motion to strike portions of Jonathan Ly's Surrebuttal Testimony and the Company's motion for relief on December 15, 2025.[84]

76. On December 16, 2025, the Company submitted Responsive Testimony of Nicholas N. Paluck regarding rate design.[85]

77. The Evidentiary Hearing was held on December 17 and December 18, 2025 in the Small Hearing Room of the Commission's offices in St. Paul, Minnesota.[86]

78. On January 23, 2026, the Company filed its Issues Matrix.[87]

79. On January 28, 2026, the Company,[88] SRA,[89] Joint Intervenors,[90] OAG,[91] CUB,[92] XLI,[93] Walmart,[94] and the Department[95] filed their Initial Briefs.

80. On January 29, 2026, the Company filed errata corrections to its Initial Brief.[96]

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[82] Order for Procedure on Motion for Relief (Dec. 11, 2025) (eDocket No. 202512-225750-01).
[83] Ex. Xcel-95 (Xcel Energy Correspondence Regarding Wildfire Issue).
[84] Order on Status Conference (Dec. 8, 2025) (eDocket No. 202512-225611-01); and Order for Procedure on Motion for Relief (Dec. 11, 2025) (eDocket No. 202512-225750-01).
[85] Ex. Xcel-98 (Paluck Responsive Testimony).
[86] *See* Evidentiary Hearing Transcript Volumes (Vol.) 1-2 (Dec. 17-18, 2025).
[87] Issues Matrix of Xcel (Jan. 23, 2026) (eDocket No. 20261-227337-01).
[88] Initial Brief of Xcel (Jan. 28, 2026) (eDocket No. 20261-227542-01). Due to the size of the Initial Brief, the processing time required due to the size was unusually long and the Initial Brief did not post until 4:36 PM and was recorded as filed on January 29, 2026. The Administrative Law Judge was immediately notified and the Company asked that the Initial Brief be accepted as timely filed. Xcel Correspondence (Jan. 28, 2026) (eDocket No. 20261-227543-01). No party objected to this request and Xcel's Initial Brief will be considered timely filed.
[89] Initial Brief of the SRA (Jan. 28, 2026) (eDocket No. 20261-227541-01) [hereinafter SRA Initial Brief].
[90] Initial Brief of the Joint Intervenors (Jan. 28, 2026) (eDocket No. 20261-227538-01) [hereinafter Joint Intervenors Initial Brief].
[91] Initial Brief of the OAG – Residential Utilities Division (Jan. 28, 2026) (eDocket No. 20261-227537-02) [hereinafter OAG Initial Brief].
[92] Initial Brief of CUB (Jan. 28, 2026) (eDocket No. 20261-227535-02) [hereinafter CUB Initial Brief].
[93] Post-Hearing Brief of XLI (Jan. 28, 2026) (eDocket Nos. 20261-227526-02-03) [hereinafter XLI Initial Brief].
[94] Initial Post-Hearing Brief of Walmart (Jan. 28, 2026) (eDocket No. 20261-227525-01) [hereinafter Walmart Initial Brief].
[95] Initial Brief of the Department (Jan. 28, 2026) (eDocket Nos. 20261-227521-01-02) [hereinafter Department Initial Brief].
[96] Xcel Errata to Initial Brief (Jan. 29, 2026) (eDocket Nos. 20261-227580-01-02).

81. On February 18, 2026, the Company filed an Addendum to the Issues Matrix, listed five additional issues no longer in dispute between the parties. No party filed a Reply to the Issues Matrix.[97]

82. On February 25, 2026, the Company,[98] SRA,[99] Joint Intervenors,[100] OAG,[101] CUB,[102] XLI,[103] and the Department[104] filed their Reply Briefs and Proposed Findings.

IV. Comments from the Public

83. Over 7,500 written and oral public comments were received by the December 30, 2025, deadline, including more than 80 individuals providing oral comments at the nine public hearings held across the Company's service territory and virtually. 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.

84. While the public raised a specific concerns on a variety of topics, there was widespread opposition to the proposed rate increase. Customers expressed concern about rate affordability and economic hardship, a belief that a rate increase would unfairly transfer wealth from customers to shareholders and executives, frustration with customer service issues, concern about residential customers paying for the costs to serve large data centers, and concerns about the overall rate-setting process.

V. Legal Standards

85. Every rate made, demanded, or received by any public utility . . . shall be just and reasonable.[105]

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[97] Xcel Issues Matrix Addendum (Feb. 18, 2026) (eDocket No. 20262-228271-01).
[98] Xcel Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228661-01) and Xcel Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228661-02). Regardless of how parties titled the documents, this Report will cite to all reply briefs in the form of [Party Name] Reply Brief and [Party Name] Proposed Findings.
[99] SRA Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228665-01) and SRA Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228665-02).
[100] Joint Intervenors Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228650-01) and Joint Intervenors Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228650-02).
[101] OAG Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228658-02) and OAG Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228658-03).
[102] CUB Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228643-02) and CUB Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228643-02).
[103] XLI Reply Brief (Feb. 25, 2026) (eDocket Nos. 20262-228655-02-03) and XLI Proposed Findings (Feb. 25, 2026) (eDocket No.20262-228655-04).
[104] Department Reply Brief (Feb. 25, 2026) (eDocket No. 20262-228640-01) and Department Proposed Findings (Feb. 25, 2026) (eDocket No. 20262-228640-02-03).
[105] Minn. Stat. § 216B.03. Minnesota Statutes are cited to the 2024 Edition unless otherwise indicated.

86. The Commission's charter when setting rates is "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers . . . ."[106]

87. Minn. Stat. § 216B.16, subd. 6 provides that:

> 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.

88. 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:[107]

> 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.

89. 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.[108] 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."[109]

90. "[B]y merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses."[110] "[T]he logic and

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[106] *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).
[107] *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).
[108] Minn. Stat. § 216B.16, subd. 4.
[109] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[110] *Id.* at 723.

relevance of the facts to the ultimate determination of whether the rate request is reasonable is of substantially more importance than the quantum of proof needed."[111]

91. A "utility is entitled to recover necessary, ongoing expenses incurred in the business of providing utility service."[112]

92. Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[113]

93. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. It considers both the claimed costs and whether ratepayers or shareholders should sustain the burden of the costs.[114]

VI. Undisputed or Resolved Issues

94. 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.[115]

A. Expense or Rate Base Related Issues

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

1. Community Solar Gardens

96. In Rebuttal Testimony, the Company updated its revenue forecast to align with the latest approved Community Solar Garden (CSG) fee structure, resulting in an increase in other revenues in the 2025 test year and 2026 plan year, and a decrease to revenue requirements.[116]

97. The Department agreed with this adjustment,[117] and no other party filed testimony regarding it.

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[111] *Id.*
[112] *In the Matter of a Request of Interstate Power Company For Authority To Change Its Rates For Gas Service In Minnesota*, 559 N.W.2d 130, 134 (Minn. App. 1997), *affirmed* 574 N.W.2d 408 (Minn. 1998) (emphasis added).
[113] Minn. Stat. § 216B.03.
[114] *In re Northern States Power Co.,* 416 N.W.2d at 722–23.
[115] A separate public and trade secret version was filed for much of the testimony in this proceeding. For public transparency, this Report cites to the public version unless information redacted in that version is material to the proposition for which the testimony is cited.
[116] Ex. Xcel-19 at 4-5 and Schedules 3A-3B at 2 (Halama Rebuttal).
[117] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

98. The Company's cost of service should reflect the updated revenue forecast to align with the latest CSG fee structure, as agreed to by the Company and the Department.

2. Customer Advances

99. In Rebuttal Testimony, the Company adjusted its customer advances to reflect a more current 13-month period ending in June 2024.[118]

100. In Surrebuttal Testimony, the Department agreed this adjustment is appropriate.[119]

101. Customer advances should reflect the 13-month period ending June 2024, as agreed to by the Company and the Department.

3. Nuclear Decommissioning and Accrual Costs

102. Costs for nuclear decommissioning are managed through the accumulation of annual accruals that are spread over the lifetime of the assets. The accrual amounts collected through rates are held externally in a trust per Nuclear Regulatory Commission rules.[120]

103. The purpose of end-of-life (EOL) nuclear fuel accrual is to recover the expense associated with the unused nuclear fuel at the time of reactor shutdown. Unlike the decommissioning funds, which are held in external accounts, the EOL nuclear fuel accrual is held in internal funds by the Company. As such, there is an added offset to rate base for the EOL funds resulting in a lower rate base.

104. The Company initially requested $21.6 million for its annual nuclear decommission accrual in the 2025 test year and 2026 plan year.[121] Xcel also initially requested $714,366 in EOL nuclear fuel accrual.[122]

105. The Department recommended updating the amounts included for these accruals to reflect the Commission's May 14, 2025 order in the Company's triennial nuclear plant decommissioning docket, Docket No. E002/M-24-394,[123] issued after the Company filed this case. Specifically, the Department recommended an annual nuclear decommission accrual of $3.8 million in the 2025 Test Year and 2026 Plan Year, which would result in an annual revenue requirement reduction of $17.7 million; and a reduction for the annual EOL nuclear fuel accrual to $455,460, an annual net reduction of $239,488.[124]

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[118] Ex. Xcel-19 at 5 and Schedules 3A-3B (Halama Rebuttal).
[119] Ex. DOC-2 at 31 and Schedule 1 (Johnson Surrebuttal).
[120] Ex. DOC-5 at 3 (Golden Direct).
[121] Ex. Xcel-68 at 51 (Johnson Direct).
[122] Ex. Ex. Xcel-68 at 53.
[123] Dockets referred to in this format in this Report refer to Commission proceedings.
[124] Ex. DOC-5 at 2-5 (Golden Direct).

106. The Company agreed with the Department's recommendation to adjust the decommissioning accrual amount to approximately $3.8 million based on the Commission's Order, resulting in annual revenue requirement reduction of approximately $17.7 million in 2025 and 2026 and agreed to the Department's recommendation to extend depreciable lives of Monticello and Prairie Island nuclear plants to align with operational lives of the plants for planning purposes in the Commission's Order in Docket No. E-002/RP-24-67, resulting in annual decommissioning accrual amount of zero for 2025 and 2026.[125]

107. The Company further agreed to adjust the end-of-life nuclear fuel accrual to also reflect the Commission order and to reflect extending the depreciable lives of the Monticello and Prairie Island nuclear plants. This adjustment reduced the decommission accrual amount to zero and the EOL accrual to $154,695 for 2025 and $159,688 for 2026.[126]

108. The Department agreed with Xcel's updated proposals for nuclear decommissioning accrual and EOL accrual.[127]

109. The nuclear decommissioning and EOL nuclear fuel accrual amount adjustments agreed to by the Company and the Department are reasonable and should be approved by the Commission.

4. Transmission, Distribution, and General (TD&G) Depreciation

110. The Company made adjustments in its Rebuttal Testimony related to FERC Account 370 and FERC Account 390 to make corrections identified in Department Information Requests and now proposes no change to depreciation rates for these accounts from the previous rate case.[128]

111. The Department agreed with the Company's rebuttal adjustment for this item.[129]

112. The Company's rebuttal adjustments related to FERC accounts 370 and 390 are reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

5. Distributed Intelligence My Energy Connection (MEC) 3.0

113. The Company proposed a rebuttal adjustment for the allocation for the MEC 3.0 project to accurately allocate the costs across all operating companies and removing 65.6 percent of projects from NSPM.[130]

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[125] Ex. Xcel-19 at 5-7 and Schedules 3A-3B (Halama Rebuttal); Ex. Xcel-86 at 5-7 (Moeller Rebuttal).
[126] Ex. Xcel-19 at 9-11 and Schedules 3A-3B (Halama Rebuttal); Ex. Xcel-86 at 5-7 (Moeller Rebuttal).
[127] Ex. DOC-6 at 4 (Golden Surrebuttal).
[128] Ex. Xcel-19 at 7 and Schedules 3A-3B (Halama Rebuttal); Ex. Xcel-86 at 7-10 (Moeller Rebuttal).
[129] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[130] Ex. Xcel-19 at 7-8 and Schedules 3A-3B (Halama Rebuttal).

114. The Department reviewed and agreed with the Company's proposed adjustment.[131]

115. The Company's rebuttal adjustments related to FERC accounts 370 and 390 are reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

6. Distributed Intelligence

116. In Rebuttal Testimony, the Company removed one non-NSPM distributed intelligence project that was inadvertently included in the MYRP Forecast resulting in a decrease to overall revenue requirement deficiency of approximately $0.2 million in 2025 and 2026.[132]

117. The Department reviewed and agreed with the Company's proposed adjustment.[133]

118. The Company's rebuttal adjustment for this project is reasonable and should be approved by the Commission, as agreed to by the Company and Department.

7. Employee Expenses

119. In Supplemental Direct and Rebuttal Testimony, the Company adjusted the Employee Expense Adjustment for the 2025 Test Year and 2026 Plan Year to include certain expenses that were inadvertently excluded in the Initial Filing, resulting in a reduction in the 2025 and 2026 revenue requirements.[134]

120. The Company's rebuttal adjustment for this project is reasonable and should be approved by the Commission.

8. Electric Vehicle Program

121. In Rebuttal Testimony, the Company adjusted the MYRP budget to include Commission-approved IT capital costs for Company electric vehicle programs inadvertently excluded in the Company's Initial Filing.[135]

122. The Department reviewed and agreed with the Company's proposed adjustment.[136]

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[131] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[132] Ex. Xcel-19 at 8 and Schedules 3A-3B (Halama Rebuttal).
[133] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[134] Ex. Xcel-18 at 6 and Schedule 13 (Halama Supplemental Direct); Ex. Xcel-19 at 9 and Schedules 3A-3B (Halama Rebuttal); Ex. Xcel-27 at 1-3 (Robinson Rebuttal).
[135] Ex. Xcel-19 at 11-12 and Schedules 3A-3B (Halama Rebuttal).
[136] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

123. The Company's adjustment for electric vehicles programs is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

9. Generation Capacity Revenues

124. Utilities can earn capacity revenues by selling excess generation capacity not needed to serve their own load to other utilities through bilateral contracts or through the Midcontinent Independent System Operator (MISO) capacity auction, also known as the Planning Resource Auction (PRA).[137]

125. The Company's Initial Filing included baseline capacity revenues based on historic revenues.[138] These included capacity revenues obtained from bilateral contracts for 2025 but did not include any capacity revenues from bilateral contracts for 2026.[139] The Company also included capacity revenues obtained from the MISO PRA for 2025 but did not include any amount for 2026.[140]

126. After Xcel's Initial Filing, it obtained additional revenues from bilateral contracts for both 2025 and 2026. The Department recommended Xcel's capacity revenue be updated to reflect these contracts.[141]

127. Xcel also obtained additional revenues from the PRA after its initial filing from the 2025-2026 PRA. Because the 2025–2026 PRA only ran through May 31, 2026, it was reasonable to expect that Xcel would get additional PRA revenue for June 1 through December 31 of that year. The Department recommended using the 2025 PRA capacity revenue figure to estimate the total for the 2026 plan year because recent actual figures provide a reasonable estimate of future expenses, and because this amount is subject to a true-up in Xcel's annual capacity tracker filings.[142]

128. The Company and the Department agreed it is reasonable to update the capacity revenue baseline amounts included in 2025 and 2026 based on the MISO PRA results.[143]

129. It is reasonable and appropriate to update the baseline capacity revenues, subject to true-up in the Company's annual capacity tracker filings, as agreed to by the Company and the Department.

10. Hosting Capacity

130. In its Initial Filing, the Company included $15.2 million for capital additions for hosting capacity beginning in 2026, while also indicating that it would incorporate any

[137] Ex. DOC-5 at 9 (Golden Direct).
[138] Ex. Xcel-17 at 19, 44-45 (Halama Direct).
[139] Ex. DOC-5 at 10, Schedule 3 (Golden Direct).
[140] Ex. DOC-5 at 10, Schedule 3 (Golden Direct).
[141] Ex. DOC-5 at 10 (Golden Direct).
[142] Ex. DOC-5 at 10–14, Schedule 3 (Golden Direct).
[143] Ex. Xcel-19 at 12-13 and Schedules 3A-3B (Halama Rebuttal); Ex DOC-6 at 4-5 (Golden Surrebuttal).

impacts based on stakeholder processes and subsequent Commission decisions in Docket No. E002/CI-24-318.[144]

131. The Joint Intervenors opposed Xcel's proposals related to hosting capacity investments and recommended that the Commission reject these investments pending additional justification, citing the lack of specifically identified project-level needs, locations, timing, and cost allocation.[145]

132. In Rebuttal Testimony, the Company stated that it no longer expected to have specific hosting capacity projects identified for implementation in 2026 and proposed removing the hosting capacity dollars from rate base, thereby removing $15.2 million to the distribution capital budget.[146]

133. The Department agreed with the Company's proposed removal of hosting capacity capital additions.[147]

134. The Company's removal of capital additions in 2026 for hosting capacity projects is reasonable and should be approved by the Commission.

11. Luverne Battery Reallocation

135. In the Company's last rate case, Docket No. E002/GR-21-630, the Commission approved a reserve reallocation of no more than $2.14 million of a reasonable cost to dismantle, dispose of, and fully restore the site associated with the Luverne Wind2Battery system. Further, the Commission required the Company perform a proposed "inverse reallocation" if actual costs are lower than $2.14 million to return unused amounts back to the groups they came from in a future proceeding. The final removal project costs were not known in time to be included in the cost of service in this case. Therefore, in its Initial Filing, the Company estimated the final removal costs to be just over $1.2 million and performed an "inverse reallocation" for the difference between the authorized $2.14 million and the estimated removal costs of $1.2 million. The Company also noted it would provide an update in rebuttal of any difference between the estimated and actual removal costs.[148]

136. In Rebuttal Testimony, the Company identified that actual removal costs were approximately $0.05 million more than estimated and proposed an adjustment to decrease the reallocation portion, thereby increasing the rebuttal revenue requirement.[149]

137. The Department reviewed and agreed with the Company's proposed adjustment.[150]

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[144] Ex. Xcel-34 at 89, 96-97 (Mensen Direct).
[145] Ex. JIN-1 at 23-30, 46 (Kenworthy Direct).
[146] Ex. Xcel-35 at 26 (Mensen Rebuttal); Ex. Xcel-19 at 13 and Schedules 3A-3B (Halama Rebuttal).
[147] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[148] Ex. Xcel-68 at 44-45 (Johnson Direct).
[149] Ex. Xcel-86 at 8-9 (Moeller Rebuttal); Ex. Xcel-19 at 15-16 and Schedules 3A-3B (Halama Rebuttal).
[150] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

138. The Company's adjustment for the Luverne Battery reallocation is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

12. Nuclear Production Tax Credit

139. Based on the uncertainty of the actual nuclear production tax credit (PTC) value the Company would receive and potential guidance from the IRS, the Company did not include any nuclear PTCs in the MYRP Forecast cost of service, but indicated that it would update the cost of service as it gained greater certainty.[151]

140. The Company provided an updated forecast for nuclear PTCs on May 1, 2025 and the Department recommended setting the baseline for nuclear PTCs on the basis of that updated forecast.[152]

141. The Company proposed a rebuttal adjustment to update the baseline nuclear PTC forecast for 2026 and the Department reviewed and agreed with the Company's proposed adjustment.[153]

142. The agreement between the Company and the Department to adjust the nuclear PTC baseline, subject to true-up in the fuel clause, is reasonable and should be approved by the Commission.

13. Solar Production Tax Credits - Allocation

143. After finalizing the cost of service for its Initial Filing, and as the Company was completing validation of the allocation of tax credits among jurisdictions, the Company identified that solar PTCs had been allocated using the Minnesota jurisdictional demand allocator, rather than allocating them consistent with the Renewable Energy Standard (RES) Rider, i.e., based on the Minnesota jurisdictional energy allocator due to their variable nature.[154]

144. The Company proposed a rebuttal adjustment to correct this allocation.[155]

145. The Department reviewed and agreed with the Company's proposed adjustment.[156]

146. The Company's adjustment for the solar PTCs is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

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[151] Ex. Xcel-17 at 57 (Halama Direct).
[152] Ex. Xcel-19 at 16-17 (Halama Rebuttal) Ex. DOC-7 at 6-8 (Uphus Direct).
[153] Ex. Xcel-19 at 16-17 and Schedules 3A-3B (Halama Rebuttal); Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[154] Ex. Xcel-17 at 57 (Halama Direct); Ex. Xcel-19 at 17 (Halama Rebuttal).
[155] Ex. Xcel-19 at 17 and Schedules 3A-3B (Halama Rebuttal).
[156] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

14. Federal Production Tax Credits

147. In its Initial Filing, the Company requested PTC treatment consistent with the previously approved process. Specifically, the Company proposed setting a new baseline PTC amount in base rates for each year of the MYRP, 2025 and 2026. The difference between actual and baseline PTCs would be recorded in the RES Tracker account, and the difference would be either refunded to or recovered from customers through the RES Rider, pursuant to Commission review and approval in future RES Rider filings.[157]

148. The Department recommended using the Company's updated PTC forecast, developed after the Initial Filing.[158]

149. The Company agreed to use the updated forecast and adjusted the baseline PTCs accordingly, and also incorporated the solar PTC allocation adjustment discussed above.[159]

150. The Company's adjustment for to the baseline for Federal PTCs, subject to true-up in the RES Rider, is reasonable and should be approved by the Commission.

15. Remaining Lives and Net Salvage Rates - Production

151. The Company filed its 2024 Annual Remaining Lives (ARL) filing on September 9, 2024 in Docket No. E,G002/D-23-356 utilizing a preliminary dismantling study. The Company filed its final 2024 Dismantling Study on January 31, 2025, after the Initial Filing in this case, and updated the ARL filing at that time to reflect the updated removal costs and associated net salvage rates. The Company also noted that it would include any changes to depreciation expenses associated with the final 2024 Dismantling Study in Rebuttal Testimony.[160]

152. The 2024 ARL filing also requested to extend the depreciation lives of the Hennepin Island and Upper Dam Hydro facilities, and these extended lives were reflected in the depreciation rates included in the Company's Initial Filing.[161]

153. The Department recommended no life extension for these hydro facilities in the ARL docket, and the Company did not object to this recommendation.[162]

154. The Company proposed a rebuttal adjustment that removed the impact of extending the depreciation lives of the two hydro facilities and also updated depreciation expense to reflect the results of the Company's 2024 Dismantling Study.[163]

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[157] Ex. Xcel-17 at 103-104 (Halama Direct).
[158] Ex. DOC-7 at 5-8 (Uphus Direct).
[159] Ex. Xcel-19 at 18-19 and Schedules 3A-3B (Halama Rebuttal).
[160] Ex. Xcel-68 at 33 (Johnson Direct); Ex. Xcel-19 at 20-21 (Halama Rebuttal).
[161] Ex. Xcel-19 at 20-21 (Halama Rebuttal).
[162] Ex. Xcel-86 at 7-8 (Moeller Rebuttal); Ex. Xcel-19 at 20-21 and Schedules 3A and 3B (Halama Rebuttal).
[163] Ex. Xcel-19 at 20-21 and Schedules 3A and 3B (Halama Rebuttal).

155. The Company's adjustment for Remaining Lives and Net Salvage Rates - Production, consistent with the Department's recommendation, is reasonable and should be approved by the Commission.

16. Remaining Lives - Nuclear

156. After the Initial Filing in this matter, the Commission issued its Order in the Company's 2024-2040 Integrated Resource Plan (IRP) docket, Docket No. E002/RP-24-67, approving the extension of the operating lives for both the Monticello and Prairie Island nuclear plants.[164]

157. The Department recommended reducing the Company's cost of service by $69.7 million for 2025 and $68.9 million for 2026 to reflect these life extensions and the Company agreed to this adjustment.[165]

158. The adjustment to the Company's cost of service to reflect updated depreciation lives of the Monticello and Prairie Island nuclear plants to match the operating lives of these plants, as approved in the Company's 2024-2040 IRP, is reasonable and should be approved by the Commission.

17. TCR Rider Removal FERC Reclassification

159. The Company proposed a rebuttal adjustment to correct for a misclassification in FERC accounts related to Advanced Metering Infrastructure (AMI) meters that it discovered in researching a discovery request from the OAG. This change had no impact on the rebuttal cost of service but moved costs between two FERC accounts.[166]

160. The Department reviewed and agreed with the Company's proposed adjustment.[167]

161. The Company's adjustment for AMI meters is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

18. TCR Rider Removal Update

162. The Rebuttal Testimony, the Company adjusted the Transmission Cost Recovery (TCR) Rider to fully remove all AMI capital costs recovered in the TCR Rider revenue and to remove the equivalent rider revenues included in the MYRP cost of service.[168]

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[164] Ex. DOC-23 at 14 (Jones Direct).
[165] DOC-23 at 13-16 (Jones Direct); Ex. DOC-24 at 5-6 (Jones Surrebuttal); Ex. Xcel-19 at 22 and Schedules 3A and 3B (Halama Rebuttal); Ex. Xcel-86 at 3-4 (Moeller Rebuttal).
[166] Ex. Xcel-19 at 23 and Schedules 3A-3B (Halama Rebuttal).
[167] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[168] Ex. Xcel-19 at 23-24 and Schedules 3A-3B (Halama Rebuttal).

163. The Department reviewed and agreed with the Company's proposed adjustment.[169]

164. The Company's adjustment for the TCR Rider Removal is reasonable and should be approved by the Commission, as agreed to by the Company and Department.

19. Service Quality

165. In Rebuttal Testimony, the Company proposed an adjustment to incorporate costs in the 2025-2026 MYRP to comply with Commission's Order in Docket No. E002/M-24-27 for Xcel to hire a third-party evaluator to evaluate Xcel's practices and policies related to capital investment planning, outage restoration practices, and shutoff practices to better understand the causes of discrepancies in shutoff rates and service reliability.[170]

166. The Department reviewed and agreed with the Company's proposed adjustment.[171]

167. The Company's adjustment to reflect the Commission's Order in Docket No. E002/M-24-27 is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

20. Sherco Inventory Write Off

168. Unit 1 of Xcel's Sherburne County Generating Station (Sherco) is scheduled to retire in 2026. As a result of the scheduled closure, the Company proposed to write off $5.9 million in obsolete inventory in 2026.[172]

169. The Department agreed that it was appropriate for Xcel to write off the obsolete inventory but disagreed that it was reasonable to write off the entire balance in 2026. Instead, the Department recommended that the Company be required amortize this balance over a three-year period beginning in 2026, similar to the Company's proposal to amortize rate case expenses.[173]

170. In response, the Company agreed with the concept of amortizing the write off but proposed to begin the amortization in 2025 instead of 2026.[174] Beginning the amortization in 2025 better aligns costs with the period the asset is available to provide service to customers.[175]

171. The Department, in turn, agreed with Xcel's proposal to begin the amortization in 2025 because it better aligned with the costs with Unit 1's remaining

[169] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[170] Ex. Xcel-19 at 26-27 and Schedules 3A-3B (Halama Rebuttal).
[171] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[172] Ex. Xcel-44 at 59 (Capra Direct); Ex. DOC-1 at 39 (Johnson Direct).
[173] Ex. DOC-1 at 39-40 (Johnson Direct).
[174] Ex. Xcel-19 at 27 (Halama Rebuttal).
[175] Ex. DOC-2, Schedule 3 (Johnson Surrebuttal).

operating life. This adjustment increases Xcel's generation operation and maintenance (O&M) expense by about $2 million in 2025 and reduces it by about $3.9 million in 2026.[176]

172. The agreed upon adjustment to amortize the Sherco Unit 1 inventory write-off amount of $8.1 million over three years and to revise the revenue requirement to reflect the three year amortization beginning in 2025 is reasonable, better aligns costs with service life, and should be approved by the Commission.

21. Wildfire Mitigation Program Expenses

173. Wildfire risks are increasing across the country. The severity and intensity of wildfires has been rising since the year 2000.[177] Xcel, as with other electric utilities, has facilities in areas that have high wildfire risk and equipment that could cause ignitions leading to wildfires.[178]

174. Xcel's wildfire risk in Minnesota is low compared to wildfire risks nationally and Minnesota as a whole.[179] For example, the wildfire expected annual loss (EAL) in Texas and Colorado, two other states where Xcel operates, are substantially higher than Minnesota's.[180]

175. Within Minnesota, Xcel's service territory is generally in the lower-risk portions of the state.[181]

176. The Company proposed a variety of programs and related expenditures in 2025 and 2026 to mitigate wildfire risk, with several of the programs being expected to continue beyond 2026.[182]

177. Minnesota's climate is warming, and experiencing more droughts and higher winds.[183] In recent years, the state has averaged approximately 217 Red Flag Warning events per year, indicating an ongoing or imminent critical fire weather pattern.[184] The State's wildfire risk is not evenly distributed, with the majority of fires originating in the northern and central regions of the state.[185] Unlike many western and southern states, where lightning or other natural causes are a primary cause of wildfires, the majority of Minnesota's wildfires are caused by human activity.[186]

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[176] Ex. DOC-2 at 13 (Johnson Surrebuttal).
[177] Ex. Xcel-47 at 3 (Sherwood Direct).
[178] Ex. Xcel-47 at 3 (Sherwood Direct).
[179] Ex. DOC-9 at 3 (Borden Direct).
[180] Ex. DOC-9 at 12, Figure 1 (Borden Direct).
[181] Ex. DOC-9 at 13, Figure 2 (Borden Direct).
[182] Ex. DOC-9 at 6 (Borden Direct), Ex. Xcel-34 (Mensen Direct) at 160-94, Ex. Xcel-47 (Sherwood Direct) at 23-39, Ex. Xcel-48 (Sherwood Supplemental Direct) at 2-9, Ex. Xcel-79 (Bloch Supplemental Direct) at 3-40.
[183] Ex. Xcel-47 at 11 (Sherwood Direct).
[184] Ex. Xcel-47 at 10–11 (Sherwood Direct).
[185] Ex. Xcel-47 at 12 (Sherwood Direct).
[186] Ex. Xcel-47 at 12 (Sherwood Direct).

178. The Company retained a third party, EDM International, Inc. (EDM), to develop a geospatial wildfire risk map specific to Xcel's territory, including service territory and assets such as transmission facilities.[187] EDM used raw datasets created by the United States Department of Agriculture Forest Service (USFS), available at wildfirerisk.org.[188]

179. The Company organized its wildfire mitigation activities into four categories: situational awareness, system resiliency, operational mitigations, and customer support. Xcel's wildfire mitigation plan includes multiple activities within each category.[189]

180. To support its proposed wildfire mitigation plan, Xcel initially budgeted for $175.3 million in capital spending and $76.8 million in O&M spending across 2025 and 2026.[190]

181. In Supplemental Direct Testimony, Xcel submitted updated budgets informed by its operationalized wildfire risk map. The updated budgets reflected higher capital spending, totaling $280.0 million across 2025 and 2026, and lower O&M spending, totaling $23.8 million across 2025 and 2026.[191]

182. The Company proposed approximately $140 million in spending on Enhanced Powerline Safety Settings (EPSS), the largest proposed expenditure in the company's wildfire mitigation plan. [192] EPSS is an operational mitigation targeted at reducing wildfire ignition risk.[193] When EPSS is activated, relays and reclosers are more sensitive to electrical faults and react faster to those faults compared to normal settings.[194] When EPSS is activated, it also disables reclosing in relays and reclosers that would normally automatically reclose after tripping because of a fault.[195] A fault creates a risk of wildfire ignition because it generally redirects power from its intended path and may cause an electric arc. Any object having power redirected into it or that is exposed to an arc will experience heating and may catch fire.[196]

183. The Company proposed spending approximately $80 million on the Overhead Pole Assessments (OPA) program.[197] OPA involves unmanned aerial drones to capture images of distribution structures and attachments.[198] The resulting images are then analyzed to identify and classify deficiencies that can impact public safety and/or reliability.[199] Xcel also plans to gather detailed informed regarding assets in the field, improving the Company's ability to operate and maintain the distribution system and

[187] Ex. Xcel-47 at 13, 16–17 (Sherwood Direct).
[188] Ex. Xcel-47 at 14 (Sherwood Direct).
[189] Ex. Xcel-47 at 26, Table 1 (Sherwood Direct).
[190] Ex. Xcel-47 at 27, Tables 2 and 3 (Sherwood Direct).
[191] Ex. Xcel-48 at 2–5, Tables 1 and 2 (Sherwood Supplemental Direct).
[192] Ex. DOC-9 at 9 (Borden Direct).
[193] Ex. Xcel-34 at 165 (Mensen Direct).
[194] Ex. Xcel-34 at 165 (Mensen Direct).
[195] Ex. Xcel-34 at 165 (Mensen Direct).
[196] Ex. Xcel-34 at 165-66 (Mensen Direct).
[197] Ex. DOC-9 at 9 (Borden Direct).
[198] Ex. Xcel-34 at 173 (Mensen Direct).
[199] Ex. Xcel-34 at 173 (Mensen Direct).

determine where to implement wildfire mitigations.[200] These assessments help identify defects on the distribution system that could result in an ignition if left unaddressed.[201]

184. The Company requested approximately $90 million in wildfire vegetation management (VM) costs for 2025 and 2026, of which it proposed to capitalize $84 million.[202] VM programs are generally designed to protect utility infrastructure from damage and to help reduce injury to the public, the risk of wildfires, and interruptions of electric service.[203] VM includes actions such as tree pruning, brush control/removal, and tree removal.[204] Xcel proposed a VM Wildfire Corridor program to manage vegetation to an "enhanced clearance standard" of ten feet rather than the six foot general clearance used in non-wildfire areas.[205]

185. After initially proposing to treat VM costs as O&M, the Company argued in Supplemental Direct Testimony that most VM expenditures should be capitalized due to the ability to plan for wildfires on a "feeder-level basis" to coordinate VM done to mitigate wildfire risk with line clearances done in preparation for capital work.[206]

186. The Company's wildfire mitigation proposal also included a number of smaller expenditures. Those plans include using artificial intelligence (AI) cameras to identify smoke plumes, installing additional weather stations across its service territory based on risk area and impact on population and assets, expanding in-house wildfire mitigation capabilities, subscriptions to advanced wildfire spread modeling software, and regularly updating the wildfire risk map developed for the Company.[207]

187. The Company's proposal did not include an analysis of the cost-effectiveness of its $300 million wildfire mitigation proposal.[208]

188. The Department developed a cost-effectiveness analysis that relied on four primary inputs: expected annual damages from wildfires; annual escalation of risk due to climate change impacts; the percentage of wildfire ignitions attributed to utility power lines; and the effectiveness of the proposed actions in reducing wildfire risk. [209] The Department concluded that implementing Xcel's wildfire mitigation plan as proposed would result in $27.7 million in risk reduction benefits, at a ratepayer cost of $790.7 million.[210]

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[200] Ex. Xcel-34 at 173–74 (Mensen Direct).
[201] Ex. Xcel-34 at 174 (Mensen Direct).
[202] Ex. DOC-9 at 38 (Borden Direct).
[203] Ex. Xcel-34 at 183 (Mensen Direct).
[204] Ex. Xcel-34 at 183 (Mensen Direct).
[205] Ex. Xcel-34 at 184 (Mensen Direct).
[206] Ex. Xcel-79 at 5 (Bloch Supplemental Direct).
[207] Ex. Xcel-47 at 32–39 (Sherwood Direct).
[208] Ex. DOC-9 at 20 (Borden Direct).
[209] Ex. DOC-9 at 22–26 (Borden Direct); Ex. DOC-10 at 23-24 (Borden Surrebuttal).
[210] Ex. DOC-10 at 24 (Borden Surrebuttal).

189. Ultimately, the Department did not oppose several of the Company's smaller-scale and foundational proposed expenditures including situational awareness (e.g., cameras), weather stations, and risk modeling tools and software.[211]

190. The Department proposed, based on its concerns about the level of support and cost-effectiveness of Xcel's proposal, the following wildfire mitigation measures for 2025 and 2026:

- The EPSS and OPA programs be implemented only in Tier 3[212] of Xcel's service territory.
- The Wildfire Corridor program be implemented on half of Tier 3 miles to test the program for efficacy, and should be implemented over two years.
- The line rebuild program and associated pole replacements should be scaled back to 50 percent of Xcel's proposal to better inform key assumptions and collect data on the cost-effectiveness of this program.
- Vegetation management should be treated as O&M expenditures.[213]

The Department believed that this proposal would address the top 30 to 50 percent of Xcel's risk at significantly lower cost than Xcel's proposals, and would allow Xcel to collect critical data that can refine future wildfire mitigation proposals.[214] The Department also argued that Xcel's proposed capitalization of VM was inconsistent with FERC guidance and inappropriate.[215]

191. Implementing the Department's recommendations would reduce capital additions by $45.99 million in 2025 and $164.35 million in 2026, and increase O&M expense by $9.19 million in both 2025 and 2026.[216] Together, this would result in a $6.3 million increase in the 2025 test year revenue requirement and a $8.3 million decrease in the 2026 plan year revenue requirement compared to Xcel's rebuttal testimony position.[217]

192. The Joint Intervenors recommended that the Commission defer approval of any wildfire mitigation costs until Xcel completes its Minnesota-specific wildfire risk assessment, compares wildfire risk to other system risks, and integrates findings into its 2025 Integrated Distribution Plan (IDP).[218]

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[211] Ex. DOC-9 at 3 (Borden Direct).
[212] Tier 3 refers to the geographic tier with the highest level of wildfire risk from Xcel's operationalized wildfire risk map. Ex. Xcel-47 at 21 (Sherwood Direct).
[213] Ex. DOC-10 at 29 (Borden Surrebuttal).
[214] Ex. DOC-9 at 4–65(Borden Direct).
[215] Ex. DOC-9 at 38–42 (Borden Direct).
[216] Ex. DOC-10 at 30 (Borden Surrebuttal).
[217] Ex. DOC-2, Schedule 1 at 1 (Johnson Surrebuttal).
[218] Ex. JIN-1 at 16-23 (Kenworthy Direct); *see also* Ex. JIN-4 at 18-22 (Kenworthy Surrebuttal).

193. Prior to the evidentiary hearing, the Company agreed to the Department's proposal for this proceeding, and further indicated an interest in developing additional mitigation practices as its understanding of wildfire risk increases with enhanced risk modelling currently under development.[219] The Joint Intervenors supported this resolution.[220]

194. The Department's proposal, agreed to by the Company, is reasonable. The Commission should implement the Department's proposed reduction to the 2025 Test Year and 2026 Plan Year revenue, and approve cost recovery of the smaller-scale and foundational programs consistent with the Department's recommendation.

22. Wildfire Mitigation Pole Loading Clearance Update

195. In its Direct and Supplemental Direct Testimony, the Company proposed certain capital additions and expenses related to its wildfire mitigation efforts and, in its Supplemental Direct testimony updated the budget for its Pole Loading Clearance (PLC) program.[221]

196. The Company identified a discrepancy between the PLC program amounts presented in the testimony of Company Witnesses Sherwood and Bloch and that incorporated in the Supplemental Direct Testimony revenue requirements, presented by Company Witness Halama.[222]

197. In Rebuttal Testimony, the Company proposed an adjustment to reconcile the cost of service calculations of Witness Halama to the amounts presented by Witnesses Sherwood and Bloch.[223]

198. The Department reviewed and agreed with the Company's proposed adjustment.[224]

199. The Company's adjustment to reflect the PLC program update is reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

23. Research and Experimental Federal and State Tax Credits

200. The Company's Initial Filing included federal research and experimentation (R&E) tax credits in the amount of $4.5 million (Minnesota Electric jurisdiction) in the 2025 test year and the 2026 plan year. The Company also included Minnesota R&E tax credits in the amount of $1.1 million (Minnesota Electric jurisdiction) in the 2025 Test Year and

[219] Ex. Xcel-95 (Xcel Correspondence Regarding Wildfire Issue).
[220] Joint Intervenors Initial Brief at 39-40.
[221] Ex. Xcel-48 at 2-4 (Sherwood Supplemental Direct); Ex. Xcel-79 at 24-27 (Bloch Direct); Ex. Xcel-18 at 5 (Halama Supplemental Direct).
[222] Ex. Xcel-48 at 4 (Sherwood Supplemental Direct); Ex. Xcel-18 at 5 (Halama Supplemental Direct); Ex. Xcel-19 at 29 and Schedules 3A and 3B (Halama Rebuttal).
[223] Ex. Xcel-19 at 29 and Schedules 3A and 3B (Halama Rebuttal).
[224] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

2026 Plan Year. The Company calculated the R&E credit amounts using an adjusted average of the qualified research expenses (QRE) for tax years 2020 through 2022.[225]

201. The Department initially proposed an adjustment to these tax credit amounts based on using tax years 2022 through 2024.[226] However, after reviewing additional information provided by the Company in its Rebuttal Testimony, the Department concluded that the Company's Initial Filing calculations were reasonable.[227]

202. The Company's test year and plan year amounts for R&E tax credits are reasonable and should be approved by the Commission.

24. North Dakota Investment Tax Credits

203. The Company included a proportional share of its North Dakota investment tax credits (ITC) in its test year and plan year, consistent with the Commission's order in the Company's last rate case.[228]

204. The Department originally proposed an adjustment to these tax credit amounts.[229] However, upon review of further information provided by the Company in Rebuttal Testimony, the Department agreed no adjustment was necessary.[230]

205. The North Dakota Tax Credits reflected in the Company's Initial Filing for 2025 and 2026 are reasonable and should be approved by the Commission.

25. Distribution Communications Infrastructure

206. The Company initially proposed to reduce reliance on third-party wide area network (WAN) services by extending Company-owned fiber to distribution. The Company stated that telecom carriers are phasing out legacy analog WAN and replacing it with Ethernet or broadband services that, while high-bandwidth, do not meet the Company's acceptable performance requirements. The Company budgeted $9.6 million in 2025 and $10.6 million in 2026 for the "Fiber Buildout Program and Projects," and in some locations would connect Company fiber to a leased fiber segment used solely by the Company.[231]

207. The Joint Intervenors initially opposed cost recovery for these investments arguing that there was an absence of quantitative WAN performance targets (e.g., latency, jitter, determinism, failover/availability) against which third-party options could be tested. The Joint Intervenors asserted that, without those specifications, the Commission could not evaluate whether alternatives—such as leased dark fiber, carrier Ethernet with strict service-level agreements (SLA), licensed microwave, or private long-term evolution

[225] Ex. Xcel-17 at 57 (Halama Direct); Ex. Xcel-19 at 41-42 and Schedule 4 (Halama Rebuttal).
[226] Ex. DOC-7 at 11-14 (Uphus Direct).
[227] Ex. DOC-8 at 5-6 (Uphus Surrebuttal).
[228] Ex. Xcel-17 at 128 (Halama Direct).
[229] Ex. DOC-7 at 8-9 (Uphus Direct).
[230] Ex. Xcel-19 at 41-42 and Schedule 4 (Halama Rebuttal); Ex. DOC-8 at 4 (Uphus Surrebuttal).
[231] Ex. Xcel-34 at 102-03 (Mensen Direct).

(LTE)/commercial cellular—could meet needs at lower lifecycle cost or faster deployment.[232]

208. The Company provided additional explanation in Rebuttal Testimony. Teleprotection is a system that uses communication channels to transmit protection signals between different locations in the electric system, typically between substations. These signals are used to coordinate the operation of protective relays, which detect faults and initiate tripping of circuit breakers to isolate faults from the electric system. This function requires a consistent, reliable, and secure communications channel, which the fiber buildout projects provide.[233]

209. Based on the additional information provided by the Company, the Joint Intervenors dropped their opposition to these investments in Surrebuttal testimony.[234]

210. The fiber buildout projects proposed in the MYRP are reasonable and the Commission should allow Xcel to recover these investments in rates.

26. Bad Debt Expense Adjustment

211. Bad debt expense is an estimate for uncollectible billed revenue for sales, services, etc. Because bad debt is typically tied to revenue, its relationship, or measure, is often expressed as a percentage of revenue. Bad debt reduces a company's financial net income. Generally accepted accounting principles (GAAP) require that an estimate be made of the current amount of revenue that will ultimately become uncollectible, to match the expenses with the corresponding revenue earned during that period. The estimated amount of bad debt expense is an accounting entry that debits (increases) bad debt expense on the income statement and credits (increases) the bad debt reserve account on the balance sheet. When an individual account is written off, it is charged against the bad debt reserve. The reserve is debited (reduced) and the receivable account is credited (reduced). The bad debt reserve should represent the amount of existing customer receivables that will ultimately not be collected.[235]

212. The Company's Initial Filing included $19.2 million of commodity bad debt expense and $109,000 for non-commodity bad debt expense in the 2025 Test Year, or 0.50 percent of projected test-year revenues. Xcel included $21.4 million of commodity bad debt expense and $109,000 for non-commodity bad debt expense in the 2026 Plan Year, or 0.53 percent of projected test-year revenues. These ratios are higher than the three-year average for the most recent years of 2022 to 2024 of 0.4 percent.[236]

[232] Ex. JIN-1 at 26-30 (Kenworthy Direct).
[233] Ex. Xcel-35 at 27-33 (Mensen Rebuttal).
[234] Ex. JIN-4 at 17-18 (Kenworthy Surrebuttal).
[235] Ex. DOC-23 at 18 (Jones Direct).
[236] Ex. Xcel-17 at 74 (Halama Direct); Ex. Xcel-38 at 35-46 (Lindgren Direct); Ex. DOC-23 at 19 (Jones Direct).

213. The Department, based on a three-year historical average, recommended the use of a bad debt factor of 0.45 percent to determine the 2025 Test Year bad debt expense amount and 0.50 percent for the 2026 Plan Year.[237]

214. Considering 2020 through the first six months of 2025, 2022 represents an outlier which skews the 2020 through 2025 averages. Actual data for 2024 and the August 2025 forecast support the reasonableness of the 2025 forecasted percentage.[238]

215. After reviewing information presented in Rebuttal testimony, the Department concluded that the Company's original proposal was reasonable.[239]

216. The Company's forecasted bad debt ratios for 2025 and 2026 of 0.50 percent and 0.53 percent are reasonable and should be approved by the Commission, as agreed to by the Company and the Department.

27. Discrete Capacity Project Investments

217. Xcel proposed an increase in Discrete Capacity Project spending from $81.1 million in 2025 to $150.5 million in 2026.[240] The Company explained that, of the 12 large projects in the MYRP timeframe, nine had capital additions that would be placed in service in 2026.[241]

218. The Joint Intervenors initially opposed this spending, arguing that additional analysis of the cost-effectiveness of the projects was required to justify the increase in 2026 spending.[242]

219. In Rebuttal Testimony, Xcel further described its process for developing Discrete Capacity Projects and its review of alternatives, including through the Company's IDP processes.[243]

220. In their Initial Brief, the Joint Intervenors indicated that they no longer opposed the Company's proposal.[244]

221. After reviewing information presented in Rebuttal Testimony, the Department concluded that the Company's original proposal was reasonable.[245]

222. The record supports Commission approval of rate recovery for the Company's discrete capacity projects.

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[237] Ex. DOC-23 at 20 (Jones Direct).
[238] Ex. Xcel-81 at 4 (Howard Rebuttal).
[239] Ex. DOC-24 at 89 and Schedule 2 (Jones Surrebuttal).
[240] Ex. Xcel-34 at 89 (Mensen Direct).
[241] Ex. Xcel-34 at 89-90 (Mensen Direct).
[242] Ex. JIN-1 at 24 (Kenworthy Direct).
[243] Ex. Xcel-35 at 19-25 (Mensen Rebuttal).
[244] Joint Intervenors Initial Brief at 45-46.
[245] Ex. DOC-24 at 89 and Schedule 2 (Jones Surrebuttal).

28. Fault Location and Isolation Service Restoration (FLISR)

223. The Company proposed investment in FLISR in 2025 and 2026 consistent with the Company's FLISR implementation plan approved in the Company's last electric rate case (Docket No. E002/GR-21-630).[246] In addition, the Company provided information to comply with filing requirements ordered in the last electric rate case, specifically, information on a FLISR performance incentive mechanism (PIM).[247] The Company provided the required information and stated its preference that a FLISR PIM not be implemented until after full FLISR deployment and three years of data are available, which would result in implementation of a potential FLISR PIM effective January 1, 2032.[248]

224. Based on the Company's Direct Testimony, the Department concluded that the Company complied with the FLISR filing requirements related to a FLISR PIM,[249] and agreed with the Company's position that the Commission not approve a FLISR PIM at this time and continue to review the FLISR PIM in the performance based ratemaking (PBR) proceeding (Docket No. E002/CI-17-401).[250] The Department also recommended that the Company continue to evaluate the FLISR PIM as part of future rate cases when FLISR is fully deployed.[251]

225. In Rebuttal Testimony, consistent with the Department's recommendation, the Company stated it will continue to evaluate the FLISR PIM as part of future rate cases when FLISR is fully deployed.[252]

226. The Commission should find that the Company complied with the filing requirements related to a FLISR PIM and approve the Company's proposed FLISR investments in 2025 and 2026. Further, the record supports that it would be premature to approve a FLISR PIM at this time, and that a FLISR PIM should not be implemented until after full FLISR deployment and three years of data are available, which would result in implementation of a potential FLISR PIM effective January 1, 2032. The Commission can evaluate a future FLISR PIM in Docket No. E002/CI-17-401 and as part of future rate cases when FLISR is fully deployed.

B. Revenue Related Issues

1. Sales Forecast

227. Test-year sales volumes impact a utility's likely revenue deficiency because sales levels affect both revenues and expenses.[253]

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[246] Ex. Xcel-34 at 109 (Mensen Direct).
[247] Ex. Xcel-34, Schedule 4 (Mensen Direct).
[248] Ex. Xcel-34 at 118 and Schedule 4 (Mensen Direct).
[249] Ex. DOC-7 at 23 (Uphus Direct).
[250] Ex. DOC-7 at 24 (Uphus Direct).
[251] Ex. DOC-7 at 24 (Uphus Direct).
[252] Ex. Xcel-35 at 42 (Mensen Rebuttal); Ex. DOC-8 at 7-8 (Uphus Surrebuttal).
[253] Ex. DOC-14 at 2 (Shah Direct).

228. Sales volume forecasts also impact the class cost of service study (CCOSS) and rate design. In designing rates, test-year sales volumes are used to allocate costs in the CCOSS, which is then used as guide to establish the revenue apportionment and other aspects of rate design. Moreover, when establishing final rates, the test-year sales volumes are used to determine the overall revenue requirements, as well as the individual tariff rates.[254]

229. In its Initial Filing, Xcel originally forecasted total retail electric sales of 28,309,961 MWh in 2025 – about 1.4 percent lower than 2023 actual sales, followed by a 3.8 percent increase in 2026 to 29,397,905 MWh.[255] Xcel attributed this forecasted growth to new large data center loads and increased electric vehicle (EV) adoption.[256]

230. The Department questioned Xcel's use of post-regression adjustments for Demand Side Management (DSM), EV adoption, and Beneficial Electrification (BE).[257] The Department argued that these adjustments introduce additional layers of estimation and uncertainty into the forecast.[258] The Department also raised concerns regarding the statistical validity of Xcel's customer count models.[259]

231. In Rebuttal Testimony, Xcel updated its 2026 sales forecast using actual sales data through May 2025 and the latest IHS Markit economic outlook.[260] The revised projection for 2026 total retail electric sales decreased by 1.4 percent compared to the forecast presented in Direct Testimony.[261]

232. The Department supported Xcel's proposal to update its 2025 test-year forecast using actual data without any DSM, EV, solar, or BE adjustments.[262] The Department further acknowledged that its concerns with the reliability of Xcel's 2026 forecast would be similarly resolved by continuation of the company's sales true-up mechanism which would ensure that 2026 rates reflect actual 2026 sales data.[263]

233. It is just and reasonable to set 2025 final rates using 2025 actual sales, as proposed by the Company, and the Commission should do so.

2. 2025 Late Fee Revenue

234. In Supplemental Direct Testimony, the Company proposed removing late payment revenue from its cost of service for both the 2025 test year and the 2026 plan year, to fund the Residential Arrears Management Program (RAMP). This increased the

[254] Ex. DOC-14 at 2 (Shah Direct).
[255] Ex. Xcel-29 at 6 (Levine Direct).
[256] Ex. Xcel-29 at 5 (Levine Direct).
[257] Ex. DOC-14 at 10, 17-18 (Shah Direct).
[258] Ex. DOC-14 at 13, 17-18 (Shah Direct).
[259] Ex. DOC-14 at 18-19 (Shah Direct).
[260] Ex. Xcel-30 at 3 (Levine Rebuttal).
[261] Ex. Xcel-30 at 3-4 (Levine Rebuttal).
[262] Ex. DOC-15 at 7 (Shah Surrebuttal).
[263] Ex. DOC-15 at 7 (Shah Surrebuttal).

Company's revenue requirement by $6.1 million and $5.8 million in 2025 and 2026, respectively.[264]

235. The Department filed Direct Testimony opposing removal of 2025 late fees and one-half of the 2026 late fees from the cost of service, reasoning that RAMP would not be approved in 2025 and will likely not be approved until well into 2026.[265]

236. In Rebuttal Testimony, the Company agreed to include all 2025 late fee revenues in its cost of service, reducing the Company's Supplemental Direct Testimony revenue requirement for 2025 by $6.1 million.[266]

237. It is reasonable, and the Commission should require Xcel, to include $6.1 million in late fee revenues in the Company's cost of service for 2025, as agreed to by the Company and the Department.

3. Capacity Revenue Balance and True-Up

238. In its Initial Filing, the Company included budgeted amounts for MISO capacity auction revenues and bilateral capacity contracts as a baseline for capacity revenues in the MYRP, together with a capacity revenue tracker so that these revenues can be trued-up to actuals, crediting all revenues to customers.[267]

239. By the time of Intervenor Direct Testimony, the MISO PRA had occurred and additional bilateral contracts were available. The Department therefore recommended updating the baseline for capacity revenues reflecting these changes.[268]

240. The Company agreed with the Department's updated capacity revenue numbers in its Rebuttal Testimony, and lowered its proposed revenue requirement accordingly.[269]

241. The Commission should approve the Company's updated capacity revenue amounts for 2025 and 2026 to set rates, subject to true-up in the Company's annual capacity tracker filings, as agreed to by the Company and the Department.

4. Prairie Island Capacity Revenues

242. Following the Company's Initial Filing, the Commission determined the Company acted imprudently in causing an outage at the Prairie Island Nuclear Generating Plant (PINGP) and the Commission asked parties to discuss whether that outage should

[264] Ex. Xcel-18 at 7-8 and Schedules 11-12 (Halama Supplemental Direct).
[265] Ex. DOC-19 at 66-68 (Bahn Direct).
[266] Ex. Xcel-19 at 14-15 (Halama Rebuttal). The parties continue to dispute the rate treatment of late payment fees for 2026.
[267] Ex. Xcel-17 at 19, 78 and Schedules 11-12 (Halama Direct).
[268] Ex. DOC-5 at 9-14 and Schedule 3 (Golden Direct).
[269] Ex. Xcel-19 at 12-13 (Halama Rebuttal).

be reflected in this case, such as incorporating the impact of any derating by MISO on the Company's capacity revenues.[270]

243. The Company provided Rebuttal Testimony, estimating lost capacity revenues for 2025 of approximately $171,000 due to this outage.[271]

244. The Department recommended an adjustment increasing revenues in both 2025 and 2026 by $171,000 to reflect these lost revenues,[272] and the Company agreed to this adjustment.[273]

245. The Commission should adjust the Company's cost of service for both 2025 and 2026 to include $171,000 in lost revenues due to the PINGP outage.

C. Cost of Capital

246. 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 parties resolved all issues related to the cost of capital except for the authorized return on equity (ROE).

1. Capital Structure

247. As part of determining the overall rate of return, the Commission must approve a capital structure for Xcel. A capital structure refers to the combination of short-term debt, long-term debt, and equity that a utility uses to finance its operations. Each financing option offers a different set of trade-offs. Short-term debt is the least risky for investors, and thus has the lowest required rate of return. Equity is the riskiest and has the highest required rate of return. Long-term debt falls between.[274]

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[270] *In the Matter of Xcel Energy's Petition for Approval of its 2023 Annual Fuel Forecast and Monthly Fuel Cost Charges,* MPUC Docket No. E002/AA-22-179, ORDER DENYING PETITION FOR RECONSIDERATION AND GRANTING REQUEST FOR CLARIFICATION at 4 (Jan. 31, 2025) (eDocket No. 20251-214793-01).
[271] Ex. Xcel-82 at 4-13 and Schedules 1-5 (Detmer Rebuttal).
[272] Ex. DOC-2 at 23-25 (Johnson Surrebuttal).
[273] Xcel Issues Matrix (Jan. 23, 2026) (eDocket No. 20261-227337-01).
[274] Ex. DOC-12 at 9 (Addonizio Direct).

248. The Company proposed the following capital structures for the 2025 test year and the 2026 plan year:[275]

2025 Capital Structure

	Ratio
Short-term debt	0.79%
Long-term Debt	46.71%
Common Equity	52.50%

2026 Capital Structure

	Ratio
Short-term debt	1.00%
Long-term Debt	46.50%
Common Equity	52.50%

249. The Department raised concerns with Xcel's proposed equity ratio but did not recommend an alternative capital structure, noting that the Company has had a relatively constant capital structure and that the Commission has approved a 52.5 percent equity ratio in every Xcel rate case since 2008.[276]

250. The Company's proposed capital structure is reasonable and should be approved by the Commission for ratemaking purposes in this proceeding.

2. Cost of Long-Term Debt

251. The Company proposed costs of long-term debt for 2025 and 2026 of 4.51 and 4.53 percent, calculated based on all expected interest and related amortization expenses.[277]

252. The Department reviewed the Company's and others' debt issuances and concluded the Company's proposed costs of long-term debt were reasonable.[278]

[275] Ex. Xcel-20 at 4 (Wehner Direct).
[276] Ex. DOC-12 at 31–32 (Addonizio Direct). Witness Addonizio further recommended that Xcel's equity ratio be considered when setting the Company's authorized ROE. Ex. DOC-12 at 32 (Addonizio Direct).
[277] Ex. Xcel-20 at 30-31 and Schedules 4-5 (Wehner Direct).
[278] Ex. DOC-12 at 33-38 (Addonizio Direct).

253. The Company's proposed costs of long-term debt for 2025 and 2026 are reasonable and should be approved by the Commission for ratemaking purposes in this proceeding.

3. Cost of Short-Term Debt

254. The Company proposed costs of short-term debt for 2025 and 2026 of 5.31 and 3.38 percent, respectively, based on forecasts of short-term interest rates from S&P Global and other considerations.[279]

255. The Department reviewed the Company's proposed costs for short-term debt and concluded they were reasonable.[280]

256. The Company's proposed costs of short-term debt for 2025 and 2026 are reasonable and should be approved by the Commission for ratemaking purposes in this proceeding.

D. Revenue Apportionment and Rate Design

1. Conservation Cost Recovery Charge

257. The Company recovers costs related to its conservation programming through the Conservation Cost Recovery Charge (CCRC), which is bundled into base rates. The CCRC is reset in general rate case proceedings, and a Conservation Improvement Program Adjustment Factor is calculated annually to reflect changes from the CCRC. The Company proposed to set the CCRC at 0.6204 cents per kWh based on conservation programming costs for the 2025 Test Year.[281] The record demonstrates that the Company's recommendation to change the CCRC is reasonable and the Commission should approve it.

2. Excess Footage Charges, Winter Construction Charges, and Dedicated Switching

258. The Company proposed updates to the rates for Excess Footage Charges, Winter Construction Charges, and Dedicated Switching.

259. The Company's approved tariffs include provisions for charges related to excess footage. The Company proposed to increase the charges based on increases in material, labor, and equipment costs, and provided cost analysis to support its proposal.[282]

260. The Company's approved tariffs also include provisions for charges when construction is needed during winter months. The charges are related to costs for thawing and trenching in adverse conditions. The Company proposed to increase the rates for

[279] Ex. Xcel-20 at 32-36 and Schedules 13-15 (Wehner Direct).
[280] Ex. DOC-12 at 38-39 (Addonizio Direct).
[281] Ex. Xcel-73 at 50-51 (Barthol Direct).
[282] Ex. Xcel-73 at 52 and Schedule 11 (Barthol Direct).

winter construction charges because of increases in material, labor, and equipment costs, and provided cost analysis to support its proposal.[283]

261. The Company also provides Dedicated Switching service for certain large customers when those customers need electric service de-energized. This typically involves situations where customers need to perform work on their own facilities, and is scheduled at a specific date and time by customers. The Company charges different rates for weekdays and weekends, and proposed to increase the rates. The Company provided cost analysis to support its proposal.[284]

262. The Company explained that the net revenue impact from these rate increases would be $1,337,580 and that the revenues were incorporated into its overall request.[285]

263. The Department initially raised concerns that the Company had not explained its tariff proposals related to Excess Footage Charges, Winter Construction Charges, and Dedicated Switching. The Department requested some additional data,[286] which the Company provided in its Rebuttal Testimony.[287] After reviewing the data provided by the Company, the Department recommended that the proposed rate changes for Excess Footage Charges, Winter Construction Charges, and Dedicated Switching be approved.[288]

264. The record demonstrates that the Company's proposal to change rates for Excess Footage Charges, Winter Construction Charges, and Dedicated Switching are reasonable and should be approved by the Commission.

E. Multi-Year Rate Plan Issues

1. Term of Plan

265. The Company proposed a two-year term for the MYRP, with a 2025 Test Year and 2026 Plan Year.[289]

266. No other party filed testimony or took a position on the term of the MYRP.

267. The two-year term is reasonable and should be approved by the Commission.

[283] Ex. Xcel-73 at 52-53 and Schedule 11 (Barthol Direct).
[284] Ex. Xcel-73 at 53-54 and Schedule 11 (Barthol Direct).
[285] Ex. Xcel-73 at 54 (Barthol Direct).
[286] Ex. DOC-19 at 53-54 (Bahn Direct).
[287] Ex. Xcel-74 at 40-42 (Barthol Rebuttal).
[288] Ex. DOC-20 at 15-16 (Bahn Surrebuttal).
[289] Ex. Xcel-15 at 2-5 (Liberkowski Direct).

2. 2026 Sales True-Up

268. The Company proposed a 2026 Sales True-Up, with no changes in the structure of the true-up from that approved in the Company's most recent rate case.[290]

269. Only the Department filed testimony on the 2026 Sales True-Up and, once the Company confirmed that it sought no change to the mechanism in place during the most recent MYRP, agreed that the 2026 Sales True-Up was reasonable and should be approved.[291]

270. The 2026 Sales True-Up, as agreed to by the Company and Department, is reasonable and should be approved by the Commission.

3. Capital True-Up

271. The Company proposed a one-way Capital True-Up with no changes in design from the Capital True-Up approved in its most recent MYRP.[292]

272. The Department agreed the Capital True-Up was appropriate and should be continued.[293]

273. No other party filed testimony or took a position on this issue.

274. The Capital True-Up, as agreed to by the Company and Department, is reasonable and should be approved by the Commission.

4. Property Tax True-Up

275. The Company proposed to use a true-up mechanism to ensure that customers pay only the property taxes that are actually incurred.[294] A property tax true-up allows the Company to surcharge or refund property tax expense to customers when the actual property taxes for a given year do not match the amount included in rates for that year.[295]

276. The true-up works 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;[296] any over-recovery would be refunded, or, symmetrically, any under-recovery would be charged, through an appropriate mechanism

[290] Ex. Xcel-15 at 37-39 (Liberkowski Direct: Ex. Xcel-29 at 13-16 (Levine Direct); Ex. Xcel-30 at 2-5 (Levine Rebuttal); Ex. Xcel-76 at 7-9 (Paluck Direct); Ex. Xcel-77 at 19-20 (Paluck Rebuttal).
[291] Ex. DOC 19 at 9-17 (Bahn Direct); Ex. DOC-20 at 4 (Bahn Surrebuttal).
[292] Ex. Xcel-15 at 40 (Liberkowski Direct).
[293] Ex. DOC-1 at 52 (Johnson Direct).
[294] Ex. Xcel-51 at 22 (Kowalowski Direct).
[295] Ex. Xcel-51 at 22 (Kowalowski Direct).
[296] Ex. Xcel-51 at 13, 22 (Kowalowski Direct).

at that time;[297] and the Company proposed that the true-up would stay in place until its next rate case.[298]

277. 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.[299] This true-up process has been in place for years, and the Company believes it has worked well to date.[300]

278. In Direct testimony, the Department proposed modifying the true-up such that the Company would not be allowed to recover the property tax expense if it exceeds five percent of the Commission approved amount to be included in the MYRP.[301]

279. In its Surrebuttal Testimony, the Department ultimately agreed that the complex nature of estimating property taxes justified the Company's proposed property tax true-up.[302]

280. The Company's proposed property tax true-up process is reasonable and should be adopted by the Commission.

F. Additional Issues

1. Fuel Clause Rider

281. The Company updated the Fuel Adjustment Factor section of the Fuel Clause Rider to be consistent with 2025 Test Year information. The Fuel Adjustment Factor Ratios by Service Category were updated to test year 2025 based on corresponding updates to Class Cost Ratios, Time-of-Use (TOU) Ratios, and Time-of-Day (TOD) Ratios. These updates were determined using the method approved by the Commission in the Company's previous rate cases.[303]

282. The Department reviewed the Company's update and recommended that the Commission approve it.[304]

283. The Company's updates to the Fuel Clause Rider, as agreed to by the Company and the Department, are reasonable and should be approved by the Commission.

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[297] Ex. Xcel-51 at 22 (Kowalowski Direct).
[298] Ex. Xcel-51 at 23 (Kowalowski Direct).
[299] Ex. Xcel-51 at 10-11, 22 (Kowalowski Direct).
[300] Ex. Xcel-51 at 22-23 (Kowalowski Direct).
[301] Ex. DOC-23 at 13 (Jones Direct).
[302] Ex. DOC-24 at 4-5 (Jones Surrebuttal).
[303] Ex. Xcel-76 at 24 (Paluck Direct)
[304] Ex. DOC-19 at 51 (Bahn Direct); Ex. DOC-20 at 29 (Bahn Surrebuttal).

2. Coal Combustion Residuals Expense Tracker

284. Coal ash, also known as Coal Combustion Residuals (CCR), is the by-product of burning coal in coal-fired power plants.[305] CCR is a regulated non-hazardous waste under 2015 Environmental Protection Agency regulations, which were significantly revised in 2024.[306] These obligations are called the "Legacy CCR Rule."[307]

285. The Legacy CCR Rule significantly expanded the scope of CCR regulations, which increased the number of locations and sites subject to these regulations. The Legacy CCR Rule became effective November 2024 and covers a host of new facilities that will require evaluation and, depending on the results of the evaluations, possible future compliance obligations.[308]

286. CCR costs are normally included within overall decommissioning costs.[309] This approach works well when decommissioning projections are stable and can be collected over the life of the asset. When decommissioning requirements change with little remaining life left for plants, however, the result is either elevated depreciation rates over the remaining life or actual decommissioning costs that exceed cost of removal reserves.[310]

287. Future changes to the CCR regulations or changes to the EPA's interpretation of those regulations could occur, and such changes in the past have resulted in extraordinary, unforeseen, incremental removal costs and have also triggered new investigation and remediation costs (or environmental liabilities) that are non-routine.[311]

288. To address this uncertainty, the Company proposed a tracker mechanism for cost recovery of these costs.[312]

289. The Department initially recommended Xcel be required to provide adequate support for CCR compliance expenses through a compliance filing before recovery is approved, and not allowing recovery for internal labor costs in the CCR tracker because these costs would not be incremental to the Company.[313]

290. In Rebuttal Testimony, the Company argued that it might need to hire resources for CCR compliance that would be incremental costs not otherwise captured in the Company's forecast. Because the CCR program is an iterative process in which each step can lead to additional requirements, it is possible that current labor and resources

[305] Ex. Xcel-68 at 53 (Johnson Direct).
[306] Ex. Xcel-59 at 16–17 (West Direct).
[307] Ex. DOC-5 at 21–22 (Golden Direct).
[308] Ex. Xcel-61 at 17 (West Direct).
[309] Ex. Xcel-68 at 54 (Johnson Direct).
[310] Ex. Xcel-68 at 54 (Johnson Direct).
[311] Ex. Xcel-61 at 28 (West Direct).
[312] Ex. Xcel-17 at 118 (Halama Direct).
[313] Ex. DOC-5 at 26 (Golden Direct).

may not be able to handle this workload and additional resources may need to be obtained. The scope of investigations and required activities are not yet fully known, and it is therefore not reasonable to assume that current resources can manage the work.[314]

291. The Department accepted Xcel's explanation of the potential for incremental internal labor costs arising from complying with the Legacy CCR Rule. The Department ultimately recommended that incremental internal labor costs be included in the costs eligible for recovery under the CCR tracker upon justification and support in its annual compliance filings.[315]

292. The Commission should approve the Company's requested CCR tracker and that require the Company to provide adequate support for any tracked expenses, including a justification as to how any labor costs included in the tracker are incremental to labor and outside services costs already collected through rate recovery.

3. Bad Debt Expense Tracker

293. In the Company's Annual Safety, Reliability, and Service Quality Report docket, Docket No. E002/M-24-27, the Joint Commenters proposed a reduction to payment plan down payments. Given the uncertain impact of that reduction on bad debt expense, the Company proposed a bad debt tracker for this case, using the now agreed-upon bad debt expense levels for 2025 and 2026 as the baseline, subject to true-up to actuals.[316]

294. CUB and ECC both supported the Company's proposal and no other party commented.[317]

295. The proposed bad debt expense tracker, as agreed to by the Company, ECC, and CUB, is reasonable and should be approved by the Commission.

4. PowerOn Auto Enrollment

296. PowerOn is an affordability program offered by the Company that limits customers' energy burden to three percent of their income.[318]

297. The Company is considering alternative eligibility options for enrolling customers in PowerOn.[319] The program is currently tailored to households that have received federal Low-Income Home Energy Assistance Program (LIHEAP) funding but are still paying more than three percent of income towards electricity bills.[320]

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[314] Ex. Xcel-60 at 3-4 (West Rebuttal).
[315] Ex. DOC-6 at 7-8 (Golden Surrebuttal).
[316] Ex. Xcel-17 at 119-20 (Halama Direct); Ex. ECC-1 at 13-15 (Shardlow Direct).
[317] Ex. CUB-3 at 24-25 (Levenson-Falk Direct); Ex. ECC-1 at 13-15 (Shardlow Direct).
[318] Ex. ECC-1 at 12 (Shardlow Direct).
[319] Ex. Xcel-81 at 17-19 (Howard Rebuttal); Ex. Xcel-71 at 4, 20, 41-43 (Martin Rebuttal).
[320] Ex. ECC-1 at 9 (Shardlow Direct).

298. In Direct Testimony, ECC Witness Shardlow recommended automatically enrolling in PowerOn all electric customers who have received LIHEAP or are otherwise deemed eligible for program participation.[321]

299. The Company estimates that automatically enrolling LIHEAP recipients into PowerOn could increase program participation by up to 14,000 electric-only customers, for a total potential incremental spend of $10 to $11 million annually.[322] Recovery of these costs was not requested in this proceeding, as the Company indicated it would make a formal request and recommendation on funding after automatic enrollment approval had been received and actual enrollment information was available for calculating program needs.[323]

300. The Company and CUB supported the ECC's proposal.[324]

301. ECC's proposal to expand PowerOn assistance by implementing auto-enrollment of the Company's LIHEAP-enrolled, electric only customers [325] is reasonable and should be approved by the Commission.

5. Reporting Requirements

302. In Docket No. E002/M-94-13, the Commission ordered deferred accounting for revenues from the sale of certain emission allowances until the Company's next general rate case, where the effects of then-new changes to the FERC Uniform System of Accounts could be examined. The Company has continued the deferral over several rate cases, including in this case. Due to the small amount (less than $5,000) in this account that has been accumulating since 2010 when the deferral was last resolved, combined with the limited market for these allowances, the Company proposed to discontinue the deferral of emission allowances with no adjustment in this proceeding.[326]

303. No party provided testimony regarding the discontinuation of the deferral of emission allowances.

304. The record supports, and the Commission should approve, Xcel's proposal to discontinue deferral of emission allowances.

305. In Docket No. E002/GR-91-1, the Company was directed to require NSP Advantage Service (now branded as Xcel Energy HomeSmart) to: 1) pay a return on the use of the Company's billing services asset; 2) compensate the Company for its

[321] Ex. ECC-01 at 11 (Shardlow Direct).
[322] Ex. Xcel-81 at 16 (Howard Rebuttal).
[323] Ex. Xcel-81 at 16 (Howard Rebuttal).
[324] Ex. Xcel-77 at 18-19 (Paluck Rebuttal); Ex. Xcel-71 at 36-41 (Martin Rebuttal); Ex. Xcel-81 at 14-16 (Howard Rebuttal); Ex. CUB-8 at 14-15 (Levenson-Falk Surrebuttal).
[325] The Company agreed to expand eligibility to electric-only customers. CUB has sought clarification of whether this would also apply to combination gas and electric customers whose gas bills are too low to qualify for gas affordability programs. The Commission may wish to solicit Xcel's position on this clarification before taking final action in this proceeding.
[326] Ex. Xcel-17 at 130 (Halama Direct).

personnel's referral time; and 3) compensate the Company for use of its mailing lists. The Company has complied with these requirements. However, due to the sale of HomeSmart in the fourth quarter of 2023, this compliance requirement is no longer applicable as of that sale.[327]

306. No party provided testimony regarding compliance with these reporting requirements related to HomeSmart.

307. Based on the information provided by the Company, the record supports discontinuance of further reporting related to HomeSmart and the Commission should approve this discontinuance.

308. In Docket No. G002/GR-97-1606, the Commission required that the Company treat Tax Benefit Transfer (TBT) leases consistent with prior Commission approved methodology. There are no TBTs included in the MYRP. Since this provision has not been triggered in many years, the Company proposed to discontinue this reporting in future rate cases.[328]

309. No party objected to the Company's request to discontinue reporting requirements related to TBTs.

310. The record supports, and the Commission should authorize, the Company to discontinue reporting on TBT leases in future rate cases.

311. In Docket No. E002/M-95-174 the Company was permitted to offer Company-owned generation to compete against other provider offerings but was ordered to track capacity-related non-performance penalties on NSP generation projects for return to customers. The Company explained that it had incurred no such penalties in this case. Since this provision has not been triggered in many years, the Company proposed to discontinue this reporting in future rate cases.[329]

312. No party objected to the Company's request to discontinue these reporting requirements related to competitive bidding.

313. The record supports, and the Commission should allow, the Company to discontinue this reporting related to competitive bidding.

6. ATO/MTO Dual Feeder Service

314. ATO/MTO (Automatic Throw-Over/Manual-Throw-Over) Dual Feeder Service is an optional service available to Commercial and Industrial customers who desire a higher level of service reliability than that provided through a single feeder. ATO/MTO Dual Feeder Service is provided through an agreement between the customer and the Company to have the Company install and/or reserve capacity in an alternate feeder which, along with an ATO/MTO switch, allows the alternate feeder to

[327] Ex. Xcel-17 at 130 (Halama Direct).
[328] Ex. Xcel-17 at 131 (Halama Direct).
[329] Ex. Xcel-17 at 132 (Halama Direct).

supply the customer's power and energy needs in the event the preferred feeder is de-energized for any reason. The Company must maintain reserve capacity on the alternate feeder at all times, in the event the alternate feeder will be used by the customer.[330]

315. Currently the customer is charged for "Excess Facilities" needed for the duplicate facilities that are required to accommodate for the ATO/MTO, including the design costs for the excess facilities prior to the work being completed, subject to true up to actuals, and winter construction charges if applicable. Currently, the Company does not charge its ATO/MTO Dual Feeder Service customers to reserve capacity on alternate feeders even though it is reserved for these customers and cannot be used by other customers.[331]

316. The Company proposed to implement a charge for new ATO/MTO Dual Feeder Service customers to cover the cost associated with reserving alternate feeder capacity for their use in the event this needs to be used, and this proposed changes will also apply to existing customers when these existing agreements expire and the customers enter into new arrangements for service.[332] These changes will allow the Company to recover costs associated with reserving this alternate feeder capacity from the customer benefitting from this service rather than from other customers.[333]

317. The Department found the Company's proposal reasonable and recommended approval of the Company's proposed changes to the ATO/MTO Dual Feeder Service Agreement. The Department also recommended that the Company track revenues under all new ATO/MTO Dual Feeder Service contracts and report them in the Company's next rates case, as well as a forecasted budget of revenues for proposed test years, to ensure there is no double recovery of the ATO/MTO Dual Feeder Service capacity fees.[334]

318. The Company confirmed in Rebuttal testimony that if the ATO/MTO charge is approved, the Company will provide in its next rate case, to the best of its ability, a forecast of anticipated revenues under the new tariff charges for those customers that have executed agreements that include the new charge.[335]

319. In Surrebuttal Testimony, the Department confirmed that the Company and the Department are in agreement on reporting in the next rate case.[336]

320. The Commission should approve the Company's proposed changes to the ATO/MTO Dual Feeder Service Tariff, which will allow the Company to recover costs associated with reserving this alternate feeder capacity from the customer benefitting from this service rather than from other customers. Further, the

[330] Ex. Xcel-34 at 195 (Mensen Direct).
[331] Ex. Xcel-34 at 195 (Mensen Direct).
[332] Ex. Xcel-34 at 196 (Mensen Direct).
[333] Ex. Xcel-34 at 196 (Mensen Direct).
[334] Ex. DOC-7 at 27 (Uphus Direct).
[335] Ex. Xcel-35 at 51 (Mensen Rebuttal).
[336] Ex. DOC-8 at 8 (Uphus Direct).

Commission should require the Company to provide in its next rate case, a forecast of anticipated revenues under the new tariff charges for those customers that have executed agreements that include the new charge.

DISPUTED ISSUES

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

VII. Revenue Requirements

322. 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 2025. Because the Company has proposed a multi-year rate plan, it has also forecasted revenue requirements for 2026 plan year.

323. 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.

A. Expense or Rate Base Related Issues

1. Sherco Unit 3 and King Allen S. King Coal Plants Remaining Lives

324. In the Company's most recent IRP, the Commission approved shortening the operating lives of the Sherco Unit 3 (Sherco 3) and Allen S. King (King) coal generating plants.[337] King will be retired in December 2028 instead of June 2037, and Sherco 3 will be retired in December 2030 rather than December 2034.[338]

325. In August, 2023, the Commission initiated Docket No. E-002, E-015, E-017/CI-23-375 (the Early Retirement Docket) to investigate depreciation accounting and other ratemaking issues as they relate to early-retiring electric generating facilities, specifically coal-fueled facilities that are being retired to meet Minnesota's electric decarbonization goals.[339]

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[337] *In re Xcel Energy's 2024–2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. 24-67, ORDER APPROVING SETTLEMENT WITH MODIFICATIONS at 10 (Apr. 21, 2025) (eDocket No. 20254-217941-01) (ORDER APPROVING XCEL 2024–2040 IRP).

[338] Ex. Xceo-68 at 41-42; *In re Xcel Energy's 2024–2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. 24-67, ORDER APPROVING SETTLEMENT WITH MODIFICATIONS at 10 (Apr. 21, 2025) (eDocket No. 20254-217941-01) (ORDER APPROVING XCEL 2024–2040 IRP).

[339] Xcel-68 at 41-42 (Johnson Direct); *In re Comm'n Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regul. Elec. Util.*, MPUC Docket No. 23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY-RETIRING GENERATING FACILITIES at 1-2 (May 14, 2025) [hereinafter, Early Retirement Order].

326. After the company submitted Direct and Supplemental direct testimony, the Commission issued its order in the Early Retirement Docket.[340] The order established a four-tiered approach for ratemaking treatment:

> Tier 1: Data Gathering Phase: Is plant used and useful, plant size, original date of retirement, impact on ratepayers and has the utility prudently operated the plant will also be considered. Move to Tier 2.
>
> Tier 2: Does the early-retiring asset meet the criteria established for accelerated depreciation? If yes, stop. Assign accelerated depreciation. If no, move to Tier 3.
>
> Tier 3: Does the early-retiring asset meet the Tier 2 standards, except that accelerated depreciation would cause rate shock? If yes, assign regulatory asset with a possible return. If no, move to Tier 4.
>
> Tier 4: Further investigation is required to determine appropriate ratemaking treatment. (Tier 4 assumes the asset is of unique nature or the plant was not used and useful at the time of early-retirement or possible prudency concern.)[341]

The Early Retirement Order noted that ratemaking treatment would be applied on a case-by-case basis, and authorized any changes to the ratemaking treatment of early-retiring generating facilities be handled in rate cases.[342]

a. Positions of the Parties

327. In Direct Testimony, the Company proposed no change be made to the remaining lives for Sherco 3 and King, and that a regulatory asset be created for each plant at the time of its retirement.[343]

328. The Department recommended that the depreciation lives of the Sherco 3 and King coal plants be adjusted to match the operating lives authorized for the plants in Xcel's 2024–2040 IRP.[344]

329. In support of its argument, the Department posited that (1) it made the same recommendation for Xcel's nuclear generating plants, which had their operating lives extended (thereby resulting in a net rate decrease of more than ten million dollars for both 2025 and 2026); (2) that matching depreciation lives to operating lives approved in IRPs is a traditional practice; (3) matching depreciation lives to operating lives reduces

[340] Early Retirement Order.
[341] Early Retirement Order at 7-8.
[342] Early Retirement Order at 8.
[343] Xcel-17 at 76 (Halama Direct).
[344] Ex. DOC-23 at 14 (Jones Direct).

intergenerational inequity; and (4) that customers will eventually pay $63 million more in rates if the Company's proposal is adopted.[345]

330. The Department's proposal would increase the Company's revenue requirement by $58.8 million in 2025 and $55.4 million in 2026.[346]

331. In Rebuttal Testimony, the Company argued that accelerated depreciation would increase the near-term annual revenue requirements, resulting in increased costs for customers, while the Company's proposed regulatory asset approach would not require this near-term revenue requirement increase.[347]

332. The OAG opposed the Department's proposal, arguing that the Commission had moved away from its prior practice of matching depreciation lives to operating lives when it developed the four-tiered approach in the Early Retirement Docket, and that shortening the Sherco 3 and King remaining lives would result in intergenerational inequity by making present-day customers pay the increased depreciation costs while future ratepayers reaped the environmental benefits of accelerated closures of coal plants.[348]

333. The OAG also opposes Xcel's proposal to create a regulatory asset, arguing that the Early Retirement Docket's framework contemplates making that decision at the time of plant closure, because whether a plant remained used and useful at the time of retirement and whether a utility prudently operated a plant cannot be assessed until the end of the facility's life.[349]

334. XLI also opposes the Department's proposal to shorten the depreciable lives for the Sherco 3 and King plants, arguing that (1) there is inadequate evidence in the record to support the proposal (including the absence of an amortization period for any remaining net book value for the Sherco 3 and King plants); (2) the proposal would result in rate shock; and (3) the proposal would result in intergenerational inequity.[350]

b. Analysis and Recommendation

335. The Department's proposal would result in rate shock by increasing rates by $58.8 million in 2025 and $55.4 million in 2026. The proposed extension of the depreciation lives, and resulting revenue requirement reduction, of Xcel's nuclear facilities is not an appropriate comparison point from which to suggest otherwise. The ultimate result of accepting the recommendations in this Report would be a substantial rate increase; and that increase would be nearly $60 million per year higher if the Sherco 3 and King depreciation lives are shortened.

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[345] Ex. DOC-23 at 14-15 (Jones Direct); Ex. DOC-24 at 19-20 (Jones Surrebuttal).
[346] Ex. Xcel-19 at 50.
[347] Ex. Xcel-19 at 51-52 (Halama Rebuttal).
[348] Ex. OAG-6 at 3-8 (Lee Rebuttal).
[349] Ex. OAG-6 at 10 (Lee Rebuttal)
[350] Ex. XLI-5 at 7-8 (LaConte Rebuttal); Ex. XLI-7 at 23-24 (LaConte Surrebuttal).

336. The Department's proposal would also result in intergenerational inequity. Customers in 2025 and 2026 would absorb the rate shock of paying for the sudden increase in rates, while environmental benefits of the accelerated closure of the two coal plants would be enjoyed by customers no longer paying for those generation assets.

337. It is immaterial whether matching depreciation lives to operating lives was previously a standard Commission practice. The Commission explicitly recognized the complexities when deciding ratemaking treatment for large coal assets retired early to achieve carbon reduction goals, and developed a new practice for addressing those situations in the Early Retirement Docket. In that proceeding, the Commission contemplated that rate treatment of such assets would be subject to the four-tiered framework previously describe.

338. Creating a regulatory asset at this time would also be inconsistent with the framework established in the Early Retirement Docket. Tier 3 of that framework applies to "assets that remain used and useful *at the time of their earlier retirements.*"[351] It is axiomatic that used and usefulness at the time of the plants' retirement cannot be assessed until the time of their retirements.

339. The Commission should adopt Xcel's recommendation, supported by the OAG and XLI, to not adjust the remaining lives for the Sherco 3 and King plants.

340. The Commission should reject the Company's proposal to create a regulatory asset for the Sherco 3 and King plants, as recommended by the OAG and XLI.

2. Prepaid Pension and Accrued Liabilities

341. In Direct testimony, Xcel proposed to include its prepaid pension asset in rate base and to earn a return at the Company's weighted average cost of capital (WACC).[352]

342. Over the life of its pension plan, the Company has contributed more dollars to the plan than it has recognized in actuarially calculated pension expense, which results in a prepaid pension asset. Conversely, the Company has recognized more retiree medical, non-qualified pension, and post-employment benefits expense than it has contributed to those plans, which results in accrued liabilities.[353] Because the amount of the prepaid pension asset exceeds the amount of accrued liabilities, the result is a net asset, which, after offset by accumulated deferred income taxes (ADIT), results in approximately $90.2 million that the Company proposed be added to rate base.[354]

[351] Early Retirement Order at 5.
[352] Ex. Xcel-57 at 84 (Schrubbe Direct).
[353] Ex. Xcel-57 at 55 (Schrubbe Direct).
[354] Ex. Xcel-57 at 55-66 (Schrubbe Direct).

343. The prepaid pension asset differs categorically from most other rate base assets. Generally, rate base assets reflect a large investment paid up front, and then a utility earns a return on that investment as the asset depreciates.[355]

344. Xcel intends to continue operating the pension trust in perpetuity.[356]

345. If Xcel terminated the trust, the value of the Company's interest, which would be affected by life expectancy, investment returns, and discount rates, cannot be reliably calculated in this proceeding.[357]

346. Any prepaid pension assets returned to the Company upon reversion would be subject to income tax and excise tax.[358]

347. The prepaid pension asset provides benefit to customers by enhancing the Company's ability to attract and retain employees.[359]

348. The prepaid pension asset also helps the Company transition employees into retirement to manage its workforce, knowledge transfer, training, and succession planning.[360]

349. The prepayments related to pension expenses are not included in operating costs and thus are not recovered as expenses at the time the prepayments are made.[361]

350. Pension contributions are legally irrevocable once placed in the pension trust, meaning they can only be used to fund the retirement benefits to employees who serve customers.[362] If not for funding the pension trust, these funds could be retained by investors, invested elsewhere, or allocated to other assets that earn a return.[363]

351. Pension contributions are deductible on NSPM's federal income tax return.[364]

352. The annual pension cost determined under the accounting methods used by the Company (i.e., the Aggregate Cost Method for the NSPM Plan, Statement of Financial Accounting Standard (FAS) 87 for the XES Plan) includes an expected return on assets (EROA).[365] The EROA is multiplied by the value of the assets in the pension trust, and the product of this calculation is subtracted from the annual pension cost.[366]

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[355] Ex. DOC-11 at 7-8 (Hunt Surrebuttal).
[356] Evid. Hrg. Tr. Vol. 1 at 208 (Schrubbe).
[357] Evid. Hrg. Tr. Vol. 1 at 209 (Schrubbe).
[358] Ex. DOC-11 at Schedule 3 (Hunt Surrebuttal).
[359] Ex. Xcel-57 at 24-25, 69 (Schrubbe Direct); Ex. Xcel-58 at 27-28 (Schrubbe Rebuttal).
[360] Ex. Xcel-62 at 41 (Ly Direct).
[361] Ex. Xcel-58 at 22 (Schrubbe Rebuttal).
[362] Ex. Xcel-58 at 2 (Schrubbe Rebuttal).
[363] Ex. Xcel-58 at 21 (Schrubbe Rebuttal).
[364] Ex. Xcl-58 at 24 (Schrubbe Rebuttal).
[365] Ex. Xcel-57 at 69 (Schrubbe Direct).
[366] Ex. Xcel-57 at 69 (Schrubbe Direct).

Therefore, the return on the prepaid pension asset reduces the annual qualified pension cost charged to customers on a dollar-for-dollar basis.[367]

353. The pension trust sees earnings on the entire amount of the assets in the pension trust. These earnings reduce customers' rates.[368] The pension plan amount that earns a return is larger than the amount on which the Company is proposing customers pay a return.[369] This is because the amount of the prepaid pension asset included in rate base reflects reductions for ADIT as well as the accrued liabilities (i.e., the net prepaid pension asset).[370]

354. The earnings on the prepaid pension asset will reduce the Company's revenue requirement by nearly $12.8 million in 2025, and are expected to reduce the Company's revenue requirement by a similar amount through 2026.[371]

355. The prepaid pension asset consists solely of shareholder (Company) supplied funds. Customers pay the annual pension expense through rates, which is subtracted out of the calculation of the prepaid pension asset[372]

356. The Department opposes a return of the WACC on Xcel's prepaid pension asset.[373]

357. In support of this argument, the Department characterizes Xcel's interest the prepaid pension asset as a contingent reversionary interest that Xcel has, at most, a nominal monetary interest in. The Department cites a variety of cases and secondary sources addressing property law to advance this argument.[374]

358. It is not necessary to characterize Xcel's propriety interest in any residual funds from pension trust property or to quantify that interest in order to resolve this dispute. The question before the Commission is not what right Xcel shareholders have to the funds in the pension trust or in what amount. Rather, the question is whether the Company is entitled to earn a return on the trust to compensate it for the cumulative investor contributions necessary to fund the prepaid pension asset.[375]

359. The Commission is required to give "due consideration . . . to other expenses of a capital nature" in determining the Company's rate base on which it may earn a fair return.[376]

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[367] Ex. Xcel-57 at 69 (Schrubbe Direct).
[368] Ex. Xcel-57 at 70 (Schrubbe Direct).
[369] Ex. Xcel-57 at 71 (Schrubbe Direct).
[370] Ex. Xcel-57 at 72 (Schrubbe Direct).
[371] Ex. Xcel-57 at 73, Table 16 (Schrubbe Direct).
[372] Ex. Xcel-57 at 81 (Schrubbe Direct).
[373] Ex. DOC-11 at 19-20 (Hunt Surrebuttal).
[374] Department Initial Brief at 61-64.
[375] *See* Ex. Xcel-58 at 6-7 (Schrubbe Rebuttal).
[376] Minn. Stat. § 216B.16, subd. 6; *see also In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, No. A23-1672, 2025 WL 249995, at *8-10 (Minn. Ct. App. Jan. 21, 2025).

360. Notwithstanding distinctions between the prepaid pension asset and many other rate base assets, the prepaid pension asset is of a capital nature. It comprises only shareholder funds.[377] Funding the asset requires utility shareholders to expend capital for a benefit that will not accrue until a future date, thereby forgoing other potential uses for those funds. Customers are an eventual beneficiary of the benefit of these funds through reduced future pension expenses.

361. The Company is entitled to earn a return of some kind on the prepaid pension asset.

362. The Department argues that, if a return is authorized, it should be limited to the Company's cost of long-term debt, arguing that such a limitation would still exceed the value of Xcel's proprietary interest in the prepaid pension asset and discourage the Company from making excessive contributions.[378]

363. The Company maintains that the WACC is the appropriate return because the prepaid pension asset is financed with a mix of debt and equity.[379]

364. Notwithstanding the Company's position, Xcel indicated that it would be willing to accept, for the purposes of this proceeding, the Department's alternative position to limit the return on the prepaid pension asset to the Company's cost of long-term debt.[380]

365. Using the cost of long-term debt for the prepaid pension asset's return, especially in light of the Company's agreement, would fairly balance the parties' concerns on this issue. This outcome compensates shareholders for their contribution to the prepaid pension asset while also mitigating any concerns about incentives for overfunding the pension trust and recognizing the distinction between the prepaid pension asset and more traditional rate base items.

366. The Commission should approve a return on the Company's prepaid pension asset, set at Xcel's cost of long-term debt.

3. Riverside Generating Unit

367. April 2025, Xcel's Riverside plant (Riverside), a steam turbine generator experienced a fault and tripped the unit, causing it to remain offline. [381]

368. The Company filed the Riverside Root Cause Report and Analysis report in Docket Nos. E002/AA-24-63 and E002/AA-25-63 on September 23, 2025.[382]

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[377] The Department characterizes this funding as "indirect" because Xcel contributes to the pension trust in the ordinary course of business. Department Reply Brief at 9. Prepaid pension contributions are not treated as operating expenses and are supplied by shareholder funds.
[378] Ex. DOC-11 at 8 (Hunt Surrebuttal).
[379] Ex. Xcel-97 at 1-2 (Schrubbe Revised Witness Summary).
[380] Ex. Xcel-97 at 1-2 (Schrubbe Revised Witness Summary).
[381] Ex. DOC-1 at 46 (Johnson Direct).
[382] Ex. DOC-2 at Schedule 6.

369. The plant is not expected to return to service until the summer of 2026. [383]

370. Riverside was in service during the early part of 2025.[384]

371. Riverside was included in the 2025-2026 capacity auction and generated capacity revenues of approximately $25.8 million during that period. [385]

372. 2025-2026 capacity revenues would be transferred to the Company's customers through the Company's established capacity tracker, thereby benefitting ratepayers.[386]

373. At least some portion of Riverside's capacity will also be included in the 2026/2027 capacity auction, though the amount of revenue that will be generated is unknown.[387]

374. The Department argued that Riverside would not be "used and useful" for the complete duration of the test year and plan year, and therefore recommended that Xcel not recover operating and maintenance expenses and that Riverside not be included in rate base for the period from May 1, 2025 through May 30, 2026.[388]

375. The Department did not oppose inclusion of property tax and depreciation expenses for Riverside.[389]

376. In support of this argument, the Department points to a Commission decision to disallow costs related to Sherco 3 due to an outage in Xcel's 2013 rate case.[390]

377. The Department also recommended that a contested case be initiated to evaluate whether Xcel acted prudently with respect to Riverside.[391]

378. The Company believes inclusion of Riverside in its rate base is warranted, pointing out that Riverside will be in service for a portion of both 2025 and 2026, the generation of capacity revenues rendered the plants used and useful, and labor costs will be incurred to return the plant to service.[392]

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[383] Ex. DOC-1 at 46 (Johnson Direct). The Company noted in its reply brief that, based on currently available information, the outage will last longer than previously expected. Xcel Reply Brief at 112, n. 5. Because this Report is based on the evidentiary record developed through the hearing, this information was not considered by the Administrative Law Judge.
[384] Ex. Xcel-16 at 23 (Liberkowski Rebuttal).
[385] Ex. Xcel-82 at 13-14 (Detmer Rebuttal); Ex. DOC-1 at 48 (Johnson Direct).
[386] Ex. DOC-1 at 48 (Johnson Direct)
[387] Ex. Xcel-82 at 14 (Detmer Rebuttal).
[388] Ex. DOC-1 at 49 (Johnson Direct), Ex. DOC-2 at 30 (Johnson Surrebuttal).
[389] Ex. DOC-2 at 30 (Johnson Surrebuttal).
[390] *In the Matter of Northern States Power Company for Authority. to Increase Rates for Electric. Service in the State of Minnesota*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (Sept. 3, 2013) [hereinafter Xcel 2012 Rate Case Order].
[391] Ex. DOC-2 at 29 (Johnson Surrebuttal).
[392] Ex. Xcel-16 at 23 (Liberkowski Rebuttal).

379. The Company opposes the Department's recommendation for a contested case, arguing that the request is premature until the Commission's solicits comments from interested stakeholders.[393]

380. The Minnesota Supreme Court previously analyzed whether public recreational facilities, acquired to satisfy a regulatory requirement to develop suitable public recreational facilities, were "used and useful" in the provision of utility service.[394]

381. In that proceeding, the Supreme Court held that the "used and useful" standard did not "require that an item must actually generate, transmit or distribute electricity, or aid in doing so," and cautioned that such a definition was "overly technical and inflexible." Instead, the standard required that the "property be in service" and "reasonably necessary to the efficient and reliable provision of utility service."[395]

382. *Senior Citizens* is instructive. It is undisputed that, for the time period at issue, Riverside will not be in service. Thus, under the Supreme Court's standard, it is not used and useful.

383. Accordingly, Riverside should be removed from the Company's rate base from May 1, 2025 through May 30, 2026.

384. Xcel's argument that it would be inherently inequitable to deny the Company a return on Riverside while crediting ratepayers for capacity revenues carries intuitive appeal. That said, it is important to note that, while Xcel would not be earning a *return* on its investment in Riverside, customers would still be repaying that investment through depreciation expense during the period where Riverside is not in service under the Department's proposal. The record does not support a determination denying customers the benefit of Riverside's capacity revenues.

385. The disputed O&M expenses, however, are a different matter. Expenses are not rate base items and thus are appropriate for recovery if they are reasonably and prudently incurred, regardless of whether Riverside is used and useful during a test year.

386. Whether the O&M expenses were prudently incurred is an inquiry that should be informed by analysis of the cause of the outage and, specifically, whether Xcel acted prudently or imprudently.

387. Due to the timing of the filing of the Riverside Root Cause Report and Analysis, the record in this proceeding cannot support a determination about prudence or imprudence related to the Riverside outage.

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[393] Xcel Reply Brief at 113.
[394] *Senior Citizens Coalition of Northeastern Minnesota v. Minnesota Public Utilities Comm'n*, 355 N.W.2d 295, 300 (Minn. 1984).
[395] *Senior Citizens Coalition of Northeastern Minnesota v. Minnesota Public Utilities Comm'n*, 355 N.W.2d 295, 300 (Minn. 1984) (internal citations omitted).

388. Because the Company bears the burden to prove that expenses were reasonably and prudently incurred, the Commission should not allow recovery of the disputed O&M expenses at this time.

389. The Commission should instead authorize the Company to create a regulatory asset for the disputed O&M related to Riverside, subject to a determination on prudency by the Commission.

390. It would be premature to initiate a contested case to evaluate prudency at Riverside. The Commission should solicit comments from interested stakeholders as to the type and scope of any such proceeding, including whether a contested case is warranted. The Commission may also wish to use this proceeding for further record development on the treatment of capacity revenues related to the Riverside outage.

4. Sherco 3 Restoration Costs

391. There was a catastrophic event that occurred at the Sherco 3 plant on November 19, 2011.[396]

392. As a result of this event, Xcel incurred $5.5 million in plant restoration costs not covered by insurance. All insurance proceeds related to this event have been refunded to customers.[397]

393. The Commission allowed Xcel to recover these costs through base rates in its 2013 rate case, and recovery has continued in every rate case since then. Due to the passage of time, a $2.4 million balance remains in the 2025 test year and a $2.1 million balance remains in the 2026 plan year.[398]

394. The Company proposes to continue recovering these costs in the same manner as in previous rate cases.[399]

395. Following a contested case, in December 2024, the Commission issued its order finding that "Xcel failed to operate and maintain Sherco Unit 3 reasonably and prudently in a manner consistent with good utility practice."[400]

396. Based on this determination, the OAG argues that the Company should no longer be allowed to recover these plant restoration costs.[401]

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[396] Ex. Xcel-19 at 34 (Halama Rebuttal).
[397] Ex. Xcel-19 at 34 (Halama Rebuttal).
[398] Ex. Xcel-16 at 21-22 (Liberkowski Rebuttal); Ex. Xcel-19 at 34-35 (Halama Rebuttal).
[399] Ex. Xcel-16 at 21-22 (Liberkowski Rebuttal); Ex. Xcel-19 at 34-35 (Halama Rebuttal).
[400] *In re Sherco Prudency Review*, MPUC Docket Nos. E-002/GR-12-961, 13-868, 13-599, 14-579, 16-523, 17,492, 18-373, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, REQUIRING REFUND OR CERTAIN DISALLOWED REPLACEMENT POWER COSTS, AND REQUIRING FURTHER ACTION at 4 (Dec. 24, 2024) (eDocket No. 202412-213317-01).
[401] Ex. OAG-5 at 24 (Lee Direct); Ex. OAG-7 at 18 (Lee Surrebuttal).

397. Adopting the OAG's recommendation would reduce the Company's revenue requirement by $404,227 in the 2025 Test Year and $384,776 in the 2026 Plan Year.[402]

398. The Company maintains that disallowing recovery would "amount to undoing a prior regulatory determination and retroactively changing the terms under which those costs were authorized."[403]

399. The Company is correct to the extent that adopting the OAG's recommendation would be a departure from prior Commission treatment of these restoration costs. Intervening events, however, warrant such a departure.

400. When the Commission has, in the past, allowed recovery of the Sherco 3 restoration costs, it did so prior to its final determination that Xcel's operation of the Sherco 3 plant was not prudent.

401. As utility imprudence was the cause of the catastrophic event, it necessarily follows that any restoration costs related to that event were imprudently incurred.

402. Because imprudently incurred costs are not appropriate for rate recovery, the Commission should adopt the OAG's recommendation and remove the unrecovered Sherco 3 recovery costs from Xcel's rate base in both the 2025 test year and 2026 plan year.

5. Time-of-Use Rate Implementation Costs

403. On December 22, 2023, in Docket No. E002/M-23-524, the Company filed its proposal to implement a TOU rate for all residential customers in accordance with the Commission's August 7, 2018 Order in Docket No. E002/M-17-775 and July 17, 2023 Order in the Company's last electric rate case.[404]

404. After this rate case was filed, the Commission issued an order in Docket No. E002/M-23-524 on May 15, 2025, approving a three-period, opt-in TOU rate and a three-period electric space heating rate.[405] As part of its approval, the Commission required the Company to file a 90-day compliance filing with (1) an implementation plan for the approved TOU rate that includes space heating rates and the integration of net

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[402] Ex. OAG-5 at 25 (Lee Direct).
[403] Ex. Xcel-19 at 35 (Halama Direct).
[404] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program*, MPUC Docket No. E002/M-17-775, ORDER APPROVING PILOT PROGRAM, SETTING REPORTING REQUIREMENTS, AND DENYING CERTIFICATION REQUEST (Aug. 7, 2018) (Order Point No. 6 required the Company to work with interested parties to develop a plan to implement a TOU rate after completion of the residential TOU pilot); *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*, MPUC Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (July 17, 2023) (Order Point No. 68 required Xcel Energy to file a proposed permanent residential time-of-use rate by December 31, 2023) [hereinafter 2021 Xcel Rate Case Order]..
[405] *In the Matter of the Petition of Xcel Energy for Approval of a Residential Time of Use Rate Design*, Docket No. E002/M-23-524, ORDER APPROVING REVISED OPT-IN PROPOSAL AND SETTING REPORTING REQUIREMENTS (May 15, 2025).

metering customers; (2) a marketing, education, and outreach plan; (3) proposed tariff changes; (4) an implementation budget and cost recovery proposal; and (5) proposed reporting requirements.[406] The Company filed its 90-day compliance filing on August 14, 2025.[407]

405. The Company's initial filing in this case included O&M costs related TOU rate implementation through the 2026 plan year but did not include the capital costs related to technical implementation. In Supplemental Direct Testimony, Company Witness Halama noted that the Company planned to incorporate costs in the MYRP in Rebuttal, consistent with the Commission's final decisions in Docket No. E002/M-23-524.[408]

406. The Commission issued the written Order for the Residential TOU design on May 15, 2025.[409] In response to that Order, the Company explained in its August 14, 2025 compliance filing in Docket No. E002/M-23-524, "Final blueprinting for the rate implementation project will be completed over the next month . . . [and] [t]he Company intends to seek cost recovery of these implementation costs through base rates as a part of our current electric rate case. These costs will be presented in our rebuttal testimony in that proceeding, which is scheduled to be filed in October 2025."[410]

407. Consistent with that filing, the Company incorporated the capital costs required to implement the Commission's TOU rate order in 2025 and 2026 into the rebuttal revenue requirement, which increased the 2025 revenue deficiency by approximately $20,000 and increased the 2026 deficiency by approximately $329,000.[411] The capital costs were needed to set up new rates in the Customer Resource System (CRS), develop programs to support customers electing to opt-in to the new rate, implement changes to allow participation for customers utilities other programs, and develop programs to support EV programs.[412]

408. The Company's Rebuttal Testimony also indicated that the rebuttal revenue requirement included $3.2 million in capital costs for a Rate Comparison Tool.[413]

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[406] *In the Matter of the Petition of Xcel Energy for Approval of a Residential Time of Use Rate Design*, Docket No. E002/M-23-524, Notice of Comment Period (Sept. 5, 2025).
[407] *In the Matter of the Petition of Xcel Energy for Approval of a Residential Time of Use Rate Design*, Docket No. E002/M-23-524, Xcel Energy Compliance Filing at 26 (Aug. 14, 2025) ("The Company intends to seek cost recovery of these implementation costs through base rates as a part of our current electric rate case. These costs will be presented in our rebuttal testimony in that proceeding, which is scheduled to be filed in October 2025. Rebuttal testimony will also include greater details on the activities required for rate implementation, including the final budget for the project.")
[408] Ex. Xcel-18 at 8, n.2 (Halama Supplemental Direct).
[409] *In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, ORDER APPROVING REVISED OPT-IN PROPOSAL AND SETTING REPORTING REQUIREMENTS (May 15, 2025).
[410] *In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, Xcel Energy Compliance Filing at 26 (Aug. 14, 2025).
[411] Ex. Xcel-19 at 27-29 and Schedules 3A-3B (Halama Rebuttal).
[412] Ex. Xcel 19 at 28 (Halama Rebuttal).
[413] Ex. Xcel-19 at 28-29 (Halama Rebuttal).

409. The Rate Comparison Tool would be designed to allow customers to compare their current rate with the TOU Rate.[414]

410. In Docket No. E002/M-23-524, parties have raised concern with the Rate Comparison Tool. The Commission has ordered Xcel to explore the feasibility of "shadow-billing," which would serve a similar purpose as the Rate Comparison Tool. The Commission did not Order Xcel to implement the Rate Comparison Tool.[415]

411. The Department agreed with Xcel's proposed rebuttal adjustment to the TOU rate implementation budget and proposed revenue deficiency increases.[416]

412. The OAG opposed recovery of all TOU capital costs, arguing that Xcel had provided insufficient information to prove it would incur any of the capital costs for the TOU rate.[417] Further, The OAG argued that Xcel had failed to provide a reliable evidentiary basis upon which to evaluate when and whether the costs would actually be incurred, even after the OAG requested further information in discovery.[418] The OAG additionally argued that Xcel did not provide any explanation for the basis of the costs it claimed, such as the calculations or assumptions underlying the costs.[419]

413. The OAG also raised specific concerns about the Rate Comparison Tool. The OAG argued that there was a significant risk that the costs attributed to the Rate Comparison Tool were already included in Xcel's initial request, making the rebuttal request for that portion of the TOU-related capital costs duplicative, and that the Rate Comparison Tool would not result in utility plant that is used and useful in the provision of utility service.[420]

414. The OAG ultimately concluded that the status of the tool as in development and "subject to change" makes it "impossible to evaluate the prudency or reasonableness of the investment based on Xcel's general characterizations."[421]

415. As an initial matter, the timing with which the TOU capital costs were brought into this proceeding is unfortunate. Ideally, a rate case initial filing would include all costs for which a utility seeks recovery. Because these capital costs were not included in the Initial Filing, the OAG (and other intervenors) were deprived of the opportunity to leverage the full duration of the testimony period to review and develop a record in support of their positions.

416. The timing of the introduction of these costs, however, was the product of the timing of Commission action in Docket E002/M-23-524, and not the result of any

[414] Ex. OAG-3 at 38 (Hinderlie Surrebuttal)
[415] Ex. OAG-3 at 36-37 (Hinderlie Surrebuttal).
[416] Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).
[417] OAG Initial Brief at 21. In Surrebuttal Testimony, the OAG recommended that the Commission consider deferred accounting for the TOU capital costs. Ex. OAG-3 at 39-40 (Hinderlie Surrebuttal).
[418] OAG Initial Brief at 21.
[419] OAG Initial Brief at 21-22.
[420] OAG Initial Brief at 19-21.
[421] Ex. OAG-3 at 38 (Hinderlie Surrebuttal).

misconduct or negligence by the Company. The introduction of these costs in Rebuttal Testimony also cannot be attributed to some exogenous factor which might warrant a determination that the reality of MYRP timing means that some costs may be incurred at a time that precludes their inclusion in the proceeding.

417. Instead, Xcel seeks recovery of costs that it is incurring to comply with an explicit directive from the Commission in another proceeding.

418. The Company has provided sufficient evidence, for all TOU capital costs except the Rate Comparison Tool, of the nature of the capital costs and the necessity of them to comply with Commission directives to meet Xcel's burden to prove that they are appropriate for rate recovery.

419. The same cannot be said of the capital costs related to the Rate Comparison Tool.

420. While the timing of Commission orders regarding the TOU rate implementation justifies the introduction of these costs in Rebuttal Testimony, it in no way diminishes the legal burden necessary to support recovery.

421. As previously discussed, a utility does not meet its burden to prove that costs should be recovered by simply proving that it has, or will, incur costs in a certain amount.

422. The Company's record support for the Rate Comparison Tool offered in testimony was limited to stating its existence and that Xcel will incur costs "to purchase software licenses" and "development costs." Indeed, most of the record information about the Rate Comparison Tool was provided by the OAG in opposition to the tool. Further, much of Xcel's justification for the reasonableness and usefulness of the tool seems to be presented (without citation) in its Initial Brief.[422]

423. This is insufficient for the Company to meet its burden to justify recovery, all the more so because the Commission has expressed an interest in consideration of shadow-billing as an alternative to the Rate Comparison Tool, and the record provides an inadequate basis to evaluate the relative merits of the two options.

424. The Commission should allow the Company to recover capital costs related to its TOU rate implementation, except that the Commission should not allow the Company to recover capital costs for the Rate Comparison Tool.

6. Reconnection Program

425. The Commission ordered Xcel to propose a reconnection program in Xcel's annual service quality docket.[423] The program protects economically vulnerable utility consumers by temporarily reconnecting their service during extreme heat events and

[422] Xcel Initial Brief at 179.
[423] Ex. OAG-3 at 40-41 (Hinderlie Surrebuttal).

when the Air Quality Index (AQI) reaches 151 or higher.[424] The Commission approved a modified version of Xcel's proposal and ordered the Reconnection Program be implemented by May 1, 2026.[425]

426. The Company added a request in Rebuttal Testimony to recover costs relating to a new program in which Xcel must temporarily reconnect service for disconnected residential customers during periods of extreme heat or poor air quality (Reconnection Program).[426] This program would add $404,000 to Xcel's rate base in the 2025 Test Year[427] and $1,600,000 to its rate base in the 2026 Plan Year.[428] Xcel also seeks recovery of $1,893,000 in operating expenses in the 2026 Plan Year.[429] Overall, these changs would increase the 2025 Test Year revenue deficiency by $28,000[430] and increase the 2026 Plan Year revenue deficiency by $2,445,000.[431]

427. During the notice and comment period, Xcel estimated that the cost of the program would include a one-time set-up cost of $360,000 and variable costs of between $38,608 and $163,780 per event.[432] In Docket No. E002/M-25-27, the OAG had advocated for expedited implementation of the Reconnection Program.[433] The OAG also argued in that docket Xcel's cost estimates were unsupported.[434]

428. The Company explained in Docket No. E002/M-25-27 that cost assumptions and estimates provided in that proceeding were preliminary and that not all costs had been forecasted.[435] Xcel stated in reply comments, "[i]n short, there are multiple and irreducible uncertainties in making these forecasts. . . . In addition, to the Company's knowledge, no other utilities in the United States are currently implementing heat and/or AQI reconnection, so we lack comparative data from other utilities and regions to inform

[424] Ex. OAG-3 at 41 (Hinderlie Surrebuttal).
[425] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E-002/M-25-27, ORDER (July 25, 2025) (eDocket No. 20257-221406-01).
[426] Ex. Xcel-19 at 20 (Halama Rebuttal).
[427] Ex. Xcel-19, Schedule 3A at 4 (Halama Rebuttal).
[428] Ex. Xcel-19, Schedule 3B at 3 (Halama Rebuttal).
[429] Ex. Xcel-19, Schedule 3B at 4 (Halama Rebuttal).
[430] Ex. Xcel-19, Schedule 3A at 4 (Halama Rebuttal).
[431] Ex. Xcel-19, Schedule 3B at 4 (Halama Rebuttal).
[432] Ex. OAG-3 at 44 (Hinderlie Surrebuttal).
[433] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E002/M-25-27, OAG Letter (July 16, 2025) (supporting decision options 9 and 10, to require implementation effective May 1, 2026); *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E002/M-25-27, OAG Comments at 2 (May 9, 2025) (recommending plan implementation on an expedited timeline).
[434] Ex. OAG-3 at 43 (Hinderlie Surrebuttal).
[435] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E002/M-25-27, Xcel Energy Reply Comments at 15 (June 3, 2025).

our predictions and cost estimates."[436] The Commission "approved Xcel's plan to institute this program with significant modifications from its original proposal."[437]

429. When the Commission ordered Xcel to implement the program, it did not state whether it found Xcel's cost estimates to be reasonable, but it did require Xcel to provide a summary of the costs of the program in future annual Service Quality reports.[438]

430. In response to OAG discovery requests regarding the Company's cost estimates,[439] Xcel responded, "[t]he costs included in Halama Direct, Schedules 3A and 3B, column 24 include the mid-range estimates from Table 1 of the June 3, 2025 Reply Comments for per-event variable costs." [440] As Xcel Energy explained in Docket E002/M-25-27, "[a]s a mid-range estimate, we use the highest number of customers of record in a disconnected status in a non-CWR month in 2024. This includes customers newly disconnected that month and customers remaining disconnected from prior months. This occurred in July 2024, when 12,453 residential and commercial customers were in a disconnected status on July 18."[441]

431. The Company also confirmed, in response to discovery, that the proposed costs were incremental to those costs already included in supplemental direct.[442]

432. The OAG recommended disallowing the Reconnection Costs in the rate case and allowing Xcel to request deferred accounting in the program's original docket, with the deferred expenses reviewed in Xcel's next rate case, faulting Xcel for inadequately explaining the variance between the initial cost estimates and those proposed or inclusion in rates, the level of support provided by the Company in support of the costs, and failing to establish that the costs were not incremental.[443]

433. Xcel has met its burden to prove that these costs are reasonable and should be included in rates in this proceeding.

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[436] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E002/M-25-27, Xcel Energy Reply Comments at 15 (June 3, 2025).
[437] Ex. OAG-3 at 41 (Hinderlie Surrebuttal).
[438] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E-002/M-25-27, ORDER at 2 (July 25, 2025) (eDocket No. 20257-221406-01).
[439] Ex. OAG-3 at 43 (Hinderlie Surrebuttal).
[440] Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Response to OAG IR 1061).
[441] *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, MPUC Docket No. E002/M-25-27, Xcel Energy Reply Comments at 16 (June 3, 2025). Further, as explained in the Company's Reply Comments, the high-end estimate takes into consideration the expected roll out of additional AMI meters in 2025 and accounts for the possibility that the number of disconnected customers in future years could be higher than 2024. *Id.*
[442] Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Energy Response to OAG IR 1061).
[443] Ex. OAG-3 at 47-50 (Hinderlie Surrebuttal).

434. The Commission directed Xcel to implement the Reconnection Program, and it necessarily follows that Xcel should be allowed to recover the reasonable costs of complying with the Commission's Order.

435. This does not end the inquiry, however, as the Commission did not render a decision on the appropriate cost level for recovery. It is not, contrary to Xcel's suggestion, inappropriate for the OAG to scrutinize the costs associated with a program that it supported in concept. Support for a given program does not require unequivocal support for any price tag for that initiative, especially when the OAG raised similar cost concerns at the time of Commission approval in Docket E002/M-25-27. And here, certainly, the disparity between the initial estimates and the amounts requested for recovery is significant enough to warrant scrutiny.

436. Xcel did, however, establish that the preliminary nature of the earlier cost estimates renders it unsurprising that the actual costs materially differed from initial estimates.

437. The Company provided adequate support for its costs to justify inclusion in rates. Further, the record provides no basis to doubt Xcel's representation that the costs are incremental. The Company has unequivocally stated as much, and in the absence of a basis to doubt this representation, it is unclear what additional evidence Xcel could provide to prove the negative that costs for the Reconnection Program were not included in the initial rate request.

438. Further, this Report previously recommended approving the Company's capital true-up mechanism. While a true-up mechanism should not be used as a justification to approve unsupported cost levels, its presence does reduce the risk to ratepayers if Xcel's forecasted capital expenditures ultimately prove to be too high.

439. For these reasons, the Commission should approve Xcel's proposed recovery of costs related to the Reconnection Program.

7. Energy Supply O&M

440. The Company's Energy Supply business area is responsible for operating and maintaining the Company's non-nuclear generation facilities that include natural gas, coal, hydro, wind, biomass, refuse, solar, and other facilities.[444] In order to safely operate and maintain these generation facilities for the benefit of customers, Energy Supply incurs O&M expenses for labor, overtime, chemicals, materials, outside services, rents, land easements, and employee expenses.[445]

441. For 2025 and 2026, Energy Supply has budgeted $167.5 million and $192.4 million, respectively, in O&M expenses (NSP Total Company).[446] Company

[444] Ex. Xcel-44 at 1-2, 11 (Capra Direct).
[445] Ex. Xcel-46 at 2 (Capra Rebuttal).
[446] Ex. Xcel-46 at 4 (Capra Rebuttal). Energy Supply's 2025 and 2026 O&M expenses are $122.5 million and $141.4 million for 2025 and 2026 MN Jurisdiction. Ex. Xcel-44 at 57 (Capra Direct).

Witness Capra provided nearly 40 pages of testimony describing the cost drivers for each of Energy Supply's O&M budget category for 2025 and 2026.[447]

442. The Company has overstated its Energy Supply O&M costs by an average of approximately 4.3 percent over the past three years, resulting in the Company spending approximately $14.7 million less than budgeted over that time.[448]

443. XLI argues that, due to this overbudgeting, ratepayers have unnecessarily paid an extra $14.7 million in Energy Supply O&M costs during that three-year period.[449]

444. XLI also noted that Xcel's 2025 Energy Supply O&M budget was 7.8 percent higher than the 2024 budget, and the 2026 budget was 15.4 percent higher than the 2025 budget.[450]

445. Based on these observations, XLI recommends that the Commission reduce Xcel's proposed Energy Supply O&M expenses by 4.3 percent in both the 2025 Test Year and 2026 Plan Year, which would result in a reduction of $4.9 million in 2025 and $5.7 in 2026.[451]

446. XLI asserted that the Company's true-up would protect it from under-recovery if the Commission were to disallow a portion of its Energy Supply O&M budget.[452]

447. In Response, Xcel offered three justifications for why its actual Energy Supply O&M expenses for 2022-2024 were lower than the amounts approved in the last rate case: (1) delays in the in-service dates for Sherco Solar I and II, (2) a waking damage payment, and (3) liquidated damages.[453]

448. When Energy Supply's O&M budgets were developed for the last electric rate case, it was assumed that Sherco Solar I would be in-service in 2023 and Sherco Solar II would be in-service in 2024.[454] Due to permitting delays, the in-service dates for both of these projects was postponed for a year.[455] These delays reduced actual Energy Supply O&M expenses in 2023 and 2024 by $0.9 and $4.2 million, respectively.[456]

449. Actual O&M expenses for 2022 to 2024 were lower than approved amounts due to a $2.5 million waking damages payment received in 2022 related to the Lake Benton Wind project and over $10 million in liquidated damage payments from 2022 to

[447] Ex. Xcel-44 at 54-92 (Capra Direct).
[448] Ex. XLI-1 at 50, Table 12, (LaConte Direct); Ex. XLI-1 at 51 (LaConte Direct).
[449] Ex. XLI-1 at 50-51 (LaConte Direct).
[450] Ex. XLI-1 at 51 (LaConte Direct).
[451] Ex. XLI-1 at 51 (LaConte Direct).
[452] Ex. XLI-7 at 14 (LaConte Surrebuttal).
[453] Ex. Xcel-46 at 4-5 (Capra Rebuttal).
[454] Ex. Xcel-46 at 4-5 (Capra Rebuttal).
[455] Ex. Xcel-46 at 5 (Capra Rebuttal).
[456] Ex. Xcel-46 at 4-5 (Capra Rebuttal).

2024 from wind service providers.[457] The waking damage payment and over $7 million of the liquidated damage payments were returned to customers through the RES Rider.[458]

450. Energy Supply's 2025 O&M budget is higher than 2024 actual expenses due to the addition of Sherco Solar III ($5.3 million), a major overhaul at Sherco Unit 3 ($7.9 million), and a one-time obsolete inventory write-off of $8.1 million due to the Sherco Unit 1 retirement.[459] Further, Energy Supply's 2026 O&M budget reflected annual base wage increases, a turbine overhaul at the Red Wing Plant Unit 1 ($1.1 million), and a generator inspection at the King Plant Unit 1 ($1.2 million).[460]

451. XLI did not dispute any of Xcel's proffered Energy Supply O&M expense drivers or the amounts budgeted by the Company in 2025 and 2026 to address each of these drivers in Surrebuttal Testimony.[461]

452. The over-budgeting in Xcel's recent Energy Supply O&M budgets, as well as the sharp increases in the budgets for 2025 and 2026, are sufficiently significant to warrant further attention.

453. Xcel's explanations for this trend were, however, sufficiently reasonable and specific to meet its burden to prove it is entitled to recovery of its proposed Energy Supply O&M budget in 2025 and 2026. This is especially true where XLI has not disputed either the reasonableness, or the amounts, of the drivers identified by Xcel.

454. Further, the argument that Xcel's true-up would protect it from over-recovery is without merit. These costs are O&M expenses, not capital expenses. The Company does not have, nor is it proposing in this case, an O&M tracker. Any under-recovery would deprive the Company of means to necessary and reasonable costs of providing electric service.[462]

455. The Commission should approve recovery of Xcel's proposed Energy Supply O&M budget for both the 2025 Test Year and the 2026 Plan Year.

8. Distribution O&M (Vegetation Management)

456. Vegetation management refers to controlling the growth of and removing trees, shrubs, and other plants that grow too close to electrical lines and other utility infrastructure.[463]

[457] Ex. Xcel-46 at 5 (Capra Rebuttal).
[458] Ex. Xcel-46, Schedule 2 (Capra Rebuttal); Ex. Xcel-46 at 5 (Capra Rebuttal).
[459] Ex. Xcel-46 at 7 (Capra Rebuttal).
[460] Ex. Xcel-46 at 7 (Capra Rebuttal).
[461] Ex. XLI-7 at 13-15 (LaConte Surrebuttal).
[462] Ex. Xcel-15 at 29-30 (Liberkowski Direct).
[463] Ex. DOC-7 at 16 (Uphus Direct).

457. The Company proposes annual budgets of $37.4 million in 2025 and $40.9 million in 2026 for distribution system vegetation management.[464]

458. The Department challenged the reasonableness of Xcel's proposed budgets because the 2025 budget is 22 percent greater than Xcel's 2024 actual spending and the 2026 budget is 9 percent greater than the 2025 proposal.[465] Additionally, Xcel has underspent its vegetation management budgets every year since at least 2022, as shown below.[466]

	2022	2023	2024	Total
Approved Budget	$43.4 million	$46.0 million	$46.2 million	$135.6 million
Actual Spending	$35.8 million	$28.6 million	$30.7 million	$95.1 million
Difference	$7.6 million	$17.4 million	$15.5 million	$40.5 million

459. Through September 2025, Xcel had only spent $20.1 million. Annualizing this spending, Xcel was only on pace to spend $26.8 million for the entire year, which would be $10.6 million under the Company's budget.[467]

460. The Department recommended that the Commission approve three-percent inflationary increases over 2024 actual spending for 2025 and 2026.[468] These adjustments would result in budgets of $31.6 million in 2025 and $32.6 million in 2026, reducing Xcel's revenues requirement by $5.8 million and $8.3 million in the respective test and plan years.[469]

461. The Company responded that the need for higher vegetation management expenses in 2025 and 2026 is driven by: (1) work that was prudently deferred in prior years in order to address higher priority work such as outage restoration; (2) contractor rate increases; (3) additional vegetation growth due to higher-than-average rainfall; and (4) forecasted inflationary increases.[470] The Company asserted its higher 2025 and 2026 vegetation management budgets are also needed to perform more vegetation management in urban areas where there is less opportunity to use mechanical equipment, which results in higher labor costs.[471]

462. The Company responded to concerns about the actual vegetation management costs for 2022 to 2024 being lower than the amounts approved in the Company's last rate case by arguing that this shows how the Company appropriately

[464] Ex. DOC-7 at 16 (Uphus Direct).
[465] Ex. DOC-7 at 17 (Uphus Direct).
[466] Ex. DOC-7 at 19 (Uphus Direct).
[467] Ex. DOC-8 at 11 (Uphus Surrebuttal).
[468] Ex. DOC-7 at 20 (Uphus Direct).
[469] Ex. DOC-7 at 20 (Uphus Direct).
[470] Ex. Xcel-35 at 44-45 (Mensen Rebuttal).
[471] Ex. Xcel-35 at 45 (Mensen Rebuttal); Ex. DOC-7 at Schedule 1 at 50-51 (Uphus Direct).

manages its overall O&M budget to address the highest priority needs of its customers.[472] The year with the greatest deviation between the budget and the rate case approved amount is 2023. In 2023, vegetation management work planned for that year was postponed to reallocate resources to storm restoration work.[473] This is because the frequency and severity of storms experienced in 2023 resulted in storm restoration O&M costs in 2023 that exceeded costs in each of the prior four-years (2019 to 2022).[474] The Company argued that due to this unanticipated expense, it adjusted other portions of its 2023 O&M budget, including reducing vegetation management, to ensure that it had adequate O&M funds to repair distribution facilities and restore service to customers.[475]

463. The Company stated in discovery that actual vegetation management costs for 2025 through September 30, 2025 "may be less than" the amount budgeted because while it had cleared more miles than initially planned for in 2025, it was able to capitalize a portion of these costs as preparation work for distribution line rebuilds.[476]

464. The Company argues that recovery is appropriate because it manages its Distribution O&M budget on an overall basis that allows for fluctuations between costs in different budget categories.[477]

465. The Department's recommendation to apply a three-percent increase to 2024 actual vegetation management costs to set the 2025 and 2026 budgets for vegetation management would cause Distribution's total O&M budget for 2025 and 2026 to fall below 2024 actual O&M expenses.[478]

466. The Company has not met its burden to prove that its budgeted vegetation management expenses are reasonable.

467. While the Company offers some explanation for variance between historical budgeted and actual expense, its explanations are less specific and quantified than its description of the drivers for the increase in the Energy Supply O&M budget.

468. Also, unlike the Energy Supply O&M budget, the argument for reducing the Company's revenue requirement is not based solely on historical data. The Department has shown that in 2025, the Company is on pace to underspend its vegetation management budget by $10.6 million.[479] Notably, this amount is greater than the Department's proposed reduction for 2025. In other words, if this trend continued through

[472] Ex. Xcel-35 at 47 (Mensen Rebuttal).
[473] Ex. Xcel-35 at 47 (Mensen Rebuttal).
[474] Ex. Xcel-35 at 47 (Mensen Rebuttal).
[475] Ex. Xcel-35 at 47 (Mensen Rebuttal).
[476] Ex. DOC-8, Schedule 1 at 3 (Uphus Surrebuttal).
[477] Ex. Xcel-35 at 48 (Mensen Rebuttal); Ex. Xcel-26 at 29 (Robinson Direct).
[478] Xcel Energy Initial Brief at 76.
[479] The data comparing actual 2025 year-to-date spending to forecasted amounts is especially persuasive on this issue. If trying to ascertain today's temperature, the reading on the thermometer is stronger evidence than arguments about the methodology supporting yesterday's meteorological forecasts.

the end of 2025, the Company would still recover more money for vegetation management through rates than it actually spent on this activity.

469. Further, a portion of the Company's explanation for why it did not spend its vegetation management budget was that it postponed vegetation management work to use the money for other activities. Ultimately, the fact that the Company did not need to perform vegetation management work at budgeted levels underscores the Department's argument that the Company had budgeted for more vegetation management was necessary. And the Company has failed to prove that that is not also the case in the 2025 Test Year and 2026 Plan Year.

470. The Company's argument with respect to its entire distribution O&M budget is also unpersuasive. Just as depreciation expenses for extended nuclear plants did not justify increased depreciation expense for the Sherco 3 and King plants, purported potential offsets in other distribution O&M categories do not justify setting rates based on an inadequately supported increase in vegetation management expenses.

471. The Commission should adopt the Department's recommendation and set the Company's authorized recovery of vegetation management expenses to a three-percent year-over-year increase of the 2024 actual totals, thereby reducing Xcel's revenue requirement by $5.8 million in the 2025 Test Year and $8.3 million in the 2026 Plan Year.

9. Transmission O&M

472. The Company requested $18.9 million in Transmission O&M for the 2025 Test Year and $19.4 million for the 2026 Plan Year.[480] The Transmission O&M budget includes costs associated with the operation and maintenance of Xcel's transmission system, such as internal and contract labor, employee expenses, fees, and materials.[481]

473. The Company's 2025 budget is nine-percent higher than its 2024 forecast.[482] Xcel stated that the increase was driven by internal labor costs due to annual increases in base pay and additional line inspections for wildfire mitigation.[483] The 2026 forecast is two-percent higher than the 2024 forecast.[484]

474. The Department recommended setting Transmission O&M expense at the level of the Company's actual Transportation O&M expenses, arguing that the consistently declining actual Transmission O&M expenses, as well as the insufficiency of Xcel's explanation in support of its requested increase, merited such an adjustment. The impact of this adjustment would be a $1.5 million reduction in the 2025 test year and a $2.0 million reduction in the 2026 plan year.[485]

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[480] Ex. Xcel-42 at 78 (Berklund Direct); Ex. DOC-5, Schedule 1 (Golden Direct).
[481] Ex. Xcel-42 at 78 (Berklund Direct).
[482] Ex. Xcel-42 at 81 (Berklund Direct).
[483] Ex. Xcel-42 at 81 (Berklund Direct).
[484] Ex. Xcel-42 at 82 (Berklund Direct).
[485] Ex. DOC-5 at 8 (Golden Direct).

475. XLI recommends reducing Transmission's O&M expenses by 16.2 percent in 2025 and 2026, or approximately $3.1 million each year.[486] XLI determined this reduction by comparing Transmission's 2022 through 2024 actual O&M expense to the approved amounts in the Company's last electric rate case, and taking the three-year average of the difference between them.[487] XLI's recommended Transmission O&M expense budgets of $15.8 million for 2025 and $16.3 million for 2026.[488]

476. Transmission's internal labor costs are budgeted to increase in 2025 and 2026 compared to prior years' actual costs due to annual increases in base pay and increases in internal labor associated with line inspections for wildfire mitigations.[489] According to the Company, the annual increases in base pay account for a $0.3 million increase in the 2025 budget compared to 2024 actuals and a $0.3 million increase in the 2026 budget compared to the 2025 budget.[490] Likewise, the increases in internal labor associated with line inspections for wildfire mitigations account for a $0.5 million increase in the 2025 budget compared to 2024 actual totals.[491]

477. Xcel asserted that internal reorganizations within the Company impacted Transmission's actual O&M expense from 2022 through 2024.[492] Specifically, in 2023, the Company formed a new Integrated System Planning (ISP) business unit, and starting that same year, certain fees and internal labor costs were shifted out of Transmission and into ISP and legal services.[493] This resulted in a $0.9 million decrease in Transmission's 2023 and 2024 actual O&M expense compared to the approved amounts in the Company's last electric rate case.[494]

478. In addition to internal labor costs, the Company's 2025 and 2026 Transmission O&M expense budgets reflect increases in materials due to inflation and increases in maintenance work, as well as employee expenses due to increases in employee training and travel.[495]

479. The Company also discussed the increase in capital investments in 2025 and 2026, including numerous transmission projects approved by MISO as part of its Long-Range Transmission Planning Tranche 1 Portfolio as well as the Minnesota Energy Connection project, that will impact 2025 and 2026 O&M expenses.[496] Company Witness Berklund asserted that "[c]apital investments are a key driver of O&M for Transmission."[497] The Company projects there will be a substantial increase in Transmission capital investments in 2025 and 2026 compared to 2024, and asserts that

[486] Ex. XLI-1 at 53 (LaConte Direct).
[487] Ex. XLI-1 at 52 (LaConte Direct).
[488] Ex. Xcel-43 at 10-11 (Berklund Rebuttal).
[489] Ex. Xcel-42 at 84 (Berklund Direct); Ex. Xcel-43 at 6-7 (Berklund Rebuttal).
[490] Ex. Xcel-43 at 7 (Berklund Rebuttal).
[491] Ex. Xcel-43 at 7 (Berklund Rebuttal).
[492] Ex. Xcel-43 at 4 (Berklund Rebuttal).
[493] Ex. Xcel-43 at 4 (Berklund Rebuttal).
[494] Ex. Xcel-43 at 4-5 (Berklund Rebuttal).
[495] Ex. Xcel-43 at 7-8 (Berklund Rebuttal).
[496] Ex. Xcel-43 at 8 (Berklund Rebuttal).
[497] Ex. Xcel-43 at 9 (Berklund Rebuttal).

this demonstrates the reasonableness of Transmission's projected increases in O&M expenses of $1.5 million in 2025 and $2.0 million in 2026 compared to 2024 actuals.[498]

480. In 2024, certain North American Electric Reliability Corporation and MISO related administrative fees and facility study costs were also shifted out of Transmission and into ISP.[499] This resulted in a $2.1 million decrease in Transmission's 2024 actual O&M expense compared to the approved 2024 O&M expense amount.[500]

481. The Company presented evidence that Transmission's 2025 O&M expense budget is ten percent lower than its 2022 actual O&M expense and Transmission's 2026 O&M expense budget is eight percent lower than its 2022 actual O&M expense.[501] Transmission's 2025 and 2026 O&M expense budgets are also lower than the most recent four-year (2021-2024) average of actual O&M expense.[502] Moreover, the Company's internal reorganization changes were taken into account when developing Transmission's 2024 O&M expense forecast ($17.3 million), which was nearly identical to 2024 actual O&M expense ($17.4 million).[503] This demonstrates that Transmission has already appropriately accounted for these changes in its rate forecasts and budgets.[504]

482. The Company further stated that the remaining difference between Transmission's actual O&M expense and the approved amounts was due to reduced O&M labor split rates.[505]

483. These changes were taken into account when developing Transmission's 2025 and 2026 O&M expense budgets.[506] In developing its budgets (including for 2025 and 2026), Transmission uses a bottom-up approach.[507] That is, each budget manager reviews their needs, factoring in work and any anticipated efficiency gains, and develops budgets in accordance with those needs and anticipated efficiency gains.[508] The individual budgets are then consolidated for a total Transmission O&M expense budget and analyzed for reasonableness and accuracy compared to recent actual trends.[509] This includes normalizing actual spend for expenses that are not expected to continue into the budget year due to changes in business conditions or one-time events.[510]

484. After reviewing Xcel's response, the Department argued that even after accounting for the reorganization, the company's actual Transmission O&M expenses for 2023 and 2024 were still $3.5 million below its forecast.[511] The Department also noted

[498] Ex. Xcel-43 at 9-10 (Berklund Rebuttal).
[499] Ex. Xcel-43 at 5 (Berklund Rebuttal).
[500] Ex. Xcel-43 at 5 (Berklund Rebuttal).
[501] Ex. Xcel-43 at 6 (Berklund Rebuttal).
[502] Ex. Xcel-43 at 3 (Berklund Rebuttal).
[503] Ex. Xcel-43 at 6 (Berklund Rebuttal).
[504] Ex. Xcel-43 at 6 (Berklund Rebuttal).
[505] Ex. Xcel-43 at 5 (Berklund Rebuttal).
[506] Ex. Xcel-43 at 5 (Berklund Rebuttal).
[507] Ex. Xcel-43 at 3 (Berklund Rebuttal).
[508] Ex. Xcel-43 at 3 (Berklund Rebuttal).
[509] Ex. Xcel-43 at 3 (Berklund Rebuttal).
[510] Ex. Xcel-43 at 3 (Berklund Rebuttal).
[511] Ex. DOC-6 at 11 (Golden Surrebuttal).

that annualizing Xcel's actual 2025 spending to date resulted in a projected 2025 actual expense of $17.07 million, less than its forecasted expense of $18.9 million and less than the Department's recommendation of $17.4 million.[512]

485. The Department and XLI have both put forward compelling evidence of a historical trend that suggests Xcel's Transportation O&M budget is too high for 2025 and 2026.

486. In response to these concerns, the Company presented detailed analysis and explanation of its budgeting process as well as specific drivers that it asserted justified the increase in Transportation O&M expense for 2025 and 2026. Taken in isolation, this evidence might be sufficient to warrant rate recovery of Transportation O&M expenses at the Company's requested levels.

487. As with the vegetation management expenses, however, actual data from 2025 bears out that the intervenors' concerns are valid. Evidence presented in Surrebuttal Testimony establishes that 2025 actual Transportation O&M expense more closely tracks, the Department's proposed level of recovery than the Company's projected budget. This data lends credibility to the Department's analysis and establishes that the Department's proposal is more reasonable than Xcel's.

488. Because the actual Transportation O&M expenditures were on pace to exceed XLI's proposed level of recovery, and because of the detailed analysis presented by the Company justifying its budget, XLI's proposal would inadequately compensate the Company for its Transportation O&M expenditures and should be rejected.

489. The Company has failed to meet its burden to prove that its proposed level of Transportation O&M expenses are reasonable for the 2025 Test Year and 2026 Plan Year. Accordingly, the Commission should adopt the Department's recommendation and authorize recovery of $17.4 million for Transportation O&M expenses for 2025 and 2026.

10. Customer Care O&M

490. Consistent with treatment in prior rate cases, the Company developed its Customer Care O&M budget by assessing the needs of the Customer Care organization and the various Operating Companies that the Customer Care division supports, and budgeting at the business function level. The Company proposed a Customer Care O&M budget for the MYRP of $27.3 million for the 2025 test year and $27.1 million for the 2026 plan year.[513]

491. The overall Customer Care O&M 2025 test year budget is a decrease from the O&M expense levels for the prior four years and represents a decrease of approximately 15 percent as compared to the 2021 Customer Care O&M expense. The Company provided testimony and data showing that, although the Customer Care O&M budget is decreasing overall, the Company anticipates an increase in Customer Care

[512] Ex. DOC-6 at 12-13 (Golden Surrebuttal).
[513] Ex. Xcel-38 at 9, 14 (Lindgren Direct).

labor costs of approximately $1.1 million attributable to employee headcount and annual wage increases. The Company also estimated an increase in Customer Care labor costs of approximately $359,000 from 2025 to 2026 attributable to annual wage increases.[514]

492. XLI member, BOMA Greater Minneapolis, has reported that at least 23 of its members have experienced billing and customer service issues since 2022, including "delayed and inaccurate bills, misapplied payments, and ineffective communications and resolutions" and erroneous disconnection notices.[515]

493. XLI recommended denial of all Customer Care expenses in both 2025 and 2026 based on these concerns.[516]

494. The Company has attempted to identify the affected BOMA members, including by requesting identification of which BOMA members continue to experience billing and customer service issues that remain unresolved. BOMA has not provided this information.[517]

495. The Company implemented alternative means to identify impacted BOMA members and respond to BOMA's concerns. Xcel's Billing Department partnered with the Account Management team to compile bi-weekly lists of identified BOMA member accounts to evaluate whether any of these accounts warrant further review to capture any account anomalies, such as billing delays, before these anomalies create the need for post-billing corrections.[518]

496. No other party has challenged the recoverability of Xcel's Customer Care O&M expenses. No party, including XLI, has disputed the amount Xcel is spending on Customer Care O&M expenses. Rather, XLI's argument seems to be effectively that, due to the purported billing errors experienced by BOMA members, Xcel's customer care efforts are inadequate such that ratepayers should not fund those activities.

497. Minn. R. 7820.3200 - .3800 impose certain requirements on electrical utilities' billing practices. While XLI has not identified which specific provision of these rules it believes Xcel is out of compliance with, it should not be controversial for customers to expect their bills to be reasonably accurate.

498. BOMA, however, has not provided the Company with information to identify which customers are potentially affected by billing errors. It is an understandable position that customers should not shoulder the burden of addressing alleged errors caused by their utility. That being said, it is difficult to see how Xcel could be expected to remedy any errors if it is not provided information sufficient to investigate the issue. Relevant to the determination here, the absence of this information precludes making findings that specify the scope and magnitude of any alleged billing issues.

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[514] Ex. Xcel-38 at 10, 16 (Lindgren Direct).
[515] Ex. XLI-1 at 59 (LaConte Direct).
[516] Ex. XLI-2 at 1, 59-64 (LaConte Direct). XLI also recommended a reduction in Xcel's authorized ROE.
[517] Ex. Xcel-81 at 7 (Howard Rebuttal).
[518] Ex. Xcel-81 at 6 (Howard Rebuttal).

499. Further, disallowance of any entire category of O&M costs actually incurred by the Company, totaling more than $27 million annually, would be a drastic remedy even if XLI's allegations were credited.

500. Xcel and XLI have agreed that the Commission's ongoing investigation into residential billing errors in Docket No. E, G-002/CI-25-341 should be expanded to include commercial customers such as BOMA.[519] That proceeding provides an opportunity for the Commission to develop a more robust record on commercial billing errors and, if appropriate, tailer a more appropriate and targeted remedy than disallowance of all of the Company's Customer Care O&M costs in this proceeding.[520]

501. The Company has met its burden to prove that its Customer Care O&M costs are appropriate for recovery in the requested amount, and the Commission should approve these costs.

11. Cost Allocators

502. Cost allocators are used to assign shared costs to Xcel's operating companies when cost causation cannot otherwise be clearly identified. In this case, the parties dispute the methodologies used in conjunction with three of Xcel's cost allocators.

a. General Allocator

503. Xcel Energy Services, Inc. (XES) 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. The Company's general allocator, used in all other jurisdictions besides Minnesota, is comprised of three equally weighted factors: total assets, total revenues, and number of employees.[521]

504. The Number of Employees factor is based on the number of employees for each operating company, with common officers from XES assigned to Xcel.[522]

505. XES employees are only allowed to use the General Allocator when the work they are doing is to support the overall enterprise, such as an XES corporate finance employee working on an Xcel securities filing or an XES Human Resources employee developing enterprise-wise policies; in all other circumstances, XES employees must direct assign their time to the proper regulated operating company or non-regulated affiliate.[523] Because NSPM has the largest number of employees, the costs of XES to

[519] XLI Initial Brief at 33; Xcel Reply Brief at 50-51.
[520] This Finding should not be interpreted as suggesting that this may not be an appropriate remedy in Docket No. 25-341 once the record is fully developed.
[521] Ex. DOC-1 at 33–34 (Johnson Direct).
[522] Ex. Xcel-49 at 13-14 (Doyle Direct).
[523] Ex. Xcel-49 at 13-17 (Doyle Direct).

support NSPM (through Human Resources, Employee Communications, and other employee-focused areas) incur the largest time and labor amounts.[524]

506. Since 2011, the Commission has required Xcel to calculate the labor component of the allocator using full-time equivalents (FTEs) hours as opposed to Xcel's preferred Number of Employees methodology, reasoning in part that allocations based on number employees could result in a subsidiary reflecting labor costs of zero if its labor is performed exclusively by employees assigned to other subsidiaries.[525] 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."[526]

507. In this case, Xcel requests to change the labor component from full-time equivalents in each operating company to the number of employees.[527]

508. The Company argues that its FTE Hours methodology results in costs that are incurred to support NSPM's regulated operations are not allocated to Minnesota customers, resulting in operations costs of the regulated utility being borne by non-regulated affiliates and other operating companies.[528]

509. The Department opposes Xcel's proposed change. The Department asserted that Xcel has not alleviated the concerns previously identified by the Commission.[529]

510. The Company has not met its burden to demonstrate that its proposed change would result in just and reasonable rates.

511. The Commission, in 2011, previously considered this issue and determined that the FTE Hours methodology was appropriate. The record in this proceeding does not warrant departing from that practice.

512. The Department has substantiated its concern that the Number of Employees methodology would result in over-allocation to the Minnesota jurisdiction. The size of the jurisdiction makes it likely that it would more often be the case that employees assigned to NSPM would perform work supporting other affiliates than employees assigned to other affiliates would perform work supporting NSPM. Smaller affiliates, with

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[524] Ex. Xcel-49 at 24-25 (Doyle Direct).
[525] Ex. DOC-1 at 34 (Johnson Direct) (citing *In re N. States Power Co.'s Cost Allocation Procedures and General Allocator,* MPUC Docket No. E,G-002/AI-10-690*,* ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (Mar. 15, 2011) (eDocket No. 20113-60362-01)).
[526] *In re N. States Power Co.'s Cost Allocation Procedures and General Allocator*, MPUC Docket No. E,G-002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS at 1-2 (Mar. 15, 2011) (eDocket No. 20113-60362-01).
[527] Ex. Xcel-49 at 26 (Doyle Direct).
[528] Ex. Xcel-49 at 18-19 (Doyle Direct).
[529] Ex. DOC-2 at 10–11 (Johnson Surrebuttal).

few or no employees would almost certainly be the beneficiary of the Number of Employees methodology.

513. Regardless of whether there is merit to Xcel's argument that the FTE Hours methodology may result in NSPM customers not being allocated the full labor costs used to support them, such concerns cannot justify over-correcting and adopting a methodology that would systemically over-charge NSPM under a regulatory paradigm where all doubt is to be resolved in favor of the consumer.

514. The Commission should reject the Company's proposal to use the Number of Employees methodology for its general allocator.

b. Interchange Agreement Allocator

515. Although Xcel has separate operating companies for Minnesota and Wisconsin (NSPW), the two companies share generation and transmission assets.[530] To assign costs to the two jurisdictions, Xcel relies on cost and revenue allocators memorialized in an interchange agreement subject to annual review and approval by the Federal Energy Regulatory Commission (FERC).[531]

516. In this case, the Company forecasted 2025-2026 Interchange revenue and expenses using 2025-2026 NSPM and NSPW budget information.[532] The demand allocator was computed based on average monthly coincident peak demands for the NSPM and NSPW systems based on three years of data.[533] In Supplemental Direct Testimony filed March 17, 2025, the Company explained it had discovered an error in the computation of the interchange demand allocator and provided a corrected demand allocator calculation.[534]

517. In May 2025, FERC approved Xcel's proposed interchange agreement for 2025.[535]

518. The Department agreed it was appropriate to correct the Interchange demand allocator for the error the Company had identified in supplemental direct testimony, but recommended the Commission also require the Company to update its Interchange billings in the revenue requirement to reflect the 2025 Interchange demand allocator approved by FERC in May 2025 in FERC Docket ER25-1620-000. This update would increase the 2025 revenue requirement by $272,723.[536]

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[530] Ex. DOC-1 at 30 (Johnson Direct).
[531] Ex. DOC-1 at 30 (Johnson Direct).
[532] Ex. Xcel-17 at 61-62 (Halama Direct); Ex. DOC-1, Schedule 4 at 7 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A).
[533] Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator); *see also* Ex. DOC-1, Schedule 4 at 7 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A) ("Coincident peak demands are based upon three years of data consisting of 18 months of actual and 18 months of projected peak demands.").
[534] Ex. Xcel-18 at 6-7 and Schedule 17 (Halama Supplemental Direct).
[535] Ex. DOC-1, Schedule 4 at 1 (Johnson Direct).
[536] Ex. DOC-1 at 29-33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).

519. The Department further recommended the Commission require Xcel to apply the 2025 Interchange demand allocator accepted by FERC in May 2025 to 2026 costs and revenues, decreasing the 2026 revenue deficiency by $2,940,237.[537]

520. The Department reasoned that using the most up-to-date allocator agreement would be consistent with the Commission's decision in Xcel's last rate case.[538]

521. The only difference between the demand allocator filed with FERC on March 14, 2025 (which was accepted on May 6, 2025) and the 2025 demand allocator presented in the Company's supplemental direct testimony was the use of updated transmission loss multipliers based on an updated system loss study included in the FERC filing.[539]

522. The Company asserts that utilizing the updated transmission loss multiplier data to compute the 2026 demand allocator would result in an increase to the 2026 revenue requirement of $282,504.[540] However, this figure appears to have been presented for the first time in the Company's Initial Brief. Not only did this preclude other parties from offering testimony analyzing and contextualizing this figure, but the Administrative Law Judge was unable to verify the calculation from the record evidence cited.

523. Recent trends in the Interchange Agreement demand allocators filed with and accepted by FERC reflect an upward trend in the allocation of costs to NSPM over recent years.[541]

524. The Company argued that application of the 2025 Interchange Agreement demand allocator to 2026 is not representative of the 2026 plan year cost of service.[542] The demand allocator is one component of the Interchange Agreement billings with NSPW. Other components of the interchange agreement that change from year to year and are filed with FERC on an annual basis include energy allocators, electric plant in service, allowance for funds used during construction, accumulated provision for depreciation/amortization, property taxes, insurance expense, depreciation and amortization expense, O&M expense, purchased power costs, taxes and tax credits, and interest expense.[543] Selectively setting, the Company argues, one component of the Interchange Agreement billings based on the prior year's data does not accurately reflect the allocation of costs and revenues under the Interchange Agreement for 2026.[544]

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[537] Ex. DOC-1 at 33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).
[538] Xcel 2021 Rate Case Order at 109 (adopting the Department's recommendation to use updated allocators "based on the most contemporary evidence in the record.").
[539] Ex. DOC-1, Schedule 4 at 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A).
[540] Xcel Initial Brief at 158 (citing Ex. Xcel-101 (Xcel Energy's Response to DOC IR 1160, Attachment C)); Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachments A and C)).
[541] XLI-1 at 86 (LaConte Direct) (Xcel Energy's Response to DOC IR 157, Attachment A)).
[542] Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160).
[543] Ex. DOC-2, Schedule 2 (Johnson Surrebuttal) (Xcel Energy's Response to DOC IR 3107).
[544] Ex. Xcel-19 at 61 (Halama Rebuttal).

525. While Xcel identified other components that also impact Interchange Agreement billings, Xcel did not update any other components of the allocator or present any specific offsetting adjustments.[545]

526. The Commission addressed similar arguments on this issue in Xcel's most recent prior rate case. In that proceeding, the Commission acknowledged the plausibility of Xcel's argument that only adjusting one component of Interchange Agreement billings may fail to reflect other changes. Ultimately, however, the Commission concluded that, in the absence of record support for any other specific updates, the Department's proposal to update the Interchange Agreement allocator was "reasonable and based on the most contemporary evidence in the record."[546]

527. There is no basis to depart from the Commission's previous practice here. Like in the previous proceeding, the Department's recommended use of the more recent Interchange Agreement allocator figures is reasonable. Conceivably, other components of Interchange Agreement billings may also warrant update. But the absence of a record supporting any such updates does not justify declining to make a specific update that is supported by the record.

528. The Commission should approve the correction made by the Company in its Supplemental Direct testimony and adopt the Department's recommendation to update Xcel's Interchange Agreement allocator.

c. Indirect Wildfire Allocations

529. In addition to other wildfire mitigation costs, Xcel incurs some wildfire costs at the XES level that cannot be directly assigned to an operating company such as those located in Texas or Colardo.[547] Xcel proposes to allocate these costs based on each utility operating company's size (using total plant ratio) relative to the entire company.[548] For the 2025 and 2026 test years, Xcel asserts that it will incur $16.5 million and $19.8 million respectively that cannot be directly allocated to a particular operating company.[549] Using the total plant ratio methodology, Minnesota electric customers would be responsible for $3.3 million in 2025 and $4.3 million in 2026 in total wildfire costs (including $1.7 million in indirect wildfire costs in 2025 and $1.8 million in indirect wildfire costs in 2026).[550]

530. The Department objected to Xcel's use of the total plant ratio methodology to assign these indirect costs. The Department asserted that Xcel's preferred methodology wrongly assumes that its jurisdictions have equivalent wildfire risks even though wildfire risk in Xcel's Colorado and Texas jurisdictions is 2.4 to 7.6 times higher than in Minnesota.[551]

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[545] Ex. DOC-2 at 6 (Johnson Surrebuttal).
[546] Xcel 2021 Rate Case Order at 108-09.
[547] Ex. DOC-1 at 42-43 (Johnson Direct).
[548] Ex. DOC-1 at 43–44 (Johnson Direct).
[549] Ex. DOC-1 at 44 (Johnson Direct).
[550] Ex. DOC-1 at 44 (Johnson Direct); Ex. Xcel-50 at 15 (Doyle Rebuttal).
[551] Ex. DOC-9 at 14 (Borden Direct).

531. The Department recommended that the Commission require indirect wildfire costs to be allocated using the same allocations that Xcel used for wildfire costs that could be directly allocated to a service company, arguing that this methodology would better reflect cost causation principles. Under this proposal, if NSPM is responsible for only ten percent of XES's direct wildfire costs, then it would also be allocated ten percent of the indirect wildfire costs. Xcel was unwilling to provide the impact of the Department's recommended methodology,[552] and based on this, the Department recommended removing all indirect wildfire costs, reducing Xcel's revenue requirement by $1.7 million in 2025 and $1.8 million in 2026.[553]

532. Based on evidence in the record, Xcel calculated the impact of allocating indirect wildfire costs based on the allocation of direct wildfire costs as decreasing the 2025 test year revenue requirement by $0.1 million and increasing the 2026 plan year revenue requirement by $0.6 million.[554]

533. The OAG also recommends that the Commission remove indirect wildfire costs from the Company's rate request, arguing that the total plant ratio does not follow cost causation and that different jurisdictions have different wildfire risks.[555]

534. The Company posits that indirect wildfire costs are not caused by discrete wildfire events, as those events, the Company asserts, do not cause the Company's need for costs such as IT supporting situational awareness tools.[556]

535. The Company defends its allocation proposal by arguing that IT adheres to a Commission approved fully distributed costing methodology. This framework was established in electric and gas rates cases in 1993[557] and reaffirmed in the Commission's September 28, 1994 Order in Docket No. G, E999/CI-90-1008.[558] The framework is used in all instances of the Cost Assignment and Allocation Manual (CAAM).[559]

536. The Company's cost assignment and allocation approach is structured around a hierarchical framework which provides, in relevant part, that (a) "[a]ll activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost.

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[552] Ex. Xcel-50 at 16 (Doyle Rebuttal).
[553] Ex. DOC-2 at 22 (Johnson Surrebuttal).
[554] Xcel Reply Brief at 105-06 (citing Ex. DOC-1, Schedule 8 (Johnson Direct) and Ex. Xcel-50 at 15, Table 1 (Doyle Rebuttal)).
[555] Ex. OAG-5 at 27-28 (Lee Direct).
[556] Ex. Xcel-50 at 20 (Doyle Rebuttal).
[557] *See In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service the State of in Minnesota*, MPUC Docket No. E-002/GR-92-1185, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Sep. 29, 1993); *In the Matter of the Application of Northern States Power Company's Gas Utility for Authority to Change Its Schedule Gas Rates for Retail Customers Within the State of Minnesota*, MPUC Docket No, E-002/GR-92-1186, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Sep. 1, 1993).
[558] *See In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E-999/CI-90-1008, ORDER FINDING COMPLIANCE, EXEMPTING NORTHWESTERN WISCONSIN, REQUIRING PREPARATION, AND CLOSING DOCKET (Mar. 1, 1995).
[559] Ex. Xcel-50 at 17 (Doyle Rebuttal).

Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction;" (b) "[i]f the fully distributed cost study indicates a direct correlation exists between a change and the incurrence of a cost and cost causation, that cost shall be allocated based upon that relationship;" (c) "cost may be allocated using a measure that has a logical or observable correlation to all the activities or jurisdictions that cause the cost to be incurred;" and (d) "activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost."[560]

537. Both sides to this disputed issue assert that the other side is seeking to depart from past practice and approved allocation methodologies.

538. The Company effectively urges that, by applying the total plant ratio, it is using a mathematically neutral tool consistent with its general allocation methodology.

539. The Department and the OAG, on the other hand, argue that the relationship between wildfire risk and indirect allocation costs is such that there is a logical or observable correlation to the activities or jurisdictions that cause the costs to be incurred. Thus, according to these parties, such direct wildfire costs across jurisdictions are a reasonable proxy for the causation of indirect wildfire costs sufficient to justify allocation of indirect wildfire costs based on the relative jurisdictional responsibility for direct wildfire costs.

540. Neither allocation method is perfect. Indirect wildfire costs likely bear some relationship to direct wildfire costs. While all jurisdictions may benefit from shared indirect wildfire costs, basic cost-benefit principles dictate that the amount of money an organization would spend on preventative and responsive measures for wildfire would be driven, in part, by the total risk of wildfire. The record establishes that some jurisdictions are at greater wildfire risk than Minnesota. This heightened risk likely motivates XES to invest in a more robust prevention and response infrastructure than it would if all jurisdictions had Minnesota's wildfire risk profile.

541. Conversely, the Department and OAG's suggested methodology of allocating indirect wildfire costs based strictly based on the allocation of direct costs likely overstates the appropriate level of cost responsibility for jurisdictions that incur either more, or more severe, discrete wildfire events in a given year. This would understate the shared benefit of the indirect costs and cause unprincipled annual fluctuations of relative cost responsibility for indirect costs that would be incurred regardless of the distribution of a particular year's wildfire activity.

542. The Department and OAG are correct that, when a utility has failed to prove the reasonableness of a cost, and the record contains an inadequate basis to support some other level of cost recovery, complete removal of the cost is appropriate.

543. This principle, however, should not be stretched to an extreme such that the absence of a methodologically perfect allocation method warrants categorical removal of costs for an activity that is inarguably reasonable and necessary for the provision of utility

[560] Ex. Xcel-50 at 17-18 (Doyle Rebuttal).

service. The very nature of indirect costs are that they cannot be precisely direct-allocated. The task of the Company is to propose, and ultimately the Commission to determine, a reasonably supported proxy for allocating these costs. Both allocation proposals are sufficiently supported to render categorical cost exclusion inappropriate.

544. While both allocation proposals have shortcomings, it is worth emphasizing that the Company's proposal, when netting out the impact to the 2025 Test Year and 2026 Plan Year revenue requirements, positively benefits Minnesota ratepayers. Giving due consideration to resolving doubt as to reasonableness in the customer's favor, as well as the Company's support for the methodology that, in this proceeding, benefits Minnesota ratepayers, the Company's proposal is the most reasonable in the record.

545. The Commission should approve recovery of indirect wildfire costs as allocated by total plant ratio.

12. Base Pay

546. The Company seeks recovery of base pay expense for 2025 and 2026.[561] The Company's base pay expense includes: (a) base wages for bargaining-unit (union) employees; (b) base pay for non-bargaining employees; and (c) paid time off and overtime for all employees.[562]

547. The Company developed its 2025 and 2026 base pay budgets using current salary/pay and headcount information for its business areas, incorporated planned headcount additions or reductions, applied projected merit increases of three percent for both bargaining and non-bargaining employees, and included forecasted amounts for overtime and paid time off.[563]

548. The Company's projected three-percent base pay increase for bargaining-unit employees is based on the applicable collective bargaining agreement.[564]

549. The Company's projected three-percent base pay increase for non-bargaining employees is supported by market-based compensation information, including compensation studies projecting base pay increases for 2025 and publicly available compensation-cost trend data.[565] Specifically, the Company provided compensation studies that showed national non-bargaining salary increases are projected to be between 3.8 and 4.5 percent in 2025.[566]

550. The Company's 2025 and 2026 base pay budgets include forecasted overtime associated with planned outages and overhauls at generation facilities.[567] For

[561] Ex. Xcel-62 at 8 (Ly Direct).
[562] Ex. Xcel-62 at 8-13 (Ly Direct).
[563] Ex. Xcel-62 at 11-12 (Ly Direct).
[564] Ex. Xcel-62 at 12 (Ly Direct); Ex. Xcel-63 at 7 (Ly Rebuttal).
[565] Ex. Xcel-62 at 12 (Ly Direct); Ex. Xcel-63 at 7-8 (Ly Rebuttal).
[566] Ex. Xcel-63 at 7 (Ly Rebuttal).
[567] Ex. Xcel-28 at 26-27 (Robinson Rebuttal).

2025, the base pay budget includes planned outages at two nuclear facilities.[568] For 2026, the base pay budget includes a planned outage at Sherco 3.[569]

551. In Company's 2025 base pay budget is approximately 3.8 percent higher than its 2024 actual base pay expense, and the Company's 2026 base pay budget is approximately 0.8 percent higher than its 2025 budget.[570]

552. Xcel has not provided FTE counts that the Department asserts are necessary to allow for proper evaluation of the request and have not otherwise explained discrepancies in base-pay calculations.[571] The Department's position, therefore, is that Xcel has not carried its burden to justify its base-pay calculation.[572]

553. The Department recommended base pay amounts of $348.16 million in 2025 and $358.61 million in 2026.[573] This calculation accepts Xcel's proposed three-percent increase in each year but starts from the 2024 approved test year amount.[574] Alternatively, the Department recommended using Xcel's average actual base pay from 2022 to 2024 and applying Xcel's proposed increases of 3.8 percent in 2025 and 0.8 percent in 2026.[575]

554. The Department also recommended that the Commission require Xcel to include an FTE count on a Minnesota jurisdictional basis for its next rate case to assist in the review of future base pay recovery requests.[576]

555. The Company explained that it cannot provide the FTE counts requested by the Department because it allocates labor costs—rather than individual employees—to the State of Minnesota Electric Jurisdiction and therefore does not maintain forecasted jurisdiction-level FTE counts tied to the forecasted rate case base-pay amounts or approved rate case amounts.[577]

556. The Company further stated that there are two main reasons that it allocates labor costs rather than FTEs.[578] The first reason is because NSPM uses XES to deliver enterprise-wide functions such as human resources, technology, finance, and legal.[579] These enterprise-wide services are provided at cost to all Xcel Energy operating companies, including NSPM.[580] When these XES employees are performing enterprise-wide work, a portion of their labor costs are allocated to NSPM's State of

[568] Ex. Xcel-28 at 26-27 (Robinson Rebuttal).
[569] Ex. Xcel-28 at 27 (Robinson Rebuttal).
[570] Ex. Xcel-28 at 26 (Robinson Rebuttal).
[571] Ex. DOC-4 at 10 (Kehrwald Surrebuttal).
[572] Ex. DOC-4 at 14-15 (Kehrwald Surrebuttal).
[573] Ex. DOC-4 at 22 (Kehrwald Surrebuttal).
[574] Ex. DOC-4 at 22 (Kehrwald Surrebuttal).
[575] Ex. DOC-4 at 23 (Kehrwald Surrebuttal).
[576] Ex. DOC-3 at 14 (Kehrwald Direct).
[577] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[578] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[579] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[580] Ex. Xcel-28 at 28 (Robinson Rebuttal).

Minnesota Electric Jurisdiction.[581] As a result, the Company stated that there is no way to tie this allocated portion of an XES employee's labor costs to a specific FTE count.[582]

557. The second reason provided by the Company is that, depending on the work that an employee is performing in a particular year, their labor costs will be allocated to either O&M or capital, which is then allocated to a specific operating company and then to the electric and gas utility.[583] These multiple allocations make it impossible to accurately correlate FTE counts to base pays amounts at the State of Minnesota Electric Jurisdictional level.[584]

558. The Company further supported its base pay request by providing actual FTE counts for both NSPM and XES for 2022, 2023, 2024, and through July 31, 2025.[585] These FTE counts show that as of June 1, 2025, the NSPM FTE count was 3,098 which is the same number of NSPM FTEs in 2024.[586] The Company also stated in response to discovery that it had no plans for a restructuring or layoffs in either 2025 or 2026.[587]

559. The Department also questioned the reasonableness of the Company's base pay amounts because there was a 14.3-percent increase in base pay from 2022 to 2023.[588] The Company provided three explanations for reasons why 2023 actual base pay was higher than 2022: (1) a 6.1-percent merit increase for bargaining employees due to a new union contract and a four-percent merit increase for non-bargaining employees; (2) higher overtime costs due to one additional nuclear outage in 2023 as compared to 2022; and (3) one-time costs associated with the 2023 Voluntary Retirement Program (VRP) and the Involuntary Retirement Program (IVRP).[589]

560. The Department further argued that the Company's base pay amounts are unreasonable because the Company's actual base pay amounts for 2024 were higher than the 2024 amount approved in the Company's last electric rate case by $15.8 million.[590] The Company stated that the Company's 2024 base pay budget in its last rate case was developed in 2021 and did not did not sufficiently account for significant inflation in the labor market that occurred after this budget was developed.[591] Specifically, the Company paid a 6.1-percent increase to bargaining unit employees in 2023 based on their new union contracts and paid a four-percent increase to non-bargaining unit employees to maintain market-competitive salaries.[592]

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[581] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[582] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[583] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[584] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[585] Ex. DOC-3, Schedule 13 at 1 (Kehrwald Direct) (Xcel Energy Response to DOC IR 183).
[586] Ex. DOC-3, Schedule 13 at 1 (Kehrwald Direct) (Xcel Energy Response to DOC IR 183).
[587] Ex. DOC-3, Schedule 5 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 164).
[588] Ex. DOC-3 at 9 (Kehrwald Direct).
[589] Ex. Xcel-63 at 6 (Ly Rebuttal). None of the costs related to the VRP and IVRP are included in the Company's rate request in this proceeding. *Id.*
[590] Ex. DOC-4 at 20 (Kehrwald Surrebuttal).
[591] Ex. Xcel-28 at 30-31 (Robinson Rebuttal).
[592] Ex. Xcel-63 at 6 (Ly Rebuttal).

561. The Department raised important questions regarding fluctuations in Xcel's base pay expenses. The Company provided substantial evidence explaining these trends, including market data, information about union contracts, the impact of significant outages on overtime levels, past pay increases, and the VRP and IVRP.

562. The Department's primary argument is effectively that, due to the lack of FTE data, it was unable to verify the reasonableness of Xcel's request. To be sure, the Company bears the burden of establishing the reasonableness of its request. The Department, however, points to no legal authority to require that this support comes in the specific form it desires. The information provided by the Company provided sufficient evidence to support its request.

563. The reasonableness of the Company's request is further supported by the fact that the 3.8-percent and 0.8-percent increases proposed for 2025 and 2026, respectively, are well within the ranges of market data provided by the Company.

564. Accordingly, the Commission should approve the Company's request for base pay in the 2025 Test Year and 2026 Plan Year.

565. As the information provided by the Company was sufficient to evaluate reasonableness of Xcel's proposal, the record does not support requiring additional FTE information in future rate cases. Accordingly, the Commission should take no action on the Department's request for such a requirement.

13. Incentive Compensation

566. Two types of employee compensation are disputed in this proceeding: Long-Term Incentive (LTI) compensation and Annual Incentive Program (AIP) compensation.

a. Long-Term Incentive Compensation

567. The Company requested recovery of $11.5 million in 2025 and $12.1 million in 2026 for LTI compensation, totaling $23.5 million over the MYRP period. Over one-third of this amount is budgeted for Xcel's top-ten-compensated executives.[593] Xcel seeks to recover both "time-based LTI" and "environmental LTI."[594] Xcel's LTI is paid in a combination of restricted stock units and performance stock units.[595]

568. The Commission recently denied Xcel's request to recover LTI in its last rate case.[596] The Commission reasoned that environmental LTI did not offer any "unique benefits" and time-based LTI may incent employees to promote shareholder, rather than customer, interests.[597]

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[593] Ex. DOC-3 at 16 (Kehrwald Direct).
[594] Ex. Xcel-62 at 23–24 (Ly Direct).
[595] Ex. Xcel-66, Schedule 2 at 9 (Mustich Direct).
[596] Xcel 2021 Rate Case Order at 15.
[597] Xcel 2021 Rate Case *Order* at 15.

569. Xcel suggests that the record in this proceeding is different than its last rate case because it provided an analysis of market competitive compensation data. Based on that market data, Xcel asserts that the levels of Target Total Direct Compensation were reasonable and consistent with market-based total compensation levels.[598]

570. The record contains no evidence of any Minnesota utility being allowed recovery of LTI.

571. Environmental LTI is measured by the reduction in carbon dioxide emissions below 2005 levels associated with the Company's electric service.[599]

572. LTI requires a three-year vesting period designed to incent eligible employees to 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 benefits customers by retaining knowledge and skills necessary to guide, manage, and operate a utility.[600]

573. LTI programs are widely used compensation vehicles for both executives and non-executive employees. A 2024 Willis Towers Watson study (electric and gas utilities only) shows that 100 percent of the 53 utility companies submitting survey data provide LTI as a component of total compensation for executive roles and nearly 75 percent provided LTI to non-executive roles. A 2021 WorldatWork study identified LTI programs across 94 percent of over 420 publicly traded companies, and 74 percent of those companies administer LTI using a combination of performance and time-based awards.[601]

574. The Department recommended that the Commission disallow any LTI recovery. The Department argues that Xcel's environmental LTI is no more ambitious than what is required by law and therefore provides no benefit.[602] The Department also pointed out that all LTI is paid in stock.[603] Paying LTI in stock inherently incents achieving company profitability.

575. XLI also recommended disallowance of LTI, similarly reasoning that LTI incents prioritizing shareholder interests and provides no incremental environmental benefit to customers.[604]

576. The Commission considered Xcel's arguments that LTI incents environmental goals and retention of employees to the benefit of consumers in Xcel's last

[598] Ex. Xcel-62 at 9-10, 21-22, Schedule 5, and Schedule 7 (Ly Direct); Ex. Xcel-66 (Mustich Direct); Ex. Xcel-67 (Mustich Rebuttal).
[599] Ex. Xcel-62 at 24 (Ly Direct).
[600] Ex. Xcel-62 at 27 (Ly Direct).
[601] Ex. Xcel-26 at 21-22 and Schedule 7 (Ly Direct) (2021 WorldatWork Incentive Pay Practices).
[602] Ex. DOC-4 at 27 (Kehrwald Rebuttal).
[603] Ex. DOC-4 at 27 (Kehrwald Rebuttal).
[604] Ex. XLI-1 at 48-49 (LaConte Surrebuttal).

rate case and still denied recovery.[605] The record here contains no principled basis to depart from that decision here.

577. While Xcel provided a large amount of information supporting the amounts of its LTI in the context of broader market trends, this information does not address the basis for past disallowances. The issue in Xcel's last rate case was not that, as a business matter, the amount of LTI paid was unreasonable. Rather, the Commission concluded, that the environmental LTI did not offer a unique benefit above Xcel's legal obligation to pursue environmental goals and the fact that LTI was paid in stock incents prioritizing shareholder interests. In other words, the question was not whether, or even how much, LTI Xcel should pay. Rather, the question was who should pay it. The additional information provided by Xcel in this proceeding does not meet its burden to show that its customers should pay this expense.

578. The Commission should disallow recovery of Xcel's LTI compensation in the MYRP.

b. Annual Incentive Program Compensation

579. The Company is requesting to recover $23.5 million in 2025 and $24.2 million in 2026 for its AIP.[606] AIP is Xcel's short-term compensation program, which is offered only to non-union employees.[607] Xcel is currently permitted to recover costs for AIP, with a cap of 15 percent of base pay, which is administered on an individual basis.[608] Xcel is seeking to increase the cap from 15 percent to 20 percent, and to administer the cap on an aggregate basis, instead of individual.[609]

580. Since 1992, the Commission has limited Xcel's recovery for short-term incentive compensation (now called AIP) to 15 percent of an employee's base salary.[610] The Commission imposed this cap based on concerns that AIP was driven by shareholder interests.[611]

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[605] 2021 Xcel Rate Case Order at 14-15.
[606] *See* Ex. Xcel-62 at 21 (Ly Direct).
[607] Ex. Xcel-62 at 13 and Schedule 4 at 4 (Ly Direct).
[608] Ex. Xcel-62 at 18–19 (Ly Direct).
[609] Ex. Xcel-62 at 18–19 (Ly Direct).
[610] *In re Appl. of N. States Power Co. for Authority to Increase Its Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E002/GR-92-1185, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25–30 (Sept. 29, 1993) (eDocket 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 percent cap and required the Company to return any unpaid incentive compensation to ratepayers. *See* ORDER AFTER RECONSIDERATION at 7 (Jan. 14, 1994) (eDocket No. 322655).
[611] *See In re Appl. of N. States Power Co. for Authority to Increase Its Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E002/GR-92-1185, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 28 (Sept. 29, 1993) (eDocket No. 355173).

581. In its last rate case, Xcel similarly requested a 20 percent cap, and to administer that cap on an aggregate basis. The Commission rejected both of these requests in the most recent rate case.[612]

582. The Department and XLI oppose both Xcel's request to increase its AIP cap, and its request to administer the cap on an aggregate basis. Both parties note that the earnings-per-share (EPS) threshold ties the AIP compensation to shareholder benefits.[613]

583. The Commission's concerns with Xcel's request to increase the cap to 20 percent were that "Xcel's AIP program is subject to a dispositive earnings-per-share threshold such that *no* AIP is paid out if earnings per share do not reach the target level, regardless of any other performance metrics."[614] The Commission then noted that because of this requirement, Xcel's AIP program was not "sufficiently broadly beneficial to justify a higher percentage of recovery from ratepayers."[615]

584. The Company argues that its existing 15 percent cap does not reflect current compensation trends that are more heavily weighted toward incentive compensation.[616] Xcel noted that employers, including the Company, have moved a greater percentage of compensation into incentive programs because they drive employee performance and reduce fixed costs.[617]

585. Notably, the Commission considered and rejected this argument in Xcel's last rate case. The Commission emphasized that, even in the face of evidence of market-based compensation levels, the concern was that it "would not be just and reasonable for *ratepayers to pay* more for incentive compensation tied to an [EPS] threshold that primarily benefits shareholders."[618] Put differently, the concern was not that 20 percent of an employee's base salary was an unreasonable level for an employer to pay. Rather, the nature of the payment was such that it would not be just and reasonable for Xcel's customers to pay above that amount.

586. The Company also argued that increasing the AIP cap to 20 percent would be consistent with the AIP caps of other Minnesota utilities. For example, in Minnesota Power's last litigated rate case, the Commission approved Minnesota Power's proposed short-term incentive capped at 20 percent of base pay.[619] The Commission has approved

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[612] Xcel 2021 Rate Case Order at 18–19.
[613] Ex. DOC-4 at 31 (Kehrwald Surrebuttal); Ex. XLI-1 at 43-46 (LaConte Direct).
[614] Xcel 2021 Rate Case Order at 18–19 (emphasis in original).
[615] Xcel 2021 Rate Case Order at 18–19.
[616] Ex. Xcel-63 at 9 (Ly Rebuttal).
[617] Ex. Xcel-63 at 9 (Ly Rebuttal); Ex. Xcel-67 at 9-10 (Mustich Rebuttal).
[618] Xcel 2021 Rate Case Order at 18 (emphasis added).
[619] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota,* MPUC Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 33 (Mar. 12, 2018) [hereinafter MP 2016 Rate Case Order].

even higher AIP caps for other utilities, including a 25 percent cap for Otter Tail Power Company and a 25 percent cap in CenterPoint Energy's last litigated rate case.[620]

587. Xcel points to no evidence, however, establishing that any of those utilities have an EPS threshold incorporated into their AIP. This materially distinguishes those Commission decisions, as the EPS threshold was a key part of the Commission's rationale for denying Xcel's nearly identical request in its last rate case. The Commission explicitly rejected the comparison to Minnesota Power's AIP plan in Xcel's rate case, noting the absence of an EPS threshold in Minnesota Power's Plan.[621] Further, Otter Tail Power Company's AIP plan has one financial criterion, and that relates to controlling O&M costs to the benefit of customers.[622]

588. The Company further argues that the EPS threshold is a gating criteria designed to ensure that the Company is performing at a minimum sustainable financial level before AIP compensation is paid.[623] Additionally, the Company urges, AIP goals are customer-focused—advancing the clean energy transition, improving the customer experience, maintaining affordable bills, and ensuring safety and reliability.[624] The Company also argues that employee performance in achieving these AIP goals is measured through objective, customer-centered metrics such as customer satisfaction, electric system reliability, public safety outcomes, and effective use of wind powered resources to curtail fuel costs for customers.[625]

589. Regardless of how Xcel characterizes the EPS threshold, the fundamental point remains. No AIP whatsoever is paid out if the EPS target is not met. In other words, no matter what other customer-facing outcomes also inform AIP, EPS is paramount because failing that one metric will deprive employees of any AIP.

590. The Company has not met its burden to prove that increasing the AIP cap to 20 percent is reasonable. The Commission should deny Xcel's request.

591. In support of its request to change the mechanism for administering the API cap to an aggregate basis, Xcel argued that applying the cap individually after the approved AIP amount is determined distorts the intent of the program by creating arbitrary limits on certain employees' payouts regardless of their actual performance.[626] The Company stated that this could weaken the link between pay and performance, reduce

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[620] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota,* Docket No. E017/GR-20-719, Direct Testimony of Peter E. Wasberg at 5 (Nov. 2, 2020); *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota,* MPUC Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 23-24, 71 (June 3, 2016) [hereinafter CenterPoint 2015 Rate Case Order].
[621] 2021 Rate Case Order at 19.
[622] Ex. XLI-1 at 46 (LaConte Direct).
[623] Ex. Xcel-63 at 17 (Ly Rebuttal) ("[T]he EPS threshold is simply a prudent management tool to ensure that the Company is financially stable enough to pay out AIP.").
[624] Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).
[625] Ex. Xcel-62 at 20-21 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).
[626] Ex. Xcel-63 at 18 (Ly Rebuttal).

fairness within the plan, and undermine its effectiveness in motivating employees to achieve customer-focused results.[627]

592. The Department countered that applying the cap on an aggregate basis would erode ratepayer protections and could result in excessive payments (such as the Company's budgeted 92-percent base salary for the ten top-paid executives).[628]

593. The record contains no principled basis on which to depart from the Commission's declination to apply the AIP cap on an aggregate basis in Xcel's last rate case. Retaining the cap in its current form protects customers from subsidizing large incentive payments to highly-compensated individuals through a program that is driven by corporate financial, and not customer, interests.

594. Accordingly, the Commission should also reject Xcel's proposal to administer the cap on an aggregate basis.

14. Top Ten Executive Compensation

595. In its Notice of and Order for Hearing in this case, one of the issues that the Commission asked parties to address was: "How much top 10 executive compensation costs should be recovered in rates?"[629]

596. In this proceeding, Xcel seeks to recover base salary, AIP (capped at 20 percent), LTI (time-based and environmental), and other compensation for its top ten highest paid employees.[630] Adjustments to the AIP and LTI compensation paid to these employees removed nearly $4.5 million from the Company's executive compensation request in this case.[631] The remaining portion of executive compensation that the Company seeks to recover in this proceeding totals $7.3 million in 2025 and $7.5 million in 2026 (State of Minnesota Electric Jurisdiction).[632]

597. To support its executive compensation request in this case, the Company submitted an independent third-party executive compensation study (Executive Compensation Study). This study compared the total direct compensation amounts for the Company's top ten highest paid employees to those of an 18-company peer group. The Executive Compensation Study concluded: "Xcel Energy's total direct compensation levels are consistent with market median levels (consistent with its compensation philosophy), and the design of the short- and long-term incentive compensation programs are consistent with market practices of utility peers."[633]

598. The Company also supplied testimony from a third-party executive compensation expert with over 35 years of experience in designing and evaluating

[627] Ex. Xcel-63 at 18 (Ly Rebuttal).
[628] Ex. DOC-4 at 45 (Kehrwald Surrebuttal).
[629] Notice of and Order for Hearing at 2 (Dec. 30, 2024) (eDocket No. 202412-213391-01).
[630] Ex. DOC-3, Schedule 18 at 6 (Kehrwald Direct).
[631] Ex. Xcel-63 at 29 (Ly Rebuttal); Ex. DOC-3, Schedule 18 at 6 (Kehrwald Direct).
[632] Ex. Xcel-63 at 29 (Ly Rebuttal).
[633] Ex. Xcel-66, Schedule 2 at 10 (Mustich Direct).

employee compensation programs.[634] This third-party expert concluded that, "Xcel Energy's Total Direct Compensation programs and comparable to and competitive with market practices of other similarly-sized utilities and are therefore reasonable."[635]

599. The Department argued that Xcel's compensation study was a useful comparison, but noted that it compared peers of Xcel Energy. Inc, instead of NSPM.[636] The Department also highlighted, and Xcel's witness admits, that the compensation study does not speak to what portion of the executive's market-competitive compensation should be recovered from ratepayers.[637]

600. The Department argued that Xcel has failed to carry its burden to show that it is reasonable for Xcel to recover compensation for its top ten executives because Xcel has not shown that they work in the interest of ratepayers.[638] The Department argued that the top-ten executives receive most of their pay through incentive compensation, thus incenting them to prioritize shareholder interest over ratepayer interests.[639] Additionally, Xcel failed to provide written performance reviews or evaluations for most of its top-ten executives.[640] Finally, the Company did not have job descriptions at all for most of these executives, and the descriptions it did have available were inadequate to meaningfully assess the specific duties of the executives.[641]

601. The OAG also argued that the structure of compensation paid to Xcel's ten highest-paid executives creates an incentive to prioritize shareholder interests over ratepayer interests.[642]

602. Specifically, the OAG emphasized that LTI compensation constitutes an average of 57 to 75 percent of the total compensation paid to Xcel's highest-paid executives.[643] LTI compensation is paid entirely in stocks.[644]

603. The OAG further argued that AIP incents executives to focus on shareholder interests because executives will not receive AIP if Xcel does not meet its EPS guidance, and at the same time, executives will receive extra AIP if Xcel exceeds its EPS guidance.[645] Thus, executives' personal financial incentive is to increase Xcel's profits to meet or exceed the AIP EPS metric. The OAG argues that AIP therefore incents executives to focus on shareholder interests over ratepayer interests.[646]

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[634] Ex. Xcel-66, Schedule 1 (Mustich Direct).
[635] Ex. Xcel-66 at 9 (Mustich Direct).
[636] Ex. DOC-4 at 54 (Kehrwald Surrebuttal).
[637] Evidentiary Hearing Transcript Volume (Tr. Vol.) 1 at 192 (Mustich).
[638] Ex. DOC-4 at 46-47 (Kehrwald Surrebuttal).
[639] Ex. DOC-4 at 57-58 (Kehrwald Surrebuttal).
[640] Ex. DOC-4 at 57-58 (Kehrwald Surrebuttal).
[641] Ex. DOC-3 at 36 (Kehrwald Direct).
[642]Ex. OAG-1 at 24-25 (Hinderlie Direct).
[643] Ex. Xcel-63 at 32 (Ly Rebuttal).
[644] Ex. DOC-3 at 40 and Schedule 10 (Kehrwald Direct).
[645] Ex. Xcel-62, Schedule 4 at 8 (Ly Direct).
[646] OAG Initial Brief at 32.

604. The OAG also issued discovery in its efforts to assess the extent to which executive activities benefitted ratepayers.[647] The OAG reviewed calendars produced in response to this discovery and asserts that there was insufficient information to determine the extent to which executives engaged in activities that benefit ratepayers.[648] The OAG also reviewed the performance evaluations, but noted that Xcel only provided them for two of its executives.[649] The OAG concluded that the majority of the discussion of one executive's performance focused on activities that further shareholder interests.[650] The OAG expressed concern that more executives do not receive performance evaluations and argued that without performance evaluations, the primary feedback employees receive regarding their performance is whether they meet compensation incentive metrics.[651]

605. The Company responded by providing evidence suggesting that it is common in the labor market to structure executive compensation with a greater percentage of incentive compensation rather than base pay. Based on peer companies, incentive compensation makes up nearly 90 percent of compensation for CEOs.[652] The Company asserts that customers benefit from this arrangement because incentive compensation allows the Company to tie pay to achievement of performance metrics and if these metrics are not met, then the compensation expense during those years shrinks.[653] However, if all compensation were paid out in fixed base salaries, the Company stated that it would be required to pay all of this compensation even in years when the performance metrics are not achieved.[654] The Company also stated that increasing fixed base salaries would increase other costs that are tied to base salaries such as disability insurance premiums.[655]

606. The Company also argued that its incentive compensation is focused on customer-centric metrics. The Company's AIP measures performance with metrics that promote customer satisfaction, safety, reliability, inclusion, and wind availability.[656] Environmental LTI is paid out based on hitting goals for reduction of carbon emissions.[657] The Company asserts that these metrics demonstrate that incentive compensation focuses and awards Xcel Energy's executives for achievement of goals that directly benefit its customers.

607. The Commission addressed this issue in Xcel's most recent rate case. In that proceeding, the Commission found that the Company had not demonstrated the reasonableness of its proposed recovery levels for executive compensation because (1) market comparisons to corporate officers who hold a fiduciary duty to shareholders

[647] Ex. OAG-3 at 13 (Hinderlie Surrebuttal).
[648] Ex. OAG-4 at 14-16 (Hinderlie Surrebuttal).
[649] Ex. OAG-3 at 16 (Hinderlie Surrebuttal).
[650] Ex. OAG-4 at 18-22 (Hinderlie Surrebuttal).
[651] Ex. OAG-3 at 22 (Hinderlie Surrebuttal).
[652] Ex. Xcel-67 at 9 (Mustich Rebuttal).
[653] Xcel Initial Brief at 112.
[654] Ex. Xcel-67 at 9 (Mustich Rebuttal).
[655] Ex. Xcel-62 at 17 (Ly Direct).
[656] Ex. Xcel-67 at 7 (Mustich Rebuttal).
[657] Ex. Xcel-63 at 23-24 (Ly Rebuttal).

but not to consumers does not establish that utility consumers should pay for Xcel's executive compensation; (2) the shareholder focus of the executive compensation package, as evidenced by Xcel's AIP and LTI programs, tie overall executive compensation to shareholder earnings; and (3) the Company failed to meaningfully consider the impact of this cost on consumers. The Commission ultimately set the recoverable compensation for Xcel's top-ten compensated executives at $150,000, reasoning that this was similar to that of Minnesota's governor, the State's highest executive officer.[658]

608. This decision was ultimately overturned via an unpublished decision by the Minnesota Court of Appeals. The contours of the Court of Appeals' decision are relevant to this proceeding. Specifically, the Court of Appeals overturned the decision because it found that the decision to use the Minesota governor's salary as the baseline for setting recoverable compensation was inadequately explained, rendering that part of the decision arbitrary and capricious.[659]

609. The Court of Appeals did not, however, disturb the Commission's determination that the Company's request for rate recovery of executive compensation was inadequately supported, and found that the three proffered explanations by the Commission warranted denial of the Company's requested level of recovery.[660]

610. All three concerns that motivated the Commission's decision in the last rate case are unresolved by this record as Xcel's primary justification for cost levels continues to be market comparisons to other utility executives. First, the Company has set forth a robust record supporting the comparability of its executive compensation packages. But this is largely beside the point. The Commission's concern in the last rate case was not a failure by Xcel to establish that its executive compensation packages were comparable with the market. Rather, the concern was whether Xcel had proved regulated utility customers should be the ones paying those costs.

611. Second, the Company's AIP and LTI programs remain largely unchanged. In relevant part here, the AIP program is subject to an EPS threshold and LTI is paid in stocks. These features were discussed previously in more detail, but nothing in this record warrants disturbing the Commission's previous determination that compensating executives in this manner aligns their interests with shareholders, further lending support to the suggestion that their compensation ought to be paid by shareholders and not captive customers.

612. Third, as is discussed in Appendix A to this Report, customers continue to raise significant affordability concerns. The Commission's concerns with the impact of rate increases that include this executive compensation are no less valid now than when it decided Xcel's previous rate case.

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[658] Xcel 2021 Rate Case Order at 21-23.
[659] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *10-11 (Jan. 21, 2025).
[660] *In re N. States Power Co.*, No. A23-1672, 2025 WL 249995 at *10-11 (Jan. 21, 2025).

613. The Company attempts to resolve the first and second concerns from the Commission's prior decision by highlighting customer-focused metrics that are included in its AIP and LTI programs. However, as previously discussed in more detail, those arguments have been previously considered and rejected by the Commission in the context of the Company's requests to increase recoverable levels of executive compensation.

614. The Commission should conclude that, for the same reasons as articulated in Xcel's most recent rate case, the Company has failed to prove that it would be just and reasonable for customers to pay for its requested level of compensation for its ten highest-paid executives.

615. If the Commission approves recovery here, it would necessarily beg the question of what level of recovery is appropriate. However, as the Court of Appeals reasoned, even if the decision to disallow the Xcel's requested recovery level is sound, any alternate level of recovery must independently be supported by the record.

616. Despite the OAG and Department's efforts through discovery, the record here does not support meaningful analysis of how these executives spend their time and the extent to which their activities benefit customer interests rather than shareholder interests.

617. To be sure, the divide between shareholder interests and customer interests is not a bright line. Customers derive a benefit from a financially sound utility that is able to provide safe and reliable service. Further, the financial state of a utility impacts, among other things, its cost of debt; a cost which is ultimately borne by customers. Also, efficiencies leading to reductions in utility expenses benefit shareholders in the short term and, once those reductions are incorporated into a utility's next rate case, customers in the longer term.

618. That said, there is also a divergence in these interests. A utility's corporate profits are driven by rates charged to captive customers. All else being equal, it should not be controversial to observe that shareholders have an inherent interest in rates being higher, while customers have an inherent interest in those same rates being lower.

619. No party argues, nor could they do so seriously, that customers could enjoy the benefit of safe and reliable electric service without functioning executive leadership.[661] Customers should pay a portion of the costs of that leadership. Accordingly, denying Xcel the ability to recover any level of compensation for its ten highest paid executives in perpetuity would be an unjust and untenable outcome, even if it is the outcome mandated in this proceeding by this record.

[661] Even cooperative and municipal utilities must have individuals preforming executive functions.

620. The OAG suggested that, in a separate docket, the Commission should explore creation of a PIM that would allow Xcel to recover a portion of executive compensation if it met certain ratepayer-focused metrics.[662]

621. The Commission should disallow the Company's request for rate recovery of compensation for its ten highest-paid executives because the Company has failed to meet its burden to prove the amount that customer should pay for these individuals, and the record supports no other specific level of recovery.

622. The Commission should also initiate a proceeding to examine Xcel's executive compensation and what, if any, mechanisms are appropriate to ensure the Company is able to earn just and reasonable rate recovery, at an appropriate level, of a necessary cost of providing electric service.

15. Other Benefits

623. In addition to incentive and benefit issues previously discussed, three additional categories of employee benefits are disputed in this proceeding: (1) Limited Availability Benefits; (2) Miscellaneous Benefit, Life, LTD Expense; and (3) Non-Qualified Expense.

a. Limited Availability Benefits

624. The limited availability benefits are a component of the Company's market-competitive compensation and benefits package, and include physicals and financial, tax, and estate planning services for executive employees.[663] The costs for these limited availability benefits are $103,003 (State of Minnesota Electric Jurisdiction) in both 2025 and 2026.[664]

625. The Department recommended removing these costs from Xcel's revenue requirement, arguing that these individuals are already highly compensated and characterizing these benefits as additional "perks" above and beyond normal compensation.[665]

626. Similar limited availability benefits are included in a majority of other utilities' compensation and benefits packages. 72 percent of the utilities in Xcel's peer group provide financial, tax, and estate planning services to their executives and approximately 50 percent provide executive physicals.[666]

627. The limited availability benefits provide benefits to customers by reducing executive turnover.[667] Executive turnover is expensive because it involves paying

[662] Ex. OAG-3 at 24-25 (Hinderlie Surrebuttal).
[663] Ex. Xcel-63 at 36 (Ly Rebuttal).
[664] Ex. DOC-3 at 50 (Kehrwald Direct).
[665] Ex. DOC-3 at 50 (Kehrwald Direct).
[666] Ex. Xcel-67 at 11-12 (Mustich Rebuttal).
[667] Ex. Xcel-63 at 37 (Ly Rebuttal).

recruitment and transition costs and can also be disruptive to Company operations.[668] Another customer benefit provided by these limited availability benefits is that they help ensure that these employees are healthy and able to focus on the needs of the Company and its customers.[669]

628. These benefits are appropriate for rate recovery. Notwithstanding the Department's characterization of them as "perks," the record establishes that they are a normal part of compensation for these types of utility employees.

629. Absent independent concerns about overall compensation levels, it is irrelevant that some portion of compensation takes the form of limited availability benefits. It would be arbitrary to disallow recovery of a portion of an otherwise appropriate level of recoverable compensation merely because that compensation takes the form of limited availability benefits.

630. The Company has met its burden to prove the reasonableness of including these costs in rates, and the Commission should allow the Company to recover its limited availability benefits.

b. Miscellaneous Benefit, Life, LTD Expense

631. The Company requested recovery of its miscellaneous benefit, life, and LTD expense in the amount of $3,976,149 for 2025 and $3,990,839 for 2026.[670]

632. No party disputes the reasonableness of rate recovery of these types of expenses.

633. The Department however, recommended that miscellaneous benefits, life, and LTD expenses be calculated for the 2025 Test Year and the 2026 Plan Year based on an average of Xcel's actual expenses from 2021 to 2024, and apply an inflator based on the average annual increases from 2021 to 2024.[671] The Department's position is that it is more accurate to use actual averages than to apply an inflator to the 2024 projection, which exceeded Xcel's 2024 actual costs.[672] The impact of the Department's recommendation is a $551,597 reduction to the 2025 Test Year and a $490,067 reduction to the 2026 Plan Year.[673]

634. The Company argues that it adequately supported the amount of miscellaneous benefit, life, and LTD expense for 2025 and 2026. Specifically, Table 2 of Company Witness Schrubbe's Direct Testimony sets forth the amounts incurred in 2023, the forecasted amounts for 2024, and the forecasted amounts for each year of the MYRP.[674] Schedules 2 and 15 of Witness Schrubbe's Direct Testimony also provide

[668] Ex. Xcel-63 at 37 (Ly Rebuttal).
[669] Ex. Xcel-67 at 11-12 (Mustich Rebuttal).
[670] Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).
[671] Ex. DOC-3 at 44 (Kehrwald Direct).
[672] Ex. DOC-3 at 43 (Kehrwald Direct).
[673] Ex. DOC-3 at 44 (Kehrwald Direct).
[674] Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

additional data, including a comparison of expense amounts in 2025 and 2026 to actual amounts incurred in prior years, as well as a further breakdown of costs in the 2025 Test Year.[675]

635. The argument on this issue can effectively be reduced to whether it is more reasonable to adopt rates for 2025 and 2026 based on Xcel's 2025 and 2026 projections for these costs, or based on actual data after the Department has established that the 2024 projections were higher than actual expenses.

636. Certainly, absent an established true-up mechanism, an MYRP should not be used to retroactively refund customers for individual expense categories where projections exceeded actual expenses. That said, the 2024 over-projection raises doubt about whether the projection would result in more accurate expense levels for 2025 and 2026 than using inflation-adjusted actual data would.

637. Unlike Energy Supply O&M expenses, the record does not sufficiently explain the 2024 over-projection for these expenses. Accordingly, the Department's proposal to use actual historical data rather than the Company's projection is reasonable.

638. However, the Department's proposal should be modified. The historical data from 2021 to 2024 relied on by the Department, notwithstanding a slight decline from 2022 to 2023, shows a clear upward trend.[676] Setting the baseline at the average of those years would result in the Company under-recovering these expenses.

639. Accordingly, the Commission should authorize the Company to recover Miscellaneous Benefit, Life, and LTD expenses at a level set by applying the Department's proposed methodology and inflation factor to 2024 actual expenses, as opposed to the Department's suggested average of actual expenses from 2021 through 2024.

16. Non-Qualified Expenses

640. The Company requested recovery of its non-qualified expense in the amount of $44,662 for 2025 and $48,394 for 2026.[677] These non-qualified expenses comprise the costs of the Company's matching contributions under Xcel Energy's Deferred Compensation Plan.[678]

641. The Department recommended disallowing these deferred compensation benefits because Xcel has not supported the request and these benefits are "excessive" considering that the employees who receive these benefits are already highly paid.[679]

[675] Ex. Xcel-57 at 8, 84-85, Schedules 2 and 15 (Schrubbe Direct).
[676] Ex. DOC-3, Schedule 6 (Kehrwald Direct).
[677] Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).
[678] Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).
[679] Ex. DOC-3 at 48 (Kehrwald Direct).

The Department also noted that the Commission has a long history of disallowing non-qualified benefits.[680]

642. In support of its request, Company stated that the Deferred Compensation Plan "is a key component of maintaining competitive total rewards" and that "[d]eferred compensation is a common practice among peer companies and helps attract and retain talent by providing additional retirement savings opportunities."[681] Specifically, the plan "offers tax-advantaged savings and allows for full employer matching contributions that would otherwise be limited by IRS caps," which supports the long-term retention of key employees.[682]

643. The Company also emphasized that it is important that Xcel's compensation and benefits remain aligned with market standards so that the Company can attract, retain, and motivate employees needed to provide safe, reliable service to customers.[683]

644. The Department did not raise specific concerns about the amount of the non-qualified expenses or the effect they have on retaining talent.

645. The Company did not dispute the Commission's past practice of denying recovery of non-qualified expenses, and instead argued that "the Commission is not bound by the decisions" in the cases cited by the Department and that "the fact that the Commission decided an issue one way in another case does not mean that the same decision would be reasonable in this case."[684]

646. To be sure, past Commission decisions are not binding precedent. That said, if the Commission reaches disparate decisions on substantially identical issues from one case to the next, it could be found to be acting arbitrability and capriciously. Facts and records vary from one case to case, and different decisions may be warranted on different records. It is, however, important for those distinctions to be principled and clearly articulated.[685]

647. The most recent Commission order cited by the Department did indeed disallow recovery of nonqualified deferred compensation plans. In that proceeding, however, the Commission noted an "absence of any measurable ratepayer benefit" in reaching that determination.[686]

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[680] Ex. DOC-3 at 47 (Kehrwald Direct).
[681] Ex. DOC-3, Schedule 25 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 120).
[682] Ex. DOC-3, Schedule 25 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 120).
[683] Ex. Xcel-62 at 35 (Ly Direct).
[684] Xcel Initial Brief at 120.
[685] For multiple parties throughout this proceeding, the weight and persuasiveness they urge should be attached to past Commission decisions and reasoning seems to fluctuate depending on whose proverbial ox is being gored.
[686] MP 20216 Order at 31-34.

648. It is, therefore, a bridge too far to draw from past Commission decisions a determination that non-qualified expenses are categorically inappropriate for ratepayer recovery.

649. The Company focuses on data to quantify the comparability of its compensation practices to peers. It then offers more generalized statements about the benefit to customers of attracting and retaining employees.

650. It is difficult to see what else Xcel could do to justify this request. There is no obvious way for the Company to isolate, quantify, and explain the specific impact on retention of one small component of its compensation package on the customer benefits of retention. And, for a rate case dispute on an issue worth less than $50,000, investing in complex modeling to attempt to do so would quickly result in the ratemaking expense of the endeavor approaching, if not eclipsing, the amount in controversy.[687]

651. On this record, the Company has demonstrated the reasonableness of its non-qualified expenses and the Commission should approve recovery of those expenses.

17. Board of Directors Expense

652. As a Minnesota corporation, Xcel is required under Minnesota law to have a Board of Directors.[688]

653. Xcel is seeking to recover over $2.5 million in compensation for XEI's Board of Directors over the multi-year rate plan, including $1.2 million in 2025 and $1.3 million in 2026.[689]

654. The Department acknowledged that some of this compensation is reasonable, but also that the Board of Directors serves significant shareholder interests and therefore recommends that Xcel's recovery be capped at 50 percent, thereby reducing the 2025 Test Year by $606,897 and the 2026 Plan Year by $661,153.[690] The Department pointed out that Xcel's own proxy statement states that director compensation is designed to align director and shareholder interests.[691] This point is further highlighted by the fact that Board members are paid, in part, with common stock.[692]

655. The Company provided evidence that its Board of Directors' compensation practices are consistent with those of other public utilities, and the Company retained an independent compensation consultant, Meridian Compensation Partners (Meridian), to

[687] This should not be read as suggesting that the value of a given issue in any way relieves the Company of its burden to demonstrate and prove reasonableness. Rather, the amount in controversy informs the level of analysis a utility presumably undergoes before making an expenditure and should need to present to justify recovery.
[688] Ex. Xcel-63 at 39 (Ly Rebuttal); Minn. Stat. § 302A.201, subd. 1.
[689] Ex. DOC-3, Schedule 30 at 6 (Kehrwald Direct) (Xcel's Response to DOC IR 2114, Department's annotated Attachment A).
[690] Ex. DOC-3 at 55 (Kehrwald Direct).
[691] Ex. DOC-4 at 66 (Kehrwald Surrebuttal).
[692] Ex. Xcel-63 at 41 (Ly Rebuttal).

review its Board of Directors' compensation amounts and practices to confirm that they are in line with the market.[693]

656. The Company points out that the Commission has traditionally approved complete recovery of its request for Board of Directors' compensation.[694]

657. The Company also stated that providing fair and market-competitive compensation is essential to attract and retain qualified directors.[695]

658. The issues raised here are similar to those addressed in Xcel's request for top-ten executive compensation. As with that issue, Xcel presents evidence that its requested amount is in line with peers and provides a benefit in the form of retaining and attracting qualified individuals. That is not, however, the crux of the dispute.

659. As with top-ten executive compensation, the chief concern raised by the Department is not whether, as a business matter, a Board of Directors should be paid or that these expenses are not in-line with industry peers. Once again, the concern is whether customers or shareholders should bear the costs.

660. It is not necessary to repeat the discussion from the top-ten executive compensation issue. The Department's concern is perhaps more starkly presented for the Board of Directors, as the expectation that the Board advance shareholder interests is explicitly reflected in the proxy statement. For the same reasons that Xcel did not meet its burden to show the reasonableness of its requested amount of top-ten executive compensation, it has not met its burden here.

661. While the Company states that the Commission has approved rate recovery for Board of Directors compensation in its entirety in the past, it points to no specific Commission decisions where the issues raised by the Department have been considered.

662. The Commission should adopt the Department's proposal to disallow 50 percent of the requested level of Board of Director's compensation in both the 2025 Test Year and 2026 Plan Year.

18. Outside Services (FERC Account 923)

663. FERC Account 923 tracks the expenses of professional service vendors, such as engineers, consultants, accountants, and attorneys, for services that are not attributable to a particular operating function or to other accounts.[696]

[693] Ex. Xcel-63 at 41 (Ly Rebuttal).
[694] Ex. Xcel-63 at 43 (Ly Rebuttal).
[695] Ex. Xcel-63 at 43 (Ly Rebuttal).
[696] *See* Uniform System of Accounts, 18 C.F.R. part 101, Account 923.

664. Commission rules require utilities to conform to FERC's uniform system of accounts.[697]

665. The Company's expenses tracked in FERC Account 923 arise from 17 different business areas, but the largest amounts are generally in six business areas: Customer and Utility Innovation, Financial Operations, General Counsel, Human Resources and Employee Services, Technology Services, and Corporate Other.[698]

666. Company requests recovery of $26.8 million in 2025 and $25.8 million in 2026 to cover outside services.[699]

667. These proposals amount to an 41.7 percent increase over Xcel's 2022 to 2024 average actual expenses for 2025, and a 36.6 percent increase for 2026.[700] The company's outside service expenses set in its last rate case exceeded its actual expense every year from 2022 through 2024.[701] During those three years, Xcel collected $5.6 million more through rates than it spent in FERC Account 923.[702]

668. The Department recommended setting the 2025 Test Year expense at Xcel's 2024 actual expense, increased by 7.5 percent, and increasing that amount another 7.5 percent for the 2026 Plan Year. The Department based this recommendation on concerns about Xcel's historical of over-forecasting of expenses, the adequacy of the explanation for the increase over the 2024 actual expenses, and the first quarter actual expenses in 2025 trending even lower than its 2024 actuals.[703] The Department chose a 7.5 percent inflator based on the most recent Bureau of Labor Statistics' Consumer Price Index (CPI), which cites a 7.5 percent annual percentage change in CPI for "Energy services – Electricity."[704]

669. The Company asserts that it does not budget by FERC Account, and argues it is illogical to focus on just one FERC Account when analyzing the Company's spending.[705] The Company urges that its forecasted O&M—at a Company-wide level—for 2025 and 2026 is the best reflection of the anticipated O&M for those years.[706]

670. The Company further argues that FERC Account 923 is a catch-all account, and is therefore especially inappropriate for this type of analysis.[707] The Company believes there is no compelling reason why expenses in it would be directly comparable from one year to the next and has experienced ups and downs in spending on many

[697] Minn. R. 7825.0300, subp. 2 (referring to the FPC (Federal Power Commission), FERC's predecessor); Ex. DOC-6 at 16 (Golden Surrebuttal).
[698] Ex. Xcel-28 at 20 (Robinson Rebuttal).
[699] Ex. DOC-5 at 14 (Golden Direct).
[700] Ex. DOC-5 at 16 (Golden Direct).
[701] Ex. DOC-5 at 15 (Golden Direct).
[702] Ex. DOC-5 at 15 (Golden Direct).
[703] Ex. DOC-5 at 17 (Golden Direct).
[704] Ex. DOC-5 at 17 (Golden Direct).
[705] Ex. Xcel-28 at 23 (Robinson Rebuttal).
[706] Ex. Xcel-28 at 23 (Robinson Rebuttal).
[707] Ex. Xcel-28 at 19 (Robinson Rebuttal).

categories in FERC Account 923 in prior years.[708] Xcel asserts that there are "undoubtedly other FERC accounts that show the Company under-recovered during the same period."[709]

671. The key drivers for the increased anticipated level of expense in FERC Account 923 for the test year and plan year are overall O&M increases related to Technology Services, Enterprise Security Services, and the initiation of the wildfire mitigation program.[710] The Company provided testimony supporting each of these areas of increased O&M.[711]

672. The Commission faced a similar issue related to FERC Account 923 in Minnesota Power's 2021 rate case, rejecting a Department proposal to use historical data in place of the utility's forces and adopting a recommendation that found the Department's proposal would fail to recognize known impacts to the Company's spending.[712]

673. This case has many similarities to the 2021 Minnesota Power rate case. The Department advanced a similar argument and the utility offered a similar response. In this proceeding, Xcel specifically pointed to Technology Services, Enterprise Security Services, and a wildfire mitigation program as drivers of the increase.

674. In this proceeding, however, actual data provides strong support for the Department's position. Specifically, first quarter data for 2025 shows the Company's actual spending in FERC 923 at an annualized level of $18.9 million. This figure is not only lower than Xcel's $26.8 million proposal and the Department's $22.5 million recommendation, but even the 2024 actual figure of $20.96 million that the Department proposes to use as the baseline for Xcel's increase.[713]

675. In the face of this actual data supporting the Department's proposal, the Company fails to meet its burden by offering generalized statements about the nature of its budgeting process.

676. Xcel's point that the catch-all nature of FERC Account 923 makes it an imperfect vehicle for this type of analysis is well taken. That said, it is also difficult to fault the Department for selecting an accounting system the Company is legally obligated to use as the basis for its analysis.

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[708] Ex. Xcel-28 at 20-21 (Robinson Rebuttal).
[709] Ex. Xcel-28 at 20 (Robinson Rebuttal). Notably, this testimony did not specifically identify any such accounts.
[710] Ex. Xcel-28 at 23 (Robinson Rebuttal).
[711] *See generally* Exs. Xcel-33 (Scheller Direct) and Xcel-47 (Sherwood Direct).
[712] *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-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 23-25 (Feb. 28, 2023) [hereinafter MP 2021 Rate Case Order].
[713] Ex. DOC-6 at 17 (Golden Surrebuttal). One quarter of data is an admittedly small sample from which to draw annualized conclusions. It should be noted, however, that the Department sought data through June 30, 2025, and the first quarter data is what the Company produced in response. Ex. DOC-6 at 17 (Golden Surrebuttal).

677. If expected variances between accounts alone explained the trends observed by the Department, one would expect to see those variances net out over time. Instead, the Department has shown that spending for outside services has come in under Xcel's expected levels in 2022, 2023, 2024, and, based on the most current available data, is on pace to do so again in 2025.

678. Because the Department has adequately supported its concerns with respect to spending on outside services, and the Company has not sufficiently addressed them, Xcel has not met its burden to prove that its requested level of rate recovery for outside services would lead to just and reasonable rates.

679. The Commission should adopt the Department's proposal for outside services.

19. Organizational Dues

680. The Company's rate request includes certain dues that the Company pays in order to be a member of the Edison Electric Institute (EEI) (approximately $677,000 annually for 2025 and 2026) and Chambers of Commerce ($221,936 annually for 2025 and 2026).[714]

681. The OAG opposes cost recovery of dues paid to EEI.[715] The OAG also argues that the Company should receive only 50-percent recovery for the Chambers of Commerce dues, on the basis that those dues should be considered economic development costs.[716]

682. The Commission must not permit recovery of a utility's travel, entertainment, and related employee expenses, including "dues and expenses for memberships in organizations or clubs" if the Commission finds the expenses are unreasonable and unnecessary for the provision of utility services.[717]

a. Edison Electric Institute

683. EEI is an association that represents all U.S. investor-owned electric companies.[718] The Company estimates that the amount of EEI dues included in its rate request is $677,000 for the 2025 test year and the same amount for the 2026 plan year.[719] These figures exclude the lobbying-related portion of EEI dues.[720]

684. The OAG argues that Xcel did not provide evidence demonstrating the ratepayer benefits of membership nor demonstrate what portion of dues benefit

[714] Ex. Xcel-28 at 5, 11 (Robinson Rebuttal).
[715] Ex. OAG-7 at 7 (Lee Surrebuttal).
[716] Ex. OAG-7 at 7 (Lee Surrebuttal).
[717] Minn. Stat. § 216B.16, subd. 17.
[718] Ex. Xcel-28 at 3 (Robinson Rebuttal).
[719] Ex. Xcel-28 at 5 (Robinson Rebuttal).
[720] Ex. Xcel-28 at 3-6 (Robinson Rebuttal).

ratepayers.[721] The OAG requested that Xcel substantiate its claimed membership benefits by providing information such as a listing of EEI presentations, trainings, and conferences its employees attended with an explanation of the ratepayer benefits for these activities.[722]

685. In response to the OAG's arguments, the Company noted that its Initial Filing contained detailed data identifying specific instances (particularly conferences) in which Company employees engaged with EEI.[723] The Company also provided detailed information describing how EEI membership helps the Company serve its customers.[724] These benefits include expertise and education on emerging policy issues, critical industry data, strategic business intelligence, training, public policy leadership, state and federal regulatory developments, and conferences.[725] The Company cannot duplicate many of these services on its own.[726] The Company also referred the OAG to EEI's website, which lists EEI's activities and programs.[727]

686. The Commission has routinely allowed electric utilities to recover EEI dues when faced with arguments similar to the OAG's.[728] Specifically, in Minnesota Power's 2021 rate case, the Commission found that membership in EEI was "reasonable and necessary to serve its customers that benefit from these memberships."[729]

687. In the 2024 Greater Minnesota Gas rate case, the Commission did disallow recovery of organizational dues. In that proceeding, the Commission found that generalized assertions regarding the importance of trainings and informational resources were inadequate, and emphasized that the utility "failed to identify any specific trainings, conference, or other educational opportunities" that utility staff had utilized.[730]

688. Unlike the Greater Minnesota Gas proceeding, Xcel has identified numerous conferences and other instances where its staff actually engaged with EEI in its initial filing.

689. Further, while no single past Commission order constitutes binding precedent in this proceeding, a clear history of allowing electric utilities to recover EEI dues supports a determination that a utility acts reasonably and prudently when it continues to incur expenses that the Commission has previously determined to be recoverable. Nothing in the record suggests that the EEI dues in this proceeding are used for a fundamentally different purpose than dues previously approved for recovery.

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[721] Ex. OAG-7 at 4, 6 (Lee Surrebuttal).
[722] Ex. OAG-5 at 6-7 (Lee Direct).
[723] Ex. Xcel-28 at 8 (Robinson Rebuttal).
[724] Ex. Xcel-28 at 3-4 (Robinson Rebuttal).
[725] Ex. Xcel-28 at 3-4 (Robinson Rebuttal).
[726] Ex. Xcel-28 at 3-4 (Robinson Rebuttal).
[727] Ex. Xcel-28 at 9 (Robinson Rebuttal).
[728] Ex. Xcel-28 at 7 (Robinson Rebuttal) (internal citations omitted).
[729] MP 2021 Rate Case Order at 22.
[730] *In the Matter of the Application for Greater Minnesota Gas, Inc. for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-022/GR-24-350, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 19 (Nov. 26, 2025) [hereinafter GMG 2024 Rate Case Order].

690. The Commission should allow the Company to recover EEI dues in its requested amount.

b. Chambers of Commerce

691. The Company requests $221,936 for the 2025 Test Year and the same amount for the 2026 Plan Year for dues to various Chambers of Commerce.[731]

692. The Commission may "allow a public utility to recover from ratepayers the expenses incurred for economic and community development."[732]

693. The Commission has previously found that,

> [s]hareholders 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.[733]

694. In past decisions, including Xcel's most recent rate case, the Commission found that chambers of commerce further business and economic activity and portions of chamber dues are used for economic development, but that economic development benefits could not be attributed to the full amount of chamber of commerce dues.[734]

695. In Xcel's most recent rate case, the Commission explicitly rejected arguments that "fostering relationships and strengthening community ties" were adequate to justify recovery at a level greater than 50 percent of dues for chambers of commerce.[735]

696. The OAG argued that the Commission should continue to treat chamber of commerce dues like economic development expenses and split the costs between ratepayers and shareholders.[736] The OAG further argued the Commission's rationale from the last Xcel rate case should apply because the economic development activities of chambers of commerce continue to benefit both ratepayers and shareholders.[737]

697. Xcel further argued that chambers of commerce play roles in their community that go far beyond economic benefit.[738] By paying dues, the Company hopes to signal to the chambers' communities that the Company is part of, and is a supporter

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[731] Ex. Xcel-28 at 11 (Robinson Rebuttal).
[732] Minn. Stat. § 216B.16, subd. 13.
[733] *See In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 21 (Feb. 1, 2022) (eDockets No. 20222-182349-01) [hereinafter Otter Tail 2020 Rate Case Order].
[734] Xcel 2021 Rate Case Order at 75-76.
[735] Xcel 2021 Rate Case Order at 74-75.
[736] Ex. OAG-5 at 9 (Lee Direct).
[737] Xcel 2021 Rate Case Order at 75.
[738] Ex. Xcel-28 at 12-13 (Robinson Rebuttal).

of, those communities.[739] Chamber activities provide a vehicle for the Company to stay connected to its customers and better serve community needs.[740] The Company emphasizes that chamber of commerce activities are substantially things such as local parades and leadership conferences.[741]

698. The Company's argument that there is a customer benefit to its participation is reasonable. This benefit supports recovery of some level of chamber of commerce due.

699. The Company has not, however, established that disturbing the Commission's past practice of limiting that recovery to 50 percent is reasonable. In Xcel's most recent rate case, the Commission declined to alter that practice absent the utility proposing "any way to quantify the relative proportions of economic-development and non-economic development benefits."[742] In the absence of such quantification here, no course change is warranted.

700. The Commission should adopt the OAG's recommendation and limit recovery of chamber of commerce dues to 50 percent of Xcel's requested levels.

20. Employee Awards and Gifts

701. The Company recognizes employees' work performance and accomplishments by providing employees with small awards and gifts.[743] These awards are provided through a program called Xcelebrate.[744]

702. The Company requests $741,047 for the 2025 Test Year and $772,320 for the 2026 Plan Year for cost recovery of the Xcelebrate recognition awards.[745]

703. The OAG recommended limiting recovery to only safety-related awards.[746] The OAG's recommendation would disallow $737,144 for 2025 and $768,252 for 2026.[747]

704. The Xcelebrate program is designed to recognize individual or team performance and accomplishments.[748] In the Xcelebrate program, employees receive points for excellent work, which can be used to obtain merchandise or gift cards through an online catalog.[749] The highest level of award is equivalent to $100, and this level requires both manager and director approval.[750] In addition, Xcelebrate is used to recognize years of contribution at five-year intervals and at retirement.[751] Spending for

[739] Ex. Xcel-28 at 12 (Robinson Rebuttal).
[740] Ex. Xcel-28 at 12-13 (Robinson Rebuttal).
[741] Ex. Xcel-28 at 12 (Robinson Rebuttal).
[742] Xcel 2021 Rate Case Order at 75.
[743] Ex. Xcel-26 at 104 (Robinson Direct).
[744] Ex. Xcel-26 at 104 (Robinson Direct).
[745] Ex. Xcel-28 at 15 (Robinson Rebuttal).
[746] Ex. OAG-7 at 10 (Lee Surrebuttal).
[747] Ex. OAG-7 at 10 (Lee Surrebuttal).
[748] Ex. Xcel-63 at 25 (Ly Rebuttal).
[749] Ex. Xcel-28 at 14 (Robinson Rebuttal).
[750] Ex. Xcel-28 at 14 (Robinson Rebuttal).
[751] Ex. Xcel-28 at 14 (Robinson Rebuttal).

holidays and life events (funerals, weddings, birthdays, etc.) is not part of the Xcelebrate program and has already been completely excluded from the Company's rate request.[752]

705. The are four expense types that are part of the Xcelebrate program: performance, years of contribution, per seat fee, and safety.[753] The performance and years of contribution categories are self-explanatory. The "per seat fee" is the cost paid by the Company to use the Xcelebrate program, and as noted above, the safety awards are not disputed.[754]

706. The OAG argues that the Commission should disallow awards and gifts not related to Xcel's safety recognition program due to lack of support in the record showing these expenses are reasonable and necessary for the provision of utility service.[755]

707. OAG argued that Xcel had only provided conclusory statements regarding the necessity of its employee awards and the request should therefore be denied.[756]

708. The Company responds that the recognition program provided through Xcelebrate helps the Company foster a culture where employees feel valued and appreciated, which drives engagement, productivity, and retention.[757] Customers benefit from the Company's retention of knowledgeable, experienced employees that can complete tasks efficiently and by having reduced costs associated with hiring and training new employees.[758] It is reasonable for the Company to reward high performance and years of contribution, and these awards are a key part of the Company's overall approach to employee compensation.[759]

709. The performance-based awards reinforce "desirable work efforts and contributions in the moment that directly support customer satisfaction and business continuity."[760] The years-of-contribution awards recognize long-term employees who bring valuable expertise and knowledge to the Company, and the awards instill both employee pride and renewed loyalty to their work serving customers.[761] The "per-seat fee" component of the Xcelebrate program is an O&M expense and no amount in that category is received by employees.[762]

710. The OAG also argued that its recommendation is consistent with prior Commission decisions involving employee recognition programs at Minnesota Power and

[752] Ex. Xcel-28 at 16-17 (Robinson Rebuttal).
[753] Ex. Xcel-28 at 14-15 (Robinson Rebuttal).
[754] Ex. Xcel-28 at 14-15 (Robinson Rebuttal).
[755] Ex. OAG-7 at 8 (Lee Surrebuttal).
[756] OAG Initial Brief at 42.
[757] Ex. Xcel-62 at 28 (Ly Direct).
[758] Ex. Xcel-63 at 25-26 (Ly Rebuttal).
[759] Ex. Xcel-28 at 17 (Robinson Rebuttal).
[760] Ex. Xcel-63 at 25 (Ly Rebuttal).
[761] Ex. Xcel-63 at 26 (Ly Rebuttal).
[762] Ex. Xcel-28 at 17 (Robinson Rebuttal).

Otter Tail Power.[763] Both cases relied on by the OAG are distinguishable from this proceeding.

711. In the 2021 Minnesota Power rate case, the Commission excluded gift cards given to employees as awards for certain periods of service, noting that that program was distinguishable from "accomplishing goals or achieving benchmarks that specifically increase product or safety" and "failed to show how service-time-recognition awards encourage or promote similar results.[764] Here, the service-time awards are only one portion of the program that is largely driven by employee performance. Further, Xcel has built a record on the customer benefits of employee retention that satisfies its burden on this issue.[765]

712. In the 2015 Otter Tail Power Company rate case, the Commission excluded from recovery a much broader employee gift program that included gifts for retirements, deaths, holidays, and other special events, determining that such gifts were "not reasonable and necessary for the provision of utility services."[766] Such gifts are unrelated to performance and present no obvious customer benefit. Xcel has shown that, in this proceeding, it is not seeking recovery of these types of gifts.

713. The Company has met its burden to prove that the portion of its employee gift program it seeks to recover is reasonable and necessary for the provision of utility service.

714. The Commission should allow Xcel to recover its requested amount for the Xcelebrate program.

21. Investor Relations Expense

715. The Company included investor relations expenses in 2025 and 2026 cost of service, asserting that these expenses are necessary to keep the credit rating agencies fully informed regarding the Company's business and financing plans and to maintain strong investor demand for its long-term debt securities. The Company argues that its Investor Relations team's efforts enable the Company to issue long-term debt securities at favorable costs, as evidenced by the Company's low cost of long-term-debt and that these costs are not discretionary expenses, since a company with publicly-traded equity must engage in investor relations activities, including but not limited to: (i) the listing of shares of XEI on the National Association of Securities Dealers Automated Quotations (NASDAQ); (ii) stock transfer agent services associated with the issuance of new common shares to investors, providing shareholders online access to accounts, and

[763] Ex. OAG-5 at 11 (Lee Direct); Ex. OAG-7 at 10 (Lee Surrebuttal).
[764] MP 2021 Rate Case Order at 30.
[765] As these employee awards are awarded to employees who are not executives, the concerns discussed earlier in this Report about distinguishing between rewarding performance that primarily benefits shareholders rather than customers are not present on this issue. The Company's arguments about the benefit to customers in attracting and retaining employees are thus more persuasive on this issue.
[766] *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 OF LAW, AND ORDER at 47-48 (May 1, 2017) [hereinafter Otter Tail 2015 Rate Case Order].

maintaining the list of registered shareholders; and (iii) an annual shareholders meeting.[767]

716. The OAG recommended that these costs should be shared evenly between ratepayers and shareholders because investor relations costs also benefit shareholder interests, which would result in a reduction of $431,324 reduction in the 2025 Test Year and $427,196 in the 2026 Plan Year.[768] The OAG argued that "[o]ther than listing the activities that make up the investor relations costs, the Company does not attempt to determine the amount of costs that are for activities that benefit ratepayers."[769] Some costs are of no or only partial benefit to ratepayers, such as annual shareholder meeting expenses.[770]

717. The Commission has previously limited recovery to 50 percent of investor relations expenses, including in the 2013 CenterPoint rate case. In that proceeding, the Commission found that some level of investor relations was necessary for the provision of utility service, but that the utility has the burden to prove "the nature, amount, and necessity of each expense claimed."[771]

718. It is undisputed in this proceeding that some level of recovery of investor relations expense is appropriate. The Company is correct that investor relations expenses confer some benefit on customers. The OAG's proposal reasonably reflects that benefit, while also recognizing the inherent shareholder benefit with an even split of the costs. This proposal is consistent with prior Commission decisions.

719. The Company has not met its burden to prove that the full cost of its investor relations expense are reasonable and necessary in the provision of utility service.

720. The Commission should adopt the OAG's recommendation and allow Xcel to recover half of its investor relations expenses through the MYRP.

22. Rate Case Expenses

721. The Company forecasted rate case expense in this case based on actual historical rate case expense from its most recent MYRP electric rate case and anticipated costs to be incurred for outside experts, regulatory and legal fees, and administrative costs such as required notices. The Company proposed recovery of the forecasted $4.9 million in rate case expense amortized over three years (2025-2027).[772]

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[767] Ex. Xcel-20 at 37-38 (Wehner Direct); Ex. Xcel-94 (Wehner Witness Summary).
[768] Ex. OAG-7 at 12 (Lee Surrebuttal).
[769] Ex. OAG-5 at 14 (Lee Direct).
[770] Ex. OAG-5, Schedule 5 at 1 (Lee Direct).
[771] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase natural Gas Rates in* Minnesota, MPUC Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, ORDER at 22 (Jun. 9, 2014) [hereinafter CenterPoint 2013 Rate Case Order].
[772] Ex. Xcel-17 at 84-85 (Halama Direct). The amount included for recovery reflects forecasted rate case expense after removing costs to account for non-regulated activities. Ex. Xcel-7 at VIII.A31 (Xcel Application Volume 4, MYRP Workpapers, Rate Case Expense).

722. The Commission has consistently allowed utilities to recover reasonable and prudent rate case expenses through general rate cases.[773] This practice is grounded in the principle that utilities should be permitted to recover costs that are necessary for providing adequate and efficient service to ratepayers, including the costs associated with regulatory proceedings. As the Commission has recognized, rate case proceedings are complex and "the Commission must decide a wide range of issues, from the accuracy of the financial information provided by the utility to the prudence and reasonableness of the underlying transactions and business judgments, to the proper distribution of the final revenue requirement among different customer classes."[774]

723. For this proceeding, Xcel has utilized 24 witnesses, including two external consultants, testifying on return on equity, rate of return, capital structure, cost of debt, and executive compensation.[775] Xcel also retained the service of three external law firms.[776]

724. The OAG recommended that rate case expenses be paid equally by Xcel's shareholders and customers, which would result in a 50 percent reduction in the Company's request. The OAG emphasized that rate Xcel's approved rate case expenses increased from $2.7 million for its 2013 rate case, to $3.3 million for its 2015 rate case, to $4.6 million for its 2021 rate case.[777]

725. The OAG argues that it is unreasonable for ratepayers to pay 100 percent of rate case expenses when the Company's shareholders receive benefits from Xcel's efforts to increase its rates.[778] Further, the OAG argues that rate cases benefit shareholders by allowing the utility to increase its revenue requirement. The OAG concludes that specific rate case expenses, such as the utility's cost-of-capital and return-on-equity witnesses, exclusively benefit shareholders.[779]

726. The Company responded by arguing that the purpose of rate case proceedings is not to increase the revenue requirement in order to issue dividends for the benefit of shareholders,[780] but to "provide regulators and interested parties a forum to determine appropriate rates for the utility and address significant issues relating to the provision of utility service."[781] The Company explained that rate case proceedings benefit customers by ensuring transparency, accountability, and Commission oversight. And while setting a reasonable rate of return is one aspect of a rate case proceeding, access

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[773] *See* CenterPoint 2013 Rate Case Order at 25 ("Reasonable, prudently incurred rate case expenses are properly included in test year costs and built into rates for recovery from ratepayers."); *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G011/GR-17-563, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 15 (Dec. 26, 2018) ("Among the costs utilities may include in their test year are reasonable, prudently incurred expenses of conducting a rate case.") [hereinafter MERC 2017 Rate Case Order].
[774] Xcel 2021 Rate Case Order at 4 (July 17, 2023).
[775] Ex. OAG-5 at 17 (Lee Direct).
[776] Ex. OAG-5 at 17 (Lee Direct).
[777] Ex. OAG-7 at 16 (Lee Surrebuttal).
[778] Ex. OAG-5 at 17 (Lee Direct).
[779] Ex. OAG-5 at 18 (Lee Direct).
[780] Ex. Xcel-19 at 44 (Halama Rebuttal).
[781] Ex. DOC-1 at 5 (Johnson Direct).

to capital is not an end in itself, but rather is required so that the Company can make the significant, ongoing investments in infrastructure necessary to serve customers and continue providing essential utility services over the long term.[782]

727. The Company also suggested that many factors beyond the Company's control directly impact the amount of rate case expense incurred. These factors include whether or not a rate case is settled or fully litigated; delays in the proceeding schedule; the extent of supplemental testimony ordered by the Commission; requirements from prior case decisions; the number of intervenors; the volume and complexity of discovery requests received; the volume and nature of intervenor direct, rebuttal, and surrebuttal testimony, and the number and complexity of issues raised; and the length and breadth of evidentiary hearings. The Company provided specific testimony regarding how factors outside its control have increased rate case expense in this case, including the volume and complexity of discovery, the number of intervenors involved in this case, and the volume and nature of testimony.[783] Through October 4, 2025, the Company had responded to over 550 Information Requests, many with multiple subparts and produced approximately 32,580 pages of responsive information, documents, and materials and over 275 live Excel files. Additionally, eight parties intervened in this contested case proceeding with 24 witnesses filing intervenor Direct Testimony and 22 witnesses filing intervenor Surrebuttal Testimony on a range of issues.[784]

728. The Company also pointed out that, for the 2021 rate case, actual rate case costs incurred exceeded the Company's forecasted rate case expense by approximately $135,000, with the variance driven by regulatory fees, not the Company's own costs. Actual regulatory fees exceeded the Company's forecast for that rate case by over $400,000, totaling more than $1.6 million.[785]

729. The OAG refutes that Xcel does not have control over rate case expenses.[786] It is certainly true that Xcel chooses when the rate case is filed, which experts or lawyers to hire, and how to manage its internal staff, retained counsel, and retained experts.

730. The Company argued that the firms and consultants it partners with bring very specific knowledge, expertise, and skill sets to the Company's rate cases. An attorney who has dealt with and has familiarity with the issues and witnesses in multiple prior cases is more efficient and cost-effective than one who has neither institutional knowledge nor familiarity with the Company and its processes. Moreover, the

[782] Ex. Xcel-19 at 44 (Halama Rebuttal) ("Further, while a reasonable rate of return (ROR) is necessary to attract investors and allow the Company to secure the capital necessary for system investments, rate cases examine all costs and other factors impacting the revenue deficiency and return on equity (ROE) is but one of those factors.").
[783] *See* Ex. Xcel-19 at 45-46 (Halama Rebuttal).
[784] *See* Ex. Xcel-19 at 46 (Halama Rebuttal).
[785] Ex. Xcel-19, Schedule 5 (Halama Rebuttal) (Xcel Energy's Response to OAG IR No. 1009).
[786] Ex. OAG-5 at 16-17 (Lee Direct).

Commission has consistently recognized the reasonableness of the Company's outside legal and expert witness expenses.[787]

731. The OAG argues that Xcel does not have an incentive to keep its rate case expenses low if it can simply pass them on to ratepayers.[788]

732. The OAG points to examples where commissions and legislatures have "reined in" investor owned utilities' rate case expenses that are passed onto ratepayers.[789] The New Hampshire Public Utilities Commission requires a bidding process if rate case expenses are estimated to be over $10,000 dollars.[790] New Jersey and Missouri both recognize that shareholders benefit from rate cases and order that only 50 percent of rate case expenses may be recovered from ratepayers.[791] Missouri's Public Utilities Commission further recognizes that 100 percent recovery "does not encourage reasonable levels of cost containment in the utility's rate case expense decisions."[792] Connecticut legislature has prohibited the recovery of any rate case expenses.[793] Colorado has a statute directing the Public Utilities Commission to "limit the amount of rate case expenses that an investor-owned electric or gas utility may recover from the utility's customers."[794]

733. As an initial matter, the Company is correct about the impact of the size and complexity of proceedings such as this. As the drafter of this Report, the Court is keenly aware of the quantity and complexity of the issues raised. Many parties in this proceeding have contributed to this reality, as demonstrated by the amount of discovery requests and testimony filings highlighted by the Company.[795]

734. The OAG focuses more on the broad point about splitting responsibility for rate case expenses, rather than the reasonableness of the specific amount in controversy. The OAG, in a sense, is correct that shareholders stand to benefit from a rate case. But this argument is somewhat reductive. The outcome of this proceeding will be the Company's statutorily authorized regulator determining the appropriate cost of providing service, and allowing Xcel to recover that amount in rates. In other words, by definition, the purpose and outcome of this case will be that Xcel is allowed to charge customers for reasonable and necessary costs. It necessarily follows that the cost of the regulatory proceeding to recover those costs is, in and of itself, a necessary cost.

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[787] Ex. Xcel-19 at 46-47 (Halama Rebuttal).
[788] Ex. OAG-7 at 15 (Lee Surrebuttal).
[789] Ex. OAG-5 at 19 (Lee Direct) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).
[790] Ex. OAG-5 at 19 (Lee Direct) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).
[791] Ex. OAG-5 at 20-21, Schedules 6-7 (Lee Direct).
[792] Ex. OAG-5, Schedule 7 at 3 (Lee Direct).
[793] Ex. OAG-5, Schedule 7 at 3 (Lee Direct).
[794] Ex. OAG-5, Schedule 8 at 1 (Lee Direct) (COLO. REV. STAT. ANN. § 40-3-102.5 (WEST 2025)).
[795] This observation should not be read as a criticism of any party. Every party in this proceeding, as well as the numerous members of the public who contributed to the record through written or oral comments, has helped build a robust and transparent record that benefits both the Court in developing its recommendation for the Commission and the public in understanding how its rates are set.

735. The OAG's arguments about shareholder responsibility are reflected in other sections in this Report. To the extent there are specific costs that ought not be borne by ratepayers, this Report recommends the appropriate adjustments. Separately reducing rate case expense recovery for the same reason would be duplicative.

736. The OAG's arguments with respect to the utility lacking an incentive to control costs that it passes on to customers through rates are also unpersuasive. This feature is not unique to rate case expenses, as the same can be said of any expense category recovered through rates. This proceeding is the very remedy for this concern. Intervenors have recommended reductions for various expense categories and, where appropriate, this Report recommends adjustments. This is not a basis for a substantial categorical reduction in the recovery level for one type of expense.

737. It is true that other jurisdictions have reached different conclusions. The Commission, however, has consistently treated reasonable and prudent rate case expenses as a fully recoverable cost of providing service. This record does not support changing course.

738. The Company has met its burden to demonstrate that its requested rate case expenses are a reasonable and necessary cost of providing service.

739. The Commission should approve recovery of rate case expenses at the Company's requested level.

23. Liquidated Damages

740. Liquidated damages are the amounts paid to the Company by wind service providers when the Company's wind facilities operate less than the amount outlined in the O&M service agreement during a given period.[796] Specifically, Xcel has service agreements with its wind service providers that include an "availability covenant" that provides a Projected Average Availability (PAA) for a given production period.[797] If the contractual Measured Average Availability (MAA) is less than the PAA for a given production period, liquidated damages are owed to Xcel.[798] For wind facilities that are being recovered in the RES Rider, all liquidated damage payments are credited back to customers through this rider.[799]

741. Xcel received $3.1 million in liquidated damages in 2022, $4.8 million in 2023, $2.2 million in 2024, and as of Surrebuttal testimony, was on pace to receive an annualized $700,424 in 2025.[800] Approximately 70 percent of these revenues are returned to customers through the Company's RES rider.[801]

[796] Ex. Xcel-46 at 9 (Capra Rebuttal).
[797] Ex. Xcel-46 at 9 (Capra Rebuttal).
[798] Ex. Xcel-46 at 9 (Capra Rebuttal).
[799] Ex. Xcel-46 at 9 (Capra Rebuttal).
[800] Ex. DOC-2 at 18 (Johnson Surrebuttal).
[801] Ex. DOC-2 at 15 (Johnson Surrebuttal); Ex. Xcel-46 at 10-11 (Capra Rebuttal).

742. The Department recommended that the Commission include approximately $945,000 in liquidated damages revenue in both test years[802] This amount reflects the average damage payment revenue, excluding revenue already returned through the RES rider.[803]

743. Xcel argued that it is inappropriate to reduce Energy Supply's 2025 and 2026 O&M expenses based on a historical average of liquidated damage amounts because the Company already refunds a portion of these liquidated damages to customers and because the amount of liquidated damages that the Company receives is highly variable such that these past amounts cannot be used to estimate future damage payments.[804]

744. In support of this argument the Company points to evidence that liquidated damage amounts are highly variable because there are a number of factors that can contribute to a wind facility not meeting its expected energy production, including site technician expertise, component reliability and serial defects, parts availability, and weather conditions.[805] To demonstrate this variability, the Company provided evidence showing that the liquidated damage amount that the Company received in 2024 was $2.6 million less than what it had received the year prior.[806]

745. The Company also provided evidence showing that its liquidated damage amounts have been declining in recent years.[807] This is because the Company has been working with service providers to improve the operational performance of its facilities.[808] These efforts have resulted in declining liquidated damage payments in both 2024 and 2025.[809]

746. The Company provided evidence that liquidated damages will likely decline in 2025 and 2026 because liquidated damages primarily occur when wind facilities are in their first few years of operation.[810] This is because the first few years of operation is when serial defects typically arise and technicians are still gaining experience on troubleshooting operational issues on new turbine models.[811] The first few years of operation is also when the costs for these wind facilities are most likely to be recovered through the RES Rider, where the liquidated damages will naturally flow to customers.[812] Indeed, from 2022 to 2024 nearly 70 percent or $7 million in liquidated damages was credited back to customers through the RES Rider.[813] As the Company does not have

[802] Ex. DOC-2 at 18 (Johnson Surrebuttal).
[803] Ex. DOC-2 at 18 (Johnson Surrebuttal).
[804] Xcel Initial Brief at 82.
[805] Ex. Xcel-46 at 12 (Capra Rebuttal).
[806] Ex. Xcel-46 at 12 (Capra Rebuttal).
[807] Ex. Xcel-46 at 12 (Capra Rebuttal); Ex. DOC-2, Schedule 5 at 3 (Johnson Surrebuttal) (Xcel Energy Response to DOC IR 3109).
[808] Ex. Xcel-46 at 11-12 (Capra Rebuttal).
[809] Ex. Xcel-46 at 12 (Capra Rebuttal); Ex. DOC-2, Schedule 5 at 3 (Johnson Surrebuttal) (Xcel Energy Response to DOC IR 3109).
[810] Ex. Xcel-46 at 13 (Capra Rebuttal).
[811] Ex. Xcel-46 at 13 (Capra Rebuttal).
[812] Ex. Xcel-46 at 13 (Capra Rebuttal).
[813] Ex. Xcel-46 at 10-11 (Capra Rebuttal).

any plans to add any wind facilities in either 2025 or 2026, it is expected that liquidated damage amounts in these years will be lower than historical 2022 through 2024 amounts that the Department uses to calculate its proposed adjustment.[814]

747. The Department is correct that some adjustment is warranted. It is not disputed that liquidated damages payments occur and that some of these payments are not returned to customers through the RES rider.

748. The Company has established that these payments are variable and difficult to predict. Rejecting an adjustment on this basis would be an untenable result. In a regulatory paradigm where all doubt as to reasonableness is resolved in favor of the consumer, the benefit of uncertainty must flow to customers. The Company cannot recover money it is not entitled to through rates simply because it is difficult to precisely quantify the correct level of recovery.

749. The Company has, however, established that the Department's proposed reduction is too high. These payments have been consistently diminishing over time, and Xcel's explanations for why they should be expected to continue to do so are persuasive. Accordingly, use of a historical average overstates the appropriate rate impact of the liquidated damages revenues.

750. Accordingly, the appropriate adjustment in this proceeding is to reduce Xcel's requested level of rate recovery by $210,127 in both the 2025 Test Year and 2026 Plan Year. This reflects the $700,424 annualized actual revenue for 2025, less the 70 percent of payments that are likely to be returned to customers through the RES rider. Because of the downward trend, such an adjustment would still be conservative from lens of the consumer.

751. The Commission should adjust Xcel's request to reflect $210,127 for revenue for liquidated damages in the 2025 test year and 2026 plan year.

24. Insurance

752. The Company seeks to recover $34.2 million in 2025 and $37.6 million in jurisdictionally allocated insurance premium costs for 2025 and 2026.[815]

753. The Commission ordered the parties to develop a record on the insurance premium expense that addressed, at a minimum, six specific categories of information. The required information includes "the forecasted and actual annual expenses for each subcategory of expenses and credits since 2017," "[t]he extent to which the Marshall Wildfire in Colorado and the 2024 Smokehouse Creek Fire Complex in Texas affect the insurance premium, rate of return, or borrowing costs for the MN jurisdiction," and if refunds and credits cannot be accurately predicted, "proposed mechanisms by which rate

[814] Ex. Xcel-46 at 13 (Capra Rebuttal).
[815] Ex. Xcel-53 at 19 (Miller Direct).

payers can be appropriately reimbursed for insurance expenses refunds and credits they have paid for in base rates."[816]

754. The Company stated 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.[817]

755. The test year insurance budget is generally based on insurance premiums paid in the prior two years, which are then adjusted to take into account the identified trends in insurance market conditions and the Company's exposure metrics. The forecast includes anticipated distributions and credits from insurers.[818]

756. The Company identified two factors that are leading to an upward trend in the Company's insurance premium budgets for the period covered by the MYRP: (1) a hardening of the insurance market, in particular affecting the Company's Master Property Insurance and Excess Liability Insurance,[819] and (2) increased utility industry losses, including losses due to events such as wildfires and gas explosions, which impact the Company's Excess Liability premiums.[820]

757. An underwriting change in 2023 resulted from the increase in wildfire claim risk across the utility industry. This change caused an increase in Excess Liability premiums effective as of the October 2024 policy renewal, impacting premium cost in 2025 and beyond.[821]

758. The Department argued that Xcel's forecast was inadequately supported, was out of line with historical increases in expense, and had not been shown to protect Minnesota ratepayers from subsidizing wildfire-related costs caused by other jurisdictions or inaccurate predictions in refunds and credits.[822]

759. The Department recommended an alternative forecast expense, using the company's actual 2024 insurance premium expenses, increased by the average annual increase in insurance expense from 2020 through 2024 to generate the 2025 forecast.[823] The Department then applied Xcel's recommended increase to the 2025 forecast to generate the 2026 forecast.[824]

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[816] Notice and Order for Hearing at 3–4 (Dec. 30, 2024) (eDocket No. 202412-213391-01).
[817] Ex. Xcel-53 at 20 (Miller Direct).
[818] Ex. Xcel-53 at 20 (Miller Direct).
[819] Ex. Xcel-53 at 23 (Miller Direct).
[820] Ex. Xcel-53 at 30 (Miller Direct).
[821] Ex. Xcel-54 at 4-5, 8 (Miller Rebuttal).
[822] Ex. DOC-23 at 23–25 (Jones Direct).
[823] Ex. DOC-23 at 25 (Jones Direct).
[824] Ex. DOC-23 at 25–26 (Jones Direct).

760. The Department advocated for using a four-year lookback period to determine the insurance premium expense.[825] The Department noted that there have been large swings in annual changes in insurance premium expense, with annual changes from 2021 to 2025 ranging from –22.13 percent to 122.67 percent.[826] Given the significant fluctuations in insurance costs from year to year, the Department believes a longer look back period is appropriate because it better captures volatility in the insurance market.[827]

761. Based on the increase in premiums from 2024 to 2026 and concerns that the Company was subsidizing the insurance costs of other jurisdictions with higher wildfire risk or claims experience based on the amount of Excess Liability premium cost allocated to the Company, XLI also recommended that the Company's recovery of Excess Liability insurance premium costs be based on an average increase, using the period from 2022 to 2024 for the average.[828]

762. Notably, neither the Department nor XLI disputes the type or amount of coverage obtained by the Company.

763. The Company updated its Excess Liability Insurance Premium information in Rebuttal Testimony, providing a July 2025 forecast that was based on six months of actual premium experience. The change in Excess Liability premium costs were not substantial, and the Company did not update its requested recovery of premium costs.[829]

764. Xcel was allocated a lower percentage of Excess Liability Premium cost in the July 2025 forecast than in the initial forecast as a result of loss and wildfire loading provided by the Company's insurance brokers.[830]

765. This evidence both corroborates the accuracy of the Company's initial forecast and demonstrates that loss and wildfire loading by Xcel's brokers is appropriately allocating risk among Xcel Energy, Inc.'s various jurisdictions.

766. The Commission should also establish a symmetrical true-up for insurance costs to ensure that the Company neither over-recovers nor under-recovers its insurance costs.[831] While true-ups should not be relied on excessively as a substitute for accurate expense forecasting, these costs are particularly well-suited for such a mechanism. The type and nature of Xcel's coverage is not disputed by any party, is a reasonable and necessary cost of providing utility service, and is subject to substantial variation in cost.

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[825] Ex. DOC-24 at 24 (Jones Surrebuttal).
[826] Ex. DOC-24 at 24 (Jones Surrebuttal).
[827] Ex. DOC-24 at 24 (Jones Surrebuttal).
[828] Ex. XLI-1 at 54-58 (LaConte Direct).
[829] Ex. Xcel-56 at 2-3 (Miller Rebuttal).
[830] Ex. Xcel-56 at 3-4 (Miller Rebuttal).
[831] The Company proposed a symmetrical true-up mechanism for these costs in Rebuttal Testimony. Ex. Xcel-56 at 11-23 (Miller Rebuttal). Neither the Department nor XLI responded to this suggestion in Surrebuttal Testimony.

A true-up would reasonably protect ratepayers from over-paying, while also allow Xcel to recovery a necessary cost.

767. The Company has met its burden to establish that its forecasted Excess Liability Premium costs are reasonable and should be approved by the Commission as the baseline for this true-up mechanism.

25. Property Tax

768. Xcel requested recovery of its forecasted property tax expense for the 2025 Test Year and 2026 Plan Year, subject to a true-up mechanism. Xcel initially forecasted $182.1 million for 2025, and an updated forecast of $184.2 million.[832] For 2026, Xcel initially forecasted $194.3 million, and provided an updated forecast of $195.4 million.[833] The forecasts for both years were updated to reflect the Company's settlement with the Department of Revenue (DOR) for its 2025 property tax valuation, and property tax bills that allowed the Company to calculate its 2024 actual effective tax rate.[834]

769. Xcel proposed to continue its current property tax true-up mechanism, which has been approved in recent Xcel rate cases.[835]

770. The Department initially recommended a five percent cap on surcharges for property tax expense.[836] After further review, the Department subsequently agreed with Xcel's proposal to continue the property tax expense true-up in its current form.[837]

771. No other party opposed the property tax true-up and it is reasonable for the true-up to continue.

772. The Department observed that the Company collected $102.5 million in excess property tax expense from customers from 2017 through 2024 that had to be returned via true-up refunds.[838] Specifically, Xcel's forecast exceeded its actual expense every year since 2017.[839]

773. Based in part on this observation, the Department raised concerns with Xcel's forecast for 2025 and 2026.[840]

774. In support of its forecasts, the Company argued that its tax expense varies each year due to changes to inputs outside of the Company's control – the DOR's Cap Rate, the DOR's weighting of valuation approaches, and the local effective tax rate.[841] The Company further asserted that because property tax expense has to be estimated

[832] Ex. Xcel-52 at 3 (Kowalowski Rebuttal).
[833] Ex. Xcel-52 at 3 (Kowalowski Rebuttal).
[834] Ex. Xcel-52 at 3–5 (Kowalowski Rebuttal).
[835] Ex. Xcel-51 at 22 (Kowalowski Direct).
[836] Ex. DOC-23 at 13 (Jones Direct).
[837] Ex. DOC-24 at 4–5 (Jones Surrebuttal).
[838] Ex. DOC-23 at 13 (Jones Direct).
[839] Ex. DOC-23, Schedule 3 (Jones Direct).
[840] Ex. DOC-24 at 12–13 (Jones Surrebuttal).
[841] Ex. Xcel-51 at 9-22 (Kowalowski Direct); Ex. Xcel-52 at 13 (Kowalowski Rebuttal).

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, the Company's forecast methodology uses the most recent available data.[842] The Company believes this ensures consistency so that forecasts can be compared from year to year, and avoids speculation about future macroeconomic circumstances that might affect property tax expense.[843]

775. The Company responded to the Department's concern about over-recoveries on property tax in past years. First, the Company actually under-recovered in 2024 for the gas jurisdiction.[844] The Company explained that from 2020 to 2023, the effective local tax rate—one of the main drivers of the Company's property tax expense—decreased and/or stayed at an artificially low level due principally to increases in residential real estate prices.[845] And, the DOR's Cap Rate—another driver of the property tax expense—increased as a result of the relatively high inflation during the period from 2021 to 2023.[846] The Company's forecast does not make assumptions about whether these conditions will continue, and the Company asserts this balances the risks of over-recovery and under-recovery.[847]

776. The Department's recommendation implicitly assumes that the local effective tax rate will continue to decrease in 2025 and 2026.[848]

777. The Company has certainly established that these expenses are inherently difficult to forecast. The Company cannot be faulted for a lack of precise accuracy in its forecasts. That said, the Department is right to be concerned about the recurring over-forecasting of property tax expenses by the Company.

778. While the difficulty of forecasting property tax expense explains large discrepancies between forecasted figures and actual expenditures, one would expect a reasonable forecast to be as likely to under-project actual expenses as frequently as it over-projects them. That is obviously not what has happened with this expense category. It is concerning that the forecast has missed the mark in the same direction for eight consecutive years, especially when the direction it misses in is the one that results in customers initially over-paying for property taxes. While the Company points to under-forecasting in its gas jurisdiction in 2024, this single contrary data point is of limited persuasive value.

779. In the face of this trend, and the burden to prove the reasonableness of the rate request rests with the Company, the Department does not need to identify a specific shortcoming in the forecasting methodology or assumptions. It is for the Company to

[842] Ex. Xcel-51 at 10 (Kowalowski Direct); Ex. Xcel-52 at 13 (Kowalowski Rebuttal).
[843] Ex. Xcel-51 at 10-11 (Kowalowski Direct).
[844] Ex. Xcel-52 at 18 (Kowalowski Rebuttal).
[845] Ex. Xcel-52 at 18 (Kowalowski Rebuttal).
[846] Ex. Xcel-52 at 19 (Kowalowski Rebuttal).
[847] Ex. Xcel-52 at 19 (Kowalowski Rebuttal).
[848] Ex. Xcel-52 at 16-17 (Kowalowski Rebuttal).

explain either that its forecasting methodology has been corrected, or that the trend observed by the Department was due to factors unlikely to recur.

780. The Company has raised valid concerns with the Department's recommendations. There is no principled basis to believe the local effective tax rate will continue to decrease in 2025 and 2026, an implicit assumption of the Department's recommendation.

781. In sum, the choices presented in this case between a forecast that history has shown to be upwardly biased and an adjustment that rests on a flawed assumption. This choice, as well as the difficulty in projecting property tax expenses, underscores the importance of the true-up for this expense category.

782. As doubt as to reasonableness must be resolved in favor of the consumer, the Department's recommendation is the legally mandated choice on this record.

783. The Commission should continue Xcel's property tax true-up and adopt the Department's recommended adjustment to the Company's property tax expense for 2025 and 2026.

26. Distribution Capacity Investments

784. The Company's Distribution business makes investments in capacity projects to handle load growth on the system and to serve load when other elements of the distribution system are out of service.[849] The Company proposed $106.6 million in capacity investments in 2025 and $206.2 million in 2026.[850] In support of this request, the Company provided testimony explaining the need for these capacity investments.[851]

785. The Joint Intervenors acknowledged the need for capacity projects to maintain system reliability but questioned the increase in capacity expansion investments in 2026, asserting that this increase warrants closer scrutiny and alignment with the Commission's IDP processes.[852] Specifically, the Joint Intervenors alleged that the 2025-2026 capacity projects have not been subject to sufficient alternatives analyses[853] and recommended that the Commission approve only "near-term, clearly justified 2025 capacity work; [and] condition or cap 2026 Discrete Capacity spending pending an IDP showing that validates need, timing, and least-cost alternatives."[854]

786. The Company argued that the Joint Intervenors' recommendation to cap 2025 capacity investments is vague in that it does not list or provide any criteria to

[849] Ex. Xcel-34 at 88 (Mensen Direct).
[850] Ex. Xcel-34 at 89 (Mensen Direct).
[851] Ex. Xcel-34 at 88-99 (Mensen Direct); Ex. Xcel-35 at 19-25 (Mensen Rebuttal).
[852] Ex. JIN-1 at 23-24 (Kenworthy Direct).
[853] Ex. JIN-1 at 24 (Kenworthy Direct).
[854] Ex. JIN-1 at 25 (Kenworthy Direct).

determine which of the Company's 2025 capacity projects would meet the Joint Intervenors definition of "near-term, clearly justified" projects and which would not.[855]

787. The Company also pointed out that each of the 2025 and 2026 discrete capacity projects included in this rate case has been previously identified in either the Company's 2023 IDP or 2024 IDP Annual Update,[856] and as such, have already gone through the Company's annual planning processes. The Company's annual planning process is a multi-step process which considers various alternatives to determine the most appropriate project to mitigate the identified system capacity issue.[857] This analysis includes an evaluation of each project's costs, risks, and effectiveness at addressing the identified need.[858] And individual capacity projects over $2 million, that are deemed feasible candidates, are also subject to an additional non-wires alternatives analysis, as required by Commission Order.[859]

788. It is not uncommon for spending on discrete capacity projects to fluctuate from year to year. Capacity projects are planned based on assessment of system growth, the risk of overloads, and the system's ability to handle single contingency events, among other things.[860]

789. The Company has met its burden to demonstrate the reasonableness of its distribution capacity investments.

790. The Commission should allow recovery for Xcel's distribution capacity investments as requested by the Company.

27. Distribution Targeted Undergrounding

791. Distribution's targeted undergrounding program is designed to improve reliability by undergrounding overhead lines with the highest historical outage rates.[861] Outages on the overhead distribution system occur 3.5 times more frequently than on the underground distribution system, and outages lasting longer than 12 hours occur ten times more frequently. Underground distribution also benefits customers not served by these lines, since crews are able to focus restoration efforts on other areas of the system, which shortens outage times.[862]

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[855] Ex. Xcel-35 at 20 (Mensen Rebuttal).
[856] Ex. Xcel-35 at 22 (Mensen Rebuttal).
[857] Ex. Xcel-35 at 22-25 (Mensen Rebuttal).
[858] Ex. Xcel-35 at 22 (Mensen Rebuttal
[859] *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan*, MPUC Docket No. E002/M-21-694, ORDER (Dec. 8, 2022); *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS (Apr. 15, 2022).
[860] Ex. Xcel-35 at 20 (Mensen Rebuttal).
[861] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).
[862] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).

792. The Company proposed $2.3 million in 2025 and $6.7 million 2026 in capital additions for its targeted undergrounding program, and provided testimony supporting these investments.[863]

793. The OAG disputed the project's cost.[864] As a result, the OAG recommends that the Commission order a cost cap of $1.5 million per mile to protect ratepayers, equal to an $800,000 reduction in the 2025 test year and a reduction of $2.2 million to the 2026 plan year capital additions.[865]

794. The OAG's proposed cost cap was based on the Company's original proposal for this program in the 2024 Safety, Reliability, and Service Quality docket[866]— which the OAG points out is the same docket cited by Xcel in the Company's supplemental testimony as the genesis of the capital additions.[867] Xcel's first cost estimates submitted in April 2025 were between approximately $1 million and $1.5 million per mile.[868] But in the rate case filing, these estimates approximately doubled to a per mile cost of $2.3 million in the 2025 test year and $2.2 million in the 2026 plan year.[869]

795. The OAG raised concerns that the costs proposed for the 2025 Test Year and 2026 Plan Year are higher than what Xcel proposed in its original proposal and that Xcel anticipated that it would continue to "refine", which could result in them increasing further.[870] Further, the OAG points out that the Company did not provide updated costs for the 2025 Test Year to support its request despite having ten months of actual costs incurred in the 2025 Test Year.[871]

796. The Company presented evidence that the cost for undergrounding a particular feeder can vary greatly depending on the location of the feeder, the type of feeder, and the construction method. The Company demonstrated that the undergrounding costs estimates cited by the OAG in the 2024 Service Quality Report (SQR) are for a select group of undergrounding projects[872] that do not account for the different construction requirements of targeted undergrounding program projects.[873] The Company also stated that the 2025 and 2026 rate case budgets were based on historical undergrounding costs and added cost allowances to provide for construction of secondary service lines, customer service drops, and construction in urban areas.[874]

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[863] Ex. Xcel-37 at 2-4 (Mensen Supplemental Direct); Ex. Xcel-35 at 2-18 (Mensen Rebuttal).
[864] Ex. OAG-5 at 32-34 (Lee Direct).
[865] Ex. OAG-5 at 34 (Lee Direct); Ex. OAG-7 at 25 (Lee Surrebuttal).
[866] Ex. OAG-5 at 31-32 (Lee Direct).
[867] Ex. Xcel-37 at 3 (Mensen Supplemental Direct).
[868] *In re N. States Power Co.'s Ann. Rep. on Safety, Reliability, and Service Quality for 2024 and Pet. for Approval of Elec. Reliability Standards for 2025*, MPUC Docket No. E-002/M-25-27, Part 3 of 3 Order Compliance at 124-25 (Apr. 1, 2025) (eDocket No. 20254-217138-05); Ex. OAG-5 at 33 (Lee Direct).
[869] Ex. OAG-5 at 33 (Lee Direct).
[870] Ex. OAG-7 at 24 (Lee Surrebuttal); Ex Xcel-35 at 5 (Mensen Rebuttal).
[871] Ex. OAG-7 at 24-25 (Lee Surrebuttal).
[872] Ex. Xcel-35 at 5 (Mensen Rebuttal).
[873] Ex. Xcel-35 at 6 (Mensen Rebuttal).
[874] Ex. Xcel-35 at 6 (Mensen Rebuttal).

797. The Company provided evidence in Rebuttal Testimony about the location of potential targeted undergrounding projects already selected for design and construction.[875] These potential projects comprise over 180 projects distributed across 59 cities or townships in multiple regions of the service territory, with a concentration in the southeast metro and Saint Paul areas.[876]

798. There are various factors that will determine which projects go ahead first, including coordination with landowners to secure easements, navigating multiple agency permitting processes, managing construction schedules around weather conditions, and addressing site-specific design constraints.[877]

799. The Company also argues that a cost cap is unnecessary because the targeted undergrounding program is a capital program and subject to the Company's proposed capital true-up mechanism.[878]

800. The Joint Intervenors commended Xcel for developing proposals to address disparities in reliability. However, the Joint Intervenors also emphasized the need for transparent, comprehensive analysis of the Company's targeted undergrounding plans in its IDP, prior to cost recovery. The Joint Intervenors sought more detail related to cost-effectiveness, community impact, and process. [879]

801. The Company has provided sufficient evidence to establish that its distribution targeted undergrounding will yield substantial reliability and other benefits to customers. The question to be resolved here is whether the cost estimates presented by Xcel are reasonable and justified by the benefits to consumers.

802. While the capital true-up does provide some protection to customers, it is not a complete solution if the costs continue to increase. The true-up does prevent customers from paying for capital costs not actually incurred, but it does nothing to protect customers from paying the actual costs for a project that is simply too expensive. Here, however, the Company has met its burden to prove that the costs in this proceeding are reasonable for these projects and should be included in rates.

803. System reliability is one of the core objectives of utility regulation. The Company has shown that its distribution targeted undergrounding will lead to significant improvement in reliability.

804. Further, the Company has adequately justified its estimates, and explained why the estimates, based on the nature of the projects planned for 2025 and 2026, exceed the more general estimates that the OAG compares them to.

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[875] Ex. Xcel-35 at 10-12 (Mensen Rebuttal).
[876] Ex. Xcel-35 at 10-12 (Mensen Rebuttal).
[877] Ex. Xcel-35 at 10 (Mensen Rebuttal).
[878] *See* Ex. Xcel-15 at 29 (Liberkowski Direct).
[879] Ex. JIN-1 at 8 (Kenworthy Direct).

805. The Commission should approve the Company's proposed 2025 and 2026 investment in the targeted undergrounding program, subject to Xcel's capital true-up.

28. Virtual Power Plants

806. A Virtual Power Plant (VPP) is an aggregation of distributed energy resources—such as smart thermostats and water heaters, residential batteries paired with rooftop solar, EV managed charging, and flexible commercial and industrial (C&I) loads—coordinated to balance supply and demand and deliver utility-grade grid services.[880]

807. The Company has described its Advanced Grid Intelligence and Security (AGIS) initiative as a "comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system…."[881] The Company stated that these investments are "making the grid smarter and more responsive, increasing system visibility and control, and enabling expanded customer options."[882] And it indicated that "these AGIS investments, in concert with future investments, will provide cumulative benefits that will help to modernize the distribution system while also providing an improved customer experience."[883]

808. The Company has made and proposes to make investments in a Distributed Energy Resource Management System (DERMS).[884] The Company is not seeking cost recovery for DERMS in this case, but the Joint Intervenors assert that it is clear the Company is proceeding with these investments during the MYRP term.[885] The Company is proposing to recover costs for its Advanced Distribution Management System (ADMS), whose visibility and grid control capabilities are closely related to the capabilities of DERMS.[886]

809. The Joint Intervenors asserted that Xcel's current and proposed investments, specifically AGIS (in this rate case) and DERMS (under development in other cases), would enable a VPP. The Joint Intervenors further asserted that a VPP program could be a customer-facing use case that helps support cost recovery for AGIS in this rate case.[887]

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[880] Ex. JIN-1 at 35 (Kenworthy Direct). The Company provided testimony suggesting that there is no uniform definition of "virtual power plant," but that it defines a virtual power plant as "an aggregation of controllable DER that is managed digitally to aggregate the capabilities of the resources to provide grid services or attributes including energy, ancillary services, and capacity." Ex. Xcel-35 at 34 (Mensen Rebuttal). For the purposes of assessing the Joint Intervenors'' recommendation, this Report assumes the recommendation relates to virtual power plants as defined by the Joint Intervenors.
[881] Ex. Xcel-34 at 105 (Mensen Direct).
[882] Ex. Xcel-34 at 7 (Mensen Direct).
[883] Ex. Xcel-34 at 8 (Mensen Direct).
[884] Ex. JIN-1 at 35-38 (Kenworthy Direct).
[885] Ex. JIN-1 at 38 (Kenworthy Direct); Ex. JIN-4 at 13-15.
[886] Ex. JIN-1 at 39 (Kenworthy Direct); *see also* Ex. Xcel-34 at 105 Mensen Direct) (describing ADMS).
[887] Ex. JIN-1 at 35, 40 (Kenworthy Direct).

810. Based on the capabilities of AGIS and other investments, including DERMS, the Joint Intervenors recommended that, "[t]o ensure ratepayers receive the full value of these investments, the Commission should require the Company to implement VPP programs that utilize these capabilities to provide peak reduction, infrastructure deferral, and customer bill benefits that the Company itself acknowledges these systems enable."[888]

811. The Company points out that prior Commission approvals of AGIS components have been supported by various cost-benefit analyses that demonstrate the value of these AGIS investments independent of any future VPP component.[889]

812. The Company further explained that is has already recently filed a VPP proposal in a separate docket.[890] Specifically, the Company submitted its Distributed Capacity Procurement (DCP) proposal on October 3, 2025,[891] as required by the Commission's April 21, 2025 Order in the Company's most recent IRP in Docket No. E002/RP-24-67. Additionally, while DERMS by itself does not represent a VPP, DERMS and Aggregator DERMS (ADERMS) are being addressed in other proceedings per direction in prior Commission Orders, including in the Company's January 31, 2025 Demand Response Compliance Filing (Docket No. E002/M-421), and in filings and stakeholder workshops associated with the Company's 2025 IDP (Docket No. E002/M-25-142).[892]

813. This proceeding is not the proper venue for the Commission to condition cost recovery of any of the Company's investments on the implementation of a VPP.

814. VPPs are an intriguing concept, and may well have benefits for customers. However, the cost benefit analysis of Xcel's investments have been discussed in other proceedings and the Company has met its burden to show that recovery of its AGIS investments is appropriate in this rate case. To meet this burden, Xcel does not need to show that it is extracting every conceivable benefit of the technology. It is sufficient to show that the existing benefits justify the investments, without regard to whether there may be additional unrealized benefits.

815. Further, Xcel is correct that the capabilities and benefits of various advanced grid technologies are being addressed in other proceedings and stakeholder workshops. These proposals are best addressed in those forums where stakeholders with a specific interest in the respective technologies have an opportunity to build a record and be heard.

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[888] Ex. JIN-1 at 40 (Kenworthy Direct).
[889] Ex. Xcel-35 at 35 (Mensen Rebuttal).
[890] Ex. Xcel-35 at 35-36 (Mensen Rebuttal). The Company also noted that it currently has in place in Minnesota other programs that could be considered virtual power plants. Ex. Xcel-35 at 39-41 (Mensen Rebuttal).
[891] *In the Matter of the Petition of Northern States Power Company for Approval of Capacity*Connect, a Distributed Capacity Procurement Program*, MPUC Docket No. E002/M-25-378, Petition (Oct. 3, 2025).
[892] Ex. Xcel-35 at 37-38 (Mensen Rebuttal).

816. The Commission should not adopt the Joint Intervenors' proposal with respect to VPPs.

29. Equity Considerations in Distribution Planning

817. As evidenced by an analysis by Joint Internvenors' Witness Chan (Pradhan/Chan Study) and a study commissioned by the Company (TRC Study), long-duration outages (CELI-12) are more likely to occur for Xcel customers in neighborhoods with a higher proportion of people of color.[893]

818. The Joint Intervenors argued that the Company and the Commission should integrate equity considerations into capital investments, operational practices, budgeting, prioritization, and rate-setting, to ensure that the households that are already the most energy insecure are also not the same neighborhoods most likely to be impacted by a long-duration grid outage or the most unlikely to adopt DERs to improve their local resiliency. The Joint Intervenors posited that "investment prioritization itself can either perpetuate or remedy historical inequities."[894]

819. The Joint Intervenors argued that Xcel's current approach to distribution planning and budgeting creates an artificial distinction between rate-setting and equity, when the Joint Intervenors believe that affordability and equity in infrastructure, reliability, and other service quality metrics are linked to distribution investment, cost recovery, and rate-setting.[895] According to the Joint Intervenors, there must be an integration of equity into these analytical and decision-making processes to effect systemic change.[896]

820. A third-party evaluation of the Company's capital investment planning and outage restoration practices is already required under Order Point 46 of the Commission's January 13, 2025 Order in the 2023 Safety, Reliability, and Service Quality (SRSQ) Docket.[897] This study will evaluate the topic of disparities identified in the Pradhan/Chan Study and the TRC Study (both filed in the Company's 2023 SRSQ Docket), and the third-party evaluator will consider the Company's capital investment planning and outage restoration practices to understand the possible causes of disparities and ways to mitigate them.[898]

821. The Joint Intervenors stated that the Interruption Cost Estimate (ICE) 2.0 Calculator, released by Lawrence Berkeley National Laboratory in 2025, provides a more robust approach to analyze outage costs to inform distribution investments with equity considerations.[899] Therefore, the Joint Intervenors recommended that the Commission require Xcel to use the ICE 2.0 methodology combined with demographic

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[893] Ex. JIN-2 at 10-11 (Chan Direct); Ex. JIN-1 at 6 (Kenworthy Direct).
[894] Ex. JIN-1 at 4 (Kenworthy Direct).
[895] Ex. JIN-1 at 4 (Kenworthy Direct).
[896] Ex. JIN-1 at 12 (Kenworthy Direct); JIN-4 at 3 (Kenworthy Surrebuttal).
[897] *In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-24-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS, Order Point No. 46 (Jan. 13, 2025).
[898] Ex. Xcel-35 at 17 (Mensen Rebuttal).
[899] Ex. JIN-1 at 9 (Kenworthy Direct).

analysis to demonstrate how its proposed distribution investments and operational procedures address documented service disparities.[900]

822. Using the ICE 2.0 application method, as described in the Joint Intervenors' Direct Testimony, to weigh outage costs by "community vulnerability factors" lacks quantitative methods of implementation.[901]

823. The Joint Intervenors recommended that the Commission require the Company to integrate equity metrics into its IDP, in its internal annual budgeting and prioritization, and ultimately in the proposals it makes in rate cases.[902]

824. The Joint Intervenors also recommended the Commission require Xcel to consider low-income communities as another factor in storm response and other emergency response actions.[903]

825. The concerns raised by the Joint Intervenors are important. Utility customers should have equitable access to reliable electric service without regard to race, income, or other socioeconomic factors. Data presented in the TRC Study and the Pradhan/Chan Study demonstrates that this is not always the case for Xcel's customers.

826. The Commission has recognized these concerns, and meaningful work is being done in the SRSQ Docket to identify appropriate reforms.

827. No change to the Company's distribution planning or budget should be ordered in this proceeding. Distribution planning is a complex process that occurs through separate dockets. Attempting to prescribe requirements related to one set of concerns, even if those concerns are well-founded, would at best reflect an incomplete analysis of the many facets of distribution planning, and at worst, circumvent the IDP process and the separate dockets in which it occurs. This is especially true when these same concerns are simultaneously being addressed in the SRSQ Docket.

828. Further, if the Commission were inclined to adopt the Joint Intervenors' recommendations, the record here would not support a sufficiently precise directive to the Company due to the lack of monetary quantification for community vulnerability factors.

829. Also, no change to the Company's operational protocols for storm response and other emergency response actions should be ordered here. This rate case addresses the adequacy of the Company's showing that costs are incurred reasonably and prudently. Specific operational changes, even if well-intentioned, would be more appropriately addressed in the SRSQ Docket.

830. The Commission should take the Joint Intervenors' concerns seriously and continue its important work in the SRSQ Docket but, in this proceeding, the Commission

[900] Ex. JIN-1 at 10 (Kenworthy Direct).
[901] Ex. Xcel-35, Schedule 1 (Mensen Rebuttal).
[902] Ex. JIN-1 at 6 (Kenworthy Direct).
[903] Ex. JIN-1 at 10 (Kenworthy Direct).

should not adopt the Joint Intervenors' recommendations with respect to equity considerations in distribution planning.

30. Equity Nox Tracker

831. The Company proposed to establish a tracker for costs of complying with the United States Environmental Protection Agency's (EPA) final rule for the Federal Implementation Plan for the 2015 8-hour Ozone National Ambient Air Quality Standards, Docket ID No. EPA-HQ-OAR-2021-0668, also referred to as the "Good Neighbor Plan" (GNP).[904]

832. The GNP seeks to limit ozone-forming emissions of nitrogen oxides (NOx) from power plants and, in some states, industrial sources. Specifically, the GNP is designed to limit ozone season emissions of NOx by establishing a NOx allowance budget for each facility based on the assumed application of certain controls. The subject facilities are included in a NOx ozone season trading program, which allows for buying and selling NOx allowances between entities. In addition, the GNP limits NOX emissions through additional rule features such as daily emissions rate limits on large coal-fired units, limits on "banking" of allowances between compliance years, and annual updates to the emission budgets starting in 2025 to account for changes in the generating fleet.[905]

833. In June 2023, the EPA published its final rule for the GNP to address the obligations of 23 states, including Minnesota, to reduce emissions that contribute to problems attaining and maintaining attainment of 2015 ozone National Ambient Air Quality Standards (NAAQS) in downwind states. The rule was effective in August 2023.[906]

834. Under the GNP, subject units are allocated NOx allowances for operation during ozone season. If a subject unit's NOx emissions exceed its allocation, it must look to purchase additional allowances on the open market from other entities in the same trading program or limit operations to remain within the number of allowances currently in its account. If implemented, the GNP will greatly reduce NOx allowance allocations in Minnesota for the ozone season.[907] Based on historic emissions data for the Company's fossil-fuel fired units, the Company anticipates the need to purchase additional allowances in order to cover emissions that would be expected between May 1 and September 30 of each year. The cost associated with the purchase of these additional allowances is not known.[908]

835. The Department supported establishment of the tracker, subject to the Company supporting costs included in the tracker in annual compliance filings.[909] No other party filed testimony related to the Company's requested tracker.

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[904] Ex. Xcel-59 at 2-3, 14 (West Direct); Ex. Xcel-17 at 115-116 (Halama Direct).
[905] Ex. Xcel-59 at 2-3 (West Direct).
[906] Ex. Xcel-59 at 4 (West Direct).
[907] Ex. Xcel-59 at 5-6 (West Direct).
[908] Ex. Xcel-59 at 9-10 (West Direct).
[909] Ex. DOC-5 at 18-21 (Golden Direct).

836. In briefing, the OAG opposed establishment of the tracker because the GNP is not in effect and may never go into effect.[910]

837. The EPA has administratively stayed the entirety of the GNP in the wake of a United States Supreme Court decision staying application of the GNP as to certain states. As a result, the GNP is currently not being enforced in any state.[911]

838. The EPA has issued a proposed rule reconsidering the GNP with respect to eight states, including Minnesota.[912] That proposed rule has not been finalized.

839. For a utility to use a tracker, it must petition the Commission for deferred accounting—an exception to standard ratemaking procedures that allows utilities to record out-of-test-year expenses.[913] The Commission may only grant deferred accounting for "good cause shown,"[914] such as situations where it is exceptionally difficult to develop a reliable test year expense amount for costs that will be incurred during a test year or when a utility incurs unforeseen and unusual expenses that are large enough to have a significant impact on the utility's financial condition.[915] Trackers are considered "highly unusual ratemaking treatment."[916]

840. The Commission should proceed with caution when approving new tracker accounts. Trackers, by their nature, undermine the rate certainty that MYRP proceedings are meant to promote, leaving customers with uncertainty as to what their true rates will actually be.

841. The parties' primary dispute as to this tracker seems to be the import of the current status of implementation of the rule and doubt as to whether, or in what form, it will eventually be implemented.

842. Here, the expenses are unusual and unforeseen because they are related to a federal regulation that is stayed and potential subject to modification or outright repeal. The Company has no meaningful control over this process, which could result in costs that cannot be precisely ascertained. Accordingly, the rate impact could be large

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[910] OAG Initial Brief at 52-53.
[911] Ex. Xcel-59 at 6-7 (West Direct).
[912] *Interstate Transport Plan Review for the 2015 Ozone NAAQS*, 91 Fed. Reg. 4026 (Jan. 30, 2026).
[913] *See In re Petition by N. States Power Co. d/b/a Xcel Energy for Approval of Deferrals Related to Depreciation O&M and Property Tax for 2022*, MPUC Docket No. G002/M-21-750, ORDER DENYING PETITION at 3 (Feb. 9, 2022) (eDocket No. 20222-182600-01).
[914] Minn. R. 7825.0300, subp. 4.
[915] *In re Application of CenterPoint Energy for Auth. To Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 39 (Jan. 11, 2010) (eDocket No. 20101-45867-01); *In re Petition by N. States Power Co. d/b/a Xcel Energy for Approval of Deferrals Related to Depreciation O&M and Property Tax for 2022*, MPUC Docket No. G002/M-21-750, ORDER DENYING PETITION at 3 (Feb. 9, 2022) (eDocket No. 20222-182600-01).
[916] *In re Application of CenterPoint Energy for Auth. To Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 39 (Jan. 11, 2010) (eDocket No. 20101-45867-01).

enough to have a significant impact on the utility's financial condition and render it almost impossible to develop a reliable test year.

843. The OAG's suggests that doubt as to whether the GNP will ultimately be implemented weighs against denying the Company's request.

844. However, if the GNP is not implemented, there will be no costs recovered through the tracker. Should this come to pass, customers will not have been prejudiced.

845. The Commission should approve the Company's request to establish this requested tracker subject to the reporting requirements recommended by the Department.

B. Revenue Issues

846. Two revenue issues are disputed in this proceeding: late payment fees and reconnection fees.

7. Late Payment Fees

847. The Company collects late payment fees when customers do not make timely payments on their utility bills pursuant to Minn. R. 7820.5500.

848. These fees take the form of a monthly late payment charge of 1.5 percent or $1.00, whichever is greater, two working days after the bill due date or as allowed by law.[917] The fee of 1.5 percent monthly, or 18 percent annually, is the maximum allowable finance fee under Minn. R. 7820.5500.[918]

849. Xcel anticipates collecting $6.1 million in late payment fees in 2025 and $5.8 million in 2026.[919]

850. As previously discussed, the parties agreed to an adjustment to the 2025 Test Year with respect to late fee revenue.

851. The Department, noting that the RAMP program to be funded by late fee revenue (described in Docket No. E-002/M-24-27) would not be in effect until mid-year 2026, recommended that the 2026 Plan Year reflect half of Xcel's anticipated $5.8 million late fee revenue for that year. This impact of the Department's recommendation would be a $2.9 million reduction in the 2026 Plan Year.[920]

852. The Company opposes the Department's recommendation, arguing that it anticipates using the full 2026 late payment fee revenues for RAMP if the Commission

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[917] Ex. CUB-3 at 18 (Levenson-Falk Direct) (citing XCEL ENERGY, MINNESOTA ELECTRIC RATE BOOK: GENERAL RULES AND REGULATIONS, SECTION 3.6, Sheet 6-16 (effective Aug. 14, 2024)).
[918] Ex. CUB-3 at 18 (Levenson-Falk Direct); Minn. R. 7820.5500, subp. 3.
[919] Xcel-39 at 4 (Lindgren Supplemental Direct).
[920] Ex. DOC-19 at 67, 70 (Bahn Direct).

approves the program, and continues to recommend initial funding of RAMP at the full $5.8 million level.[921]

853. CUB recommended that late payment charges be waived for all customers, or alternatively waived for low-income customers and lowered to the actual cost of interest paid by the Company for all other customers.[922] CUB noted that the Company pays an interest rate of 5.3935 percent annually—or approximately 0.45 percent monthly—on residential past-due balances.[923] ECC supported CUB's alternative recommendation.[924]

854. 750,000 residential customers were assessed multiple late payment charges between 2022 and 2024, which CUB argues shows that such fees do not effectively motivate customers to pay their bills on time.[925] CUB emphasizes that the Company has not provided any testimony, studies, information, or substantiating documents and exhibits to support its claim that late payment charges lead to the timely payment of utility bills.[926]

855. CUB also notes that other states and jurisdictions have reduced or eliminated late payment charges for residential customers.[927] CUB also identified several instances where the Kentucky Public Service Commission (KPSC) evaluated the assessment of late payment charges and found they had "little discernible effect on the timeliness of residential customer payments for utility service." [928] KPSC further determined that the addition of late payment charges to utility bills "makes it less likely customers who have already failed to timely pay will be able to do so at all," potentially increasing bad debt expense and the cost of service for the remainder of the utility's customers.[929]

856. The Company opposed CUB's recommendation to eliminate late fees. The Company argued that Commission-approved existing rates carry the presumption that they are just and reasonable. The Company is not requesting a change to the amount, terms or conditions of the late payment fee that is currently established in the Company's

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[921] Ex. Xcel-19 at 14-15 (Halama Rebuttal); Ex. Xcel-81 at 9-10 (Howard Rebuttal).
[922] Ex. CUB-3 at 23 (Levenson-Falk Direct); Ex. CUB-8 at 21-22 (Levenson-Falk Surrebuttal).
[923] Ex. CUB-3 at 20-21 (Levenson-Falk Direct); Ex. CUB-5, Schedules 21-22 (Levenson-Falk Direct Schedules); Ex. CUB-8 at 20 (Levenson-Falk Surrebuttal). CUB also recommends that the RAMP program not be approved. This recommendation is separately addressed in the appropriation Section of this Report.
[924] Ex. ECC-2 at 3, 5 (Shardlow Surrebuttal).
[925] *See* Corrected Citizens Utility Board of Minnesota Information Request No. 16 (Feb. 4, 2026); *see also* Ex. CUB-5, Schedule 18 (Levenson-Falk Direct Schedules) (providing Company's original response to CUB Information Request No. 16); CUB Reply Brief at 5.
[926] Ex. CUB-3 at 21 (Levenson-Falk Direct); Ex. CUB-5, Schedules 19-20 (Levenson-Falk Direct Schedules); Ex. CUB-8 at 19 (Levenson-Falk Surrebuttal).
[927] Ex. CUB-3 at 21-22 (Levenson-Falk Direct) (noting that Massachusetts and New Jersey prohibit late payment charges for all residential customers, while Illinois, Montana, Maine, Michigan, and Ohio provide late payment protections for low-income households or those enrolled in utility assistance offerings).
[928] Ex. CUB-3 at 22 (Levenson-Falk Direct) (quoting Ex. CUB-5, Schedule 12 at 3 (Levenson-Falk Direct Schedules); CUB Initial Brief at 29; *see also* Ex. CUB-5, Schedules 11-13 (Levenson-Falk Direct Schedules).
[929] Ex. CUB-3 at 23 (quoting Ex. CUB-5, ALF-D-11 at 7); CUB Initial Brief at 30.

tariffs. The Commission previously approved Xcel Energy's existing tariffs, determining them to be just and reasonable.[930]

857. The Company disputes that it bears the burden to prove the reasonableness of its late fee charges and argued that it provided record evidence that the absence of late fees disincentivizes customers from paying bills on time. The Company provided evidence that, as a result of a late payment fee and disconnection moratorium, arrearages nearly doubled, from roughly $44 million at the end of 2019 to $85 million at the beginning of 2022. During the COVID-19 disconnection moratorium from March 2020 through July 2021, past-due balances grew from $57 million to $81 million.[931]

858. In sum, there are four proposals for late fee revenues: (1) approve the Company's proposal to use its full projected 2026 late fee revenue for the RAMP program; (2) attribute half of the projected late fee revenue to the RAMP program thereby reducing the 2026 plan year by $2.9 million; (3) order the Company to waive all late fees; and (4) order the Company to waive late fees for low-income customers and lower the fees for all other customers.

859. Taking first the question of whether the late fees should be allowed or reduced, CUB and the Company dispute who bears the burden on this issue. Minn. Stat. § 216B.16, subd. 4 provides that the burden of proof "to show that [a] rate change is just and reasonable shall be upon the public utility seeking the change." Here, however, Xcel is not a public utility seeking a change. Unlike a forecasted increase to an expense item that would result in a rate increase, Xcel merely seeks to continue assessing a previously approved late fee schedule. Thus, CUB bears the burden to prove its proposed change is just and reasonable.

860. Which party bears the burden of proof is not outcome determinative on this issue. Whether CUB or the Company bears the burden, the record establishes that continuing to charge late fees is reasonable. The Company assesses late fees at a level explicitly authorized by Minn. R 7820.5000, subp. 3. While Xcel charges the maximum late fees permitted by the rule, the rule provides no standard to assess whether the Company should be required to charge a lower rate. This presumptively, if not conclusively, establishes the reasonableness of Xcel's late fees.

861. Further, the Commission has previously approved these fees, thereby concluding that they are just and reasonable.

862. CUB's evidence of the number of customers paying late fee balances does not persuasively establish that late fees are not a deterrent to falling into arrearage. This is an oversimplified analysis that fails to control for rate increases or economic conditions.

863. Xcel's evidence of increasing arrearages during the late fee moratorium imposed during the COVID-19 pandemic also paints an incomplete picture, as it fails to

[930] Xcel Reply Brief at 36 (citing *Reserve Min. Co. v. Minn. Pub. Util. Comm'n*, 334 N.W.2d 389, 392 (Minn. 1983); *St. Paul Area Chamber of Comm. v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 350, 358 (Minn. 1977)).
[931] Ex. Xcel-71 at 49 (Martin Rebuttal).

account for the economic disruption and employment conditions flowing from the pandemic.

864. Faced with two imperfect pieces of data, the Company's evidence is more persuasive. Notwithstanding the methodological limitations, ballooning arrearage balances during a late fee moratorium is strongly suggestive that there is at least some correlation between the two data points.

865. For these reasons, the Commission should approve Xcel's continued use of late fees as proposed by the Company.[932]

866. Turning to the issue of how to treat late fee revenue in the 2026 plan year, the Company's proposal to dedicate the entire 2026 late fee revenue to the RAMP program is reasonable.[933]

867. Nothing about mid-year approval of the RAMP program precludes the Company from using the entire 2026 late fee revenue to fund the program. The record supports a determination that the Company intends to and should do so. Accordingly, rates should reflect this proposal.

868. The Commission should reject the Department's proposal to reduce the 2026 plan year revenue requirement by including 50 percent of the Company's late fee revenue for that year.

8. Reconnection Fees

869. The Company charges a reconnection fee based on the actual cost of reconnection pursuant to Minn. R. 7820.2600. The reconnection fee is $13.50 for customers with AMI and $95 (effective as of January 1, 2026) for customers who opted out of AMI and receive manual meter reading. These costs are actual costs, whether utilizing AMI technology or otherwise. The funds currently collected in reconnection fees are an offset to revenue requirements. Therefore, if they are waived, there would be an increase to revenue requirements of an equal amount.[934]

870. CUB recommended in this proceeding that reconnection fees be eliminated for residential customers with AMI.[935] CUB argued such fees "make it harder for customers to regain access to electricity service and prolong the negative effects of

[932] This recommendation should not be read as unsympathetic to the plight of customers facing difficulty paying their utility bills. No Minnesotan should find themselves so burdened by utility rates that they are unable to afford their bills. That said, by eliminating late fees or reconnection fees, the burden of paying for this service necessarily falls to other ratepayers of varying economic circumstances. The proper remedy for concerning levels of disconnections and arrearages is to ensure that overall rates are broadly affordable. This underscores the importance of the Company in controlling its rate increase requests, the various intervenors in scrutinizing such requests, and ultimately the Commission to approve just and reasonable rates with due regard for the needs of the Company to provide service.

[933] This recommendation presumes Commission approval of the RAMP program, which is analyzed and recommended in a different Section of this Report.

[934] Ex. Xcel-71 at 25-27 (Martin Rebuttal); CUB-3 at 14 (Levenson-Falk Direct).

[935] Ex. CUB-3 at 14-17 (Levenson-Falk Direct); Ex. CUB-8 at 15-18 (Levenson-Falk Surrebuttal).

disconnection."[936] Eliminating reconnection fees, CUB argued, would reduce barriers to the restoration of service and make it easier for customers to enter into arrangements for the payment of arrears.[937] Because the cost impact to other customers would be minimal, CUB suggested waiving reconnection fees would balance benefits and burdens among customers and create a more equitable rate structure.[938]

871. In the alternative, CUB recommended the Commission consider waiving reconnection fees for low-income households and customers that indicate they are unable to pay, even if they do not qualify as low-income.[939]

872. As another alternative, CUB recommended the Commission excluding labor costs from reconnection fees, arguing that such fees could lead to double recovery.[940]

873. The ECC supported eliminating reconnection fees and argued that both the Company and intervening parties "want people to seek out reconnection, ideally after conversations . . . about available affordability programs if needed, [and] as soon as possible."[941]

874. The Company opposes waiving disconnection fees and argued that eliminating reconnection fees for disconnected customers would result in an increase in the Company's revenue requirement. As a result, waiving these fees shifts the reconnection costs that the Company incurs to other ratepayers because those costs would be recovered uniformly from all customers. The Company posits that, although the immediate cost shift was likely to be small, the estimates that CUB relies on are based on an assumption of 36,000 reconnections per year, which could increase depending on the number of actual disconnections and reconnections.[942]

875. The Company recommended that, if the Commission agrees with CUB that equity is served by waiving some reconnection fees, those fees should be waived for low-income customer under agreed upon criteria to be established after further discussion amongst stakeholders to better balance the consideration of customers facing social disparities while mitigating the costs imposed on customers who have not incurred late fees, including most low-income customers that timely pay their utility bills.[943]

876. Seeking a way to provide relief for utility customers who have found themselves subject to payment-related disconnections is a noble pursuit. It is certainly true that reconnection fees represent another barrier to restoring electrical service for Minnesotans who struggle to afford their electric bills.

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[936] Ex. CUB-3 at 15 (Levenson-Falk Direct).
[937] Ex. CUB-3 at 15 (Levenson-Falk Direct).
[938] Ex. CUB-8 at 16-17 (Levenson-Falk Surrebuttal).
[939] CUB Initial Brief at 37.
[940] CUB Initial Brief at 37-38.
[941] Ex. ECC-2 at 5 (Shardlow Surrebuttal).
[942] Ex. Xcel-71 at 25-27 (Martin Rebuttal).
[943] Xcel Initial Brief at 61.

877. This relief, however, would come at a cost. Reconnection fees are not a punitive measure assessed to customers; they are a recovery of an actual cost incurred to effectuate reconnections. If not recovered through reconnection fees, these costs would be a recoverable cost of service that would be borne by other ratepayers, including many who are also in difficult financial situations.

878. It is not necessary to weigh these competing concerns to resolve this issue. Minn. R. 7820.2600 unambiguously provides that a utility may charge a reconnection fee based on the cost of reconnection as stated in the utility's filed tariff.

879. No party disputes that Xcel's reconnection fees are based on the actual cost of reconnection or that they are provided for in Xcel's tariff.

880. Thus, Xcel has established that its reconnection fees are permissible pursuant to Minn. R. 7820.2600.

881. Further, as labor costs are part of the actual cost of reconnection, the Commission should not require Xcel to exclude labor costs from its reconnection fees.

882. The Commission should reject the CUB's proposal to require Xcel to waive reconnection fees, as well as its alternate proposal to waive these fees for certain customers.

C. Cost of Capital

1. Return on Equity (ROE)

a. Introduction and Legal Standard

883. The only remaining cost of capital issue in this proceeding concerns the ROE to be allowed.

884. Minn. Stat. § 216B.16, subd. 6, states:

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

885. 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*.[944] The Court has stated, "What annual rate

[944] *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679, (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

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."[945]

886. 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.[946]

887. 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.[947]

888. 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,"[948] 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."[949]

889. The Commission has observed that "[s]etting the cost of equity is a fact-intensive and record-specific judgment."[950] The Commission considers the record as a whole, with the objective of establishing a reasonable return based on the record in its entirety.[951]

890. The Commission's approach is consistent with the United States Supreme Court's observation that "[t]he Constitution does not bind rate-making bodies to the service of any single formula or combination of formulas. Agencies to whom this

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[945] *Bluefield*, 262 U.S. at 692.
[946] *Hope*, 320 U.S. 591 at 603 (internal citation omitted).
[947] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980) (citing *Bluefield*, 262 U.S. at 690).
[948] *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)).
[949] *Hibbing*, 302 N.W.2d at 11.
[950] MERC 2017 Rate Case Order at 26.
[951] MERC 2017 Rate Case Order at 26.

legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances."[952]

891. Xcel's most recently approved ROE is 9.25 percent.[953]

b. Summary of the Parties' Positions[954]

892. The parties' recommended ROEs are summarized as follows:

Xcel	10.30%
The Department	9.25%
XLI	8.96%
CUB	9.0%
Walmart	≤9.25%

893. Xcel recommended an ROE of 10.30 percent within an indicated range of 10.00 percent to 11.00 percent.[955] The Company provided several analyses, including a Constant Growth Discounted Cash Flow (DCF) model, a Two-Growth DCF model, a Capital Asset Pricing Model (CAPM), a Bond Yield Plus Risk Premium model (RPM), and an Expected Earnings Analysis.[956]

894. The Department recommended an ROE of 9.25 percent.[957] This amount was approximately 40 basis points higher than the cost of equity derived from the Department's Multi-Stage DCF analysis.[958]

895. XLI recommended an ROE of 8.96 percent.[959] This result was derived from the 9.56 percent average of results of several DCF models, including a Constant Growth DCF model, a Two-Stage[960] DCF Model, and a Multi-Stage DCF Model,[961] adjusted

[952] *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942).
[953] Xcel 2021 Rate Case Order at 92.
[954] The Joint Intervenors did not make a specific ROE recommendation, but provided testimony urging the Commission to consider energy affordability when setting Xcel's ROE. Ex. JIN-2 at 41-47 (Chan Direct).
[955] Ex. Xcel-24 at 4-5 (Nowak Direct).
[956] Ex. Xcel-24 at 35-52 (Nowak Direct).
[957] Ex. DOC-12 at 85 (Addonizio Direct).
[958] Ex. DOC-12 at 85 (Addonizio Direct).
[959] Ex. XLI-1 at 31 (LaConte Direct).
[960] In this proceeding, different parties used the terms "Two-Stage" and "Two-Growth" in reference to a specific version of the DCF model. This distinction appears to be semantic and the terms are used interchangeably in this Report.
[961] Ex. XLI-1 at 25 (LaConte Direct).

downward by a 50-basis point risk adjustment[962] and ten basis points to account for billing issues.[963]

896. CUB recommended an ROE of 9.0 percent. CUB's recommendation is not derived from a specific model and falls within a range from 7.7 percent to 9.3 percent that CUB's witness believes reflects a reasonable cost of equity for Xcel.[964]

897. Walmart did not provide independent modeling, but recommended that the Commission not approve an ROE higher than the Company's current 9.25 percent ROE based on several factors, including recent ROEs approved by the Commission and other regulators in the nation.[965]

c. Proxy Groups

898. One method for estimating Xcel's cost of equity in this proceeding is to identify a proxy group of publicly traded companies that pose risks to equity investors similar to the investment risks of Xcel, which is not publicly traded company poses. It is notable that while Xcel is not itself public traded, its parent Xcel Energy, Inc. is.[966]

899. The Department compiled a list of all companies categorized as electric utilities by Value Line, a well-known investor service.[967] The Department then applied various screens designed to make sure the proxy group companies were reasonably comparable to Xcel.[968] This process produced a list of 16 companies.[969]

900. Starting with a list 36 investor-owned electric utility companies identified by Value Line, Xcel developed its own proxy group by applying various screens.[970] This process produced a list of 15 companies as of Direct Testimony.[971]

901. In Rebuttal Testimony, the Company applied the same screening criteria which resulted in the removal of two companies due to recent merger and acquisition activity and added a company that now met its criteria.[972]

902. CUB and XLI utilized the same proxy group that Xcel used in its Direct Testimony.[973]

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[962] Ex. XLI-1 at 28-30 (LaConte Direct).
[963] Ex. XLI-1 at 30-31 (LaConte Direct).
[964] Ex. CUB-1 at 43-44 (Kihm Direct).
[965] Ex. WAL-1 at 14 (Austin Direct).
[966] Ex. DOC-12 at 14–15 (Addonizio Direct).
[967] Ex. DOC-12 at 16 (Addonizio Direct).
[968] Ex. DOC-12 at 17–20 (Addonizio Direct).
[969] Ex. DOC-12 at 20–21 (Addonizio Direct); *see also* Ex. DOC-13 at 4 (Addonizio Surrebuttal) (reflecting minor adjustments to account for recent developments).
[970] Ex. Xcel-24 at 31–33 (Nowak Direct).
[971] Ex. Xcel-24 at 33 (Nowak Direct).
[972] Ex. Xcel-25 at 12 (Nowak Rebuttal).
[973] Ex. CUB-1 at 30 (Kihm Direct); Ex. XLI-1 at 22 (LaConte Direct).

903. Differences in the proxy groups utilized by parties did not meaningfully cause differences in the results of their various models. Rather, other analytic, methodological, and philosophical determinations account for the disparate ROE recommendations in this proceeding.

d. Financial Models

904. There are various methodologies that may be used to estimate a reasonable ROE.

905. In this proceeding, parties offered cost of equity calculations based on the following models: DCF, CAPM, Bond Yield Plus Risk Premium, and Expected Earnings Analysis.

906. 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 rate of return.[974]

907. The DCF model has three components: current stock price, a stream of future dividend payments paid in perpetuity, and the required rate of return on equity. With estimates of any two of the inputs, the third can be calculated. Current stock prices are directly observable, and future dividend streams can be estimated by applying projected growth rates to the current, known level of dividends. Using this information, a company's rate of return on equity can be calculated. Applying this equation to each company in their respective proxy group, an analyst can estimate Xcel's cost of equity.[975]

908. There are three DCF models in this record: Constant Growth, Two-Growth or Two-stage, and Multi-Stage.

909. In a Constant Growth DCF model, dividends are assumed to grow in perpetuity at a chose growth rate.[976]

910. In a Two-Growth DCF model, dividends are assumed to one growth rate for an initial period, before transitioning to a different growth rate that is assumed to remain constant in perpetuity.[977]

911. In a Multi-Stage DCF model, dividend growth rates are estimated for three stages: (i) years one through five; (ii) years six through ten or years six through 20 years; and (iii) from the end of the second stage in perpetuity.[978]

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[974] Ex. DOC-12 at 40 (Addonizio Direct).
[975] Ex. DOC-12 at 40–41 (Addonizio Direct).
[976] Ex. DOC-12 at 53 (Addonizio Direct).
[977] Ex. DOC-12 at 53 (Addonizio Direct).
[978] Ex. DOC-12 at 46–47 (Addonizio Direct).

912. The DCF methodology has been widely used in regulatory proceedings for decades.[979] The Commission has traditionally relied heavily on the Two-Growth DCF model when setting authorized ROEs.[980]

913. The Commission has never adopted nor categorically rejected the Multi-Stage DCF analysis, but it has recognized it may be "particularly useful for smoothing out more sharply anticipated variations in growth rates."[981]

914. Another model used by the parties to estimate Xcel's cost of equity was the CAPM. The CAPM is premised on the idea 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 tandem with the market as a whole.[982]

915. While the CAPM is theoretically sound, empirical studies have shown it does a poor job explaining equity returns.[983] The Commission has recognized the diminished reliability of the CAPM for estimating a reasonable ROE.[984]

916. The RPM compares the risk premium implied by historical authorized ROEs compared to prevailing interest rates at the time of prior regulatory decisions. The analysis incorporates historical ROE decisions under a variety of capital market conditions. A regression analysis of the relationship between interest rates and authorized returns reveals a statistically significant relationship which is then applied to estimate a reasonable return given current and expected interest rates.[985]

917. 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.[986]

918. The Expected Earnings Analysis is a comparable earnings analysis that calculates the earnings that investors expect to receive on the book value of a stock, using an accounting-based approach that relies on investment analysts' projections of earnings on book equity.[987]

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[979] Ex. DOC-12 at 40 (Addonizio Direct).
[980] Xcel 2021 Rate Case Order at 89.
[981] *In re Appl. of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, MPUC Docket No. E017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, & ORDER at 34 (Feb. 1, 2022) (eDocket No. 2022-182349-01) [hereinafter Otter Tail 2020 Rate Case Order].
[982] Ex. DOC-12 at 57-58 (Addonizio Direct).
[983] Ex. DOC-12 at 59 (Addonizio Direct).
[984] *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) (eDocket No. 202010-167656-01) [hereinafter Great Plains 2019 Rate Case Order].
[985] Ex. Xcel 24 at 47-49 (Nowak Direct); Ex. Xcel 25 at 40-41, 75-76 (Nowak Rebuttal).
[986] Great Plains 2019 Rate Case Order at 15.
[987] Ex. Xcel-24 at 49-51 (Nowak Direct).

e. Cost of Equity versus Authorized ROE

919. There was significant dispute among the parties as to whether, and to what extent, authorized ROEs are distinct from the actual cost of equity.

920. According to the Department, the cost of equity is not synonymous with ROE. The Department refers to empirical evidence that allowed ROEs typically exceed the cost of equity.[988]

921. The Department argued that there are strong theoretical reasons to set the allowed ROE equal to the cost of equity. In general, competition in the capital markets should drive the expected return on any stock to its cost of equity. If investors, on average, think the expected return on a stock is greater than the cost of equity, they will buy the stock, driving the price up (and therefore the expected return down) to the point that the expected return equals the cost of equity. But if investors, on average, think the expected return on a stock is lower than the cost of equity, owners of the stock will start to sell it, driving the price down until the expected return increases to the cost of equity. Because stock prices adjust such that the expected return is always equal to the cost of equity, new, incremental investors should only ever expect their investments to earn the cost of equity.[989]

922. Given that investors should only ever expect their investments to earn the cost of equity, the Department asserted, if the allowed ROE were to be set at the cost of equity the utility should theoretically be assured of an adequate supply of capital to make necessary investments, it will have no incentive to pursue unnecessary investments, and ratepayers should receive safe and reliable service at the lowest possible cost.[990]

923. Even though it would be appropriate to set the allowed ROE at the cost of equity, the Department found that regulators rarely did so, citing data that utility market values tended to exceed book values. The Department explained the book value of a company's equity is equal to the value of all its assets as recorded on its balance sheet, minus the value of all its liabilities. For a utility, most of its assets are its utility plant in service (which gets recorded at original cost), and most of its liabilities are the accumulated depreciation on its plant in service and its outstanding debt. And when a utility is allowed to earn more than its cost of equity, the market value of its equity exceeds its book value; the ratio of its market value to its book value is greater than one.[991]

924. CUB argues that finance models can be useful tools to estimate a utility's cost of equity, but they cannot, alone, produce a result that fairly balances the interest of a utility's shareholders and ratepayers because they contain no variable for fairness or the ratepayer interest.[992] CUB recommends the Commission need not "jettison the

[988] Ex. DOC-12 at 70–71 (Addonizio Direct).
[989] Ex. DOC-12 at 71 (Addonizio Direct).
[990] Ex. DOC-12 at 73 (Addonizio Direct).
[991] Ex. DOC-12 at 75 (Addonizio Direct).
[992] Ex. CUB-1 at 43 (Kihm Direct)

models completely," but should "adjust the role they play, moving them from center stage to the sidelines."[993]

925. The Company asserts that the existence of a significant disparity between authorized ROEs and the true cost of equity is inconsistent with reasonable market-based models, counter to current market trends, and that setting ROE on that basis would inject uncertainty into the rate-making process by departing from long-standing principles of regulation.[994]

926. Notably, neither CUB nor the Department recommend completely divorcing analytical results from the process of setting Xcel's ROE.

927. The Department has shown, based on its independent cost of equity estimates,[995] that there is sufficient reason to be concerned that authorized utility ROEs systemically overstate the true cost of equity for rate-regulated utilities such that it merits some consideration in setting the Company's authorized ROE. That said, the Commission's historical reliance on the Two-Growth DCF and other models as well as the witness testimony supporting those models establishes that a drastic departure from past Commission practice is not warranted.[996]

f. Xcel's Proposed ROE

928. Xcel recommended an ROE of 10.30 percent.[997]

929. To reach this recommendation, Company witness Nowack applied the Constant Growth DCF, Two-Growth DCF, CAPM, RPM, and Expected Earnings Analysis.[998]

930. Xcel's results for the Commission-favored Two-Growth DCF model were as shown in the following table:[999]

[993] Ex. CUB-1 at 38 (Kihm Direct).
[994] Ex. Xcel-25 at 3 (Nowak Rebuttal).
[995] These estimates are discussed below in further detail in the section of this Report describing the Department's proposed ROE.
[996] Applying CUB's analogy, concerns about discrepancies between the cost of equity and authorized ROEs should not take center stage and relegate the modeling results to the sideline. Rather, the modeling should remain at center stage, but the cost of equity concerns should be present on the sideline.
[997] Ex. Xcel-24 at 5 (Nowack Direct).
[998] Ex. Xcel-24 at 35-52 (Nowack Direct).
[999] Ex. Xcel-24 at 43 (Nowak Direct).

Table 5
Two-Growth DCF Results

	Low	Mean	High
30-day average	8.68%	10.11%	12.55%
90-day average	8.89%	10.34%	12.77%
180-day average	9.02%	10.56%	13.00%

931. Witness Nowak testified that, in addition to examining analytical models, establishing a fair and reasonable ROE for the Company must recognize that market expectations with respect to future risks and growth opportunities can vary from company to company. Accordingly, Nowack considered, the Company's regulatory environment and its business and financial risks when determining where the Company's cost of equity falls within the range of results.[1000]

932. Witness Nowak reviewed the regulatory mechanisms available to the Company and designed to either mitigate certain business risks or to provide more timely recovery of costs, and compared those to the mechanisms available to his proxy group companies.[1001] For any of these mechanisms to have a material effect on the cost of equity, it would require that the mechanism changes the risk of the Company relative to the proxy companies, such that investors would change their return requirements as a consequence of the mechanism.[1002]

933. Review of the mechanisms available to both Xcel and the proxy group companies did not identify material risk differences, but instead supported treating the results from the proxy group as representative of the business risk of a prudently managed, regulated vertically-integrated electric utility like the Company.[1003] Specifically, this review shows the proxy companies to have a mix of similar mechanisms as those available to Xcel Energy, with instances of both more and less favorable mechanisms on individual items.[1004]

934. Witness Nowak also considered the effect of "flotation costs," or the costs associated with the sale of new issuances of common stock.[1005] Witness Nowak's

[1000] Ex. Xcel-24 at 53 (Nowak Direct).
[1001] Ex. Xcel-24 at 54-57 and Schedule 11 (Nowak Direct).
[1002] Ex. Xcel-24 at 56 (Nowak Direct).
[1003] Ex. Xcel-24 at 55 and Schedule 11 (Nowak Direct); Ex. Xcel-25 at 79-80 (Nowak Rebuttal).
[1004] Ex. Xcel-24 at 55 and Schedule 11 (Nowak Direct).
[1005] Ex. Xcel-24 at 60-62 and Schedule 10 (Nowak Direct).

analysis indicated that consideration of flotation costs results in a seven-basis point addition to the ROE analytical results, a figure with which the Department agreed.[1006]

935. The results of Mr. Nowak's initial analyses and his recommended ROE were as follows:[1007]

	Average	Median
Primary Analyses		
Average DCF	10.37%	10.43%
Constant Growth DCF	10.41%	10.43%
Two-Growth DCF	10.34%	10.43%
CAPM	11.92%	11.78%
Risk Premium	10.38%	10.38%
Average	10.89%	10.89%
Benchmark Analysis		
Expected Earnings	10.71%	10.12%
Other Considerations		
Flotation Costs	0.07%	0.07%
Recommended Range	**10.0% - 11.0%**	
Recommended ROE	**10.30%**	

936. Based on this analysis, Witness Nowack concluded that a range from 10.00 to 11.00 percent represented a reasonable range for setting Xcel's ROE.[1008] Within this range, his recommended ROE of 10.30 percent falls below the midpoint of his range and below the results of his Two-Growth DCF analysis.[1009]

937. Witness Nowak provided updated analyses in his Rebuttal Testimony, which showed modest upward and downward movement from the results of his Direct Testimony analyses, depending on the model.[1010] Given these modest changes, and the fact that the Company's recommended ROE continued to fall at the low end of the updated range of his analytical results, Witness Nowak continued to recommend an ROE

[1006] Ex. Xcel-24 at 61 and Schedule 10 (Nowak Direct); Ex. DOC-12 at 57 (Addonizio Direct) (the Department's testimony indicated a seven to eight basis point adjustment was appropriate).
[1007] Ex. Xcel-24 at 4-5 (Nowak Direct).
[1008] Ex. Xcel-24 at 5 (Nowak Direct).
[1009] Ex. Xcel-24 at 5 (Nowak Direct).
[1010] Ex. Xcel-25 at 13 and Schedules 2-8 (Nowak Rebuttal).

of 10.30 percent, which continued to be below his now updated Two-Growth DCF analysis.[1011]

g. The Department's Proposed ROE

938. The Department recommended an ROE of 9.25 percent.[1012]

939. The Department relied on a Multi-Stage DCF analysis to anchor its estimate of Xcel's cost of equity. This analysis includes three different stages of growth rates.[1013]

940. In the first stage—years one through five—the estimated that dividends would grow at forecasted three to five-year earnings growth rates developed by respected investor services S&P Capital IQ Pro and Zacks Investment Research.[1014] In the second stage, the Department assumed each proxy company's dividend growth rate would converge linearly from the stage one growth rate to the stage three growth rate.[1015] In the third stage, the Department estimated that dividends would grow at the same rate as U.S. gross domestic product (GDP).[1016]

941. The Department reasoned that it was appropriate to transition from equity analysts' growth rates to forecasted GDP growth rates because financial literature suggests that equity analysts' long-term earnings growth forecasts are generally biased upwards, and overestimate future growth.[1017] The Department also pointed to broad agreement that no company can grow at a rate faster than the economy as a whole in perpetuity, because a company that did so would eventually become larger than the economy as a whole, which is a facially unreasonable assumption.[1018]

942. In support of its position that GDP growth is appropriate for the third-stage of a DCF analysis, the Department cited financial literature explaining that "[l]ong-term growth rates exceeding the real growth in GDP plus inflation are generally not sustainable." And, as a result, "[m]ost analysts use more conservative growth rates in calculating the terminal value."[1019] The Department further pointed to historical data establishing a close relationship between earnings, dividend, and GDP growth since 1947.[1020]

943. Applying this methodology, the Department produced the following Multi-Stage DCF results:[1021]

[1011] Ex. Xcel-25 at 13, 84 (Nowak Rebuttal).
[1012] Ex. DOC-12 at 85 (Addonizio Direct).
[1013] Ex. DOC-12 at 46–47 (Addonizio Direct).
[1014] Ex. DOC-12 at 46–47 (Addonizio Direct). The Department performed this analysis using both a ten-year and 20-year transition period.
[1015] Ex. DOC-12 at 46–47 (Addonizio Direct).
[1016] Ex. DOC-12 at 46–47 (Addonizio Direct).
[1017] Ex. DOC-12 at 48 (Addonizio Direct).
[1018] Ex. DOC-12 at 42, 48–49 (Addonizio Direct).
[1019] Ex. DOC-12 at 49–50 (Addonizio Direct).
[1020] Ex. DOC-12 at 50 (Addonizio Direct).
[1021] Ex. DOC-12 at 52 (Addonizio Direct).

	Mean Low ROE	Mean Avg. ROE	Mean High ROE
Multi-Stage DCF with 10-year 2nd stage	8.16%	8.74%	9.63%
Multi-Stage DCF with 20-year 2nd stage	8.59%	9.13%	9.91%

944. The Department conducted a CAPM analysis but relied upon it only as a check on the reasonableness of its multi-stage DCF analysis.[1022] The updated Surrebuttal results of the Department's CAPM analysis including a flotation cost adjustment) ranged from 5.88 percent to 7.45 percent.[1023]

945. The Department also considered independent cost of equity estimates as a check on the reasonableness of its analysis.[1024] According to the Department, considering these independent estimates is useful to ensure that cost of equity estimates produced solely for the purpose of a rate case are not significantly outside the range of "mainstream" thinking about the cost of capital, which should give analysts and ultimate decision makers in rate cases more confidence in their decisions.[1025]

946. The Department first considered reports about Xcel Energy, Inc. produced by various equity research firms, two of which routinely include estimates of Xcel Energy, Inc.'s cost of equity.[1026] The Department also considered estimates from well-known surveys, including a quarterly survey of over 300 financial executives led by the Federal Reserve Bank of Richmond, an annual survey conducted by Dr. Pablo Fernandez of the IESE Business School in Spain, and an estimate produced by Dr. Aswath Damodaran of New York University used by FactSet.[1027]

947. As these independent estimates resembled the Department's multi-stage DCF and CAPM results, the Department asserted that they confirmed the reasonableness of its DCF and CAPM estimates, and perhaps indicated its DCF results may be "slightly high."[1028]

948. Based on this comparison, Witness Addonizio recommended an ROE of 9.25 percent, 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.[1029]

949. The Department reasoned that maintaining Xcel's existing ROE of 9.25 percent was reasonable because it would be above Xcel's cost of equity and below

[1022] Ex. DOC-12 at 44 (Addonizio Direct).
[1023] Ex. DOC-13 at 6 (Addonizio Surrebuttal)
[1024] Ex. DOC-12 at 65 (Addonizio Direct).
[1025] Ex. DOC-12 at 66 (Addonizio Direct).
[1026] Ex. DOC-12 at 67 (Addonizio Direct).
[1027] Ex. DOC-12 at 67–69 (Addonizio Direct).
[1028] Ex. DOC-12 at 69–70 (Addonizio Direct).
[1029] Ex. DOC-1 at 51 (Addonizio Direct).

the average, but generally within the range of ROEs recently authorized in other jurisdictions.[1030]

950. The Department acknowledged this recommendation is on the low end of recently allowed ROEs for other electric utilities, but noted that it is comfortably above Xcel's estimated cost of equity, including flotation costs (8.82 percent).[1031]

951. In addition, the Department pointed out that neither allowed ROEs nor the average cost of equity of the Department's proxy group showed any meaningful upward trend over the last year, indicating that an increase from the current authorized ROE is not warranted.[1032]

952. The Department also cited Xcel's representations that the Company was able to issue debt at interest rates much lower than one of its sister companies with its current authorized ROE at 9.25 percent.[1033]

953. The Department also noted that Standard & Poor's upgraded NSPM's credit rating following the Commission's decision to set NSPM's authorized ROE at 9.25 percent in the Company's prior rate case. Thus, the Department concluded that an authorized ROE of 9.25 percent does not appear to have hindered the Company's ability to raise capital at a reasonable cost.[1034]

h. XLI's Proposed ROE

954. XLI recommended an ROE of 8.96 percent in Direct Testimony.[1035]

955. XLI Witness LaConte developed an ROE recommendation through the use of three DCF models (a Constant Growth, Two-Stage, and Multi-Stage) and two CAPM analyses (historical and projected). The results of Witness LaConte's DCF analyses were a 9.56 percent ROE (before adjustment) as shown in the following table:[1036]

[1030] Ex. DOC-12 at 85 (Addonizio Direct).
[1031] Ex. DOC-12 at 85 (Addonizio Direct).
[1032] Ex. DOC-12 at 85 (Addonizio Direct).
[1033] Ex. DOC-12 at 85 (Addonizio Direct).
[1034] Ex. DOC-12 at 85 (Addonizio Direct).
[1035] Ex. XLI-1 at 31 (LaConte Direct).
[1036] Ex. XLI-1 at 23-26 (LaConte Direct).

Table 8 Estimated ROE Using DCF Method	
Model	**Value**
Constant Growth Low	9.36%
Constant Growth Mean	10.38%
Constant Growth High	11.84%
Two-Stage	9.58%
Multi-Stage Low	8.29%
Multi-Stage Mean	8.58%
Multi-Stage High	8.91%
Average	9.56%
Source: Schedule Nos. 3 -7.	

956. Witness LaConte's application of the Two-Growth DCF analysis incorporates a long-term GDP growth rate. This is a departure from Two-Growth DCF analyses the Commission has relied in the past, which have never incorporated a long-term GDP growth rate into the analysis.[1037]

957. XLI Witness LaConte employed the CAPM model as a check on the two-growth DCF analysis.[1038]

958. XLI asserts that evidence of various risk mitigation measures also supports an ROE of 8.96 percent or lower. The Company possesses various risk mitigation tools, including a variety of adjustment clauses, a sales true-up, and the MYRP itself, which together reduce the risk of Xcel under-recovering its revenue requirement.[1039]

959. Specifically, the Company is one of only seven other companies in the proxy group of 58 companies that holds six or more adjustment clauses.[1040]

[1037] Ex. Xcel-25 at 71-72 (Nowak Rebuttal). Xcel asserts that, if the long-term GDP growth rates were removed from Witness LaConte's Two-Growth DCF model, the result would be 10.36 percent; similar to the results of both the Department and the Company's Two-Growth DCF analyses.
[1038] Ex. XLI-1 at 19 (LaConte Direct).
[1039] Ex.XLI-1 at 28-29 (LaConte Direct).
[1040] Ex. XLI-1 at 29 (LaConte Direct).

960. Witness LaConte adjusted the results of her modeled ROE down by 50 basis points to account for the Company's risk, and ten basis points to account for concerns with the Company's provision of reliable billing and customer service.[1041]

i. CUB's Proposed ROE

961. CUB recommended an ROE of 9.0 percent.[1042]

962. CUB Witness Kihm utilized CAPM and DCF models to analyze Xcel's risk relative to comparable companies and evaluate the Company's financial integrity and ability to attract investors and estimate the Company's cost of equity.[1043]

963. The results of Witness Kihm's DCF and CAPM analyses suggest that Xcel's cost of equity is 7.7 percent.[1044] This estimate closely matches—but is higher—than independent finance analyst, *Morning Star*'s cost of equity estimate for the Company.[1045]

964. After using models to estimate the Company's cost of equity, Witness Kihm encouraged the Commission to weigh other record evidence and public policy factors to make pragmatic adjustments to arrive at a rate of return that appropriately balances the competing interests of ratepayers and shareholders.[1046] In particular, Witness Kihm recommended that the Commission consider analysis of affordability-related issues to inform its ROE decision.[1047]

965. Ultimately, Witness Kihm recommended an ROE of 9.0 percent.[1048]

j. Flotation Cost Adjustments

966. 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.[1049]

967. Witness LaConte did not provide a flotation cost adjustment, arguing that it was unnecessary because the adjustment does not reflect actual flotation costs incurred by Xcel.[1050]

[1041] Ex. XLI-2 at 28 (LaConte Direct). The customer service issues were discussed in an earlier section of this Report.
[1042] Ex. CUB-1 at 47 (Kihm Direct).
[1043] Ex. CUB-1 at 21-36 (Kihm Direct).
[1044] Ex. CUB-1 at 37 (Kihm Direct).
[1045] Ex. CUB-1 at 37 (Kihm Direct).
[1046] Ex. CUB-1 at 42-45 (Kihm Direct); *see also FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 586 (1942) (stating utility regulators should "make the pragmatic adjustments which may be called for by particular circumstances" when establishing an authorized return).
[1047] Ex. CUB-1 at 43 (Kihm Direct).
[1048] Ex. CUB-1 at 47 (Kihm Direct).
[1049] Ex. DOC-12 at 54 (Addonizio Direct).
[1050] Ex. XLI-1 at 39-40 (LaConte Direct).

968. 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.[1051]

969. The Company provided the data necessary to compute the Company's historical flotation cost.[1052]

k. Analysis

970. Having already determined that the ROE should be set based on consideration of some kind of financial modeling, it is necessary to assess which model or models should be relied on and, ultimately, how to use the model or models to determine the appropriate ROE in this proceeding.

971. The Commission has traditionally relied on DCF analyses in determining the allowed ROE. Specifically, the Commission has long relied on either Constant Growth DCF or Two-Growth DCF models, with consistent preference for the Two-Growth DCF for over the past decade.[1053]

972. The Commission's following finding from Xcel's most recent electric rate case is supported by the record in this proceeding:

> The two-growth DCF model provides a fundamentally sound framework through which to analyze the Company's relative risk in relation to comparable companies, and through which to evaluate the Company's financial integrity and ability to attract investors in light of current as well as expected market conditions. This 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). It uses growth forecasts to model dividend growth in years one through five, and then applies a different growth rate for years six and beyond, offsetting the limitations of the constant growth model, which assumes dividends are expected to grow at a constant rate over time.[1054]

973. For these reasons, the Commission should rely primarily on the Two-Growth DCF model when setting Xcel's ROE in this proceeding.

[1051] Ex. DOC-12 at 55-56 (Addonizio Direct).
[1052] Ex. DOC-12 at 56 (Addonizio Direct); Ex. Xcel 24 at Schedule 10 (Nowak Direct).
[1053] Ex. Xcel-25 at 10-11 and Table 2 (Nowak Rebuttal).
[1054] Xcel 2021 Rate Case Order at 89.

974. Because XLI's Two-Growth DCF Model differed from versions of the model previously relied on by the Commission incorporating GDP growth rates, the Commission should rely on the Two-Growth DCF performed by either the Department or the Company.

975. Ultimately, the results of the Department and Xcel's Two-Growth DCF models were similar, resulting in an average ROE of either 10.57 percent (Department Surrebuttal) or 10.38 percent (Xcel Rebuttal), minimizing the importance of the selection between the two models. As the utility seeking the ROE increase's model is actually the lower of the two, the Commission should accept 10.38 percent as the implied ROE from its preferred Two-Growth DCF model for the purposes of this proceeding.

976. The Commission also recognizes "that relying too heavily on a single set of results from one model could inadvertently narrow the range of reasonable returns considered, needlessly eliminating relevant data from close examination."[1055]

977. For this reason, it is important for the Commission to also give weight to at least one additional model in the record.

978. One concern identified with the Two-Growth DCF methodology in this proceeding is the implicit assumption that the Company will grow faster than the GDP in perpetuity, thereby eventually outgrowing the entire economy. While the parties dispute the import of this implicit assumption, it nevertheless exists and is a weakness in the model.[1056]

979. The Department's Multi-Stage DCF model corrects this weakness by modeling an eventual convergence of the Company's growth to the long-term GDP growth rate.

980. To be sure, there are problems with using the long-term GDP as the Department does. From 1947 through 2024, the utility sector as a component of GDP has grown at a faster compound average annual rate than the overall GDP growth rate.[1057] Thus, while perpetual growth in excess of the GDP is an unreasonable assumption, the record does not support the Department's implicit assumption that convergence to the GDP growth rate will occur on the time horizon of 15 to 25 years.[1058]

[1055] Xcel 2021 Rate Case Order at 89.

[1056] Acknowledging a model's weakness does not invalidate its use as a key piece of evidence in this proceeding. As statistician George Box has written, "all models are wrong, but some are useful."

[1057] Ex. Xcel-25 at 25-26 (Nowak Rebuttal).

[1058] It bears noting that Xcel's Witness Nowak, in other proceedings, has recommended adoption of a Multi-Stage DCF model and asserted that long-term GDP growth rates are a commonly used proxy for long-term growth rates in regulatory proceedings. Ex. DOC-31 at 62, 69 (Nowak 2020 National Grid Direct); Ex. DOC-33 at 45, 52 (Nowak 2023 Central Hudson Direct). During cross-examination, Witness Nowak qualified previous testimony in other proceedings supporting his use of GDP growth rates in DCF analysis as "necessary due to precedent." Evidentiary Hearing Tr. Vol. 1 at 91 (Nowak). That being said, in his previous testimony, Mr. Nowak offered an unqualified "yes" when asked if the Multi-Stage DCF model "offer[ed] improvements" over the Two-Stage DCF model. Ex. DOC-33 at 45 (Nowak 2023 Central Hudson Direct).

981. In other words, while the Multi-Growth DCF analysis rectifies a modeling weakness of the Two-Growth DCF, this record also suggests that the Multi-Growth DCF represents an over-correction. Accordingly, the modeling results in this record suggest that Xcel's ROE should be set in the range of 8.71 percent (Department Surrebuttal Multi-Stage DCF)[1059] to 10.34 percent (Company Rebuttal Two-Growth DCF).

982. At the time of the Company's last rate case filing in October 2021, the 18-month trailing average authorized ROE for vertically integrated electric utilities was 9.52 percent. By the time of the Initial Filing in the current case, the average authorized ROEs increased by approximately 30 basis points to 9.83 percent and average returns have remained at that level through 2025.[1060] This implies that, all else being equal, an increase in the Company's ROE from its current level is appropriate.

983. At the time of the Company's October 2021 rate case filing, the average yield on the 30-year Treasury was 2.06 percent. By the time of the Initial Filing in the current case, the average 30-year Treasury yield had risen to 4.54 percent and continued to increase to 4.88 percent in August 2025.[1061] This also implies that, all else being equal, an increase in the Company's ROE from its current level is appropriate.

984. These factors establish that the Company is entitled to an increase of some level to its existing 9.25 percent ROE. This reduces the range of supportable ROE figures to 9.25 percent to 10.34 percent.

985. DCF results based on equity analysts' growth rates are affected by upward bias due to structural incentives motivating higher projected growth rates. While a court settlement that became effective in 2003 resulted in short-term reduction in this bias, the upward bias still exists.[1062]

986. This upward bias, along with the Department's independent earnings analysis and the Company's demonstrated ability to access capital with its current 9.25 percent ROE, supports a conclusion that even though the Two-Growth DCF is the most reasonable analysis in the record, it overstates the appropriate ROE for Xcel.

987. The record does not support XLI's proposed downward risk reduction adjustment of 50 basis points. This would be a dramatic adjustment to the Company's ROE. Further, of the companies in Xcel's proxy group, 47 percent allow fully- or partially-forecasted test years, 52 present have full or partial decoupling mechanisms, and 82 percent have cost recovery mechanisms for capital adjustments.[1063] Thus, Xcel's

[1059] Specifically, this figure is the result of the Multi-Stage DCF model that assumes convergence on long-term GDP growth rates after 25 years, which is a more reasonable assumption that the model with a ten year second stage. Due to the extended history of utilities growing at a higher rate than GDP, the longer assumption is more reasonable.
[1060] Ex. Xcel-25 at 3 (Nowak Rebuttal).
[1061] Ex. Xcel-25 at 4 (Nowak Rebuttal). (Noting that while there is an expectation for the Federal Reserve to decrease interest rates, consensus projections demonstrate that future reductions in the Fed Funds rate will primarily affect short-term rates, with long-term rates expected to remain near current levels.)
[1062] Ex. DOC-13 at 17-20 (Addonizio Surrebuttal).
[1063] Ex. Xcel-25 at 70-71 (Nowack Rebuttal).

purported reduced risk as compared to the proxy group is, at best, significantly overstated by XLI.

988. The record also does not support a downward risk adjustment of ten basis points for customer service issues. As previously discussed, there are other proceedings better suited to address those concerns. Also, a specific basis point adjustment based on these concerns, even if they were well-founded, would imply a level of analytical rigor not supported by the record.

989. The Department explained that Xcel's equity/debt ratio is higher than any of the members of the Department's proxy group. This is a sign that Xcel Energy, Inc. could be deploying a financial strategy known as "double leverage" by using debt to finance Xcel Energy, Inc.'s equity investments in subsidiaries, resulting in holding incremental debt at the parent level and ensuring a portion of the benefits accrue to shareholders, rather than customers.[1064] While the Department did not oppose approval of Xcel's proposed capital structure on this basis, the Department did recommend considering this factor in determining Xcel's authorized ROE.[1065]

990. The Department is correct that Xcel has a high equity/debt ratio, and that this ratio benefits shareholders at the expense of customers. Accordingly, the record supports consideration of this factor when deciding where, within the reasonable range of ROEs, the Commission should set the Company's ROE.

I. ROE: Summary Conclusion, and Recommendation

991. The Commission must provide an analysis based on facts in the record and must determine a fair rate of return which is supported by the record.[1066]

992. As discussed in more detail above, the following findings inform the state of the record:

a. Changing market conditions and ROE decisions around the country establish that the Company is entitled to an increase of some kind to its authorized ROE.

b. The Two-Growth DCF analysis presented by the Company is the most reasonable estimate of the Company's ROE in the record. The results of this model imply an ROE of 10.34 percent.

c. The Company's demonstrated ability to access capital with an ROE of 9.25 percent, concerns about analyst bias inflating modeling results, and the Department's independent earnings estimates establish that, while it is the most reasonable analysis in the record,

[1064] Ex. DOC- at 28-30 (Addonizio Direct).
[1065] Ex. DOC- at 32 (Addonizio Direct).
[1066] "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.

the Two-Growth DCF overstates the appropriate ROE for the Company.

d. It is important to consider multiple models. The Commission should also give some weight to the Department's Multi-Stage DCF analysis, the results of which imply an ROE of 8.71 percent because this model corrects a specifically identified shortcoming of the Two-Growth DCF Model, though the Multi-Stage DCF analysis' own limitations establish that the Multi-Stage DCF analysis understates the appropriate ROE.

e. 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.

f. It is reasonable to include a flotation cost adjustment of eight basis points (which is reflected in the Company's Two-Growth DCF analysis and the Department's Multi-Stage DCF analysis).

993. Applying these principles, none of the recommendations made by the parties have sufficient support in the record to warrant adoption by the Commission. The Commission should reject these recommendations and instead authorize an ROE of 9.8 percent for the Company.

994. An ROE of 9.8 percent would:

a. Represent a 50 basis point increase to the Company's ROE, exceeding the approximately 30 basis point increase in the 18-month trailing average of ROEs between the filing of the Company's most recent rate case and the instant rate case.

b. Exceed the Department's Multi-Stage DCF results, which understates the appropriate ROE, by 109 basis points.

c. Be exceeded by the Company's Two-Growth DCF analysis, which overstates the appropriate ROE, by 54 basis points. This difference also appropriately addresses the Department's concerns about the investment risk stemming from the Company's equity-heavy capital ratio.

d. Be approximately two-thirds of the way between the Department's Multi-Stage DCF analysis and the Company's Two-Growth DCF analysis, appropriately reflecting that the Multi-Stage DCF warrants consideration but that the Two-Growth DCF analysis is the most reasonable analysis in the record.

e. Incorporate an eight basis point flotation cost adjustment.

f. Allow, in light of the Company's demonstrated ability to access capital with a 9.25 percent ROE, the Company an opportunity to earn a fair return on its investments.

g. Be very comparable to the national average authorized ROE for vertically integrated electric utilities of 9.77 percent.[1067]

VIII. Class Cost of Service Study (CCOSS)

995. After a revenue requirement has been determined, the next steps are to determine how much revenue should be collected from each class, and how that revenue should be collected from each class. One of the tools used to guide this process is the CCOSS.

996. According to the to the National Association of Utility Commissioners, performing a CCOSS has three steps: (1) cost functionalization, (2) cost classification, and (3) cost allocation.[1068] 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.[1069] 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.[1070] In the third step, these functionalized and classified costs are "allocated" to specific customer classes using specific parameters known as "allocation factors."[1071]

997. CCOSSes do not directly determine any component of the Company's revenue or rate design. Rather, they are models that attempt to quantify the costs caused by various classes of customers, which is one factor for the Commission to consider when apportioning revenue between the customer classes. Accordingly, it is not necessary for the Commission to approve, adopt, or reject any individual CCOSS or any one component within the CCOSS. Rather, the Commission should analyze the relative merits of the various CCOSSes presented and apply that analysis when deciding how much weight to give those results when setting the Company's revenue apportionment.

998. The Company, the Department, the OAG, XLI, and SRA provided recommendations about the design of the CCOSS, which revealed several disputed design issues.

[1067] Ex. WAL-1 at Exhibit 4 (Austin Direct).
[1068] Ex. DOC-16 at 6 (Zajicek Direct).
[1069] Ex. DOC-16, Schedule 1 at 18-19 (Zajicek Direct).
[1070] Ex. DOC-16, Schedule 1 at 20-21 (Zajicek Direct).
[1071] Ex. DOC-16, Schedule 1 at 18-22 (Zajicek Direct).

A. Classification of Fixed Production Plant

999. Fixed production costs refer to costs for generation plant, including non-fuel O&M costs, that do not vary based on output.[1072]

1000. In this proceeding, Xcel used the stratification method to separate fixed production costs into demand- and energy-related subfunctions based on the cost of a comparable peaking plant.[1073] Xcel has used the stratification method since the late 1970s.[1074]

1001. Under the stratification method, generation costs up to the amount of a comparable peaking plant are classified as demand-related and costs above that amount are classified as energy-related. 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.[1075]

1002. XLI argued that stratification is obsolete given the development of renewable energy on Xcel's system. XLI disagreed with the stratification method's classification of wind and solar plant as primarily energy-related because these resources cannot reduce fuel costs during portions of the year when they do not produce energy.[1076] Instead of the stratification method, XLI supported classification of fixed production plant using the Average and Excess Four Coincident Peak (AED-4CP) method for allocating fixed production plant.[1077]

1003. XLI further argued that the AED-4CP method should be used in this case because the Commission has used this method for Minnesota Power, and the AED-4CP method has been used in other jurisdictions.[1078]

1004. The Department supported the stratification method, arguing that wind and solar resources "do not have fuel costs, and thus clearly are invested into in part to reduce fuel costs."[1079]

1005. While the OAG raised concerns about the stratification method, it also concluded that the stratification method is superior to the AED-4CP method because the AED-4CP allocates costs associated with peaking capacity according to excess demand, which the OAG characterizes as a "mathematical construction, not a quantity that is directly observable in the electric system."[1080]

[1072] Ex. Xcel-74 at 11 (Barthol Rebuttal).
[1073] Ex. Xcel-73 at 15 (Barthol Direct).
[1074] Ex. Xcel-73 at 15 (Barthol Direct).
[1075] Ex. Xcel-73 at 15 (Barthol Direct).
[1076] Ex. XLI-3 at 8 (Ly Direct).
[1077] Ex. XLI-3 at 8 (Ly Direct).
[1078] Ex. XLI-3 at 14-15 (Ly Direct).
[1079] Ex. DOC-18 at 4 (Zajicek Surrebuttal).
[1080] Ex. OAG-9 at 4, 7, 9-10 (Scharber Rebuttal).

1006. In Xcel's last rate case, the Commission acknowledged that the Company was increasingly acquiring energy from solar- and wind-powered generators, but was not persuaded that this fact altered the applicability of the stratification method, finding that the stratification method "provides a sounder rationale for distinguishing between energy-related and capacity-related costs" than the AED-4CP method.[1081]

1007. Minnesota Power's use of AED-4CP to allocate fixed production costs does not mean that it is the best measure of cost causation for the Company's Minnesota system since Minnesota Power's customer base is materially different than Xcel Energy's and Minnesota Power has similar peaks in both the winter and summer months, while Xcel's forecasted 2025 summer peak is 39 percent higher than its winter peak.[1082] These distinctions render the comparison to Minnesota Power unpersuasive.

1008. Further, the AED-4CP's use of a pure energy allocator, without weighting for marginal energy costs, is unreasonable.[1083]

1009. Because the stratification method more accurately distinguishes energy-related and capacity-related costs, the Commission should give more weight to CCOSSes that apply the stratification method than CCOSSes that apply the AED-4CP method.

B. Allocation of Demand-Related Production Costs (D10S Allocator)

1010. The D10S allocator is used to allocate demand-related production costs after the plant stratification method is applied. It identifies the percentage of overall demand that is caused by each customer class for a specific time period. Then demand-related fixed production plant costs are allocated to classes based on these percentages.[1084]

1011. In its Order in the Company's last electric rate case, the Commission directed the Company to "calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data."[1085]

1012. Since MISO does not forecast when its peak hour might be in the future, the Company used MISO historical data for 2023. This was the most recent year with complete data when this proceeding was filed.[1086] In 2023, the MISO system peaked on August 23, 2023 at 4:00 p.m. To apply the D10S allocator for the 2025 Test Year, the Company evaluated the forecasted loads on August 23, 2025 at 4:00 p.m. [1087]

[1081] Xcel 2021 Rate Case Order at 97.
[1082] Ex. Xcel-74 at 13-14 (Barthol Rebuttal).
[1083] Ex. Xcel-74 at 14 (Barthol Rebuttal).
[1084] Ex Xcel-73 at 17 (Barthol Direct).
[1085] Xcel 2021 Rate Case Order at 99.
[1086] Ex. Xcel-73 at 18-19 (Barthol Direct).
[1087] Ex. Xcel-73 at 19-20 (Barthol Direct).

1013. The OAG believes that Xcel's implementation of this method was unreasonably arbitrary.[1088] The OAG raises three primary concerns. First, Xcel chose to represent "peak" loads that are not coincident with MISO's system peak or even Xcel's own system peak because they fall on weekends in 2025 and 2026.[1089] From 2006 to 2024, the MISO peak has never occurred on a weekend day.[1090] Second, Xcel used forecasted, not historical, data to determine the class shares themselves.[1091] Third, the OAG argued that Xcel's methodology is extremely sensitive to the choice of a single peak hour.[1092] The OAG showed that Xcel's results would change drastically if MISO's 2024 peak was used instead of the 2023 peak.[1093]

1014. The OAG designed an alternative D10S allocator to use in its CCOSSes in this case. The OAG reviewed MISO's peaks from 2011 to 2024 to determine the range of days and times most likely to include the MISO peak.[1094] The OAG's allocator considered that (1) all peaks occurred between June 21 and August 26; (2) they always occurred during the hours ending at 3:00 or 4:00 p.m. CST; and (3) they never occurred on a weekend.[1095] Because Xcel does not currently have historical class-load data,[1096] the OAG next looked at Xcel's load forecasts for 2025 and 2026 and, for each class, summed its loads at the hours of 3:00 and 4:00 p.m. on weekdays between June 21 and August 26.[1097] The OAG then divided those class load totals by the sum of the system loads for the same hours to yield the OAG's alternate D10S allocator.[1098]

1015. The Department argued that the hours selected by the OAG "don't correctly reflect the impact of the Company's system peak."[1099]

1016. XLI also criticized the OAG's alternate D10S allocator, demonstrating that 77 hours (82 percent) of the total hours selected by the OAG "fall significantly below the system peak."[1100] The resulting average load presented by the OAG's hours is just 82 percent of peak load.[1101]

[1088] Ex. OAG-8 at 5-16 (Scharber Direct); Ex. OAG-10 at 1-13 (Scharber Surrebuttal).
[1089] Ex. OAG-8 at 7 (Scharber Direct).
[1090] Ex. OAG-8 at 7 (Scharber Direct).
[1091] Ex. OAG-8 at 7 (Scharber Direct).
[1092] Ex. OAG-8 at 8 (Scharber Direct).
[1093] Ex. OAG-8 at 8-9 (Scharber Direct).
[1094] Ex. OAG-8 at 11 (Scharber Direct).
[1095] Ex. OAG-8 at 11-12 (Scharber Direct).
[1096] Ex. OAG-8 at 11 (Scharber Direct). For future cases, the OAG suggests using class load data corresponding to the month, day, and year of the MISO peak—adjusted for forecasted changes to class load shares—to enhance the precision of the cost-allocation process because the allocator would represent class load shares at the time of an actual system peak. Ex. OAG-8 at 8 (Scharber Direct).
[1097] Ex. OAG-8 at 12 (Scharber Direct).
[1098] Ex. OAG-8 at 12 & Table 2 (Scharber Direct).
[1099] Ex. DOC-18 at 11 (Zajicek Surrebuttal).
[1100] Ex. XLI-6 at 5 (Ly Rebuttal).
[1101] Ex. XLI-6 at 5 (Ly Rebuttal).

1017. Xcel also argued against the OAG's alternate D10S allocator, arguing that it was effectively "an average summer demand allocator" which did not accurately reflect how the Company designs, builds, and operates its peaking generation resources.[1102]

1018. Both versions of the D10S allocator proposed in this proceeding are severely flawed. The OAG's alternate D10S allocator is not truly a measure of Xcel's system peak, it is an average peak that does not reasonably model Xcel's system and the cost causation of various aspects of the Company's peaking generation.

1019. Conversely, while the Company cannot be faulted for complying with the Commission's directive to use a D10S allocator based on a historical MISO peak, specific circumstances in this proceeding diminish the reliability of the application of that peak in this proceeding. Most notably, the MISO peak has not occurred on a weekend, as shown by data dating back to 2006. It is therefore reasonable to conclude that weekends are systemically different from weekdays when it comes to determining the MISO peak. Thus, using a weekend day as the presumed MISO peak for 2025 and 2026 is an unreasonable assumption.

1020. The OAG's analysis also persuasively highlights the sensitivity of the D10S allocator to these modeling decisions. There appears to be no principled reason to use historical 2023 data to forecast the 2025 and 2026 peak when 2024 data is now available. The OAG has demonstrated that using more recent data would result in a drastic shift in the Company's CCOSS.[1103]

1021. Ultimately, with respect to the D10S allocator, the record in this proceeding calls for a choice between two models that both suffer from flaws that have been shown to significantly impact the results of the CCOSS.[1104] This, perhaps more than any other dispute with respect to the CCOSS in this case, underscores the dangers of assuming that any one model, or even an amalgamation of models, can provide a precise and accurate measure of cost causation.

1022. The Commission should not give greater or less weight to any of the CCOSS results presented in the case based on how the proponent applied the D10S allocator. Rather, the Commission should consider these models in tandem and give due recognition to the fact that the disparate results of the models reflect their sensitivity to unavoidable limitations of the modeling process itself. These limitations should also limit the extent to which CCOSS results are perceived to imply any particular revenue apportionment proposal as an objective reflection of class cost causation.

[1102] Ex. Xcel-74 at 17 (Barthol Rebuttal).
[1103] Ex. OAG-8 at 9 and Table 1 (Scharber Direct).
[1104] This is a criticism of neither the models themselves nor the witnesses who endorsed them. Rather, it is a reflection of the reality of CCOSS modeling and its inherent limitations.

C. Allocation of Demand-Related Transmission Costs

1023. The Company classifies transmission costs as both demand-related and energy-related.[1105]

1024. In its Order in the Company's last electric rate case, the Commission directed the Company to classify its transmission costs at 70 percent demand-related and 30 percent energy-related, and to allocate the demand-related transmission costs using a 12CP allocator.[1106] The "CP" stands for coincident peak, and the 12 indicates the use of a coincident peak for each of the 12 months of the year.[1107]

1025. 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.[1108] 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."[1109]

1026. The OAG argues that the 12 CP allocator continues to best reflect transmission demand cost causation and how Xcel is compensated for its transmission assets. In Xcel's last rate case, the Commission cited "growing acceptance of relying on a broader concept of peak demand" beyond just a single peak.[1110] The Commission also described the importance of transmission system reliability in all seasons of the year, not just on a single peak day. As the Commission explained, utilities tend to take generation assets offline for maintenance in the spring and fall, leaving the system vulnerable to unplanned outages.[1111] Managing unplanned outages requires ensuring adequate transmission capacity year-round as the grid's supply and demand levels fluctuate.[1112]

1027. The Company expressed concerns that that the 12CP allocator spreads demand-related costs of the transmission system to customers based on the average of the 12 coincident peaks in each month.[1113] In effect, the 12CP allocator is a measure of average demand. However, the Company states that it plans its system to meet peak demand – not average demand. If the Company did not plan its system to meet the highest peak demand, it would not be able to serve customers on that day. Department witness Zajicek and XLI witness Ly agreed with the Company's reasoning.[1114]

1028. XLI argued that using an E8760 allocator for the energy-related portion of transmission costs recognizes the reliability risks throughout the year and assigns costs

[1105] Ex. Xcel-73 at 22 (Barthol Direct).
[1106] Xcel 2021 Rate Case Order at 159.
[1107] Ex. Xcel-73 at 22-23 (Barthol Direct).
[1108] Ex. OAG-4 at 15 (Twite Direct).
[1109] Ex. Xcel-84 at 22 (Peppin/Barthol Direct).
[1110] Xcel 2021 Rate Case Order at 102.
[1111] Xcel 2021 Rate Case Order at 102.
[1112] Xcel 2021 Rate Case Order at 102.
[1113] Ex. Xcel-73 at 24 (Barthol Direct).
[1114] Ex. DOC-16 at 35 (Zajicek Direct); Ex. XLI-3 at 19 (Ly Direct).

to customers on that basis.[1115] XLI reasoned that it was not necessary to also accomplish this goal with the allocator for demand-related costs, as occurs with a 12CP allocator.[1116]

1029. The Commission's reasoning in Xcel's last rate case was sound. Continued use of the 12CP allocator addresses seasonal needs for system reliability and focusing on a single peak would fail to adequately address that reality.

D. Classification and Allocation of Shared Distribution Costs

1030. As required by the Commission in the Company's last rate case,[1117] the Company filed three CCOSSs using different methods to classify distribution system costs: the Minimum System Method, the Basic Customer Method, and the Peak-and-Average Method.

1. Minimum System Method

1031. The Minimum System Method calculates the cost of a "minimum" distribution system that is needed to connect customers to the system, but not serve demand. This method classifies costs below this minimum system threshold as customer-related, and classifies costs above this threshold are as demand-related.[1118]

1032. The Company estimated the minimum threshold using two different calculations: the Minimum Size Method and the Zero-Intercept Study.[1119]

1033. The Minimum Size Method calculation identifies the smallest-size piece of equipment, and assumes that anything larger is selected to meet demand. The calculation estimates the total cost that would result if the smallest-sized equipment was used for all installations, based on specific cost information about that piece of equipment.[1120]

1034. The Zero-Intercept Study calculates a no-capacity minimum system by applying statistical analysis to data about the existing system, including the size of equipment and its cost.[1121] This calculation results in a statistical estimation of the cost of a distribution system that has zero capacity.[1122]

1035. The Company created its Minimum System Study using both of these calculation methods. For each piece of equipment in the distribution system, the Company selected the method that resulted in the lower customer-related percentage, to ensure that the analysis did not overstate customer classification.[1123]

[1115] Ex. XLI-3 at 20 (Ly Direct).
[1116] Ex. XLI-3 at 20 (Ly Direct).
[1117] Xcel 2021 Rate Case Order at 105-06.
[1118] Ex. Xcel-73 at 35-36 (Barthol Direct).
[1119] Ex. Xcel-73 at 35-36 (Barthol Direct).
[1120] Ex. Xcel-73 at 35-36 (Barthol Direct).
[1121] Ex. Xcel-73 at 36-37 (Barthol Direct).
[1122] Ex. Xcel-73 at 37 (Barthol Direct).
[1123] Ex. Xcel-73 at 37 (Barthol Direct).

1036. The OAG perceives several flaws with the Minimum System Method that cause it to overstate customer costs. First, the OAG believes the Minimum System Method overstates the customer-related portion of the distribution system by assuming the main driver of minimum-size shared distribution costs is the number of customers, when the main driver of distribution costs is the size of a utility's service territory.[1124] The OAG argues this approach is unfair to customers who do not expand the size of Xcel's service territory when added to the system.[1125] Second, the OAG believes that distribution costs are not related to the addition of new customers.[1126]

1037. The Department supports the use of multiple CCOSS results. Department witness Zajicek recommended a range of results built upon the Company's Minimum System Method and the Basic Customer Method, with both updated to allocate demand-related transmission costs using the D10S allocator.[1127]

1038. XLI witness Ly did not challenge the Company's Minimum System Method.[1128]

2. Basic Customer Method

1039. The Basic Customer Method classifies distribution plant that serves a single customer as 100 percent customer-related and all other costs as demand-related.[1129] Under this method, equipment such as meters and non-shared service drops are allocated as customer-related, and other equipment is classified as demand-related.[1130]

1040. The Company opposes the use of the Basic Customer Method because, according to Xcel, the method does not reflect cost causation because it does not recognize that the costs of primary conductor, secondary conductor, and transformers are driven by the addition of customers.[1131] By way of specific example, Xcel stated that "[t]he Company would not install a transformer in the middle of a field without any customers – it only adds conductors and transformers to the system when they are needed to reach new customers, which means that the system costs for conductors and transformers are driven in part by the number of customers."[1132]

1041. XLI similarly argued that the Basic Customer Method fails to recognize the impact of attaching customers to the system independent of the amount of power and energy consumed when addressing distribution network costs.[1133]

[1124] Ex. OAG-8 at 21-22 (Scharber Direct).
[1125] Ex. OAG-8 at 22-23 (Scharber Direct) (citing James C. Bonbright, *Principles of Public Utility Rates* 349 (1st ed. 1961)).
[1126] Ex. OAG-8 at 21-22 (Scharber Direct).
[1127] Ex. DOC-16 at 41-42 (Zajicek Direct).
[1128] Ex. XLI-3 at 25 (Ly Direct).
[1129] Ex. Xcel-73 at 42 (Barthol Direct).
[1130] Ex. OAG-8 at 22 (Scharber Direct).
[1131] Ex. Xcel-73 at 44 (Barthol Direct).
[1132] Ex. Xcel-74 at 25 (Barthol Rebuttal).
[1133] Ex. XL-3 at 24 (Ly Direct).

1042. While not opposing inclusion of the Basic Customer Method, the Department raised concerns that expansion in the size of the distribution system will always include an element of customer-driven costs.[1134]

1043. The OAG endorses the Basic Customer Method, arguing that it may actually overestimate customer-related costs by including service drops serving multiple customers in multi-family buildings, even though those costs are not related to an individual customer.[1135]

3. Peak-And-Average Method

1044. The Peak-and-Average Method assumes that a portion of the costs of the distribution system are driven by the volume of energy that customers use. The "baseline energy needs" of the system, based on the Company's load factor, are classified as energy-related. The rest is classified as demand-related.[1136]

1045. The OAG recommends, and in fact prefers, the use of the Peak-and-Average method for the CCOSS because it treats some distribution costs as energy-related under the assumption that some shared distribution costs would be needed even if all customers used power at a 100 percent load factor.[1137] The OAG does not provide specific examples of what costs should be considered energy-related.

1046. The Company, the Department, and XLI oppose the use of the Peak-and-Average Method for classifying distribution costs.

1047. The Company argues that the Peak-and-Average method is inappropriate because it ignores the fact that distribution conductors and transformers are driven by the addition of customers. If the equipment was sized to meet a customer's average energy usage, then this equipment would not be appropriately sized to meet the peak demand of that customer.[1138]

1048. Department witness Zajicek recommended the Commission not consider a Peak-and-Average CCOSS because of the Peak-and-Average Method's energy-related treatment of shared distribution costs, as well as concerns about the method understating the customer-related component of shared distribution costs.[1139]

1049. XLI witness Ly testified that the Peak-and-Average method classifies 55 percent of the costs of conductor and transformer costs to energy without evidence that year-round energy usage drives the size and types of equipment required by NSPM

[1134] Ex. DOC-16 at 18 (Zajicek Direct).
[1135] Ex. OAG-8 at 22-23 (Scharber Direct).
[1136] Ex. Xcel-73 at 45 (Barthol Direct).
[1137] Ex. OAG-8 at 26 (Scharber Direct). To the extent the OAG's support of the Peak-and-Average Method is driven by treating only discrete customer-specific costs as customer-related, the OAG's argument on that feature in support of the Basic Customer Method applies equally to the Peak-and-Average Method.
[1138] Ex. Xcel-74 at 25-26 (Barthol Rebuttal).
[1139] Ex. DOC-16 at 30, 42 (Zajicek Direct).

to attach customers to the grid and ensure that the grid can meet the expected peak demand of its customers.[1140]

4. Demand Adjustment

1050. The Department recommended that the Commission require the Company to provide an updated study calculating its demand adjustment applied to the Minimum System Method in its next rate case.[1141] The Company agreed with this recommendation and the Commission should order the Company to do so.

5. Findings And Conclusions On Shared Distribution Costs

1051. The Commission should continue to rely on multiple methodologies for classifying and allocating shared distribution costs. All models presented in this proceeding carry sufficient supporting testimony and theoretical support to preclude any model being entirely disregarded.

1052. As an initial matter, none of the models presented are perfect, nor could they be. In an effort to model the cost causation of shared distribution costs, the models necessarily rest on imperfect assumption. Consideration of the multiple models in the record highlights the range of results that occurs from the choice of these assumptions as well as the danger of accepting any one model as an objective representation of cost causation.

1053. The primary reason for the controversy surrounding modeling distribution costs is that a substantial portion of these costs are not driven by energy, demand, or number of customers. The OAG persuasively identified that a key driver of distribution costs is instead the size of a utilities' service territory. This requires analysts to find a "dumping ground[]" for distribution system costs.[1142] The dramatic swings in modeling results based on these decisions demonstrates that whether and how much of these costs are "dumped" into the customer-, energy-, or demand-related categories can have tremendous impacts on conclusions about class cost causation.

1054. Of course, concluding that multiple models should be considered does not necessarily imply that all models are entitled to equal weight.

1055. While the OAG provided some justification for treating a portion of the shared distribution costs as energy-related, the Company, Department, and XLI provided persuasive arguments that the analytical framework of the Peak-and-Average Method is significantly flawed. Specifically, the OAG has not identified any specific cost items that vary based on customer energy usage. Accordingly, the Peak-and-Average should be given significantly less weight than the Basic Customer Method or the Minimum System Method when setting rates in this proceeding.

[1140] Ex. XLI-6 at 14-15 (Ly Rebuttal).
[1141] Ex. DOC-16 at 36-37 (Zajicek Direct).
[1142] Ex. OAG-8 at 33 (Scharber Direct).

1056. There is legitimate debate in this record about whether a portion of shared distribution costs should be considered customer-related, and the Basic Customer Method as well as the Minimum System Method both provide over-simplified yet reasonable perspectives on how to treat those costs. The Basic Customer Method understates customer-cost causation by disregarding the reality that distribution system extensions only occur to connect new customers to the system. Conversely, the Minimum System Method overstates customer-cost causation by assuming that all shared distribution costs other than those caused strictly by capacity needs are customer-related. Neither method is perfect, but together they form the bookends of a reasonable range of conclusions about the causation of shared distribution costs. Accordingly, the Commission should give both methods equal weight when setting rates in this proceeding.[1143]

6. Classification and Allocation of AMI

1057. Costs related to meters have been traditionally classified as customer-related costs because meters are installed to connect each customer to the system and the number of meters varies directly based on the number of customers. Xcel proposes to continue allocating AMI meters in this manner.[1144]

1058. The OAG recommends that AMI costs should be classified as one-third customer-related, one-third energy-related, and one-third capacity related.[1145]

1059. First, the OAG recommended that AMI meters be classified as demand-related because they are used for demand-response programs, and provide information to customers and the Company about energy use. This helps manage peak demand and also can reduce investment in baseload or transmission plant, thereby reducing both demand- and energy-related costs.[1146]

1060. The Company argues that, while the AMI meters can be used for demand-response programs and can provide information to customers and the Company about energy uses, that does not mean that the costs for the AMI meter vary based on these functions. The costs of the AMI meter does not change based on the design of new demand-response programs. Within a customer class, the cost of the meters continues to be entirely driven by the number of customers.[1147]

1061. Second, the OAG points to the Commission's order regarding AMI classification for Minnesota Power.[1148] The Company accurately notes that classification of AMI meters in the Minnesota Power rate case was not a litigated issue and that case

[1143] This does not imply setting interclass revenue apportionment at or near the midpoint of these models. Such an outcome would result in rates set based purely on class cost causation, without regard to any other factor.
[1144] Ex. Xcel-74 at 26-27 (Barthol Rebuttal).
[1145] Ex. OAG-8 at 30 (Scharber Direct).
[1146] Ex. OAG-10 at 28-29 (Scharber Surrebuttal).
[1147] Xcel Initial Brief at 255.
[1148] Ex. OAG-10 at 26 (Scharber Surrebuttal).

was fully resolved by settlement.[1149] While the Company asserts that this limits the persuasiveness of the Minnesota Power decision, the Commission has also explicitly recognized the energy- and demand-related components of AMI costs in two prior Minnesota Power and Otter Tail Power Company rate cases despite arguments to the contrary.[1150]

1062. Third, the OAG argued that classifying one-third of AMI costs as customer-related is reasonable because metering investment have increased from approximately $100 million to approximately $300 million in the last ten years.[1151]

1063. New AMI meters cost approximately $95.65, compared to $49.73 for the pre-AMI meters, suggesting that limiting the customer-related portion of AMI meters to one-third of their total cost understates the customer component of AMI costs.[1152]

1064. The Company asserts that these costs are not an apples-to-apples, comparison, because the cost for connect/disconnect is not included in the $49.73 estimate for pre-AMI meters, but is included in the $95.65 cost estimate for AMI meters.[1153]

1065. The Company is correct that, at an individual customer level, the cost of AMI meters varies directly in proportion to the number of customers. This observation, however, does not resolve the issue.

1066. The system-wide costs of AMI meters is driven in part by demand- and energy-related concerns. If the sole purpose of the meter was to enable the connection of customers to the system, this could be accomplished at the reduced cost of a pre-AMI meter. Xcel is instead investing more money in AMI meters, and this premium is justified by the anticipated demand- and energy-related benefits of these meters. While the Company attempts to dismiss this by distinguishing between cost-causation and the benefits of the AMI technology, this is a distinction without a difference. The premium paid for more advanced, expensive AMI meters, as compared to pre-AMI meters is, in fact, caused by energy- and demand-related concerns.[1154]

1067. Xcel is also correct that the OAG's proposed split of these costs as demand-, energy-, and customer-related is flawed. The OAG does not claim any precise mathematical basis for its proposed allocation of AMI technology. Comparison of the per meter cost between the two types of meters establishes that the OAG proposal

[1149] Xcel Initial Brief at 255.
[1150] MP 2021 Rate Case Order at 59-61; Otter Tail 2020 Rate Case Order at 49-50, 70.
[1151] Ex. OAG-10 at 26-27, Table 4 (Scharber Surrebuttal).
[1152] Ex. OAG-8 at 27 (Scharber Direct).
[1153] Xcel Initial Brief at 256. The Company made this assertion in its brief without citation to testimony or other record evidence. This limits the persuasiveness of the assertion.
[1154] *See* Ex. DOC-18 at 5-6 (Zajicek Surrebuttal) ("we would not bother to install AMI meters unless they offered additional benefits or were cheaper than older traditional meters combined with the costs to read those meters" and "[t]he only reason to install AMI meters would be because the Company wanted to enable other uses, and thus those are the drivers of the portion of the AMI meter cost beyond those associated with traditional meters.")

understates the appropriate level of customer costs for AMI meters. This weakness, however, is less significant than the Company's proposal to disregard entirely the demand- and energy-related component of AMI meters.

1068. The Company recommended that it is not necessary to make a final determination on the classification of AMI meters at this time. In this case, the base rate revenue requirement includes a limited amount of internal labor costs related to AMI deployment. All other AMI costs are being recovered through the TCR Rider.[1155] The OAG responds that implementing its classification in this proceeding is appropriate because it anticipates the Company rolling AMI costs into rate base in the next rate case.[1156]

1069. The Commission should approve the OAG's proposed classification of AMI costs for any relevant rate purpose between now and a decision in Xcel's rate case.

1070. Because the recommendation on this issue is for the Commission to effectively adopt the least flawed proposal in the record, the Commission should also adopt the Department's recommendation and require the Company to provide a study showing the costs of AMI meters compared to the costs of traditional meters and the cost of reading those meters compared to AMI meters, and to classify the difference between those costs as either demand- or energy-related in Xcel's next rate case.[1157] This should allow the Commission to more precisely allocate the costs of AMI meters in that proceeding.

E. Classification and Allocation of Other Production O&M

1071. The Production O&M costs that vary with energy usage are classified as energy-related, and the remaining costs are classified based on the type of production plant they are related to. This is referred to as the location method.[1158] The Company has used this method since it was approved by the Commission in its 2013 rate case.[1159]

1072. XLI opposes the Company's classification of Other Production O&M and proposes that the Company change the methodology to classify regional market expenses and labor-related production O&M as demand-related, with the remaining costs classified as energy-related.[1160]

1073. The Commission rejected XLI's same argument in the 2013 rate case, noting "it is not evident that classifying each O&M category as energy- or capacity-related

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[1155] Xcel Initial Brief at 253-254.
[1156] OAG Reply Brief at 49.
[1157] Ex. DOC-18 at 5-6 (Zajicek Surrebuttal).
[1158] Ex. Xcel-74 at 37-38 (Barthol Rebuttal)
[1159] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 68-69 (May 8, 2015) [hereinafter Xcel 2013 Rate Case Order].
[1160] Ex. XLI-3 at 15-17 (Ly Direct).

based on whether the category is predominantly variable or fixed results in an accurate energy/capacity allocation."[1161]

1074. The Commission should, consistent with its Order in Xcel's previous rate cases dating back to the proceeding filed in 2013, approve the Company's proposal for classifying and allocating Production O&M costs. These costs are incurred as a result of the generation resources and Xcel's proposed methodology aligns the costs with the generation to which they relate.

F. Allocation of Economic Development Discounts

1075. Economic development discounts reflect discounts that some customers receive from tariffed rates, as has been authorized by the Commission. In the Company's last rate case, the Company allocated economic development discounts using the R01 Total Present Revenue allocator. In that case, XLI proposed that economic development discounts be allocated with a base revenue allocator because these discounts pertain to base revenues and not fuel or riders. The Company agreed with XLI's proposal and changed the allocation from the R01 Total Present Revenue to the R02 Base Present revenue allocator, which does not include fuel and riders, in this rate case.[1162]

1076. The OAG opposes this change. The OAG argues that Xcel's argument for changing from an allocator that includes fuel costs to one that does not was inapplicable because neither is fundamentally tethered to cost causation. Instead, the R01 allocator is designed to allocate costs on the basis of potential benefits provided by economic development rates.[1163] If cost causation was determinative, the OAG argues that these costs would be allocated entirely to the C&I Demand class, since members of this class alone "cause" the costs.[1164] Instead, the fact that these costs that arise from a handful of customers are allocated across all of Xcel's customer classes is based on the potential benefits received by those classes.[1165]

1077. The OAG further reasoned that the rationale for allocating the costs of economic development discounts must be based on the benefits that all customer classes may receive from a broader sharing of fixed system costs.[1166] This broader sharing, beyond sharing the actual revenues, would be due to the addition of the discount recipients' peak load and energy requirements to the demand and energy allocators, not through the revenue they provide.[1167]

1078. The Company, the Department, and XLI each oppose the OAG's recommendation and agree that it is appropriate to use the R02 allocator.

[1161] Xcel 2013 Rate Case Order at 68.
[1162] Ex. Xcel-74 at 39 (Barthol Rebuttal).
[1163] Ex. OAG-10 at 32 (Scharber Surrebuttal).
[1164] Ex. OAG-10 at 31 (Scharber Surrebuttal).
[1165] Ex. OAG-10 at 32 (Scharber Surrebuttal).
[1166] Ex. OAG-10 at 32 (Scharber Surrebuttal).
[1167] Ex. OAG-10 at 32-33 (Scharber Surrebuttal).

1079. The Company explained that the OAG's recommendation is not consistent with cost causation because "[e]conomic development discounts are not related to fuel costs, so it makes more sense to allocate them using a revenue allocator that does not include fuel costs".[1168]

1080. The Department pointed out that "economic development discounts provide benefits for the entire system by attracting more customers, spreading fixed costs between more customers, and thus should be allocated to all customers."[1169]

1081. XLI also argued that economic development costs do not directly impact fuel costs.[1170]

1082. Because economic discount rates do not provide a discount on fuel costs, it would be unreasonable to use an allocator that incorporates fuel. Thus, the Commission should approve use of the R02 Base Present revenue allocator for Xcel's economic development discounts.

G. CCOSS Summary and Conclusions

1083. A comparison of the different CCOSSes offered in this proceeding are summarized in the following table:[1171]

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG	Peak & Avg	3.5%	-8.9%	15.7%	28.7%
OAG	Basic Customer	5.8%	-8.5%	13.9%	31.3%
DOC	Basic Customer	9.6%	-11.8%	11.5%	26.9%
Xcel Energy	Hybrid	13.5%	-6.2%	8.3%	30.6%
SRA	Hybrid	13.5%	-6.1%	8.3%	29.3%
DOC	Hybrid	15.0%	-7.2%	7.3%	26.1%
XLI	Hybrid	16.1%	-2.0%	6.3%	19.9%

[1168] Ex. Xcel-74 40 (Barthol Rebuttal).
[1169] Ex. DOC-17 at 2-3 (Zajicek Rebuttal).
[1170] Ex. XLI-6 at 20-21 (Ly Rebuttal).
[1171] Ex. Xcel-75 at 8 and Table 2; Ex. OAG-10 at 38 (Scharber Surrebuttal). This chart shows the results of the various models in this proceeding using the Company's 2026 Rebuttal Revenue Requirement.

1084. As explained in the Findings above, all of these models merit some consideration when setting rates in this proceeding, but not all models should be weighed equally.

1085. The OAG's Peak-and-Average Model is entitled to significantly less weight than other models in the record because of theoretical shortcomings of that model. Also, XLI's Hybrid model is entitled to significantly less weight because of its treatment of fixed production plant costs.

1086. The Commission should give the most weight to the Hybrid models proposed by the Department and Xcel as well as the Basic Customer models presented by the Department and the OAG. These CCOSSes reflect a variety of modeling decisions and assumptions that, as described above, are meritorious and defensible despite their respective flaws. Accordingly, the Commission should consider these models when evaluating the cost-causation of various customer classes. In doing so, the Commission should recognize that none of the models produce a result that can be said to be an objectively accurate reflection of class cost-causation. Any revenue apportionment result that falls within the results of these models can be said to be "at cost" to the extent cost can be fairly determined on this record.[1172]

IX. Rate Design[1173]

1087. 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.

1088. Rate design, in contrast to the determination of the revenue requirement, is a quasi-legislative function.[1174] This step of the ratemaking process largely involves policy decisions to be made by the Commission.[1175]

1089. 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."[1176] That is, rate design is not a formulaic process, but involves balancing many factors.[1177]

[1172] Certainly, the differences in the implied revenue responsibility of various classes shifts substantially based on which of these four models is being used, especially when considering the amount of revenue the Company seeks to recover through this proceeding. But this observation does not change the underlying determination that the unavoidable limitations of CCOSS modeling cannot support a more precise determination of class cost-causation.

[1173] Some parties also use the term "rate design" to categorically refer to intra-class rate design issues. This Report uses the term "rate design" more broadly to include both interclass revenue apportionment and intra-class rate design issues, and will refer to intra-class rate design issues with more specific terminology to avoid ambiguity.

[1174] *St. Paul Area Chamber of Commerce v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977).

[1175] *St. Paul Area Chamber,* 251 N.W.2d at 357.

[1176] *St. Paul Area Chamber*, 251 N.W.2d at 354.

[1177] *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.").

1090. Rates should offer utilities a reasonable opportunity to earn their revenue requirements.[1178] They should promote efficiency and conservation.[1179] They also should promote renewable energy use.[1180] And, they should avoid "rate shock" and unreasonable discrimination against any customer class.[1181] In balancing these priorities, the Commission must resolve any doubts in favor of consumers.[1182]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; continuity with prior rates; ease of understanding; ease of administration; and promotion of conservation.[1183]

A. Revenue Apportionment

1091. Revenue apportionment is the first step of rate design.[1184] After costs are allocated among customer classes (revenue requirement), each customer class is assigned a percentage of the total retail rate revenue requirement as approved by the Commission.[1185] When determining the revenue apportionment among customer classes, the Commission has considered the range of cost allocations and a variety of non-cost factors to inform the final revenue apportionment.[1186]

1092. The starting point of the Company's revenue requirement was the Company's Hybrid Minimum System CCOSS. From this starting point, the Company proposed to move all classes 20 percent towards cost, as determined by its CCOSS. The Company proposed to limit the movement towards cost to 20 percent in consideration of rate continuity and customer understanding.[1187]

[1178] Minn. Stat. § 216B.16, subd. 6 (2024).
[1179] Minn. Stat. §§ 216B.03–.04 (2024).
[1180] Minn. Stat. § 216C.05, subd. 1 (2024).
[1181] Minn. Stat. §§ 216B.03, .07 (2024).
[1182] Minn. Stat. § 216B.03 (2024).
[1183] *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 36-37 (Jun. 12, 2017) [hereinafter Xcel 2015 Rate Case Order].
[1184] Ex. DOC-19 at 18 (Bahn Direct).
[1185] Ex. DOC-19 at 18 (Bahn Direct).
[1186] Ex. DOC-19 at 19 (Bahn Direct).
[1187] Ex. Xcel-76 at 11 (Paluck Direct).

1093. The results of the Company's revenue apportionment proposal are shown in the following table:[1188]

Proposed Revenue Apportionment with Company Adjustments		
Class	**Revenue Apportionment**	**Apportionment Factors**
TY 2025		
Residential	$1,516.98	*40.12%*
Non-Demand	$124.54	*3.29%*
C&I Demand	$2,105.20	*55.68%*
Lighting	$34.14	*0.90%*
Total Retail	$3,780.85	*100.00%*
PY 2026		
Residential	$1,616.05	*40.46%*
Non-Demand	$135.69	*3.40%*
C&I Demand	$2,206.41	*55.24%*
Lighting	$35.95	*0.90%*
Total Retail	$3,994.09	*100.00%*

1094. The Department, Walmart, and the SRA all supported the Company's 2025 revenue apportionment.[1189]

1095. XLI recommended a different revenue requirement that would result in a lower increase for Demand classes, and a larger increase for other classes. XLI's argument is primarily based XLI's CCOSS. XLI argues that the Commission must take action to ensure that industrial rates are five percent below national averages, based on the goal established in Minn. Stat. § 216C.05.[1190] XLI also argues that Xcel's recommendation to move 20 percent toward cost would increase, rather than decrease, inter-class subsidies. XLI recommends moving nearly all the way to its determination of cost, while mitigating individual class increases such that no customer class would receive an increase that exceeds 150 percent of the system average.[1191]

1096. The OAG also presented a revenue apportionment proposal. The OAG's allocation analysis began by using an average of the cost-share results from the OAG's

[1188] Ex. Xcel-78 at 3, Table 1 (Paluck Surrebuttal).
[1189] Ex. DOC-20 at 5 (Bahn Surrebuttal); Walmart Initial Brief at 10-11; SRA Initial Brief at 3-4.
[1190] This argument ignores that XLI's proposal would violate this goal with respect to the residential class.
[1191] Ex. XLI-3 at 33-34 (Ly Direct).

three CCOSSes (Basic Customer CCOSS, Peak and Average CCOSS, and the OAG's Minimum-System or Hybrid CCOSS).[1192] The OAG used an equally weighted average to reflect the Commission's preference for considering a range of classification methods.[1193]

1097. The OAG then determined it was appropriate to have no rate increase for Small General service in both 2025 and 2026 under Xcel's currently requested revenue requirement, because even if Xcel's full Rebuttal revenue requirement were authorized, all three of the OAG's CCOSSes showed that consideration of cost would imply a rate reduction for this class.[1194]

1098. The OAG also considered the ability to pass on energy costs. Customer classes have varying abilities to pass on costs. Commercial and industrial customers are generally able to pass on the costs of an input, like electricity, to their own customers to some degree. "Larger firms with more monopoly power, facing a less elastic demand curve, may be able to pass along costs to a higher degree. Smaller businesses in a more competitive market, on the other hand, will generally be less able to pass along costs, if their customers can substitute away from their product or service[.]"[1195] customers cannot pass on price increases to any degree, and options for substituting away from electricity are limited.[1196]

1099. The OAG also considered the ability to pay of various customer classes. The OAG points to information in the record regarding the current inability of many residential customers to pay their bills. This is shown by energy burden, historic disconnection levels, historic levels of arrears, and persistent inflation. Several witnesses, from multiple parties, offered testimony on these issues.[1197]

1100. The OAG's analysis showed that customers with lower incomes have a high "energy burden," the portion of household income devoted to paying gas and electric bills.[1198] An energy burden above six percent is considered high, while above ten percent is considered severe.[1199] The total energy burden for Minnesota households below the federal poverty level is about 22 percent, with an electricity-specific energy burden of 12 percent.[1200] Even for the 19 percent of Minnesota households with incomes below 200 percent of the federal poverty level, a significant number of Minnesotans live with a high or severe energy burden.[1201] In the metro area specifically, where Xcel's residential

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[1192] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).
[1193] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).
[1194] Ex. OAG-10 at 38-39 (Scharber Surrebuttal).
[1195] Ex. OAG-8 at 36 (Scharber Direct). Witness Scharber agreed, however, that the ability of large industrial customers to pass on price increases should be balanced against considerations of whether large customers will move towards self-generation or move out of Xcel's service territory if prices increase sharply. Ex. OAG-8 at 37-38 (Scharber Direct).
[1196] Ex. OAG-8 at 36-37 (Scharber Direct).
[1197] *See generally, e.g.*, Ex. OAG-8 at 38-41 (Scharber Direct); Ex. OAG-1 at 27-32 (Hinderlie Direct); Ex. CUB-3 (Levenson-Falk Direct); Ex. CUB-8 (Levenson-Falk Surrebuttal); Ex. JIN-2 (Chan Direct); Ex. JIN-5 (Chan Surrebuttal); Ex. DOC-22 at 3 (Schmitz Rebuttal).
[1198] Ex. OAG-8 at 38-39 (Scharber Direct).
[1199] Ex. OAG-8 at 39 (Scharber Direct).
[1200] Ex. OAG-8 at 39 (Scharber Direct).
[1201] Ex. OAG-8 at 39 (Scharber Direct).

customers are concentrated, low-income customers[1202] struggle with significant energy burdens at a median of 7.2 percent, while a quarter of low-income households in the metro area were found to have "severe" energy burdens, above 14 percent.[1203]

1101. The results of the OAG's revenue apportionment are shown in the following table:[1204]

Table 7
OAG Recommended Apportionment at Xcel's Proposed Revenue Requirement

Customer Class	OAG Proposed Class Shares	Class Revenues at Xcel's Proposed Revenue Requirement ($000s)	Class Increases at Xcel's Proposed Revenue Requirement Under OAG Apportionment	
			($000s)	%
2025: Based on Xcel's proposed revenue requirement of $3,780,853				
Residential	**38.87%**	$1,469,748	$41,741	2.9%
Small General	**3.16%**	$119,617	$0	0.0%
Large General	**57.06%**	$2,157,295	$161,564	8.1%
Lighting	**0.90%**	$34,193	$2,918	9.3%
Total	**100.00%**	$3,780,853	$206,223	5.8%
2026: Based on Xcel's proposed revenue requirement of $3,994,095				
Residential	**39.01%**	$1,558,246	$97,783	6.7%
Small General	**3.18%**	$126,894	$0	0.0%
Large General	**56.91%**	$2,272,943	$261,167	13.0%
Lighting	**0.90%**	$36,012	$4,458	14.1%
Total	**100.00%**	$3,994,095	$363,408	10.0%

1102. The Company and XLI's revenue apportionment both select a single CCOSS and drive towards cost according to their respective models, generally adjusting only to reduce some class increases in order to mitigate rate shock. This is problematic for two reasons.

1103. First, as previously discussed, limitations of the modeling process make it perilous to assume that any one model provides a true representation of cost. This concern is especially pronounced with respect to XLI's proposed revenue apportionment, which relies on a model that is more flawed than Xcel's.

1104. Second, notwithstanding concerns about whether cost can be truly ascertained, by recommending that revenue apportionment move towards cost, adjusted only to mitigate rate shock, XLI and the Company implicitly argue for the Commission to disregard any other considerations that it has historically and appropriately considered

[1202] In this context, low-income was defined as 80 percent of median income. *See* Ex. OAG-8 at 39 (Scharber Direct).
[1203] Ex. OAG-8 at 39-40 (Scharber Direct).
[1204] Ex. OAG-10 at 40, Table 7 (Scharber Surrebuttal).

when setting revenue apportionment.[1205] Effectively, XLI and the Company both ask the Commission to consider only cost of service and rate shock when making this decision.

1105. Adjusting the Company's revenue apportionment in an attempt to harmonize it with the results of any specific model would presume a level of precision, objectivity, and accuracy in the modeled estimates that the record does not support. Instead, the Commission should recognize that when apportioning revenue, it exercises quasi-legislative authority. Thus, the Commission should also consider the other non-cost considerations that it has historically relied on to select the revenue apportionment proposal that advances the Commission's various legitimate policy objectives. The OAG's recommendation accomplishes this.

1106. One key weakness of the OAG's recommendation is the extent to which it is weighted by the Peak-and-Average model. That said, the OAG's apportionment recommendation still falls within the range of results of its Basic Customer and Minimum System cost estimates for both the Residential and Large General Service classes. These are both defensible CCOSSes methodologies, which renders the OAG's proposal a cost-based recommendation. It is further reasonable to exclude the Small General Service class from any increase based on the persuasive evidence that that class is already paying significantly above cost as estimated by a range of models.[1206]

1107. Unlike XLI and the Company, the OAG's proposal also reflects consideration of ability to pay and ability to pass on costs. These factors are also relevant to revenue apportionment determinations, as evidenced by previous Commission and judicial determinations.[1207]

1108. For these reasons, the Commission should adopt the OAG's revenue apportionment recommendation as the proposal in the record that most faithfully balances cost of service with other relevant factors for apportioning revenue.

1109. The Company proposed to establish one revenue apportionment for the 2025 Test Year and a different apportionment for the 2026 Plan Year. The Company argued that there are different costs and revenues in each of the years, and particularly pointed to an increase in forecasted sales to the C&I Demand class. Because of this change, the Company asserted that it is important to update the revenue apportionment for the 2026 Plan Year.[1208]

[1205] If, for example, the Commission were to adopt Xcel's approach in this and subsequent rate cases, then Xcel's revenue apportionment would asymptotically approach Xcel's calculation of cost of service, eventually resulting in a revenue apportionment based solely on cost of serving the various classes, with no consideration of any other factors.

[1206] *See* Ex. OAG-10 at 38, Table 6 and 40, Table 7 (Scharber Surrebuttal).

[1207] *In re Application of Minn. Power for Authority to Increase Elec. Serv. Rates in Minn.*, MPUC Docket No. E-001/GR-08-415, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 63 (May 4, 2009) (eDockets No. 20095-37158-01) [hereinafter MP 2008 Rate Case Order]; *See also St. Paul Area Chamber of Com. v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 357 (Minn. 1977); Minn. Stat. § 216B.16, subd. 15; Xcel 2021 Rate Case Order at 111.

[1208] Ex. Xcel-77 at 6 (Paluck Rebuttal).

1110. The OAG ultimately agreed that different revenue apportionments for the 2025 Test Year and 2026 Plan year were appropriate, as reflected in the OAG's recommended apportionment.[1209]

1111. The Department, primarily relied on previous Commission decisions which established only one revenue requirement for a MYRP.[1210]

1112. The Commission should adopt different the different revenue apportionments recommended by the OAG for the 2025 Test Year and 2026 Plan Year.

B. Residential Customer and Small Commercial Customer Charges

1113. Most customer classes have a multi-part rate that includes an energy rate based on usage and a monthly fixed charge. The fixed charge is referred to as the customer charge. Residential and small commercial customers currently pay a customer charge of $6.00 per month. The Company proposed to increase the customer charge to $11.00.[1211]

1114. The Company asserts that its customer charge is designed to reflect pricing that is accurate and fair for all customers. The proposed customer charge is intended to recover a larger portion of customer-related costs and fixed costs.[1212] According to the Company's Hybrid Minimum System CCOSS, customer-related costs are approximately $24.00 per month. The Company proposed an increase such that approximately 45 percent of customer related costs, according to Xcel's model, would be recovered through the customer charge.[1213]

1115. The Company also argued that a customer charge of $11.00 would be consistent with previously established customer charges, accounting for inflation. The customer charge set in December 2013, adjusted for inflation, would be approximately $11.00 by the end of 2025.[1214] In addition, the Company asserted that an $11.00 customer charge would maintain the traditional ratio between the energy charge and customer charge. In the past, this ratio had been approximately 6.00, but with a $6.00 customer charge it would increase to 9.93, indicating that more cost is being recovered through the usage charge.[1215] Further, the Company noted that a customer charge of $6.00 is lower than 90 percent of other utilities nationally, while an customer charge of $11.00 would still be lower than average nationally.[1216] Finally, the Company noted that its current residential and small commercial customer charge is out-of-step with the other investor-owned electric utilities in Minnesota. Minnesota Power currently

[1209] Ex. OAG-10 at 38, 43.
[1210] Ex. DOC-19 at 24-25 (Bahn Direct); Ex. OAG-8 at 45 (Scharber Direct).
[1211] Ex. Xcel-76 at 14-16 (Paluck Direct).
[1212] Ex. Xcel-76 at 14-16 (Paluck Direct).
[1213] Ex. Xcel-76 at 16, Table 6 (Paluck Direct).
[1214] Ex. Xcel-76 at 17, Figure 1 (Paluck Direct).
[1215] Ex. Xcel-76 at 18, Table 7 (Paluck Direct).
[1216] Ex. Xcel-76 at 20, Figure 2 (Paluck Direct).

has a residential customer charge of $9.00, and Otter Tail Power Company has a residential customer charge of $10.75.[1217]

1116. The Company argued that it is important to appropriately balance fixed and usage charges in order to produce economically efficient rates. The Company noted that a low fixed charge requires a higher usage rate, which increases rate impacts on customers with low-income, high-usage customers, customers with large families, or customers that have switched to electric heat.[1218] The Company noted that artificially high usage rates, resulting from low customer charges, could discourage customers from considering transportation and heating electrification.[1219]

1117. The OAG opposes this increase, arguing that the "customer-related costs" that Xcel points to for its proposed increase include a variety of costs beyond those recommended by rate design theorists, who generally agree that customer charges should be set as the costs of metering and billing along with costs associated with "taking on another customer."[1220] The OAG also posits that including only marginal costs aligns with the NARUC Manual and is the established methodology in other jurisdictions including Connecticut and Texas.[1221]

1118. The OAG estimated customer-specific expenses and assets to include: costs related to meters, services, meter-reading, customer accounts, and customer assistance.[1222] Even using Xcel's proposed rate of return in this analysis, the OAG estimated that customer-specific costs for the residential class were $5.82 in 2025 and $5.71 in 2026, if Xcel receives its rebuttal revenue requirement.[1223]

1119. The OAG demonstrated that a lower customer charge promotes both intraclass equity and protects low-income customers. Increases in customer charges will raise a low-usage customer's bill by a greater percentage than a high-usage customer's bill.[1224]

1120. Customers with lower incomes tend to use less energy overall, as shown by the Company's data, showing the median monthly electricity usage for households making more than $100,000 was 1.5 to two times higher than households with incomes under $50,000.[1225] An increase in the customer charge would likely result in a greater

[1217] Ex. Xcel-77 at 13 (Paluck Rebuttal).
[1218] Ex. Xcel-77 at 13 (Paluck Rebuttal).
[1219] Ex. Xcel-77 at 13 (Paluck Rebuttal).
[1220] Ex. OAG-8 at 47-48 (Scharber Direct).
[1221] *See* Ex. OAG-8 at 50 (Scharber Direct) (quoting Conn. Gen. Stat. § 16-243bb and *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Subst. R. § 25.344*, Docket No. 22344, Interim Order Establishing Generic Customer Classification and Rate Design at 6 (Tex. Pub. Util. Comm'n Nov. 22, 2000)).
[1222]Ex. OAG-8 at 51 (Scharber Direct); Ex, OAG-10 at 47 (Scharber Surrebuttal).
[1223] Ex. OAG-12 (Scharber Amended Witness Statement) (providing corrected figures following receipt of Xcel corrected information request response).
[1224] Ex. OAG-8 at 54-56 (Scharber Direct).
[1225] Ex. OAG-8 at 58-59, sched. HS-D-19 (Scharber Direct) (citing Xcel's Residential Energy Use Study – Minnesota Market).

percentage increase in the monthly bills of low-income households than those of higher-income households.

1121. The OAG also estimated the impact of Xcel's proposed customer charge on energy conservation. To do this, the OAG estimated the potential energy savings from a lower customer charge using EIA data on price elasticity of demand for Residential electricity.[1226] While the individual savings were not large, due to Xcel's large Residential customer sales, a customer charge of $6.00 versus $11.00 dollars would have potential savings of 50,000 to 100,000 MWh for the Residential class alone.[1227]

1122. The Department also opposed an increase to the customer charge. The Department pointed to a prior Commission decision that stated, "[t]he most powerful tool for heightening conservation-consciousness is maintaining a clear link between consumption and cost. Customer charges, by definition, weaken this link."[1228]

1123. Additionally, the Department pointed to a prior Commission decision that recognized: "customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills."[1229]

1124. The Department further asserted that decoupling can be paired with lower customer charges to send price signals to customers encouraging energy conservation to the maximum reasonable extent.[1230]

1125. The ECC also opposes the customer charge increase, arguing that the Company's proposal would place added cost pressure on residential households across usage levels, raising concerns for low-income and low-usage households that face affordability challenges.[1231]

1126. The OAG, the Department, and ECC have established that no increase to the residential or small commercial customer charges is warranted in this proceeding.

1127. The OAG's cost modeling persuasively demonstrates that Xcel's current $6.00 customer charge is close to the customer-specific costs. It is reasonable to set customer charges based on narrowly-define customer-specific costs because lower customer charges necessarily imply higher usage charges, which in turn incent energy conservation by increasing the financial benefit to customers who reduce usage. The OAG has provided quantitative analysis demonstrating that denying Xcel's request could result in savings of 50,000 to 100,000 MWh for the residential class. Thus, the OAG and

[1226] Ex. OAG-8 at 60 (Scharber Direct).
[1227] Ex. OAG-8 at 60 (Scharber Direct).
[1228] *In re Appl. by CenterPoint Energy for Auth. to Increase Nat. Gas Rates in Minn.*, MPUC Docket No. G-008/GR-04-901, ORDER ACCEPTING & MODIFYING SETTLEMENT & REQUIRING COMPLIANCE FILING at 8 (June 8, 2005) (eDocket No. 2112919) [hereinafter CenterPoint 2004 Rate Case Order].
[1229] Xcel 2021 Rate Case Order at 116-17.
[1230] Ex. DOC 19 at 10-11 (Bahn Direct).
[1231] Ex. ECC-1 at 2-3 (Shardlow Direct).

Department's recommendation would comply with the statutory requirement to set rates to encourage energy conservation to the maximum reasonable extent.[1232]

1128. Further, the OAG has demonstrated that an increase to the customer charge is likely to more significantly impact low-income customers.

1129. The Commission should deny the Company's request to increase its customer charge for the residential and small commercial classes.

C. Residential Arrears Management Program (RAMP)

1130. In the Company's 2023 Safety, Reliability and Service Quality Annual Report docket, the Commission ordered Xcel to propose a program to use the interest payments from residential late payment fees to mitigate costs for low-income customers. The relevant Commission Order Point states that:

> Xcel must file in supplemental direct testimony to its rate case filed November 1, 2024 in Docket E002/GR-24-320 a program similar to its offering in Colorado where interest payments and fees from late bill payments are donated to low-income customer assistance programs or the elimination of late fees and interest.[1233]

1131. The Company proposed the RAMP, designed to address customer arrears and thereby reduce energy burden and the potential for service disconnection. As in the Colorado program, the Company proposed funding RAMP by using residential late payment fees collected from customers, which are currently used to offset the revenue requirement in a rate case. These fees would then be applied in a pre-determined credit amount to eligible customers with past due balances to mitigate credit activity and potential disconnection of service.[1234]

1132. RAMP would be available to any residential customer who (1) has an active account with Xcel in the State of Minnesota, (2) can self-attest that their income is at or below 80 percent of the established Area Median Income for their county and household size, (3) has not qualified for or received Energy Assistance Program (EAP) benefits from the Department of Commerce, and (4) has a past due balance of $300 or more, as long as funds remain available.[1235]

1133. The Company estimated that residential customers will pay $6.1 million in late payment fees in 2025 and $5.8 million in 2026. The Company explained that, although this number varies annually, the Company's estimates are a viable approximation of what the Company might anticipate to collect each year. The Company proposed to calculate the total amount of residential late payment fees and divide that

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[1232] Minn. Stat. § 216B.03 (2024).
[1233] *In the Matter of Xcel Energy's 2023 Safety, Reliability and Service Quality Annual Report*, MPUC Docket No. E002/M-24-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS at Order Point No. 33 (Jan. 13, 2025).
[1234] Xcel-39 at 3-4 (Lindgren Supplemental Direct).
[1235] Xcel-39 at 3 (Lindgren Supplemental Direct).

total by the number of customers with an active account with Xcel in Minnesota, and meeting the enrollment criteria above, to derive the one-time benefit amount that each customer could receive. The program would be administered by Xcel to be as cost-effective as possible. The Company estimated a need for up to five percent of the late payment fee revenues to fund RAMP administration, including outreach to potentially qualifying customers and staffing to administer the program, consistent with administration costs of similar programs in Minnesota and Colorado.[1236]

1134. The Company originally proposed to dedicate the entirety of its projected 2025 Test Year and 2026 Plan Year late payment fee revenue to RAMP, increasing its revenue requirement accordingly.[1237]

1135. The Department recommended approval of RAMP with six modifications: (1) Eligible customers must be on a payment plan arrangement with Xcel; (2) Xcel will reach out to customers who are not on a payment plan arrangement but who are eligible to initiate payment plan arrangement with customer; (3) Customers enrolled in the program would be eligible for the elimination of all late fees applied to the past due accounts after the customer has enrolled in the payment arrangement schedule; (4) RAMP shall not be funded for 2025; (5) RAMP shall be funded for 2026 up to 50 percent of the total residential late fee operating revenues for 2026, up to $2.9 million; and (6) Xcel Energy shall provide annual program status reports that must include eight criteria to assess customer participation, program spending, and program effectiveness.[1238]

1136. ECC supports the Department's proposed modifications.[1239]

1137. CUB opposed RAMP and instead recommended that the Commission require the Company to waive late payment fees for all residential customers, as addressed previously. As it relates to RAMP, CUB argued that customers must have arrears of $300 or more to qualify for RAMP, and thus those customers must pay late fees before they receive RAMP assistance, harming the customers the program proposes to support. In the alternative, CUB recommended that late payment fees be applied to PowerOn instead of being used to create RAMP.[1240]

1138. The Company agreed to five of the six modifications proposed by the Department. Company Witness Howard agreed to the Department's modification to ensure eligible customers are placed on a payment plan arrangement or budget billing, at the customer's discretion, but noted that since the purpose of RAMP is to avoid disconnection by applying late fee payments towards the elimination of past due balances of low-income customers, many customers may have no need for a payment plan. If the amount of RAMP funds allocated to a customer does not eliminate that customer's

[1236] Xcel-39 at 4-6 (Lindgren Supplemental Direct).
[1237] Ex. Xcel-18 at 7-8 and Schedules 11-12 (Halama Supplemental Direct). Recommendations regarding the revenue requirement impacts of this proposal were addressed in a previous section of this Report.
[1238] Ex. DOC-20 at 22-23 (Bahn Surrebuttal).
[1239] Ex. ECC-2 at 4-5 (Shardlow Surrebuttal).
[1240] Ex. CUB-3 at 14-15 (Levenson-Falk Direct); Ex. CUB-8 at 21-22 (Levenson-Falk Surrebuttal).

arrears, the Company agreed to ensure that customer is enrolled in a payment plan or budget billing.[1241] The Department's recommendation to fund RAMP at 50 percent of residential late fee operating revenues for 2026 was addressed and rejected in an earlier section of this Report.

1139. The Company also agreed to remove late fees as part of the RAMP enrollment process, to retain 2025 late payment fees as an offset to the revenue requirement, and to provide an annual program status report including the Department's proposed criteria.[1242]

1140. In response to CUB, the Company noted that the Commission ordered Xcel to propose a program to mitigate costs for low-income customers, and RAMP achieves that goal. The Company argued that RAMP would help customers reduce arrears year-round, in particular during summer months when the EAP program is closed and customers are more likely to experience a disconnection of service. RAMP's design would extend assistance to customers with income up to 80 percent of the Area Median Income, which for many counties is substantially higher than the PowerOn threshold of 50 percent of State Median Income, and would provide assistance to customers with income above the PowerOn threshold but who still have high arrears and are struggling to avoid disconnection.[1243]

1141. The Company's proposal to implement the RAMP program, along with the accepted Department modifications, is reasonable and comports with the requirements set forth in the Company's 2023 Safety, Reliability and Service Quality Annual Report docket. Further, the Company's agreement to waive late fees adequately addresses CUB's concerns about customers needing to pay late fees in order to remain eligible for the program.

1142. The Commission should adopt the Company's proposal and the Department's modifications, except that the Commission should allow the Company to fund the RAMP program with all 2026 late payment fee revenue.

D. Low-Income Discount Rate

1143. The Joint Intervenors proposed a study leading to the creation of a universal low-income rate that would apply to all low-income customers. The Joint Intervenors argued that the Company's affordability programs do not reach all customers who are low-income or have a high energy burden and are inadequate to provide the needed support to low-income customers. The Joint Intervenors estimated that a universal low-income rate that would apply to all low-income customers would have an annual cost of $100 million to provide a direct disbursement to every household below 200 percent of

[1241] Ex. Xcel-81 at 10-11 (Howard Rebuttal).
[1242] Ex. Xcel-81 at 11-12 (Howard Rebuttal).
[1243] Ex. Xcel-71 at 29-31 (Martin Rebuttal).

the Federal Poverty Level to lower their electricity bills sufficient to reduce those customers' energy burden to six percent.[1244]

1144. In support of the proposal, the Joint Intervenors argued that the U.S. Department of Energy's Low-Income Energy Affordability Data (LEAD) tool estimates that 13 percent of the Company's residential customers live in a census tract with average energy burden above 6 percent. The Joint Intervenors estimated that 300,000 of the Company's customers could be considered low-income, and of which 150,000 also have a high energy burden, noting that "[t]hese figures are rough approximations . . . and should be more carefully estimated with customer research more specifically calibrated to the Company's customer base." Witness Chan argued that because the Company reported 69,700 customers participating in an affordability program in 2023, the Company's affordability programs are insufficient to meet low-income customers' needs.[1245]

1145. The Joint Intervenors argued that the Commission could justify a low-income rate under its mandate to consider customer ability to pay under Minn. Stat. § 216B.16, subd. 15(a) and its obligation to set equitable rates under Minn. Stat. § 216B.03.[1246]

1146. The Company asserted that the LEAD tool was not the best means to estimate low-income customers, noting that the LEAD tool is a useful general resource to evaluate energy costs and other demographic data but is not designed to precisely quantify the energy burden specific to Xcel's customers. The U.S. Department of Energy states that the LEAD tool is "an online, interactive platform that allows users to explore and compare various national, state, city, or county profiles with ***estimated***, locally specific low-to-moderate income household energy characteristics." The Department of Energy cautions that the LEAD tool "is not meant to be used as a substitute for program or policy evaluations, or to track the impact of a program or policy. It *should not* be used as a program management tool, and it will not provide information on year to year changes because it is based on five year running averages."[1247]

1147. The Company disputed the Joint Intervenors' argument that the existing affordability programs are not and cannot be adequate to address existing affordability challenges. The Company demonstrated that estimates of affordability program enrollment were incomplete and significantly undercounted the number of customers enrolled in those programs. The Company produced data showing that 119,091 customers were enrolled in affordability programs in 2023-2024.[1248]

1148. The Company asserted that it anticipated customer enrollment in these programs to increase further. Enrollment in PowerOn, which previously grew by over 100 percent over the last five years, is expected to further increase as a result of the

[1244] Ex. JIN-2 at 29-31, 37 (Chan Direct).
[1245] Ex. JIN-2 at 31-32 and note 45 (Chan Direct).
[1246] JIN Initial Brief at 16.
[1247] Ex. Xcel-71 at 55 (Martin Rebuttal) (quoting Low-Income Energy Affordability Data (LEAD) Tool Fact Sheet, https://www.energy.gov/sites/default/files/2024-07/lead-tool-factsheet_072624.pdf (emphasis added)).
[1248] Ex. Xcel-71 at 56 and Table 1 (Martin Rebuttal).

Company's support for ECC's proposal to auto-enroll electric-only customers meeting the program criteria. Similarly, the Low Usage Affordability Credit (LUAC), approved in the Company's last rate case, increased its enrollment from 14,459 at the end of 2024 to approximately 19,500 as of October 2025, and the Company estimates that 87,000 customers could receive discounts through LUAC in the coming years. The Company is exploring flexibilities created by recent amendments to the statutory definition of "low-income household" to extend self-attestation of income and categorical eligibility to other affordability programs to further drive enrollment.[1249]

1149. The Company also argued that the Joint Intervenors' proposal ignores the distinction between bill credits and discounted base rates, the latter of which do not address the costs of fuel and other charges on a customer's bill. The Company asserts that bill credits are consistent with Minn. Stat. § 216B.03, which requires that "rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of customer." The Company stated that bill credits are a preferential method to provide assistance because the Company can ensure that it is not charging different rates to different customers that could be viewed as discriminatory.[1250]

1150. The Department also raised concerns with the Joint Intervenors proposed universal low-income rate. Specifically, the Department noted that the Joint Intervenors' estimate that $100 million would be needed to ensure all energy-burdened Xcel customers would have their energy costs reduced to less than six percent of their income relies on several unrealistic assumptions, including that there would be no benefits provided to technically ineligible households (leakage) and that $100 million would only provide $333 annually to eligible households when assuming 300,000 eligible customers. The Department asserts that this amount would be insufficient to notably impact the energy burdens of the lowest income customers or the costs of implementing the rate would need to be significantly higher.[1251]

1151. The Company offers multiple rates without evidence of a differential cost of service, including specifically the LUAC rate discount.[1252] Moreover, the Company recognized that its proposed expansion of LUAC "does not have a cost-of-service basis."[1253] In addition, the Company offers a Business Incentive and Sustainability (BIS) Rider and Competitive Response Rider (CRR), which it has acknowledged "are justified not through the lens of cost to serve but the additional benefits these customers bring to existing customers by reducing other customers' revenue requirements."[1254]

1152. Joint Intervenors argued that the Company's rationale for the BIS Rider and CRR applies to a universal low-income rate, stating that "differentiating residential rates

[1249] Ex. Xcel-71 at 57 (Martin Rebuttal).
[1250] Ex. Xcel-71 at 60-61 (Martin Rebuttal)
[1251] Ex. DOC-22 at 4 (Schmitz Rebuttal).
[1252] Ex. JIN-5 at 25 (Chan Surrebuttal).
[1253] Ex. JIN-5 at 25 (Chan Surrebuttal).
[1254] Ex. JIN-5 at 26 (Chan Surrebuttal).

can meaningfully reduce the bad debt expense of utilities, providing a ratepayer benefit to all customers."[1255]

1153. Fundamentally, there are two disputes on this issue. First, there is a question as to whether a low-income discount rate would be lawful or would constitute an impermissibly discriminatory rate. Second, assuming the legality of such a rate, there is the substantive question of whether the Commission should initiate a process to develop a low-income rate.

1154. Certainly, there are fair concerns as to whether treating a subset of residential customers differently by offering a low-income rate would be unreasonable and discriminatory, in violation of Minn. Stat. § 216B.03. This issue is, however, more nuanced than the Company's argument implies.

1155. Minn. Stat. § 216B.03 does prohibit rates that are "unreasonably preferential, unreasonably prejudicial, or discriminatory" and requires them to be "sufficient, equitable, and consistent in application to a class of consumers." Nothing in Minn. Stat. § 216B.03, however, requires class distinctions to be made solely based on the cost of serving customers. Further, as previously discussed, "ability to pay" is a well-established factor for the Commission to consider when making determinations about rate design.

1156. It could be argued that low-income customers are sufficiently distinct from other residential customers to warrant being considered a distinct class. But it is not necessary to go that far to establish the legality of a low-income rate.

1157. The Joint Intervenors accurately identify the BIS Rider and CRR as examples of rates that treat customers differently for reasons other than cost-causation on the system. Just as those rates are justified by system-wide benefits, a low-income rate that reduced bad debt expense would provide a benefit to the system. Such a rate is not categorically prohibited by Minn. Stat. § 216B.03.

1158. As the Joint Intervenors' proposal is for a process to develop a rate, and not to implement a specific, fully-developed proposal, it is not possible to assess on this record whether any specific proposal would comport with § 216B.03. But nor is it necessary to do so to consider the merits of initiating a process to develop such a rate.

1159. Turning to whether the Commission should initiate a process, the Company and the Department raise fair concerns about the feasibility and adequacy of a potential low-income rate. These concerns are worthy of consideration, but the Joint Intervenors have also established that there is a need to provide additional assistance to low-income customers.

[1255] Ex. JIN-5 at 26 (Chan Surrebuttal).

1160. Initiating a process to develop a low-income rate would allow the parties' arguments about the merits of a low-income rate to be tested and refined against more concrete proposals.

1161. The Commission should initiate a process to develop a potential low-income rate. In doing so, the Commission should not predetermine that implementing such a rate would be appropriate.[1256] Rather, the process should result in a proposal that can be evaluated based on its specific parameters and characteristics, including thorough consideration of the arguments raised in this proceeding. Further, the process should evaluate whether any specific proposal comports with Minn. Stat. § 216B.03.

E. Street Lighting

1162. The Street Lighting class has a different rate design than other classes. In general, Street Lighting customers pay a monthly charge based on the number of lights at particular wattages, with lower wattage lights having a lower monthly cost.[1257]

1163. In the Company's last rate case, the Company reached a settlement with SRA regarding street lighting rates and rate design. The agreement included a provision requiring the Company to "revise the rate design workpapers to more clearly identify direct assignment of costs to streetlighting customers, and system demand and energy costs."[1258] Company Witness Paluck explained that "[b]ased on the discussions that led to the settlement, the Company interpreted this language as an agreement to simplify and make the rate code A30 rate design work papers more transparent." As a result, the Company modified the rate design for Street Lighting for this case. [1259]

1164. SRA argues that cost-based adjustment to the underground premium for rate A30 is necessary to better align the rates for underground fed streetlighting to actual costs and to help ease the magnitude of the proposed rate increase for low wattage overhead Light Emitting Diode (LED) fixtures on rate A30 that would result if Xcel's rate design were adopted as proposed.[1260]

1165. SRA argues that setting the underground premium at 55 percent of Xcel's calculated value, instead of the 50 percent proposed by the Company, will partially ameliorate the rate shock for overhead low wattage LED A30 customers.[1261]

1166. The way that Street Lighting rates are designed can result in larger percentage increases for low wattage classes. When the monthly cost to increase street

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[1256] Put differently, the Commission should not decide here that it is reasonable and appropriate to implement a low-income rate. That determination should remain an open question in the process recommended by the Administrative Law Judge.
[1257] Ex. SRA-3 at 6, Table 4 (Bride Rebuttal).
[1258] *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,* MPUC Docket No. E002/GR-21-630, JOINT STIPULATION OF SUBURBAN RATE AUTHORITY AND XCEL ENERGY at 2 (Mar. 24, 2023).
[1259] Ex. Xcel-77 at 20-21 (Paluck Rebuttal).
[1260] Ex. SRA-4 at 4-8 (Bride Surrebuttal).
[1261] Ex. SRA-5 at 6-8 (Bride Surrebuttal – NOT PUBLIC).

lights increases, it could result in a certain dollar-amount increase to the monthly charge. The percentage increase for a low wattage rate, like A30, would be greater than other wattages even though the actual monthly impact is the same. In the past, the A30 rate design had unique features to mitigate this impact, but the Company had removed them because the settlement in the last case required simplification of the A30 rate design.[1262]

1167. The Company explained that concerns of rate shock for Street Lighting customers may be overstated. Most Street Lighting customers have a portfolio of wattages, only some of which is comprised of low-wattage A30 rates. As a result, even if the A30 rates have a higher percentage increase, the higher wattage rates would have a lower percentage increase, resulting in a moderated impact to the overall bill.[1263]

1168. The Company argued that SRA's proposed change was not needed because there was not a need to address rate shock. The Company also noted that SRA had not raised this recommendation until Surrebuttal, which limited the ability of the Company and other parties to analyze and respond. The Company suggested that the SRA could raise the issue in a future rate proceeding.[1264]

1169. An adjustment to Street Lighting rate design is not warranted at this time. The basis for rate design, as it relates to street lighting, is based on the cost of providing service to Street Lighting customers. Further, rate shock should be considered in the context of an overall bill impact. As low wattage street lights are not a class of ratepayer, but rather part of customers' portfolios of street lights, the record does not contain sufficient support that rate shock concerns warrant a departure from the Company's cost-based proposal. Also, adopting a new rate design proposal offered for the first time in Surrebuttal testimony could lead to unforeseen consequences as parties did not have an opportunity to evaluate the SRA's proposal through further rounds of testimony.

F. Super Large Customer Tariff

1170. In the Company's most recent IRP, the Commission ordered the Company to "make a filing in a new docket with a proposal for development of a new rate class or sub-class and tariff for super-large customers."[1265] Before making this decision, the Commission deliberated whether to combine these issues into this rate proceeding and decided not to do so.[1266]

[1262] Ex. Xcel-78 at 4 (Paluck Surrebuttal).
[1263] Ex. Xcel-77 at 23 (Paluck Rebuttal). The SRA asserts that this would not be true for "a municipality with a majority of overhead streetlights." SRA Reply Brief at 12. The SRA, however, points to no analysis demonstrating how many such customers there are, or quantifying the overall rate impact on such customers.
[1264] Xcel Initial Brief at 282-83.
[1265] *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. E-002/RP-24-67, ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS at Order Point No. 32 (Apr. 21, 2025).
[1266] *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, Docket No. E-002/RP-24-67, Decision Options – Commissioner Sullivan at 1 (Feb. 19, 2025).

1171. That proposal was filed on July 16, 2025 in Docket No. E-002/M-25-289. 13 stakeholders, several of whom are not parties to this case, have filed comments in that proceeding.[1267]

1172. XLI and the Joint Intervenors recommend that several issues related to the super-large tariff be decided in this rate case.

1173. XLI recommends that the new tariff should create a new class, rather than a sub-class. XLI also recommends that the allocation for incremental revenues should be changed.[1268]

1174. XLI and the Joint Intervenors each recommend that the Company be ordered to file a new CCOSS to incorporate the tariff.[1269]

1175. The Company stated that it could not do so because the tariff has not yet been approved, there are no billing determinants for customers with which to design a CCOSS, and that even if this data existed it would take several months of work to create a new CCOSS. The Company also stated that the proposed compliance CCOSS would have no impact on the 2025 Test Year or 2026 Plan Year because there are not anticipated to be any customers eligible for the tariff in those years, which means there would be no costs, revenues, or incremental revenues.[1270]

1176. Adjudication of the merits of this issue is not appropriate here. As a practical matter, there is no record evidence that the Company will receive revenues from super-large customers in either the 2025 Test Year or 2026 Plan Year. Thus, a revised CCOSS addressing those customers will not impact the rate determinations made in this proceeding.

1177. A separate proceeding in Docket No. E-002/M-25-289 is addressing the specific issue of super-large customers. The Commission is in a better position to make reasoned decisions addressing this issue in that more specific proceeding, especially as the proposal for a new CCOSS was first made in Surrebuttal testimony, depriving other interested parties a meaningful opportunity to develop the issue. Further, as a matter of procedural fairness, several stakeholders not party to this case have actively participated in Docket No. E-002/M-25-289. Accordingly, making a decision in this proceeding would unfairly exclude those parties from participating in the process.

1178. For these reasons, the Commission should decline to take action on XLI's proposal for a new CCOSS and instead address this issue in Docket No. E-002/M-25-289. Certainly, in that proceeding, the Commission may order future filings and take other appropriate action related to super-large customers.

[1267] Ex. Xcel-98 at 2 (Paluck Responsive).
[1268] Ex. XLI-9 at 21-24 (Ly Surrebuttal).
[1269] Ex. XLI-9 at 21-24 (Ly Surrebuttal); Joint Intervenors Initial Brief at 48.
[1270] Ex. Xcel-98 at 4-6 (Paluck Responsive).

G. Disconnection Moratorium and Rate Study Alternative

1179. The Joint Intervenors recommended that the Commission implement a moratorium on disconnections for all customers based on the claim that disconnections do not serve any purpose. In the alternative, the Joint Intervenors recommend that the Commission authorize a randomized control trial (RCT) to test the impact of disconnection practices by testing different ramifications for real Xcel customers that are otherwise subject to disconnection.[1271]

1. Disconnection Moratorium

1180. In the first seven months of 2025, Xcel disconnected 2.4-times more customers than the average year-to-date number of disconnections in the 16 years prior to the COVID-19 pandemic.[1272]

1181. The Joint Intervenors pointed to a study showing that,

> a 10 percentage point increase in a neighborhood's population of people of color is associated with a 17-22 percent increase in the rate of disconnections across a range of models that control for other socioeconomic factors (including median income, poverty level, unemployment rate, population density, housing tenure, year, county, and housing age).[1273]

1182. Based on these observations, the Joint Intervenors recommended that the Commission establish an indefinite moratorium on disconnections until the company can demonstrate that the benefits of disconnection outweigh the costs.[1274]

1183. The Company argued that disconnection moratoria negatively impacted arrearages and negatively impacted customers in the long run by eliminating opportunities for the Company to connect with customers and make them aware of affordability programs and payment plans, in addition to making some customers ineligible for some forms of crisis assistance that require a disconnection notice.[1275]

1184. Record evidence shows that the COVID-19 pandemic disconnection moratorium from March 2020 through July 2021 caused residential arrearages to nearly double, from approximately $44 million at the end of 2019 to approximately $85 million at the beginning of 2022. Total residential past-due balances similarly grew from $57 million to $81 million.[1276]

[1271] Ex. JIN-2 at 3 (Chan Direct); Ex. JIN-3 at 13-16 (Chan Rebuttal).
[1272] Ex. JIN-2 at 5 (Chan Direct).
[1273] Ex. JIN-2 at 6 (Chan Direct) (citing Ex. JIN-2 at Attachment 2, Pradhan, Bhavin and Gabriel Chan. 2024. "Minnesota's energy paradox: Household energy insecurity in the face of racial and economic disparities" *The Electricity Journal* 37(6): 107423, at 7-8.).
[1274] JIN Initial Brief at 20-21.
[1275] Ex. Xcel-71 at 50 (Martin Rebuttal).
[1276] Ex. Xcel-71 at 49 (Martin Rebuttal).

1185. The Joint Intervenors argued that other disruptions to employment and income impacted bad debt during the COVID-19 pandemic, and that debt levels have not changed with increased disconnection rates since that time.[1277]

1186. Minn. R. 7820.1000 explicitly permits Xcel to disconnect service to customers for failure to pay. The rule does not impose any requirement that a utility demonstrate that disconnections serve a public purpose.

1187. While the record is mixed on the substantive merits as to the efficacy of payment-related disconnections, those arguments do not control this issue. The Company is unambiguously permitted to disconnect customers for failing to pay their bill for utility service under Minn. R. 7820.1000 so long as it complies with the notice requirements of Minn. R. 7820.2400. The Commission should not impose a disconnection moratorium on the Company.

2. Randomized Control Trial

1188. As an alternative to the disconnection moratorium, the Joint Intervenors recommended that the Commission order the Company to conduct an RCT to evaluate the impact of disconnections on late payments and arrears.[1278]

1189. The Joint Intervenors state that an RCT is an ethical framework used to evaluate causal inference in high-stakes processes.[1279] The Joint Intervenors believe that an RCT would provide the evidence necessary to make informed decisions about disconnection practices.[1280]

1190. Minn. Stat. § 216B.07 prohibits a utility from granting any unreasonable preference or advantage or subjecting a person to any unreasonable prejudice or disadvantage as to utility rates or services.

1191. The Commission should decline to order an RCT for two reasons. First, doing so would require the Company to treat similarly situated customers differently with respect to disconnections based only on random selection. This would violate Minn. Stat. § 216B.07. It is of no consequence that no customer would be worse off during the RCT, because the statute prohibits both unreasonable prejudices or advantages.

1192. Second, as Minn. R. 7820.1000 unambiguously permits payment-related disconnections without regard to the presence or absence of evidence as to the efficacy of disconnections, the benefits of such a study would be limited. Even if the evidence showed that payment-related disconnections did not effectively incent payment of utility bills, the disconnections are still permitted by rule. Certainly, such a study could have societal value and be relevant in another proceeding were the Commission to consider

[1277] Ex. JIN-2 at 8 (Chan Direct); *see also* Ex. JIN-5 at 5-7 (Chan Surrebuttal).
[1278] JIN-3 at 14 (Chan Rebuttal).
[1279] Ex. JIN-3 at 6, 17 (Chan Rebuttal).
[1280] Ex. JIN-2 at 6-8 (Chan Direct); Ex. JIN-3 at 7 (Chan Rebuttal).

amending Minn. R. 7820.1000, but it is not appropriate to order such a study in this rate case.

H. Statutory Affordability Goals/Alternate Rate Proposal

1193. It is the energy policy of the State that retail electricity rates for each customer class be at least five percent below the national average.[1281]

1194. Responding to this state policy goal in the Company's last rate case, the Commission ordered that:

> 77. Xcel must, in the advanced rate design docket, include an analysis on its compliance with Minnesota's goal for rates to be 5 percent lower than the national average, Minn. Stat. § 216C.05, subd. 2(4), including a minimum of the following issues:
>
> a. The impact of its proposed rate increase on compliance with the statutory goal;
>
> b. The impact of conservation on bills and its relevance to the statutory goal;
>
> c. Strategies that could be employed to improve compliance with the statutory goal; and,
>
> d. An alternate rate increase proposal that would be in compliance with the statutory goal, and Xcel's justifications for proposing any rate increases in excess of the alternate plan.[1282]

1195. The Company addressed this Order Point 77 via a March 31, 2025 compliance filing in Docket No. E002/CI-24-115. The Company concluded that its compliance with the Commission's order was justified because its "adjusted retail average rate based on what customers actually pay for electric service was 6.8 percent lower than the national system average rate" and therefore "the Company has not developed an alternative rate proposal."[1283]

1196. The Joint Intervenors criticized the Company's analysis and argued that the compliance filing did not comply with the statutory goal or Order Point 77, in that it: (1) relied on a baseline comparison of the Company's rates to rates of only other investor-owned utilities, rather than the rates of all utilities as required by statute; (2) made adjustments to its average rates to account for selected statutorily required programs,

[1281] Minn. Stat. § 216C.05, subd. 2(4).
[1282] Xcel 2021 Rate Case Order at 161, Order Point 77.
[1283] Ex. JIN-2 at 13 (Chan Direct).

which is not expected by statute; and (3) compared the average rate across classes, rather than the rates for each customer class as required by statute.[1284]

1197. The Joint Intervenors presented analysis using unadjusted rates for all customers and for only residential customers, and compared Xcel's rates to the U.S. average rates, the average retail utility rates, and the average investor-owned utility rates. This analysis showed that the Company's rates are higher than the national average.[1285]

1198. The Company argued that "trends in the Company's rate cases and rates are largely driven by reductions in sales," and pointed to Xcel's successful conservation and energy-efficiency programs as a cause for these reductions.[1286] At the same time, Xcel stated that these declining sales do not lead to lower system costs because the Company continues to experience customer count growth larger than other utilities.[1287]

1199. Xcel argues that average bills are a more relevant comparison point for comparing its rate affordability to other utilities[1288] and that increasing rates can be a sign that conservation programs are operating effectively.[1289]

1200. The Joint Intervenors argued that the filing made in Docket No E-002/CI-24-115 was not compliant with the Commission's Order in Xcel's last rate case and recommended the Commission again require the Company to develop and file, in this docket or another docket such as Docket No. E002/CI-24-115 (advanced rate design docket), an alternate rate proposal that is in compliance with the affordability goal in Minn. Stat. § 216C.05, subd. 2(4), and provide its justifications for proposing rate increases in excess of the alternate proposal.[1290]

1201. As an initial matter, it is not appropriate to make a finding here as to whether the compliance filing in Docket No. E002/CI-24-115 comports with the Commission's Order in Xcel's last rate case. Whether or not a filing in a docket not before the Court complies with an order in a different proceeding that is also not presently before the Court is outside the scope of this proceeding.

1202. The parties provide different perspectives on the merits of evaluating affordability by focusing on retail rates versus total bills. While there are principled reasons for favoring either metric over the other, this debate is irrelevant when it comes to evaluating whether a utility's rates meet the goal articulated in Minn. Stat. § 216C.05, subd. 2(4). That goal is clearly expressed in terms of "retail electricity *rates* for *each customer class*."[1291] It is not for the parties to decide whether the statutory affordability

[1284] Ex. JIN-2 at 15-17 (Chan Direct).
[1285] Ex. JIN-2 at 18-20 (Chan Direct).
[1286] Ex. Xcel-16 at 5 (Liberkowski Rebuttal).
[1287] Ex. Xcel-16 at 9 (Liberkowski Rebuttal).
[1288] Ex. Xcel-71 at 51-52 (Martin Rebuttal).
[1289] Ex. Xcel-77 at 24-27 (Paluck Rebuttal)
[1290] Ex. JIN-2 at 3, 21-22 (Chan Direct).
[1291] Minn. Stat. § 216C.05, subd. 2(4) (emphasis added).

goal should be expressed in terms of bills or rates; the Legislature has already answered that question.

1203. The Joint Intervenors' analysis shows that, when evaluating retail rates per each customer class, Xcel's proposed rates fall short of the statutory affordability goal.

1204. Accordingly, the Commission should order the Company to make a filing consistent with the Joint Intervenors' recommendation. In doing so, the Commission should make clear that the "statutory goal" is to be understood in terms of retail rates, and not total bills, for each customer class.

X. Other Recommendations and Issues

A. Cost of Long-Term Debt and Capital Structure in Future Rate Cases

1205. The Department argued that Xcel did not address whether its proposed capital structure minimizes costs. Instead, the Company offered anecdotal examples of how its existing capital structure reduced borrowing costs for specific debt issuances relative to other utilities.[1292] The Department believes this information fails to address the trade-offs between the uses of debt and equity, or whether its proposed capital structure optimizes the total capital cost.[1293]

1206. In reviewing Xcel's proposal, the Department concluded that Xcel's capital structure may include a higher-than-optimal level cost of capital. The Department reached this conclusion by comparing Xcel's proposed capital structure with the capital structures of the companies in the Department's proxy group. Xcel's capital structure relied more heavily on equity and less on long-term debt than all 16 other proxy companies.[1294]

1207. The Department also expressed concerns that a credit downgrade, due to indirect exposure to its sister and parent companies, for NSPM could result in factors external to the Company resulting in higher debt costs. [1295]

1208. The Department recommended that the Commission, in future rate cases, require Xcel to (1) demonstrate that its proposed capital structure is cost-minimizing or reasonably departs from the least cost capital structure in future rate case proceedings and (2) demonstrate that the costs of each debt issuance made since its prior rate case reasonably reflect the risks of NSPM and are not inflated by risks associated with other entities within Xcel Energy, Inc.'s corporate structure.[1296]

1209. The Company opposes the Department's recommendations. Specifically, the Company argues that there is no objectively optimal capital structure, that the company already files information about security issuances, and that the Department's

[1292] Ex. DOC-12 at 23–25 (Addonizio Direct).
[1293] Ex. DOC-12 at 12, 24-25 (Addonizio Direct).
[1294] Ex. DOC-12 at 27-29 (Addonizio Direct).
[1295] Ex. DOC-12 at 35-38 (Addonizio Direct).
[1296] Ex. DOC-12 at 100 (Addonizio Direct).

recommendations would rely on too many assumptions and unprovable counterfactuals to be worthwhile.[1297]

1210. The Department responded by arguing that, as the Company bears the burden to prove the reasonableness of its proposed rate changes under Minn. Stat. § 216B.16, subd. 4, Xcel should be required to provide information sufficient to show that ratepayers are not compensating the Company's investors for risks that ratepayers have nothing to do with.[1298]

1211. The Department's recommendations are reasonable. The Company's approved cost of capital affects a substantial amount of money in its rate cases. As Xcel does not issue its own equity, much of the analysis for setting its cost of capital is based on assumptions and modeling. The information the Department seeks is not unique in this respect. And the Department is correct that Xcel's customers should not pay for risks attributable to the Company's sister and parent companies.

1212. The Commission should order the Company to, in its next rate case, provide the information related to the Company's cost of debt and capital structure requested by the Department.

B. Definition of Energy Justice

1213. The Company stated that equity, energy justice, and environmental justice "are core values for the Company, and we are working to integrate them into every relevant program, plan, and docket."[1299] The Company recommended against adopting a definition of energy justice, in part for procedural justice reasons, stating that because "[e]quity and energy justice are relevant to all utilities that fall under the Commission's jurisdiction and span many different proceedings beyond rate cases."[1300] For this reason, the Company stated that, "[s]hould the Commission seek to formalize definitions of these terms, the Company supports the creation of a broader Commission docket involving all regulated utilities and their stakeholders."[1301]

1214. The Commission has a "working definition" of "equity," drawn from an internal memorandum from the Commission's DEI Committee to Commission Staff:.

> Equity refers to a fair and just, but not necessarily equal, allocation intended to mitigate disparities in benefits and burdens. Equity in a regulatory framework means providing inclusive and equitable service to all customers, so that all customers have equitable opportunities, access, and results, and both benefits and burdens of the provision of energy are fairly

[1297] Ex. Xcel-23 at 13 (Liberkowski Rebuttal).
[1298] Ex. DOC-13 at 42 (Addonizio Surrebuttal).
[1299] Ex. Xcel-70 at 9 (Martin Direct).
[1300] Ex. Xcel-70 at 8 (Martin Direct).
[1301] Ex. Xcel-70 at 8 (Martin Direct).

distributed across all community groups. Some individuals or communities may need different levels of support to gain equitable service.[1302]

1215. Both Xcel and the Department characterized this definition as "adequate for this rate case."[1303]

1216. The Joint Intervenors agreed with the Company that equity and energy justice are relevant to all utilities and other types of cases. For that reason—the wide-reaching importance of these concepts—along with the value of clarity in discussing these terms, the Joint Intervenors recommended that the Commission adopt a definition of energy justice from the Initiative for Energy Justice, explaining that this definition has been well vetted by a respected national organization focused on this topic.[1304]

1217. In the alternative, the Joint Intervenors supported the Company's recommendation to establish a broader proceeding where all utilities and stakeholders may participate.[1305] However, Joint Intervenors stated that, while a broader proceeding would enable broader participation and further procedural justice in that respect, many interested stakeholders may not have the capacity to meaningfully participate in a formal Commission proceeding, which would undermine procedural justice. Therefore, if the Commission adopts this alternative recommendation, Joint Intervenors encouraged the Commission to establish a reasonable timeframe for this proceeding and other procedural guardrails to ensure that less-resourced groups can meaningfully participate. Further, the Joint Intervenors recommended that, in doing so, the Commission should investigate or otherwise engage stakeholders from other state commissions that have already adopted definitions of energy justice to inform this process.[1306]

1218. The Commission should initiate a stakeholder process to develop a formal definition of energy justice. This is an important issue, but also one that could affect many stakeholders and multiple utilities. Xcel is correct that procedural justice warrants a proceeding where other interested parties can participate. The Commission should also consider the Joint Intervenors' parameters to ensure that this proceeding is broadly accessible to interested stakeholders.

C. Energy Affordability and Elimination of Energy Insecurity as a Public Interest

1219. The Joint Intervenors argued that "[t]he principles of energy justice, particularly recognition justice and restorative justice, suggest that access to affordable energy and reducing the number of energy-insecure households should be treated as a public good."[1307]

[1302] Ex. Xcel-70 at 5 (Martin Direct); Ex. Xcel-71 at 7-8 (Martin Rebuttal); Ex. DOC-21 at 6-7 (Hirasuna Direct).
[1303] Ex. DOC-21 at 6-7 (Martin Rebuttal); Ex. Xcel 71 at 7-8 (Hirasuna Direct).
[1304] Ex. JIN-2 at 3, 25 (Chan Direct).
[1305] Ex. JIN-2 at 3, 25 (Chan Direct).
[1306] Ex. JIN-2 at 25 (Chan Direct).
[1307] Ex. JIN-2 at 26 (Chan Direct).

1220. The Joint Intervenors further argued "economic criteria, particularly the ability to pay principle, suggest that when viewed as a public good, the costs of implementing rates that improve affordability should be allocated broadly to customers, including to those with a greater ability to pay."[1308]

1221. Ultimately, the Joint Intervenors recommended that the Commission formally recognize universal energy affordability and the elimination of energy insecurity to be in the public interest. They also recommended that the Commission should allow for the costs of guaranteeing universal affordability, when justified, to be allocated to customers broadly based on energy justice principles.[1309]

1222. The Joint Intervenors raise important concerns about affordability and elimination of energy burden. The record here highlights the inflationary pressure on consumers related not just to electricity and natural gas—where the CPI increased 4.9 percent and 1.5 percent, respectively, from July 2023 to July 2024—but also food, whose CPI increased 2.2. percent.[1310]

1223. The Joint Intervenors are correct that affordability and eliminating energy burden are important regulatory goals. These goals are reflected in this Report's through its consideration of "ability to pay" as one of the factors leading to its recommendation on revenue apportionment, as well as the recommendation that the Commission initiate a new proceeding to evaluate a low-income rate.

1224. No further action is necessary on the Joint Intervenors' recommendation.

D. Wildfire Mitigation and Integrated Distribution Plan

1225. To address concerns about the wildfire mitigation costs discussed earlier, the Joint Intervenors recommended that Xcel:

a. Complete its Minnesota-specific wildfire risk assessment;

b. Conduct a comparative risk analysis that evaluates wildfire risk both (a) in relation to Xcel's other jurisdictions, such as Colorado and Texas, where urgent mitigation investments may be more pressing, and (b) relative to other safety and reliability risks in Minnesota's distribution system;

c. Incorporate those findings into its 2025 IDP or its next IDP as appropriate;

d. Engage stakeholders through the Commission's IDP process; and

[1308] Ex. JIN-2 at 27 (Chan Direct).
[1309] Ex. JIN-2 at 3, 29-30 (Chan Direct).
[1310] Ex. OAG-1 at 27 (Hinderlie Direct).

e. Seek future cost recovery with specific, justified investment proposals supported by its analysis.[1311]

1226. While the earlier resolution of the rate treatment of wildfire mitigation projects is adequate for this proceeding, this is clearly an important issue that will require substantial utility investment in the future.

1227. The Joint Intervenors recommendations are reasonable to ensure that the Commission is able to effectively evaluate additional projects in future planning dockets. The Commission should adopt the Joint Intervenors' recommendation.

CONCLUSIONS OF LAW

1. The Commission and the Administrative Law Judge have jurisdiction to consider this matter under Minn. Stat. § 14.50 and Minn. Stat. §§ 216B.08, .09, .15, and .16 (2024).

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

3. Every rate set by the Commission shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers.[1312]

4. 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 (2024).[1313]

5. The burden of proof is on the public utility to show that a rate change is just and reasonable.[1314] Any doubt as to reasonableness should be resolved in favor of the consumer.[1315]

6. The record supports the resolution of the matters set forth in Xcel's Initial Filing that are uncontested, settled, or resolved. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Rates set in accordance with this Report would be just and reasonable.

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

[1311] Ex. JIN-1 at 20 (Kenworthy Direct).
[1312] Minn. Stat. § 216B.03.
[1313] Minn. Stat. § 216B.03.
[1314] Minn. Stat. § 216B.16, subd. 4.
[1315] Minn. Stat. § 216B.03.

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.

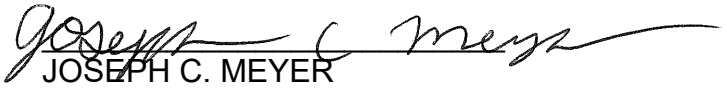
2. The text of the Findings and Conclusions should govern the mathematical and computational aspects of the Findings and Conclusions. The computations should be adjusted so as to conform to the Findings and Conclusions contained in the Report.

3. The Commission should incorporate the agreements made by the parties in the course of this proceeding into its Order.

4. The Commission should adopt the recommendations set forth in the Findings of Fact above.

5. The Commission should order the Company to make further compliance filings regarding rates and charges, rate design decisions, and tariff language necessary to implement the recommendations set forth in this Report.

Dated: April 29, 2026



JOSEPH C. MEYER
Administrative Law Judge

Reported: Shaddix & Associates

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.1275, .2700 (2025), 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:

September 15, 2025, at 6:30 p.m. at Washington County Heritage Center, 1862 Greeley Street, Stillwater, Minnesota;

September 16, 2025, at 11:30 a.m. at St. Cloud Public Library, 1300 West Germain Street, St. Cloud, Minnesota;

September 16, 2025, at 6:00 p.m. via WebEx;

September 17, 2025, at 1:30 p.m. at Battle Creek Recreational Center, 73 Winthrop Street South, Saint Paul, Minnesota;

September 22, 2025, at 6:30 p.m. at Buckham West Senior Center, Anderson Room, 19 Division Street West, Faribault, Minnesota;

September 23, 2025, at 1:30 p.m. via WebEx;

September 23, 2025, at 6:00 p.m. at Edina Library, 5280 Grandview Square, Edina, Minnesota;

September 24, 2025, at 1:30 p.m. at V-3 Center, 701 Plymouth Avenue North, Minneapolis, Minnesota; and

September 25, 2025, at 1:30 p.m. at Prairie Island Community Center, 1158 Island Lake Boulevard, Welch, Minnesota.

Appearances:

James Denniston, Laura Steinhaeuser, and Riley Conlin appeared and spoke on behalf of Xcel;[1316]

Michael Zajicek, Craig Addonizio, Holly Jones, Andrew Bahn, Ashley Uphus, Andrew Golden, Donald Hirrasuna, and Peter Teigland, appeared and spoke on behalf of the Department;

Wendy Raymond, Joey Cherney, Katherine Hinderlie, and Helen Scharber, appeared and spoke on behalf of the OAG;

Andrew Larson, Godwin Ubani, Robert Manning, Christine Pham, Jason Bonnett, and Eric Willette, appeared and spoke on behalf of Commission staff.

[1316] Additional Xcel representatives also attended the public hearings and responded to questions and comments from members of the public.

The public comment period closed on December 30, 2025.[1317] Written comments were filed in the Commission's electronic docket system (eDockets).

SUMMARY OF PUBLIC COMMENTS

1. Over 7,500 public comments were received by the December 30, 2025, deadline set by the Commission, including over 80 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. Several groups of written comments were the same or substantially similar. One group of these comments characterized the proposed rate increases as resulting in ratepayers subsidizing Xcel's executive compensation and shareholder profits and urging Xcel to focus on providing customers choices for renewable energies.[1318] Another group focused on a specific subset of topics: concerns about Xcel's transparency and the safety of its operations; how Xcel shifts the burden of its costs to customers; economic impact and hardship; Xcel reinvesting its profits into the Company; and asking the Commission to reject the rate proposal until Xcel addresses customer concerns.[1319] These and other groups of comments discussed topics that are addressed in more detail under the specific subject headings below. A number of comments, though similar, were not identical.[1320] Variations within and among similar comments were also considered and are reflected in the summary below.

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 rate increase.[1321] Others suggested that any rate increase should be smaller than that requested by the Company.[1322]

Economic Hardship / Unaffordability

5. A substantial number of individuals expressed concern that the rate increase requested by the Company would impose a financial hardship.[1323]

[1317] Notice of Approval of Proposed Notice (June 23, 2025) (eDocket No. 20256-220126-01).
[1318] *See, e.g.*, Comment by Felicia Peterson (Oct. 7, 2025) (eDocket No. 202510-223636-01); Comment by James L. Schrack (Oct. 7, 2025) (eDocket No. 202510-223636-02).
[1319] *See, e.g.*, Comment by Pana Xiong (Jan. 5, 2025) (eDocket No. 20251-214492-03); Comment by Alec Stewart (Jan. 2, 2025) (eDocket No. 20251-213843-08).
[1320] *See, e.g.,* Comment by Maranda Oeltjen (Dec. 15, 2025) (eDocket No. 202512-225919-01); Comment by Janice Hobbs (Dec. 15, 2025) (eDocket No. 202512-225919-01).
[1321] *See, e.g.*, Comment by Cassandra Roaché (Aug. 6, 2025) (eDocket No. 20258-221814-01).
[1322] *See, e.g.*, Comment by Joseph Kasel (Apr. 4, 2025) (eDocket No. 20254-217290-02).
[1323] *See, e.g.*, Comment by Shirley Dietzmann (Feb. 27, 2025) (eDocket No. 20253-216720-05).

6. Commenters often explained that the requested rates would be unaffordable due to macroeconomic or individual economic circumstances affecting the affordability of electric rates. The circumstances included: recent increases in energy and non-energy costs;[1324] the effects of the Covid-19 pandemic;[1325] the effects of federal tariff policies; [1326] customers and households with low-, [1327] fixed-, [1328] and/or single-incomes;[1329] and, the cost of other needs such as food or medical expenses.[1330] Many commenters stated that the rate increase would force them to make difficult decisions about which necessities they could afford.[1331]

7. Some commenters identified recent increases in energy costs leading to unaffordability, particularly in connection with the interim rate increase in January 2025.[1332] A handful of these commenters specifically objected to Xcel's ability to increase rates prior to approval.[1333]

8. Several commenters objected to the requested increases as exceeding the general rate of consumer price inflation.[1334] Others observed that their own wages or income were not increasing as quickly as their electric costs.[1335] Multiple commenters argued that the requested rate of increase was unreasonable, but a smaller increase would be reasonable—generally, suggesting increases that fell within the two to three percent range.[1336]

9. Several commenters stated that Xcel's proposed rate plan would have significant negative economic impact. Some commenters thought that the increased rates would drive customers away from Xcel.[1337] Fred Ames described how increased energy costs could impact the operation of large healthcare organizations.[1338] Americans for Prosperity Minnesota stated that Xcel has been shutting off power for a growing number of customers since 2024, and that further increases would have a cascading effect on businesses and customers that would hurt the economy.[1339] Other commenters predicted that further rate increases would drive people out of their homes or the state entirely,

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[1324] *See, e.g.*, Comment by Theresa Alvarardo (Nov. 20, 2025) (eDocket No. 202511-225173-01); Comment by Melissa Crowell (Nov. 22, 2025) (eDocket No. 202511-225215-02); St. Paul 1:30 p.m. Tr. at 23 (Sep. 17, 2025) (Jim Elli).
[1325] *See, e.g.*, Comment by Amu Schluender (Feb. 24, 2025) (eDocket No. 20253-216720-04).
[1326] *See, e.g.*, Comment by Jocelyn Provencher (Mar. 3, 2025) (eDocket No. 20254-217290-03).
[1327] *See, e.g.*, Comment by Deama Agular (Feb. 20, 2025) (eDocket No. 20253-216720-01).
[1328] *See, e.g.*, Minneapolis 1:30 p.m. Tr. at 34 (Sep. 24, 2025) (Susu Jeffrey).
[1329] *See, e.g.*, Comment by Michael Bach (Dec. 6, 2025) (eDocket No. 202512-225605-02).
[1330] *See, e.g.*, Comment by Cheryl Baldwin (Nov. 21, 2025) (eDocket No. 202511-225215-01); Comment by Aubree Derksen (Dec. 21, 2025) (eDocket No. 202512-226080-01).
[1331] *See, e.g.*, Comment by Heather Miller (Dec. 5, 2025) (eDocket No. 202512-225605-01).
[1332] *See, e.g.*, Comment by Patti Weber (Feb. 7, 2025) (eDocket No. 20254-217290-01); Comment by Robyn M (Aug. 6, 2025) (eDocket No. 20258-221873-01).
[1333] *See, e.g.*, Comment by Nancy Rosenow (Feb. 1, 2025) (eDocket No. 20254-217290-17).
[1334] *See, e.g.*, Comment by Brandon Walker (Aug. 19, 2025) (eDocket No. 20258-222236-01).
[1335] *See, e.g.*, Comment by Robert Sabota (Sep. 17, 2025) (eDocket No. 20259-223149-01).
[1336] *See, e.g.*, St. Cloud 11:30 a.m. Tr. at 33-34 (Sep. 16, 2025) (Chelsea Kilanowski); Comment by Shane Lampi (Aug. 8, 2025) (eDocket No. 20258-221939-01).
[1337] *See, e.g.*, Comment by Samantha M (Nov. 20, 2025) (eDocket No. 202511-225173-01).
[1338] Comment by Fred Ames (Sep. 24, 2025) (eDocket No. 20259-223264-01).
[1339] Comment by Americans for Prosperity Minnesota (Dec. 29, 2025) (eDocket No. 202512-226342-01).

speculating that this would result in an unsustainable situation where there are less paying customers to financially support Xcel.[1340]

Conservation Efforts

10. Many commenters, like Alexis Smith and Chris Black, 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.[1341] Kristen Carpenter, for example, wrote "many of us on fixed incomes already have our thermostats set so low as to be uncomfortable and live with a minimum of electricity usage in order to keep our bills as low as we can. What can we possibly have control over in this instance? I've given up…"[1342] Several commenters, such as Maarie Gayther, argued that the push to conserve energy contradicted was contradicted by the sales true-up adjustment.[1343]

Comments by Business Customers

11. Several business owners opposed the proposed rate increase. Liza Timmers observed that business energy costs affect the prices that consumers pay for services and goods.[1344] Charissa Behringer rejected the idea of Xcel increasing charges to customers to cover its own business investments, stating she would not do the same to her customers.[1345] Other business owners highlighted that they are experiencing economic hardship that would make a rate increase unaffordable.[1346] Susan Mayer described how she had to close her small business due to rising energy costs from Xcel.[1347]

Xcel Should Control Costs Rather Than Raise Rates

12. Several commenters stated that Xcel has not explored options outside of raising customer rates and should consider cutting its costs.[1348] Public comments included a range of suggested categories for cost reductions that should be made prior to considering a rate increase. Cost categories proposed for possible savings included:

[1340] *See, e.g.*, Comment by Phyllis Lentsch (Jan. 3, 2025) (eDocket No. 20251-214185-03); Comment by John Young (Jan. 31, 2025) (eDocket No. 20254-217290-16).
[1341] *See, e.g.*, Comment by Alexis Smith (Mar. 21, 2025) (eDocket No. 20253-216705-01); Comment by Chris Black (Mar. 5, 2025) (eDocket No. 20254-217290-06).
[1342] Comment by Kristen Carpenter (Feb. 7, 2025) (eDocket No. 20254-217290-11).
[1343] Comment by Maarie Gayther (Dec. 23, 2025) (eDocket No. 202512-226193-01).
[1344] Comment by Liza Timmers (Dec. 11, 2025) (eDocket No. 202512-225796-01).
[1345] Comment by Charissa Behringer (Sep. 24, 2025) (eDocket No. 20259-223296-03).
[1346] *See, e.g.*, St. Cloud 11:30 a.m. Tr. at 40-42 (Sep. 16, 2025) (Mark Geller); Comment by David and Lorrie Fette (Jan. 27, 2025) (eDocket No. 20253-216019-08).
[1347] WebEx 1:30 p.m. Tr. at 35-37 (Sep. 23, 2025) (Susan Mayer).
[1348] *See, e.g.*, WebEx 1:30 p.m. Tr. at 20-25 (Sep. 23, 2025) (Tracy Salwei); Comment by Eric Zimmerman Zuckerman (Sep. 12, 2025) (eDocket No. 20259-223027-01).

executive and upper management compensation,[1349] advertising,[1350] the extra pages in customers' bills,[1351] and labor inefficiency.[1352]

13. A handful of comments contended that Xcel's investments in renewable energy were driving costs.[1353] Others asserted that renewable energy is inexpensive, should be prioritized, and that the reduced energy cost should result in lower customer bills.[1354]

Xcel Should Reinvest Profits Rather than Raise Rates

14. A significant number of commenters questioned the need for a rate increase in light of recent reports of Xcel's profits and executive pay.[1355] Many, like Kelly Michel, argued that Xcel should reinvest profits into infrastructure rather than giving it to shareholders and raising rates.[1356]

Incentives Not Aligned to Public Interest

15. Commenters, such as George Crocker, asserted that Xcel's profit incentive does not coincide with the public interest.[1357] M. Miles expressed that more Commission oversight is needed to ensure Xcel's incentives are aligned with the best interests of their customers.[1358]

16. Many commenters stated that ratepayers would not see any benefits from the increased rates.[1359] Robin Putnam commented that the rate increase should not be allowed unless Xcel can show substantial, verified, and voted on customer benefits.[1360]

Residential Customer Charge Increases

17. Several commenters argued that a fixed residential customer charge increase was unfair, particularly when some customers do not receive the same quality of service as other customers.[1361] Liz Jaeger spoke against increasing the residential fixed customer charges because they do not incent use of solar energy or other

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[1349] *See, e.g.*, Comment by Ken Huben (Feb. 3, 2025) (eDocket No. 20254-217290-15); Comment by Lisa Hoffman-Konn (Sep. 15, 2025) (eDocket No. 20259-223066-01); Comment by Seth Gore (Dec. 6, 2025) (eDocket No. 202512-225605-02).
[1350] *See, e.g.*, Comment by Stephen Barger (Feb. 18, 2025) (eDocket No. 20253-216720-09).
[1351] *See, e.g.*, Comment by David Douglas (Mar. 10, 2025) (eDocket No. 20254-217290-12).
[1352] *See, e.g.*, Comment by Connie Goers (Feb. 24, 2025) (eDocket No. 20253-216720-02).
[1353] *See, e.g.*, Comment by Vern Johnson (Dec. 15, 2025) (eDocket No. 202512-225919-02); Comment by Jan Hawkes (Feb. 17, 2025) (eDocket No. 20253-216720-05).
[1354] *See, e.g.*, Comment by Benjamin Christopher Henry (Jan. 2, 2025) (eDocket No. 20251-213843-05).
[1355] *See, e.g.*, Comment by Scott Saunders (Aug. 5, 2025) (eDocket No. 20258-221780-01); Comment by Lindsay Shimizu (Dec. 16, 2025) (eDocket No. 202512-225919-02).
[1356] *See, e.g.*, Comment by Kelly Michel (Sep. 24, 2025) (eDocket No. 20259-223296-01).
[1357] Comment by George Crocker (Sep. 16, 2025) (eDocket No. 20259-223068-01); George Crocker, Stillwater 6:30 p.m. Tr. at 33-37 (Sep. 15, 2025) (George Crocker.
[1358] Comment by M. Miles (Feb. 18, 2025) (eDocket No. 20253-216720-07).
[1359] *See, e.g.*, Comment by Janice Grussendorf (Feb. 14, 2025) (eDocket No. 20253-216720-11).
[1360] Comment by Robin Putnam (Feb. 6, 2025) (eDocket No. 20254-217290-01).
[1361] *See, e.g.*, Comment by Sherrie Kinmounth (Sep. 19, 2025) (eDocket No. 20259-223225-01).

conservation efforts.[1362] Korinne Dennis asked whether Xcel had considered if the proposed fixed customer charge increase would inequitably burden low-income households.[1363]

18. Some commenters suggested that Xcel consider alternatives to a fixed rate increase such as charging more to customers who use more power.[1364]

Other Customer Issues

19. Many commenters expressed frustration about the frequency in which Xcel raises customer rates and how there does not appear to be an end in sight.[1365]

20. Several commenters objected to the idea of paying for weather events in other states such as Texas.[1366] Other commenters stated that they should not have to pay for Xcel's infrastructure plans related to nuclear plants or leakage.[1367]

21. Multiple commenters felt that the rate increase was unfair in light of the many additional charges Xcel has added onto their bills.[1368] Customers specifically objected to charges beyond the base energy fee, such as the affordability charge.[1369]

22. A few commenters expressed concern about Xcel's ability to reassess or add onto prior charges should the rate increases be approved.[1370]

Rate of Return/Return on Equity

23. Many commenters specifically objected to Xcel citing shareholder profits, ROE, or overall rate of return as a basis for the rate increases. The vast majority of these commenters stated customer rates should not contribute to shareholder profits and found Xcel's focus on the issue inappropriate or concerning.[1371] Richard J. Kolkmann believes

[1362] St. Paul 1:30 p.m. Tr. at 38-39 (Sep. 17, 2025) (Liz Jaeger).
[1363] WebEx 6:00 p.m. Tr. at 62-63 (Sep. 16, 2025) (Korinne Dennis).
[1364] *See, e.g.*, Comment by Denise Marti (Mar. 5, 2025) (eDocket No. 20254-217290-06).
[1365] *See, e.g.*, Comment by Mary Ann Urbashich (Mar. 5, 2025) (eDocket No. 20254-217290-07); Comment by Toni McNaron (Mar. 17, 2025) (eDocket No. 20254-217290-08).
[1366] *See, e.g.*, Comment by Louise Jacobs (May 5, 2025) (eDocket No. 20255-218755-01); Comment by Lee Samuelson (Sep. 16, 2025) (eDocket No. 20259-223107-01).
[1367] *See, e.g.*, Stillwater 6:30 p.m. at 44 (Sep. 15, 2025) (Ryan Michael); Edina 6:00 p.m. Tr. at 34-36 (Sep. 23, 2025) (Susan Martinson).
[1368] Comment by Tyler Breuch (Oct. 8, 2025) (eDocket No. 202510-223842-01).
[1369] Comment by Gerald Turnquist (May 14, 2025) (eDocket No. 20255-219098-01); Comment by Reed Vanthove (Feb. 4, 2025) (eDocket No. 20253-216720-12).
[1370] *See, e.g.*, Monica Reese (Sep. 16, 2025 public comment) (eDocket No. 20259-223107-01).
[1371] *See, e.g.*, Minneapolis 1:30 p.m. Tr. at 24-26 (Sep. 24, 2025) (Elis Bradshaw); Minneapolis 1:30 p.m. Tr. at 26-28 (Sep. 24, 2025) (Josh Zimmerman); Comment by Alexander Roth (Sep. 24, 2025) (eDocket No. 20259-223296-02).

Xcel's requested ROE to be excessive and explained that he found testimony in favor of the requested ROE to be misleading after analyzing the numbers presented.[1372]

Service Quality Issues

24. Many customers criticized the reliability of Xcel's electric service. Evan Tobin of Minneapolis reported that he experiences blackouts every month during the summer in the most populated area of the state due to Xcel letting aging transformers in the neighborhood explode and catch fire instead of preemptively replacing them.[1373] Rochelle Sharp of May Township commented that her whole street loses power on a regular basis and experienced 14 extended outages in 2024 alone, significantly adding to her expenses due to spoiled food, purchasing wood for fires, and investing in a $500 generator for backup power.[1374] Several other commenters, including James Vair of St. Louis Park, Dennis and Joan Sachs of White Bear Lake, and Bill Mosby of St. Michael, also complained of frequent power outages.[1375]

25. Multiple customers criticized Xcel's customer service and maintenance practices.[1376] Erik Lundin of Bloomington stated he lost power several times since 2022 and described multiple calls he made to Xcel asking whether they needed to do maintenance.[1377] An Xcel representative confirmed that a tree in his backyard needed service in 2024, but he was told it would not happen that year despite Xcel's stated policy of conducting maintenance in the area every four to seven years.[1378] He was told by a representative in 2025 that Xcel would no longer be doing routine maintenance in the area at all, despite the issue remaining unresolved.[1379] Mark Sommers of Waseca commented that Xcel does little maintenance in rural areas.[1380]

26. Several customers criticized Xcel's billing services specifically.[1381] Lee Benson discussed how Xcel outsourced residential billing services and prioritizes business customers.[1382] Dean Morrison commented that Xcel has failed to accept payments from him on several occasions and that he regularly received repeated charges on his bills.[1383] Jill Gruber-Downing commented that she did not receive a bill from Xcel

[1372] Edina 6:00 p.m. Tr. at 20-25, 50-55 (Sep. 23, 2025) (Richard J. Kolkmann).
[1373] Comment by Evan Tobin (Sep. 24, 2025) (eDocket No. 20259-223296-02).
[1374] Comment by Rochelle Sharp (Jan. 30, 2025) (eDocket No. 20254-217587-02).
[1375] *See, e.g.*, Comment by James Vair (Jan. 3, 2025) (eDocket No. 20251-214080-01); Comment by Dennis Sachs & Joan Sachs (Feb. 18, 2025) (eDocket No. 20253-216720-06); Comment by Bill Mosby (Jan. 31, 2025) (eDocket No. 20254-217587-02).
[1376] *See, e.g.*, Comment by Linda Zuidema (Aug. 11, 2025) (eDocket No. 20258-221980-01); Edina 6:00 p.m. Tr. at 41-44 (Sep. 23, 2025) (Carol Jensen).
[1377] Edina 6:00 p.m. Tr. at 27-31 (Sep. 23, 2025) (Erik Lundin).
[1378] Edina 6:00 p.m. Tr. at 28-30 (Sep. 23, 2025) (Erik Lundin).
[1379] Edina 6:00 p.m. Tr. at 30 (Sep. 23, 2025) (Erik Lundin).
[1380] Comment by Mark Sommers (Feb. 20, 2025) (eDocket No. 20253-216720-01).
[1381] *See, e.g.*, Comment by Andrew Wensmann (Dec. 7, 2025) (eDocket No. 202512-225605-03); Comment by Mike Olson (Jan. 15, 2025) (eDocket No. 20251-214754-07); Comment by Jaime Dreher (Dec. 23, 2025) (eDocket No. 202512-226196-01).
[1382] Stillwater 6:30 p.m. Tr. at 38-40 (Sep. 15, 2025) (Lee Benson).
[1383] Comment by Dean Morrison (Sep. 16, 2025) (eDocket No. 20259-223107-01).

for over 3 months due to a glitch in the system.[1384] Despite contacting Xcel about the issue, the customer service team informed her that she was not allowed to talk to a supervisor or anyone in billing that could correct the error.[1385] It took her over three months to get the situation escalated so that she could view and pay her bill.[1386] BOMA Greater Minneapolis submitted a comment on behalf of 23 members of the organization who have experienced delayed and inaccurate bills, misapplied payments, and ineffective communications and resolutions from Xcel's customer service since approximately 2022.[1387]

27. A handful of commenters compared Xcel's services unfavorably to electrical companies both in and out of state.[1388] Sara Kowski commented she has frequently lost power in her 14 years of being an Xcel customer, while her parents who live 30 minutes away and use a different electricity provider have only lost power twice in 47 years.[1389]

28. Various commenters expressed frustration with Xcel's business practices. Several customers commented on how they do not receive credit from Xcel after power outages.[1390] Several commenters stated that other providers in Minnesota are not raising rates to nearly the same extent as Xcel.[1391] A handful of commenters specifically criticized Xcel's handling of issues like smart meters, land sales, and contaminated water leakages.[1392]

29. In contrast, other commenters spoke positively about Xcel's services, expressing a willingness to pay for a rate increase to ensure the continuation of Xcel's customer service.[1393]

30. Some commenters suggested that Xcel's rate increase should depend at least in part on a demonstration of improved service quality.[1394]

Xcel's Investment in Energy Sources

31. Many public comments discussed the types of energy sources that Xcel should focus its efforts on. Several comments expressed support for Xcel's investment in

[1384] Comment by Jill Gruber-Downing (Jan. 1, 2025) (eDocket No. 20251-213688-07).
[1385] Comment by Jill Gruber-Downing (Jan. 1, 2025) (eDocket No. 20251-213688-07).
[1386] Comment by Jill Gruber-Downing (Jan. 1, 2025) (eDocket No. 20251-213688-07).
[1387] Comment by BOMA Greater Minneapolis (July 2, 2025) (eDocket No. 20257-220649-01).
[1388] *See, e.g.*, Comment by David Peterson (Feb. 6, 2025) (eDocket No. 20254-217290-01); Comment by Cameron Field (Jan. 3, 2025) (eDocket No. 20251-214080-12).
[1389] Comment by Sara Kowski (Sep. 14, 2025) (eDocket No. 20259-223066-02).
[1390] *See, e.g.*, Comment by Richard Pedrow (Jan. 30, 2025) (eDocket No. 20253-216720-18).
[1391] *See, e.g.*, Comment by Emily Waller (Sep. 22, 2025) (eDocket No. 20259-223225-01).
[1392] *See, e.g.*, Comment by Stacy E Herfindahl (Apr. 7, 2025) (eDocket No. 20254-217587-01); Comment by Mo Honeywell (Sep. 5, 2025) (eDocket No. 20259-222788-01); Comment by Thomas K. Overton (Feb. 14, 2025) (eDocket No. 20252-215408-01).
[1393] *See, e.g.*, Comment by Phil Brasket (Sep. 16, 2025) (eDocket No. 20259-223066-01); Comment by Liudmyla Pozharnova (Feb. 6, 2025) (eDocket No. 20252-215046-01).
[1394] *See, e.g.*, Comment by Nicholas Glover (Nov. 4, 2025) (eDocket No. 202511-224666-01).

wind and solar energy or criticized nuclear energy.[1395] Several other commenters criticized wind and solar energy or otherwise argued that Xcel should invest in energy sources such as nuclear, coal, or natural gas.[1396]

Data Centers

32. Many comments discussed data centers and their impact on Xcel's rate proposal. A significant portion of these comments expressed concern about or objected to the construction of data centers in Minnesota.[1397] Several commenters suspected that Xcel's proposed rate increases were a way to have consumers subsidize Xcel's investment into data centers.[1398] Some commenters stated that data centers use significantly more energy than residential customers and argued that the corporations that maintain the data centers should pay any costs associated with them.[1399] Jan Sebby contended that data centers do not fit any existing rate classes of customers, and are instead in a class by themselves, so residential and small business customers should be insulated from data center costs.[1400]

Transparency and Accountability

33. Many customers called for Xcel to be more transparent both about its rate plan and its business practices. Commenters specifically sought more transparency from Xcel regarding the Company's justifications for the rate increase,[1401] Company expenses,[1402] the status of its projects such as the clean energy transition,[1403] plans for if Xcel fails to meet its goals,[1404] and how the rate increases benefit customers specifically.[1405]

34. Several customers expressed desire for the Commission to hold Xcel more accountable for its actions and performance.[1406] Some commenters called for the

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[1395] *See, e.g.*, Comment by Ashley Mondor (Sep. 15, 2025) (eDocket No. 20259-223066-01); Comment by Karen Hadder (Mar. 3, 2025) (eDocket No. 20254-217290-05).
[1396] *See, e.g.*, Comment by Thomas Gadow (Feb. 20, 2025) (eDocket No. 20253-216720-01); Comment by Daniel Ludwig (Jan. 4, 2025) (eDocket No. 20251-214259-05); Comment by Tom Riedner (Feb. 24, 2025) (eDocket No. 20253-216720-03).
[1397] *See, e.g.*, Comment by Amy Opseth (Sep. 15, 2025) (eDocket No. 20259-223107-01); St. Paul 1:30 p.m. Tr. at 48-49 (Sep. 17, 2025) (Amanda Sikorski).
[1398] *See, e.g.*, Comment by Craig Kirby (Feb. 3, 2025) (eDocket No. 20254-217290-15); Comment by Nate Miller (Jan. 15, 2025) (eDocket No. 20251-214754-07).
[1399] *See, e.g.*, Stillwater 6:30 p.m. Tr. at 27 (Sep. 15, 2025) (Cliff Bujold); Comment by Patrick Murphy (Sep. 12, 2025) (eDocket No. 20259-223027-01).
[1400] Welch 1:30 p.m. Tr. at 21-22 (Sep. 25, 2025) (Jan Sebby).
[1401] *See, e.g.*, Comment by Peter Choukalas (Jan. 8, 2025) (eDocket No. 20251-214604-02).
[1402] *See, e.g.*, Comment by Clifford Bujold (Mar. 6, 2025) (eDocket No. 20253-216212-01).
[1403] Comment by Jacqueline Day (Jan. 1, 2025) (eDocket No. 20251-213490-01).
[1404] Comment by Jeremiah Gagner (Jan. 8, 2025) (eDocket No. 20251-214604-03).
[1405] *See, e.g.*, Comment by Lilly Kerner (Sep. 26, 2025) (eDocket No. 20259-223411-01); Comment by Myles Campbell (Sep. 24, 2025) (eDocket No. 20259-223296-04).
[1406] *See, e.g.*, Comment by Jeremiah Strong (Oct. 3, 2025) (eDocket No. 202510-223634-01); Comment by Michael Bishop (Apr. 21, 2025) (eDocket No. 20254-218016-01).

Commission or the State of Minnesota to audit Xcel.[1407] A handful of commenters believe that Xcel has been providing the public with erroneous information such as incorrect economic forecasts or energy usage data.[1408]

Support for Xcel's Proposed Rate Increases

35. A handful of commenters supported Xcel's requested increases. Multiple comments in support of Xcel's proposal cited the need for increased investment into infrastructure for data centers and the transition to clean energy.[1409] Thomas Ring stated that the rates should be increased because Xcel loses millions of dollars from customers not paying their bill.[1410] Michael Kosloske commented that he supports the requested increases because he is a shareholder and the Commission makes it difficult to increase rates.[1411]

36. Some commenters specifically identified the need for reliable electric service, and expressed an interest in ensuring the power grid is reliable and protected.[1412]

Dissatisfaction with Public Comment Process

37. Several comments found the public comment website and commenting process to be difficult to navigate.[1413]

38. Some commenters observed that they did not timely receive the public-hearing-schedule notice. Lynne Crockett stated that she did not know about the hearings until the last minute.[1414] Rosemary Wacker stated that she only heard of the St. Cloud public hearing one week before the proceeding through her job, and had not otherwise received notification about the proposed rate increase.[1415] Anna Paruccini commented that she could not find information on when the public hearing would be.[1416]

39. Several comments expressed frustration that the feedback postcards distributed by the Commission did not provide a return stamp and required customers to pay for their own postage.[1417]

[1407] *See, e.g.*, Comment by Timothy Scott (Sep. 24, 2025) (eDocket No. 20259-223296-04); Comment by Mical Caterina (Dec. 18, 2025) (eDocket No. 202512-226082-02).
[1408] *See, e.g.*, Comment by Karl Schwan (Sep. 28, 2025) (eDocket No. 20259-223411-02); Comment by Shaun Feist (Feb. 10, 2025) (eDocket No. 20252-215269-11).
[1409] *See, e.g.*, Comment by Terrence Nayes (Jan. 1, 2025) (eDocket No. 20251-213492-03); Comment by Comment by Mary Ahern (Feb. 18, 2025) (eDocket No. 20253-216720-08).
[1410] Comment by Thomas Ring (Dec. 11, 2025) (eDocket No. 202512-225793-01).
[1411] Comment by Michael Kosloske (Jan. 13, 2025) (eDocket No. 20252-215269-10).
[1412] *See, e.g.*, Comment by Lorri Brunette (Jan. 3, 2025) (eDocket No. 20251-214044-07).
[1413] *See, e.g.*, Comment by Reid Waldeland (Jan. 21, 2025) (eDocket No. 20252-214972-01).
[1414] Comment by Lynne Crockett (Sep. 24, 2025) (eDocket No. 20259-223296-04).
[1415] St. Cloud 11:30 a.m. Tr. at 44-45 (Sep. 16, 2025) (Rosemary Wacker).
[1416] Comment by Anna Paruccini (Jan. 13, 2025) (eDocket No. 20252-215269-08).
[1417] *See, e.g.*, Comment by Andrew Singer (Feb. 18, 2025) (eDocket No. 20253-216720-08).

40. Gabrielle Pillmann expressed frustration about phone users being unable to speak during the September 16, 2025, virtual hearing.[1418]

41. Some commenters commented on the accessibility of the public hearings.[1419] Barbara Hoyhtya stated that there should be meetings closer to her area.[1420] Derek Peters commented that the Commission should require all public hearings to be scheduled at times accessible to current ratepayers, specifically citing the St. Cloud public hearing that took place at 11:30 a.m. as being inconvenient for affected individuals who were unable to take time off of work.[1421]

42. Steve Irlbeck described Xcel's presentation at the St. Cloud public hearing as "poor" and leaving many with a poor feeling about the Cand its leadership.[1422]

43. Tim Cothran expressed concern that the process for public engagement had been made intentionally difficult and prevented many citizens from participating in the discussion.[1423]

Energy Justice / Equity

44. Several comments characterized the proposed rate increase as a form of wealth extraction, transfer, or redistribution from poor, marginalized, or underserved communities to utility executives and shareholders.[1424] Some comments concerned the disproportionate impact of a rate increase on low-income communities.[1425]

Other Issues

45. Although a large number of commenters highlighted Xcel's monopoly as their electricity provider in to support their position that the Commission must scrutinize Xcel's rate increase proposal and protect captive customers, [1426] several other commenters criticized the vertically integrated monopoly model itself for electric utilities, and urged consideration of alternatives to Xcel's status as monopoly in particular.[1427]

[1418] Comment by Gabrielle Pillmann (Sep. 16, 2025) (eDocket No. 20259-223107-01).
[1419] *See, e.g.*, St. Paul 1:30 p.m. Tr. at 27-28 (Sep. 17, 2025) (Elia Rubio).
[1420] Comment by Barbara Hoyhtya (Nov. 27, 2025) (eDocket No. 202512-225362-01).
[1421] Comment by Derek Peters (Sep. 18, 2025) (eDocket No. 20259-223149-01).
[1422] Comment by Steve Irlbeck (Sep. 22, 2025) (eDocket No. 20259-223225-01).
[1423] Comment by Tim Cothran (Sep. 24, 2025) (eDocket No. 20259-223296-02).
[1424] *See, e.g.*, Comment by Dennis Wagner (Sep. 16, 2025l) (eDocket No. 20259-223149-01).
[1425] *See, e.g.*, WebEx 6:00 p.m. Tr. at 62-63 (Sep. 16, 2025) (Korinne Dennis).
[1426] *See, e.g.*, Comment by Mel Krueger (Aug. 6, 2025) (eDocket No. 20258-221813-01); Comment by Mark Heaney (Oct. 31, 2025) (eDocket No. 202511-224589-01).
[1427] *See, e.g.*, Comment by Scott Wilson (Dec. 11, 2025) (eDocket No. 202512-225745-04); Comment by Josef Harris (Jan. 2, 2025) (eDocket No. 20251-213938-09).

46. Several comments expressed frustration at or distrust of the Commission's role in the rate proposal process.[1428] A handful of commenters predicted that their comments would not matter to the Commission[1429]

[1428] *See, e.g.*, Comment by Mat Zniewski (Jan. 2, 2025) (eDocket No. 20251-213704-05); Comment by Damian Palacios (Sep. 26, 2025) (eDocket No. 20259-223411-01).
[1429] *See, e.g.*, Comment by Eric Rode (Jan. 1, 2025) (eDocket No. 20251-213551-02); Comment by Cecilia Keeling (Feb. 14, 2025) (eDocket No. 20253-216720-11).

MINNESOTA
COURT OF ADMINISTRATIVE HEARINGS

Court of Administrative Hearings
PO Box 64620
Saint Paul, MN 55164-0620
651-361-7900
mn.gov/cah/

April 29, 2026

See Attached Service List

Re: ***In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota***

CAH 28-2500-40515
MPUC E-002/GR-24-320; E-002/GS-24-321

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, RECOMMENDATION** in the above-entitled matter. The Court of Administrative Hearings' file is now closed.

If you have any questions, please contact me at (651) 361-7845, samantha.cosgriff@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,

Samantha Cosgriff

SAMANTHA COSGRIFF
Legal Assistant

Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
COURT OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota	CAH Docket No.: 28-2500-40515 MPUC E-002/GR-24-320; E 002/GS-24-321

On April 29, 2026, a true and correct copy of the **FINDINGS OF FACT, CONCLUSIONS OF LAW, RECOMMENDATION** was served by eService, and United States mail, (in the manner indicated on the attached service list) to the following individuals:

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties		450 Syndicate St N Ste 35 Saint Paul MN, 55104 United States	Electronic Service		No	24-320Official CC Service List
2	Justin	Andringa	justin.andringa@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
3	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
4	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
5	Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy		414 Nicollet Mall7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
6	Ryan	Barlow	rbarlow@cozen.com	Cozen O'Connor		150 South Fifth St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
7	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	24-320Official CC Service List
8	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-320Official CC Service List
9	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
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11	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-320Official CC Service List
12	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-320Official CC Service List
13	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential	Suite 1400 445 Minnesota St. St. Paul MN,	Electronic Service		No	24-320Official CC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
					Utilities Division	55101 United States				Service List
14	Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
15	Joey	Cherney	joey.cherney@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street STE 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
16	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	24-320Official CC Service List
17	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-320Official CC Service List
18	Brandon	Crawford	brandonc@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
19	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	24-320Official CC Service List
20	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
21	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
22	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
23	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
24	Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy		414 Nicollet Mall - 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
25	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-	Electronic Service		No	24-320Official CC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Reliance Minneapolis MN, 55406 United States				Service List
26	Eden	Faure	eden.faure@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
27	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	24-320Official CC Service List
28	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	24-320Official CC Service List
29	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	24-320Official CC Service List
30	Allen	Gleckner	agleckner@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-320Official CC Service List
31	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	24-320Official CC Service List
32	Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY		401 Nicollet Mall FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
33	Shubha	Harris	shubha.m.harris@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401 - FL 8 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
34	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
35	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	24-320Official CC Service List
36	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
37	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	24-320Official CC Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
38	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
39	Amrit	Hundal	amrit.hundal@ag.state.mn.us		Office of the Attorney General - Department of Commerce		Electronic Service		No	24-320Official CC Service List
40	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	24-320Official CC Service List
41	Richard	Johnson	rickjohnson@cozen.com	Cozen O'Connor		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
42	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
43	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
44	Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center		35 E Wacker Drive Suite 1600 Chicago IL, 60302 United States	Electronic Service		No	24-320Official CC Service List
45	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
46	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
47	Amber	Lee	amber.lee@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
48	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
49	Ryan	Long	ryan.j.long@xcelenergy.com			414 Nicollet Mall 401 8th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
50	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis	Electronic Service		No	24-320Official CC

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55406 United States				Service List
51	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-320Official CC Service List
52	Robert	Manning	robert.manning@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
53	Ashley	Marcus	ashley.marcus@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
54	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
55	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
56	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-320Official CC Service List
57	Stephen	Melchionne	stephen.melchionne@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street, Ste. 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
58	Greg	Merz	greg.merz@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
59	Joseph	Meyer	joseph.c.meyer@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164 United States	Electronic Service		Yes	24-320Official CC Service List
60	Hirsi	Mohamed	hirsi.mohamed@state.mn.us		Public Utilities Commission	121 7th Place E, Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
61	Marta	Monti	marta@energycents.org	Energy CENTS Coalition		823 E. 7th Street St. Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
62	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
63	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
64	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	24-320Official CC Service List
65	Wendy	Raymond	wendy.raymond@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street Suite 600 St. Paul MN, 55101 United States	Electronic Service		No	24-320Official CC Service List
66	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	24-320Official CC Service List
67	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	24-320Official CC Service List
68	Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy		414 Nicollet Mall FL 5 Minneapoli MN, 55401 United States	Electronic Service		No	24-320Official CC Service List
69	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
70	Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.		225 South Sixth Street Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
71	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	24-320Official CC Service List
72	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	24-320Official CC Service List
73	George	Shardlow	george@energycents.org	Energy CENTS Coalition		823 E. 7th Street Saint Paul MN, 55106 United States	Electronic Service		No	24-320Official CC Service List
74	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	24-320Official CC Service List
75	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN,	Electronic Service		No	24-320Official CC

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						55102 United States				Service List
76	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	24-320Official CC Service List
77	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
78	Scott	Strand	sstrand@elpc.org	Environmental Law & Policy Center		60 S 6th Street Suite 2800 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
79	James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
80	Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine, P.A.		225 6th St Ste 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
81	Anthony	Willingham	anthony.willingham@electrifyamerica.com	Electrify America		1950 Opportunity Way Suite 1500 Reston VA, 20190 United States	Electronic Service		No	24-320Official CC Service List
82	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-320Official CC Service List
83	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	24-320Official CC Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Justin	Andringa	justin.andringa@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
2	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
3	Ryan	Barlow	rbarlow@cozen.com	Cozen O'Connor		150 South Fifth St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
4	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-321Official CC Service List
5	Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
6	Colette	Brashears	colette.brashears@kutakrock.com	Kutak Rock LLP		1277 E. Joyce Blvd., Suite 300 Fayetteville AR, 72703 United States	Electronic Service		No	24-321Official CC Service List
7	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-321Official CC Service List
8	Olivia	Carroll	oliviac@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
9	Joey	Cherney	joey.cherney@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street STE 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
10	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-321Official CC Service List
11	Brandon	Crawford	brandonc@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 St. Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
12	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-321Official CC Service List

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13	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
14	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
15	Eden	Faure	eden.faure@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
16	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	24-321Official CC Service List
17	Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall, 401-7 Minneapolis MN, 55401 United States	Electronic Service		No	24-321Official CC Service List
18	Valerie	Herring	vherring@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S. Eighth Street Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
19	Amrit	Hundal	amrit.hundal@ag.state.mn.us		Office of the Attorney General - Department of Commerce		Electronic Service		No	24-321Official CC Service List
20	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
21	Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center		35 E Wacker Drive Suite 1600 Chicago IL, 60302 United States	Electronic Service		No	24-321Official CC Service List
22	Amber	Lee	amber.lee@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
23	Amy	Liberkowski	amy.a.liberkowski@xcelenergy.com	Xcel Energy		414 Nicollet Mall 7th Floor Minneapolis MN, 55401-1993 United States	Electronic Service		No	24-321Official CC Service List
24	Robert	Manning	robert.manning@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 Saint Paul	Electronic Service		No	24-321Official CC Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55101 United States				
25	Ashley	Marcus	ashley.marcus@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
26	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	24-321Official CC Service List
27	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	24-321Official CC Service List
28	Stephen	Melchionne	stephen.melchionne@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street, Ste. 1400 St. Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
29	Joseph	Meyer	joseph.c.meyer@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164 United States	Electronic Service		Yes	24-321Official CC Service List
30	Hirsi	Mohamed	hirsi.mohamed@state.mn.us		Public Utilities Commission	121 7th Place E, Suite 350 Saint Paul MN, 55101 United States	Electronic Service		No	24-321Official CC Service List
31	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
32	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	24-321Official CC Service List
33	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	24-321Official CC Service List
34	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	24-321Official CC Service List
35	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	24-321Official CC Service List
36	George	Shardlow	george@energycents.org	Energy CENTS Coalition		823 E. 7th Street Saint Paul MN, 55106 United States	Electronic Service		No	24-321Official CC Service List