

**BEFORE THE MINNESOTA COURT OF
ADMINISTRATIVE HEARINGS**

600 North Robert Street
P.O. Box 64620
St. Paul, MN 55164-0620

**FOR THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF MINNESOTA**

121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

In the Matter of the Application of Northern
States Power Company d/b/a Xcel Energy for
Authority to Increase Rates for Electric Service
in the State of Minnesota

PUC Docket No. E002/GR-24-320, 321
CAH Docket No. 28-2500-40515

**PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND
RECOMMENDATIONS
SUBMITTED BY THE
XCEL LARGE INDUSTRIALS**

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The following appearances were made:

Eric Swanson and Elizabeth Schmiesing, Winthrop & Weinstein; Ian Dobson, Northern States Power Company; Valerie Herring and Elizabeth Brama, Taft Stettinius & Hollister, LLP; and Ryan P. Barlow and Patrick T. Zomer, Moss & Barnett, appeared on behalf of Northern States Power Company d/b/a Xcel Energy.

Richard Dornfeld, Katherine Arnold, Amrit Hundal, and Stephen Melchionne, Assistant Attorneys General, appeared on behalf of the Department of Commerce.

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

Brian Edstrom, Senior Regulatory Advocate, Brandon Crawford and Olivia J. Carroll, appeared on behalf of the Citizens Utilities Board of Minnesota.

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

George Shardlow and Marta Monti, Executive Director, appeared on behalf of the Energy CENTS Coalition.

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

Joseph L. Sathe and Samuel B. Ketchum, Kennedy & Graven, Chartered, appeared on behalf of Suburban Rate Authority.

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

STATEMENT OF THE ISSUES

1. Has the Company met its affirmative burden to show that its proposed rate increase is just and reasonable?
2. What revenue allocation (i.e., which customer classes pay for the potential rate increase) best aligns with Minnesota law and state energy policy?
3. Are the Company's rates structured to reasonably recover costs from each customer class?

BACKGROUND

I. Applicant and Other Parties

1. Northern States Power Company d/b/a Xcel Energy, ("the Company," "NSP," or "Xcel Energy") the Applicant in this proceeding, is a utility based in Minneapolis, Minnesota, which provides electric service in Minnesota, North Dakota, and South Dakota.

2. The Minnesota Department of Commerce, Division of Energy Resources (the "Department" or "DOC") is a government agency that provides analysis and technical assistance to the Minnesota Public Utilities Commission (the "Commission").

3. The Citizens Utility Board of Minnesota ("CUB") is a non-profit organization that advocates for Minnesota's residential utility customers.

4. Energy CENTS Coalition ("ECC") is a non-profit organization representing low- and fixed-income utility customers throughout the state.

5. Walmart Inc. ("Walmart") is an American multinational retail corporation. In Minnesota, Walmart operates 79 retail units and one distribution center and employs over 24,000 associates.¹

6. The Xcel Large Industrials ("XLI") is an *ad hoc* consortium of large industrial customers of Xcel Energy, consisting for purposes of this filing of BOMA Greater Minneapolis, Flint Hills Resources Pine Bend, LLC; Marathon Petroleum Corporation; and USG Interiors, Inc.

7. The Minnesota Office of the Attorney General – Residential Utilities Division ("OAG") is a government agency statutorily charged with representing the interests of residential and small business customers in utility services matters before the Commission pursuant to Minn. Stat. § 8.33.

8. The Suburban Rate Authority ("SRA") is a municipal joint powers association organized pursuant to Minn. Stat. § 471.59. Most of the SRA member municipalities are retail customers of Xcel Energy, as well as the residents and businesses residing within those cities.

¹ Walmart Petition to Intervene at 1.

SRA member municipalities act as regulatory bodies of Xcel Energy’s use of right-of-way and the placement of Xcel Energy facilities therein and on other properties within those cities.²

9. For purposes of this filing, the Joint Intervenors (“JI”) is comprised of Cooperative Energy Futures; Environmental Law & Policy Center; Minnesota Interfaith Power & Light; and Vote Solar (jointly represented by Environmental Law & Policy Center), collectively.

II. Procedural Background

1. On November 1, 2024, the Company filed a Multiyear Rate Plan (“MYRP”) seeking a \$353.3 million increase in 2025 (9.6%), and an incremental \$137.5 million increase in 2026 (4.8%), totaling approximately \$490.7 million (13.2%) over the two-year period.³ The filing also included an interim rates proposal under Minn. Stat. § 216B.16, subd. 3.⁴

2. On November 5, 2024, the Commission issued a notice requesting comment on (1) whether the Company’s application complies with Minnesota rules and statutes for a change in rates, (2) whether this matter should be referred to the Court of Administrative Hearings (“CAH”) for a contested case proceeding, and (3) other issues and concerns related to this docket.⁵

3. On November 12, 2024, the Department filed comments concluding that Xcel Energy complied with the filing requirements and recommending that the Commission refer the general rate case to OAH for a contested-case proceeding.⁶

4. On November 12, 2024, CUB filed a Petition to Intervene.⁷

5. On November 18, 2024, the Company filed reply comments.⁸

6. On December 12, 2024, the Commission met to consider the initial filing.

² The SRA member cities include: Bloomington, Brooklyn Park, Burnsville, Carver, Chanhassen, Circle Pines, Deephaven, Eden Prairie, Edina, Fridley, Golden Valley, Hopkins, Lauderdale, Maple Grove, Maplewood, Minnetonka, Mound, Orono, Plymouth, Robbinsdale, Rogers, Roseville, St. Anthony Village, St. Louis Park, Shoreview, Spring Lake Park, Spring Park, Victoria, Wayzata, and Woodbury.

³ Notice of and Order for Hearing at 1 (Dec. 30, 2024) (eDocket No. 202412-213391-01) (“Notice of and Order for Hearing”).

⁴ Notice of Change in Rates and Interim Rate Petition (Nov. 1, 2024) (eDocket No. 202411-211511-01).

⁵ Notice of Comment Period – Notice of Comment Period on Completeness and Procedures (Nov. 5, 2024) (eDocket No. 202411-211632-01).

⁶ Comments (Nov. 12, 2024) (eDocket No. 202411-211839-01).

⁷ Initial Comments and Petition to Intervene (Nov. 12, 2024) (eDocket No. 202411-211851-02).

⁸ Reply Comments (Nov. 18, 2024) (eDocket No. 202411-212101-01).

7. On December 17, 2024, the Company filed revised financial schedules following the Commission’s decision to suspend the proposed rates and allow interim rates to be put into place.⁹

8. In an order dated December 30, 2024, the Commission accepted the Company’s filing and suspended the proposed rates. By separate order, the Commission set interim rates and referred this case to the CAH for a contested-case proceeding. The matter was assigned to Administrative Law Judge (“ALJ”) Joseph Meyer.¹⁰

9. On February 20, 2025, ECC filed a Petition to Intervene.¹¹

10. On March 10, 2025, the Company made a compliance filing to confirm customers had been notified of interim rates, which were charged beginning in the January 2025 billing cycle.¹²

11. On April 30, 2025, the Joint Intervenors filed a Petition to Intervene.¹³

12. On April 29, 2025, Walmart Inc. filed a Petition to Intervene.¹⁴

13. On January 24, 2025, XLI filed a Petition to Intervene.¹⁵

14. On November 10, 2025, the Company filed a letter regarding the Commission’s Interim Rates Order to inform parties it would not file a Petition for approval of a 2026 interim rate increase.¹⁶

15. On March 31, 2025, SRA filed a Petition to Intervene.¹⁷

16. On January 31, 2025, the ALJ issued the First Prehearing Order setting the schedule for the contested case proceeding.¹⁸

⁹ Compliance Filing – Interim Rates (Dec. 17, 2024) (eDocket No. 202412-213124-01).

¹⁰ Order Accepting Filing and Suspending Rates (Dec. 30, 2024) (eDocket No. 202412-213389-01); *see also* Notice of and Order for Hearing (Dec. 30, 2024) (eDocket No. 202412-213391-01); Order Setting Interim Rates (Dec. 30, 2024) (eDocket No. 202412-213390-01).

¹¹ Petition to Intervene (Jan. 22, 2025) (eDocket No. 20251-214232-01).

¹² Compliance Filing – Interim Rates (Mar. 10, 2025) (eDocket No. 20253-216254-0).

¹³ Petition to Intervene (Apr. 30, 2025) (eDocket No. 20254-218395-01).

¹⁴ Walmart Inc. Petition to Intervene (Apr. 29, 2025) (eDocket No. 20254-218272-02).

¹⁵ XLI Petition to Intervene (Jan. 24, 2025) (eDocket No. 20251-214380-02).

¹⁶ Reply Comments – 2026 Interim Rates (Nov. 10, 2025) (eDocket No. 202511-224825-01).

¹⁷ Petition to Intervene (Mar. 31, 2025) (eDocket No. 20253-217053-01).

¹⁸ Order – First Prehearing Order (Jan. 31, 2025) (eDocket No. 20251-214-744-01).

17. On January 27, 2025, the ALJ issued a Protective Order to govern the proceedings.¹⁹
18. On February 10, 2025, the ALJ granted XLI's Petition to Intervene.²⁰
19. On February 14, 2025, the ALJ granted ECC's Petition to Intervene.²¹
20. On April 15, 2025, the ALJ granted SRA's Petition to Intervene.²²
21. On May 19, 2025, the ALJ granted Walmart and the Joint Intervenors' Petitions for Intervention.²³
22. On March 17, 2025, Xcel Energy filed Supplemental Direct Testimony and Schedules of Company witnesses Benjamin C. Halama, Gregory J. Robinson, Nora C. Lindgren, Marty D. Mensen, Anne Z. Sherwood, Kelly A. Bloch.²⁴
23. On June 3, 2025, the Company filed a notice of withdrawal for Company Witness Robinson.²⁵
24. On July 25, 2025, the OAG filed a joint motion to compel discovery.²⁶

¹⁹ Order – Protective Order (Jan. 27, 2025) (eDocket No. 20251-214424-01).

²⁰ Order – Order Granting Unopposed Intervention Petition for XLI (Feb. 10, 2025) (eDocket No. 20252-215166-01).

²¹ Order – Order Granting Unopposed Intervention Petition of ECC (Feb. 14, 2025) (eDocket No. 20252-215402-01).

²² Order – Order Granting Unopposed Intervention Petition of SRA (Apr. 15, 2025) (eDocket No. 20254-217644-01).

²³ Order – 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).

²⁴ Testimony – Supplemental Direct Testimony and Schedules of Company Witness Halama (Mar. 17, 2025) (eDocket No. 20253-216469-02); Testimony – Supplemental Direct Testimony and Schedules of Company Witness Robinson (Mar. 17, 2025) (eDocket No. 20253-216469-03); Testimony – Supplemental Direct Testimony and Schedules of Company Witness Lindgren (Mar. 17, 2025) (eDocket No. 20253-216469-04); Testimony – Supplemental Direct Testimony and Schedules of Company Witness Mensen (Mar. 17, 2025) (eDocket No. 20253-216469-05); Testimony – Supplemental Direct Testimony and Schedules of Company Witness Sherwood (Mar. 17, 2025) (eDocket No. 20253-216469-06); Testimony – Supplemental Direct Testimony and Schedules of Company Witness Bloch (Mar. 17, 2025) (eDocket No. 20253-216469-07).

²⁵ Notice of Withdrawal – Robinson (Jun. 3, 2025) (eDocket No. 20256-219536-01).

²⁶ Joint Motion to Compel Discovery (Jul. 25, 2025) (eDocket No. 20257-221445-01).

25. On July 31, 2025, the Company filed an errata to the Application and Direct Testimony and Schedules of Witnesses Benjamin S. Levine, Marty D. Mensen, Anne Z. Sherwood, Robert L. Miller, Yen Ly, and Christopher Barthol.²⁷
26. On August 19, 2025, the ALJ held a motion hearing regarding the Joint Motion to Compel Discovery.
27. On August 22, 2025, SRA filed the Direct Testimony of James D. Bride.
28. On August 22, 2025, CUB filed the Direct Testimony and Schedules of Steve Kihm and Annie Levenson-Falk.
29. On August 22, 2025, JI filed the Direct Testimony of William D. Kenworthy and Gabriel Chan.
30. On August 22, 2025, Walmart filed the Direct Testimony of Eric S. Austin.
31. On August 22, 2025, XLI filed the Direct Testimony and Schedules of Billie S. LaConte and Jonathan Ly.
32. On August 22, 2025, the OAG filed the Direct Testimony of Helen Scharber, Shoua Lee, and Katherine Hinderlie.
33. On August 22, 2025, DOC filed the Direct Testimony and Schedules of Eric Borden, Michael Zajicek, Ashley Uphus, Sachin Shah, Terry M. Myers, Mary Beth Kehrwald, Holly Jones, Mark A. Johnson, Donald Hirasuna, Andrew Golden, Andy Bahn, and Craig M. Addonizio.
34. On August 22, 2025, ECC filed the Direct Testimony and Schedules of George Shardlow.
35. On August 29, 2025, the ALJ issued an order granting in part and denying in part the motion to compel.²⁸
36. On September 5, 2025, the ALJ held a prehearing conference to discuss logistics and planning for the public hearings.
37. On September 29, 2025, XLI filed errata to the testimony of Jonathan Ly.²⁹

²⁷ Errata (Jul. 31, 2025) (eDocket No. 2027-221604-01).

²⁸ Order – Order Granting in Part and Denying in Part Motion to Compel (Aug. 29, 2025) (eDocket No. 20258-222555-01).

²⁹ Errata to Direct Testimony of Jonathan Ly (Sep. 29, 2025) (eDocket Nos. 20259-223371-01, 20259-223371-03, 20259-223371-04, 20259-223371-05).

38. On October 1, 2025, the Company filed a letter regarding the 2026 Interim Rates.³⁰
39. On October 8, 2025, the Commission issues a notice of comment period on the Company's interim rate request.³¹
40. On October 10, 2025, SRA filed the Rebuttal Testimony of James Bride.
41. On October 10, 2025, the Company filed the Rebuttal Testimony of Nicholas N. Paluck, Christopher J. Barthol, Nicholas F. Martin, Mark P. Moeller, Robert V. Mustich, Yen Ly, Jeffrey L. West, Richard R. Schrubbe Robert L. Miller, William T. Kowalowski, Nicole L. Doyle, Paul J. McGregor, Randy A. Capra, David J. Berklund, Nicholas J. Detmer, Diedra K. Howard, Kelly A. Bloch, Marty D. Mensen, Benjamin S. Levine, Gregory J. Robinson, Joshua C. Nowak, Todd A. Wehner, Benjamin C. Halama, and Amy A. Liberkowski.
42. On October 10, 2025, XLI filed the Rebuttal Testimony of Jonathan Ly and Billie LaConte.
43. On October 10, 2025, JI filed the Rebuttal Testimony of Gabriel Chan.
44. On October 10, 2025, OAG filed the Rebuttal Testimony of Helen Scharber and Shoua Lee.
45. On October 10, 2025, DOC filed the Rebuttal Testimony of Michael Zajicek and Michael Schmitz.
46. On October 21, 2025, OAG filed a Motion to Strike Rebuttal Testimony of Xcel.³²
47. On October 31, 2025, the OAG filed comments on the interim rate refund, DOC filed comments on the interim rate refund, and XLI and CUB filed joint initial comments regarding the same.
48. On November 4, 2025, NSP filed comments to the OAG's Motion to Strike.³³
49. On November 4, 2025, DOC filed a Response Supporting OAG's Objection.³⁴
50. On November 10, 2025, NSP filed reply comments regarding 2026 interim rates.
51. On November 10, 2025, DOC filed reply comments regarding 2026 interim rates.

³⁰ Letter (Oct. 1, 2025) (eDocket No.202510-223492-01).

³¹ Notice of Comment Period (Oct. 8, 2025) (eDocket No. 202510-223704-01).

³² OAG Motion to Strike Rebuttal Testimony of Xcel (Oct. 21, 2025) (eDocket 202510-224157-02).

³³ NSP Comments to OAG Motion (Nov. 4, 2025) (eDocket No. 202511-224660-01).

³⁴ DOC Response Supporting OAG-RUD's Objection (Nov. 4, 2025) (eDocket No. 202511-224653-01).

52. On November 12, 2025, the ALJ issued an Order Denying OAG's Motion to Strike.³⁵
53. On November 25, 2025, SRA filed the Surrebuttal Testimony of James D. Bride.
54. On November 25, 2025, ECC filed the Surrebuttal Testimony of George Shardlow.
55. On November 25, 2025, CUB filed the Surrebuttal Testimony of Steve Kihm and Annie Levenson-Falk.
56. On November 25, 2025, NSP filed the Surrebuttal Testimony of Nicholas N. Paluck, Christopher J. Barthol, and Nicholas F. Martin.
57. On November 25, 2025, JI filed the Surrebuttal Testimony of Gabriel Chan and William Kenworthy.
58. On November 25, 2025, OAG filed the Surrebuttal Testimony of Katherine Hinderlie, Helen Scharber, and Shoua Lee.
59. On November 25, 2025, XLI filed the Surrebuttal Testimony of Billie LaConte and Jonathan Ly.
60. On November 25, 2025, DOC filed the Surrebuttal Testimony and Schedules of Michael Zajicek, Ashley Uphus, Sachin Shah, Mary Beth Kehrwald, Holly Jones, Mark A. Johnson, Steven Hunt, Andrew Golden, Eric Borden, Andy Bahn, and Craig M. Addonizio.
61. On December 4, 2025, the Company filed errata to the Surrebuttal Testimony of Company Witnesses Marty D. Mensen, Nora Lindgren, Christopher Barthol, Diedra Howard, Robert Miller, and Yen Ly.
62. On December 4, 2025, OAG filed errata to the Surrebuttal Testimony of OAG Witness Katherine Hinderlie.
63. On December 4, 2025, DOC filed errata to the Surrebuttal Testimony of DOC Witness Eric Borden.
64. On December 5, 2025, the Company filed a Notice of Motion and Motion to Strike.³⁶
65. On December 11, 2025, the Company filed a Motion for Relief.³⁷

³⁵ Order Denying Motion to Strike (Nov. 12, 2025) (eDocket No. 202511-224861-01).

³⁶ Notice of Motion and Motion to Strike (Dec. 5, 2025) (eDocket No. 202512-225566-01).

³⁷ Motion for Relief (Dec. 11, 2025) (eDocket No. 202512-225738-02).

66. On December 11, 2025, XLI filed a Response to Xcel Energy’s Motion to Strike.³⁸
67. On December 11, 2025, DOC filed a response to Xcel’s Motion for Relief.³⁹
68. On December 12, 2025, the Company filed a letter to inform the Commission and parties of its position on wildfire-related costs in the 2025 test year and 2026 plan year.⁴⁰
69. On December 15, 2025, a status conference was held regarding the Company’s Motion for Relief.
70. On December 17 and 18, 2025, an evidentiary hearing was held.
71. On January 23, 2026, the Company filed its issues matrix.⁴¹
72. On January 28, 2026, CUB filed its initial brief.⁴²
73. On January 28, 2026, OAG filed its initial brief.⁴³
74. On January 28, 2026, SRA filed its initial brief.⁴⁴
75. On January 28, 2026, XLI filed its initial brief.⁴⁵
76. On January 28, 2026, JI filed its initial brief.⁴⁶
77. On January 28, 2026, Walmart filed its initial brief.⁴⁷
78. On January 28, 2026, the Department filed its initial brief.⁴⁸
79. On January 29, 2026, Xcel Energy filed its initial brief.⁴⁹

³⁸ Response to Xcel Energy’s Motion to Strike (Dec. 11, 2025) (eDocket No. 202512-225778-02).

³⁹ DOC Response to Xcel’s Motion for Relief (Dec. 11, 2025) (eDocket No. 202512-225770-01).

⁴⁰ Letter (Dec. 12, 2025) (eDocket No. 202512-225803-01).

⁴¹ Other – Issues Matrix (Jan. 23, 2023) (eDocket No. 20261-227337-01).

⁴² Brief – CUB Initial Brief (Jan. 28, 2026) (eDocket No. 20261-227535-02).

⁴³ Brief – OAG Initial Brief (Jan. 28, 2026) (eDocket No. 20261-227537-02).

⁴⁴ Brief – Initial Brief of the Suburban Rate Authority (Jan. 28, 2026) (eDocket No. 20261-227541-01).

⁴⁵ Brief – Initial Post-Hearing Brief of XLI (Jan. 28, 2026) (eDocket No. 20261-227526-02).

⁴⁶ Brief – Initial Brief of the Joint Intervenors (Jan. 28, 2026) (eDocket No. 20261-227538-01).

⁴⁷ Brief (Jan. 28, 2026) (eDocket No. 20261-227525-01).

⁴⁸ Brief (Jan. 28, 2026) (eDocket No. 20261-227521-01).

⁴⁹ Brief – Initial Brief (Jan. 29, 2026) (eDocket No. 20261-227542-01).

MATTERS REFERRED TO COURT OF ADMINISTRATIVE HEARINGS

80. This matter was referred to the ALJ on December 30, 2024.⁵⁰

81. The Commission directed the parties to develop a full record, addressing, at a minimum the following issues:

- The standard rate case issues, including the impacts of data centers.
- Whether it is appropriate to use the proposed hypothetical capital structure or whether an alternate capital structure should be adopted.
- Reasons for the significant changes of the following costs since the last rate case:
 - Customer Accounting – \$16.5 million.
 - Customer Service and Information – \$34.0 million increase.
 - Administrative and General – \$67.8 million increase.
 - Depreciation – \$112.9 million increase.
- The increase in the distribution budget with a focus on how the increased spending will impact reliability.
- How much Top 10 executive compensation costs should be recovered in rates?
- What grid reinforcement program and associated costs should be approved.
- 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.
- Develop a full record that ensures decisions made in Docket E-002/CI-24-318 are properly reflected in the 2026 Test Year.
- Future ADMS functionalities, lifespan, and costs.
- 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.
- Should Xcel's proposed 2025 and 2026 sales true-ups be approved?

⁵⁰ Order – Notice of and Order for Hearing (Dec. 30, 2024) (eDocket No. 202412-213391-01).

- Develop a record for prepaid pension asset that, at a minimum addresses the following:
 - 1. 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.
 - 2. The actual contributions amounts made by the Company for each of the years.
 - 3. The amount of pension expense recovered from ratepayers as an O&M expense each year.
 - 4. 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.
 - 5. Whether the method of calculating pension expense (ACM or FAS87) affects the extent to which the asset is shareholder funded and, if so, how.
 - 6. 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.
- M. Develop a record addressing whether the fuel to steel transition will result in intergenerational cost shifting and, if so, make recommendations addressing this issue.
- N. Develop a record for insurance premium expense that, at a minimum, addresses the following:
 - 1. Provide the forecasted and actual annual expenses for each subcategory of expenses and credits since 2017.
 - 2. A detailed description of each subcategory and their business purpose.

- 3. 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.
- 4. 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, including distributions from captive insurance and mutual insurance pools.
- 5. 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.
- 6. 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.

BURDEN OF PROOF

82. When seeking a change in rates, it is always the Company’s burden to demonstrate its proposal is reasonable.⁵¹ “Every rate made, demanded, or received by any public utility ... shall be just and reasonable.... Any doubt as to reasonableness should be resolved in favor of the consumer.”⁵²

83. The Company is required to “prove not only that the facts [it] present[s] are reasonable, but that the costs [it] seek[s] to recover are rate-recoverable, that the rate recovery mechanisms [it] propose[s] are permissible, and that the rate design [it] advocate[s] is equitable, under the ‘just and reasonable’ standard set by statute.”⁵³

84. The Company only meets its burden by demonstrating that its proposals are reasonable based upon a preponderance of the evidence.⁵⁴

⁵¹ Minn. Stat. § 216B.16, subd. 4 (“The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.”).

⁵² Minn. Stat. § 216B.03.

⁵³ *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*, PUC Docket No. G-008/GR-15-424, Findings of Fact, Conclusions, and Order at 4–5 (June 3, 2016); *see also St. Paul Area Chamber of Commerce v. Minn. Pub. Utils. Comm’n*, 251 N.W.2d 350 (Minn. 1977).

⁵⁴ *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*, PUC Docket No. G-008/GR-15-

85. In determining if the Company has met its burden of proof, the Commission “is not so much concerned with the sufficiency and credibility of the evidence, as it is concerned with whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission’s statutory responsibility to enforce the state’s public policy that retail consumers of utility services shall be furnished such services at reasonable rates.”⁵⁵

86. The Company’s burden of proof in this proceeding, therefore, requires satisfaction of a two-part process. First, the Company must establish the amount of a given cost as a judicial fact.⁵⁶ Second, the Company must establish that it is just and reasonable for ratepayers (as opposed to the Company’s shareholders) to bear those costs.⁵⁷

87. The Company carries a heavy, but not insurmountable, burden in this case.

FINDINGS OF FACT

REVENUE REQUIREMENT ISSUES

I. Return on Equity (“ROE”)

88. The Company’s frequent annual rate increases have driven its rates above the national average, as demonstrated in the table below. For example, the Company testified that “the NSP Minnesota industrial rate for 2024 is about 18 percent above the national average.”⁵⁸

424, Findings of Fact, Conclusions, and Order at 5 (June 3, 2016) (citing *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989)).

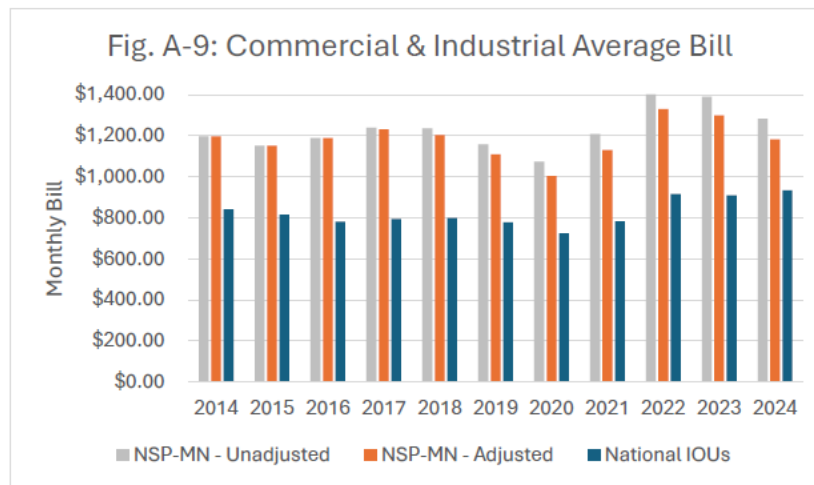
⁵⁵ *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).

⁵⁶ *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).

⁵⁷ *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 723 (Minn. 1987) (finding that “by 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.”).

⁵⁸ Hearing Transcript (“Tr.”) Vol. 1 at 23:18-25 (Liberkowski).

Table 1: Comparison of NSP-MN and National C&I Average Bills⁵⁹



89. The Company is required by Minnesota law to ensure that “retail electricity rates for each customer class be at least five percent below the national average.”⁶⁰

90. Approval of the Company’s MYRP as proposed would exacerbate existing rate discrepancies, driving costs for industrial customers from 13% to 22% above the national average, solidifying its noncompliance with Minn. Stat. § 216C.05.⁶¹

91. The Company’s proposed ROE of 10.30% is unreasonable.⁶²

92. In response to the Company’s proposal, the Department, CUB, and XLI sponsored expert testimony supporting a different ROE.

93. XLI’s expert, Witness LaConte, offered testimony in support of an 8.96% ROE.⁶³

94. The Department’s expert recommends an ROE of 9.25%.⁶⁴

95. CUB supports an ROE of 9.0%.⁶⁵

⁵⁹ Ex. XLI-10, Attachment A at 3 (Compliance Filing Advanced Rate Design For Load Management Docket No. E002/CI-24-115).

⁶⁰ Minn. Stat. § 216C.05, subd. 2(4).

⁶¹ Ex. XLI-3 at 32:13-17 (Ly Direct).

⁶² XLI Initial Br. at 8.

⁶³ XLI Initial Br. at 12.

⁶⁴ Department Initial Br. at 12.

⁶⁵ CUB Initial Br. at 1.

96. The determination of a proper ROE is a pragmatic exercise. Both Witness LaConte and Witness Nowak recognize that an element of subjective judgment exists that factors into recommending an ROE.⁶⁶

97. While methodologies exist and are used to estimate a reasonable ROE, the Commission has stated a preference for the two-growth discounted cash flow (“DCF”) methodology.⁶⁷ Therefore, the two-growth range of results should be given priority in this proceeding.

98. The Company offers no evidence that its current authorized ROE of 9.25% has been insufficient to maintain its very high credit rating. The Company acknowledged in discovery that “NSP has not experienced difficulties accessing capital markets since its last litigated base rate case.”⁶⁸

99. Additionally, the Company provides no evidence supporting the need for a 105-basis point increase to attract capital and maintain financial integrity. The Company’s ROE analysis improperly applies several methods that have been rejected in other jurisdictions, such as by the Federal Energy Regulatory Commission (“FERC”)⁶⁹ (i.e., Risk Premium approach and the Expected Earnings method), and incorporates a flotation cost adjustment—none of these methods or adjustments are “widely used or accepted by this Commission or regulatory commissions in other jurisdictions.”⁷⁰

100. Company Witness Nowak improperly combined the Company’s DCF analysis with the results of its CAPM, Risk Premium, and Expected Earnings analyses. To the extent Witness Nowak’s ROE recommendation incorporates use of those methodologies, the ALJ should recommend little to no weight be given to the recommendation.

101. Following the Commission’s guidance regarding the two-growth DCF method, XLI Witness LaConte built an ROE recommendation through use of three DCF models (a Constant

⁶⁶ See Ex. Xcel-24 at 34:23-35:4 (Nowak Direct) (explaining his process of selecting various models to consider when determining the appropriate cost of equity); Ex. XLI-2 at 28:6-10 (LaConte Direct) (explaining her use of a risk adjustment).

⁶⁷ *In the Matter of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, PUC Docket No. E017/GR-20-719, Findings of Fact, Conclusions, and Order at 34 (Feb. 1, 2022) (concluding the two-growth DCF method is the best approach).

⁶⁸ Ex. XLI-8 at 9:12-10:1 (LaConte Surrebuttal) (citing NSP Response to XLI IR No. 40).

⁶⁹ FERC explicitly determined that no evidence exists to suggest investors use the Risk Premium methodology or evidence that would resolve the circularity problems inherent in the Risk Premium model; therefore, FERC 1 excludes the Risk Premium model for estimating the ROE. *Association of Businesses Advocating Tariff Equity et al. v. Midcontinent Independent System Operator, Inc., et al.*, Docket Nos. EL14-12-016, Order on Remand at 16. (Oct. 17, 2024).

⁷⁰ Ex. XLI-2 at 3:1-6 (LaConte Direct).

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% ROE (before adjustment).⁷¹

102. Based on the Commission's explicit guidance that the DCF methodology is the best approach across methodologies, the ALJ should focus the ROE determination on the two-growth DCF modeling results, which may be further refined to reflect the Company's risk factors and additional adjustments proposed by Witness LaConte.⁷²

103. In her final recommendation, Witness LaConte adjusted the results of her modeled ROE down by 50 basis points to account for the Company's reduced risk, and 10 basis points to account for NSP's failure to meet requirements for providing reliable billing and customer service.⁷³

104. XLI's recommended ROE of 8.96% reasonably tracks the two-growth DCF results of both the Company and Ms. LaConte.⁷⁴

105. Consistent with long-standing Commission preference, Witness LaConte employed several accepted models (i.e., CAPM) based on financial theory to provide a further check on the two-growth DCF analysis.⁷⁵

106. Evidence of various risk mitigation measures also supports an ROE of 8.96% or lower. The Company possesses various risk mitigation tools, including a multitude of adjustment clauses, its sales true-up, its projected test-year, and the MYRP itself, which together facilitate NSP's rate increases for an additional year without filing a rate case.⁷⁶

107. The Company is one of only seven other companies in the proxy group of 58 companies that holds six or more adjustment clauses.⁷⁷ These risk mitigation measures serve to reduce the Company's relative risk profile.

108. The Company's "credit metrics exceed, or are well within the range, required by S&P to maintain an A/A- credit rating which is the rating that NSPM wishes to continue to support and maintain."⁷⁸

⁷¹ Ex. XLI-2 at 26:1-2 (LaConte Direct).

⁷² See Ex. XLI-2 at 18:5-7 (LaConte Direct).

⁷³ Ex. XLI-2 at 28:13-16 (LaConte Direct).

⁷⁴ XLI Initial Br. at 15-17.

⁷⁵ Ex. XLI-2 at 19:3 (LaConte Direct) ("The CAPM methodology was performed as a check on my DCF analyses.").

⁷⁶ XLI Initial Br. at 18.

⁷⁷ XLI Initial Br. at 18.

⁷⁸ XLI Initial Br. at 13 (citing Ex. XLI-2 at 8:4-6 (LaConte Direct) (internal quotations omitted)).

109. Record evidence also shows that the Company’s cost recovery mechanisms are driving earnings per share (“EPS”).⁷⁹

110. XLI’s initial brief shows over 50% of the increase in EPS for Xcel Energy, Inc. from \$3.21 in 2023 to \$3.44 in 2024 was due to NSP increasing its EPS by \$0.13 from \$1.28 to \$1.41.⁸⁰ According to the 10-K, “[o]ngoing earnings [for NSP] increased due to higher recovery of electric and natural gas infrastructure investments, partially offset by increased depreciation and interest charges.”⁸¹

111. Further, numerous NSP customers have experienced significant billing and customer service issues, despite the Company’s statutory charge and regulatory requirements to provide customers with a certain level of care.⁸²

112. The Company bears the burden to demonstrate that its rate requests are reasonable and that it is meeting its service quality requirements.⁸³

113. The Company’s testimony supporting its proposed ROE is unpersuasive; whereas testimony put forth by XLI is credible and should be given greater weight.

II. Annual Incentive Pay (“AIP”) and Long-Term Incentive Compensation

114. Incentive compensation is the “additional payment to employees to reward certain behavior and/or results.”⁸⁴

115. The Company requests incentive compensation, totaling \$23.5 million for 2025, and \$24.2 million for 2026.⁸⁵ The requested amount represents an increase to the cap on incentive compensation to 20% of aggregate base pay, an increase from its current 15% cap.⁸⁶

116. XLI and the Department opposed the Company’s proposal and recommend maintaining the AIP cap at 15%.⁸⁷

⁷⁹ XLI Reply Brief at 9; *see* Ex. DOC-26 at 26 (Xcel Energy Inc.’s 2024 Form 10-K).

⁸⁰ Ex. DOC-26 at 26 (Xcel Energy Inc.’s 2024 Form 10-K).

⁸¹ Ex. DOC-26 at 26 (Xcel Energy Inc.’s 2024 Form 10-K).

⁸² Ex. XLI-2 at 59:3-6 (LaConte Direct).

⁸³ Minn. Stat. § 216B.03; *see* Minn. Rules Chapter 7826.

⁸⁴ Ex. XLI-2 at 43:2-3 (LaConte Direct).

⁸⁵ Ex. XLI-2 at 43:6-9 (LaConte Direct).

⁸⁶ Ex. Xcel-64 at 15:22-25 (Ly Direct); Ex. XLI-2 at 43:11-12 (LaConte Direct).

⁸⁷ XLI Initial Br. at 19; Department Initial Br. at 50.

117. The Company’s Annual Incentive Program (“AIP”) is available to exempt, non-bargaining employees. The AIP represents a component of the employee’s total compensation package.⁸⁸

118. The AIP is intended to “align the focus and execution of key, strategic business goals,”⁸⁹ and to incentivize the Company’s achievement of Corporate Key Performance Indicators (“KPI”), which are as follows: (1) Customer Satisfaction, (2) Public Safety, (3) Electric System Reliability, (4) Employee Safety, (5) Diversity, Equity, And Inclusion, and (6) Wind Availability.⁹⁰

119. Prior to achievement of the AIP, the Company must also achieve a certain earnings per share (“EPS”) threshold, which serves as the ultimate trigger for the AIP to be released.⁹¹

120. AIP is not paid unless the Company’s EPS threshold is reached.⁹²

121. Evidence in the record illustrates that AIP is not driven by ratepayer outcomes—it is driven by outcomes that benefit the Company and its shareholders. The fundamental driver of AIP is the affordability triggers, which are based on the Company meeting specific EPS targets.⁹³

122. The Company argues that KPIs incentivize employees to achieve ratepayer-focused outcomes.⁹⁴ I find this evidence unpersuasive, because the Company admits that no AIP is paid without meeting the affordability trigger.⁹⁵ Therefore, the driver of AIP is creating a specific base level of shareholder returns, not protecting ratepayers.

123. Other Minnesota utilities have received an increase to their AIP cap on the basis that they have eliminated skewed incentives favoring shareholders.

124. The Company has not sufficiently shown that it does not have skewed incentives; that its AIP payout hinges on achievement of EPS is a significant incentive skewed toward shareholders.

⁸⁸ Ex. Xcel-64 at 13:16-27 (Ly Direct).

⁸⁹ Ex. Xcel-64 at 13:16-27 (Ly Direct).

⁹⁰ Ex. Xcel-64 at 15:9-15 (Ly Direct); Ex. Xcel-64 at Schedule 4a (Ly Direct).

⁹¹ Ex. Xcel-64 at 20:14-15 (Ly Direct).

⁹² XLI Initial Br. at 21.

⁹³ XLI Initial Br. at 20-21.

⁹⁴ Ex. Xcel-62 at 20:17-21:6 (Ly Direct).

⁹⁵ XLI Initial Br. at 20-21; Evidentiary Hearing Tr. Vol. 1 at 148:19-25 (Ly).

125. The Department asserts explicitly that the Company’s AIP program “continues to incentivize employees to act in shareholders’, not ratepayers’ interests because an earnings-per-share threshold must still be met before payouts occur.”⁹⁶

126. Similarly, the OAG agrees that AIP compensation “is fundamentally predicated on maximizing shareholder value.”⁹⁷

127. The Company also seeks recovery of long-term incentive compensation in rate base,⁹⁸ requesting to recover \$11.5 million in LTI in 2025 and \$12.1 million in 2026.⁹⁹

128. The Company’s LTI scheme is structured such that one component is tied to environmental goals, while the other is tied to time-based compensation.¹⁰⁰

129. The environmental goals the Company proposes to achieve are similar or the same to what Minnesota’s Carbon-Free Standard requires (i.e., an electric utility to generate or procure electricity from carbon free technologies in an amount equivalent to 100% of the utility’s electric sales to retail customers in Minnesota.”¹⁰¹).

130. Ratepayers should not be responsible for funding utility incentives based on what the utility is already required to do by state law. That provides no incremental benefit to ratepayers.

131. Further, regarding the time-based component of LTI, this component is based on achieving certain financial targets that benefit shareholders, not ratepayers. I am not persuaded that this is an expense that should be recovered from ratepayers.¹⁰²

III. Operations & Maintenance Expense (“O&M”)

132. Energy Supply O&M, which relates to the Company’s “generation fleet and include[s] Internal Labor, Contract Labor, Materials, Chemicals and Other.”¹⁰³

133. The Company proposed to recover Energy Supply O&M expense (\$122.3 million and \$140.7 million in 2025 and 2026, respectively) and Transmission O&M expense (\$18.9 million and \$19.4 million in 2025 and 2026, respectively).¹⁰⁴

⁹⁶ DOC Initial Br. at 49.

⁹⁷ OAG Initial Br. at 31.

⁹⁸ Ex. XLI-2 at 48:3-4 (LaConte Direct).

⁹⁹ Ex. XLI-2 at 48:3-4 (LaConte Direct).

¹⁰⁰ Ex. XLI-2 at 48:6-8 (LaConte Direct).

¹⁰¹ Minn. Stat. § 216B.1691, subd. 2g (2024).

¹⁰² Ex. XLI-2 at 48:15-49:2 (LaConte Direct).

¹⁰³ Ex. XLI-2 at 50:9-10 (LaConte Direct).

¹⁰⁴ XLI Initial Br. at 24.

134. The Company historically overstates its Energy Supply O&M and Transmission O&M costs. For Energy Supply O&M, the Company has overstated it by an average of about 4.3% over the past three years, which represents an additional approximately \$14.7 million recovered from ratepayers that was unnecessary over the past three years.¹⁰⁵

135. For Transmission O&M, NSP's consistent overstatement of its Transmission O&M expense averages 16.2% over the last three years, resulting in customers paying an additional \$11.4 million for this expense.¹⁰⁶

136. The Company continues that trend in this rate case, budgeting more than is needed.¹⁰⁷

137. Further, the Company's use of a projected test year, rather than historical test year, to set rates can disadvantage customers, leading to excessive or biased projections.¹⁰⁸

138. Allowing the Company to recover higher rates will directly deny customers the opportunity to benefit from the Company's lower Energy Supply O&M costs through lower rates.

139. The Commission should protect ratepayers by approving lower Energy and Transmission O&M costs to ensure they pay the lowest possible rate, while also assuring the Company can be made whole through its true-up mechanism.¹⁰⁹

IV. Excess Liability Insurance

140. Excess Liability Insurance ("ELI") is procured by NSP's parent company, Xcel Inc., and allocated out to its subsidiaries.

141. NSP's allocated ELI expense has increased by an overwhelming 160% from its last base rate case.¹¹⁰

142. NSP's historical and projected ELI expenses have steadily increased from 2014 through 2026.¹¹¹

143. Such an increase might be expected from other of Xcel Energy, Inc.'s subsidiaries due to increased risk of wildfires and association mitigation costs. The same cannot be said for NSP.

¹⁰⁵ See Ex. XLI-2 at 50:14, Table 12, NSPM Projected and Actual Energy Supply O&M Expense (LaConte Direct); Ex. XLI-2 at 51:1-11 (LaConte Direct).

¹⁰⁶ Ex. XLI-2 at 52:7-10 (LaConte Direct).

¹⁰⁷ XLI Initial Br. at 25.

¹⁰⁸ Ex. XLI-8 at 13:22-25 (LaConte Surrebuttal).

¹⁰⁹ See Ex. XLI-8 at 14:9-15 (LaConte Surrebuttal).

¹¹⁰ Ex. XLI-2 at 54:16-18 (LaConte Direct).

¹¹¹ XLI Initial Br. at 26-27.

144. NSP customers should not subsidize the costs to mitigate wildfire activity in other territories in the country.¹¹²

145. NSP and its customers should only pay their fair share of the ELI premium. It is improper for NSP customers to subsidize increased ELI expenses due to wildfire activity in other territories in the country.¹¹³

V. Depreciation Expense

146. The Company proposes at the time of each plant retirement to transfer any remaining net book value and unamortized balance to a regulatory asset and earn a return at its weighted average cost of capital.¹¹⁴

147. The Company proposes to maintain the current depreciation rates for the Sherco 3 and King plants, continuing to “recover the King and Sherco Unit 3 plants over the currently approved remaining lives reflected in based rates, which are based on a June 2037 and December 2034 closure date, respectively.”¹¹⁵

148. The Department proposes to adjust the depreciable lives of the King Plant, Sherco Unit 3, and the Monticello and Prairie Island Nuclear Plants to reflect NSP’s integrated resource plan’s (“IRP”) authorized operating lives, adjustments that would result in a \$10.9 million decrease in the revenue requirement in 2025, and a \$13.6 million decrease in 2026.¹¹⁶

149. The Commission authorized a four-tiered approach for ratemaking treatment for plants retired before the end of their depreciable lives:

Tier 1 is a data gathering phase. Tier 2 determines if the early retiring assets qualify for accelerated depreciation as the appropriate ratemaking treatment, providing doing so does not result in rate shock. If that occurs, then Tier 3 should be used, which creates a regulatory asset with a possible return. Tier 4 is available for assets requiring additional analysis to determine the appropriate return, or no return, on the early-retiring plant.¹¹⁷

150. Neither the Department nor the Company provided adequate information on which to substantiate the Department’s proposal.¹¹⁸

¹¹² Ex. XLI-2 at 57:5-10 (LaConte Direct).

¹¹³ Ex. XLI-2 at 57:5-10 (LaConte Direct).

¹¹⁴ Ex. XLI-8 at 22 :3-5 (LaConte Surrebuttal).

¹¹⁵ Ex. XLI-5 at 9:4-11 (LaConte Rebuttal) (citing NSP Response to XLI-90).

¹¹⁶ Ex. XLI-5 at 3:9-16 (LaConte Rebuttal).

¹¹⁷ Ex. XLI-5 at 4:1-7 (LaConte Rebuttal).

¹¹⁸ XLI Initial Br. at 28-29.

151. The Company and the Department also failed to produce the amortization period for any remaining net book value of the Sherco Unit 3 and King plants.¹¹⁹

152. Additionally, the Department did not provide evidence that its proposal would comply with the Commission's four-tiered approach.

153. The Department's approach could lead to intergenerational inequity, which "occurs when ratepayers pay for an asset but do not receive the benefits of that asset, or ratepayers who do receive the benefit of the asset do not pay for it."¹²⁰

154. The Department's proposal to adjust the depreciation rate for the King Plant and Sherco Unit 3 may also result in rate shock.¹²¹

155. State law binds the Commission to set rates, to the maximum reasonable extent, to meet the goals in Minn. Stat. 216C.05, subd. 2(4).¹²²

156. Adjusting the depreciation rate for these plants would drive sharp increases in customer rates.¹²³

157. The Commission has warned against accelerated depreciation on the exact basis that it may cause rate shock, or have other "significant rate impacts."¹²⁴

158. It is premature to determine ratemaking treatment for the King Plant or Sherco Unit 3, given neither the Company nor the Department have provided sufficient evidence that the regulatory asset approach would balance the interests of customers and NSP, and "the amortization period for the regulatory asset would not be determined until the actual retirement of the plants."¹²⁵

159. The Company's customers should not be burdened by the costs of early retirement of coal-fired generation facilities.

¹¹⁹ Ex. XLI-8 at 23:1-4 (LaConte Surrebuttal).

¹²⁰ Ex. XLI-5 at 6:19-22 (LaConte Rebuttal).

¹²¹ XLI Initial Br. at 29-30.

¹²² XLI Initial Br. at 22-24.

¹²³ Ex. XLI-5 at 7:16-18 (LaConte Rebuttal).

¹²⁴ Ex. XLI-5 at 8:3-5 (LaConte Rebuttal) (citing *In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E-002, E-015, E-017/CI-23-375, Order Establishing Four-Tiered Approach for Ratemaking Treatment of Early Retiring Generating Facilities at 5 (May 14, 2025) (eDocket No. 20255-218956-01)).

¹²⁵ XLI Initial Br. at 30-31.

VI. Customer Care O&M Expense

160. The Company has a statutory mandate to provide a certain level of service to its customers, including a mandate to render bills regularly, and to forecast accurate monthly amounts for year-to-date tracking, budgeting, and reconciliation purposes.¹²⁶

161. As a regulated monopoly, the Company's rates and billing procedures must comply with the requirements of Chapter 7820 of the Minnesota Rules, including but not limited to 7820.3200 through 7820.3800.¹²⁷

162. XLI member, BOMA Greater Minneapolis, has reported its members experiencing an inordinate volume of billing and customer service issues since 2022, including "delayed and inaccurate bills, misapplied payments, and ineffective communications and resolutions" and erroneous disconnection notices.¹²⁸

163. The Company has a Customer Care organization intended to provide effective customer service to ratepayers, but the organization has failed to meet its obligation to provide customers with adequate customer service.¹²⁹

164. The Company has failed to provide basic customer service to the members of BOMA Greater Minneapolis on an ongoing basis, which has resulted in significant adverse impacts for its customers.¹³⁰

165. The issues experienced by these customers are well known, so much so that the Commission has opened a separate docket into this matter for residential issues, Docket No. 25-341.¹³¹ At the Commission's February 19, 2026 agenda meeting, the Commission determined to expand Docket No. 25-341 to include C&I customers, and require the Company to conduct the same reporting for C&I customers as it currently does for Residential customers.

166. The Company should not be allowed to recover Customer Care O&M expenses where it cannot meet its statutory obligations to its customers.

¹²⁶ Minn. R. 7810.1400, subp.1.

¹²⁷ Ex. XLI-2 at 64:2-7 (LaConte Direct).

¹²⁸ Ex. XLI-2 at 59:3-6 (LaConte Direct).

¹²⁹ Ex. XLI-2 at 59:17-20 (LaConte Direct).

¹³⁰ XLI Initial Br. at 32.

¹³¹ See *In the Matter of an Investigation into Xcel Energy's Residential Billing Errors*, Docket No. E,G-002/CI-25-341, Order Initiating Investigation (Sept. 10, 2025) (eDocket No. 20259-222889-01).

CLASS COST OF SERVICE STUDY (“CCOSS”)

VII. General

167. State law requires the CCOSS for any utility rate case filing,¹³² and CCOSS represents the starting point for determining the appropriate revenue allocation of a utility’s proposed revenue requirement.

168. A CCOSS is an analysis that separates the utility’s total costs into portions on behalf of the various customer classes to determine each class’s responsibility for a utility’s total costs. This analysis consists of three steps: (1) a *functionalization* of costs, (2) a *classification* of those costs’ primary causative factors, and (3) an *allocation* of those costs among the various customer classes.

169. A utility’s investments and expenses are functionalized as production, transmission, distribution, and other functions. Once functionalized, the primary causative factor of the cost is determined (i.e., classifying the cost as demand/capacity related, energy related, or customer related).

170. Finally, costs are allocated to different customer classes based on allocation factors that reflect the contributions of each class to the need for the costs, which should reflect cost causation.¹³³

171. Three parties submitted CCOSSs in this matter: the Company (supported by the Department), XLI, and the OAG.

172. The Company supported continued use of the stratification (or Equivalent Peaker) methodology.¹³⁴

173. The OAG supports the Company’s use of the stratification method and recommends use of a revised D10S allocator (i.e., twelve coincident peak (“12 CP”) allocator) for allocation of demand-related production plant costs.¹³⁵

174. XLI argued that the Company CCOSS should be replaced by a CCOSS using the Average and Excess – Four Coincident Peak (“AED-4CP”) methodology and prepared a new CCOSS (“XLI CCOSSs”).

¹³² Minn. R. 7825.4300, subp. C.

¹³³ Ex. XLI-3 at 5:5-10 (Ly Direct).

¹³⁴ Ex. XLI-3 at 6:16-18 (Ly Direct).

¹³⁵ OAG Initial Br. at 56.

175. The results of each CCOSS, which are produced in Table 2 of Company Witness Barthol’s Surrebuttal Testimony, are illustrated below in Table 1.¹³⁶

Table 2: 2026 CCOSS Results Comparison

**Table 2
2026 CCOSS Results Comparison – Deficiency %**

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG ⁴	Peak & Avg	3.6%	-8.8%	15.7%	28.7%
OAG ⁵	Basic Customer	5.9%	-8.4%	13.9%	31.4%
DOC ⁶	Basic Customer	9.6%	-11.8%	11.5%	26.9%
Xcel Energy ⁷	Hybrid	13.5%	-6.2%	8.3%	30.6%
SRA ⁸	Hybrid	13.5%	-6.1%	8.3%	29.3%
DOC ⁹	Hybrid	15.0%	-7.2%	7.3%	26.1%
XLI ¹⁰	Hybrid	16.1%	-2.0%	6.3%	19.9%

176. Based on the following analysis, I find that the OAG CCOSSs and Company CCOSS contain material flaws that render them unfit for consideration in this proceeding. Instead, I find that the AED-4CP is well-reasoned and should be the sole study used to inform revenue allocation.

a. Company CCOSS Proposal

177. The Company’s proposed CCOSS relies on the obsolete stratification methodology, which identifies plant investment incurred to provide capacity (i.e., demand-related) and investment that is a substitute for fuel costs (i.e., energy-related).¹³⁷

178. The Company classifies fixed production plant into capacity and energy-related potions as follows:

The Company classifies fixed production plant into capacity versus energy related sub-functions using a process called “Plant Stratification.”... In the NARUC manual, this process has also been referred to as the Equivalent Peaker method ... The capacity-related portion of the fixed costs of owned-generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost and the highest operating cost). The percent

¹³⁶ Ex. Xcel-75 at 8:1-3, Table 2 (Barthol Surrebuttal). Table 1 is a re-creation of Table 2 in Witness Barthol’s Surrebuttal Testimony and incorporates the same data.

¹³⁷ Ex. Xcel-73 (Barthol Direct). This approach is also known as the Equivalent Peaker methodology.

of total generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized 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.¹³⁸

179. Stratification, when operating properly, is intended to benefit customers such that “classes allocated a higher per-kW non-fuel production costs via a properly designed demand allocator would benefit from the lower per MWh fuel and purchase power expense via a properly designed energy allocator.”¹³⁹

180. Thus, when working as intended, “high-load-factor customers (customers who use more energy year-round) are allocated a proportionally larger share of fuel savings typically associated with the higher capital cost plants as a trade-off for being allocated a much higher percentage of production capital costs (i.e., “Capital Substitution”).”¹⁴⁰

181. However, the expected benefits that accompany Capital Substitution are absent in this proceeding.

182. If Capital Substitution were occurring, “classes allocated a higher per kW non-fuel production costs via a properly designed demand allocator would benefit from the lower per MWh fuel and purchase power expense via a properly designed energy allocator.”¹⁴¹

183. That symmetry does not exist in this proceeding,¹⁴² as demonstrated in XLI Witness Ly’s Schedule 1 (reproduced at Table 2 below), and therefore, the methodology is obsolete.

¹³⁸ Ex. Xcel-73 at 15:17-24 (Barthol Direct).

¹³⁹ XLI Initial Br. at 37.

¹⁴⁰ Ex. XLI-3 at 9:11-13 (Ly Direct).

¹⁴¹ XLI Initial Br. at 37.

¹⁴² See Ex. XLI-3, Schedule 1 (Ly Direct).

**Table 3: Comparison of Allocations of Non-Fuel Production Costs
and Fuel Purchased Power Expense.**

NORTHERN STATES POWER COMPANY - MINNESOTA
Allocated Non-Fuel Production Costs
& Fuel and Purchased Power Expense
Test Year Ended December 31, 2025

Line	Customer Class	Non-Fuel Production Costs		Fuel and Purchased Power Expense	
		Cost	Percent	Cost	Percent
		\$/kW	Difference	\$/MWh	Difference
		(1)	(2)	(3)	(4)
1	Residential	\$489	-14.0%	\$43.68	2.1%
2	C&I Non-Demand	\$617	8.6%	\$43.15	0.8%
3	C&I Demand	\$594	4.5%	\$42.60	-0.5%
4	Lighting	NA	NA	\$35.85	-16.2%
5	NSPM Average	\$568	0.0%	\$42.80	0.0%

Source: MN CCOSS 2025.

184. The E8760 allocator used by the Company to allocate fuel costs compounds this issue, failing to lower costs for C&I customers. For example, the residential class is “allocated non-fuel production costs 14% below the NSP average, but is allocated fuel and purchased power expenses just 2% above average.”¹⁴³

185. The lack of fuel savings may be explained by the Company’s increased reliance on some of the most capital-intensive resources, intermittent resources (i.e., wind and solar).

186. Fuel costs cannot be lowered when wind and solar resources are not operating; thus, spreading the costs of the generation to all hours of the year defies logic.¹⁴⁴

187. Because stratification is demonstrably failing to function as intended, I find that the Company CCOSS should be rejected.

188. I find that the Company’s classification of Other Production O&M expenses is flawed because it also relies on stratification, and ignores that labor costs, which do not vary with energy costs, comprise a majority of other production O&M expenses.¹⁴⁵

¹⁴³ Ex. XLI-3 at 9:23-10:2 (Ly Direct).

¹⁴⁴ Ex. XLI-3 at 8:1-7 (Ly Direct); XLI Initial Br. at 38.

¹⁴⁵ Ex. XLI-3 at 16:3-6, 14-16 (Ly Direct).

189. I find that the Company has not provided the requisite quantitative analysis to support that 30% of its transmission plant is dedicated solely to resources that provide low-cost energy to its customers.¹⁴⁶

190. The Company proposes use of the Minimum System Method (“Hybrid Method”) as the “most reasonable method to classify distribution system costs...”¹⁴⁷ XLI and the Department also support use of this method for purposes of this rate case.

191. The Department supports use of the Basic Customer Method, and the OAG supports use of the Basic Customer method and the Peak and Average (“P&A”) method.

192. Each method is used to determine customer- and demand-related costs of the distribution network.

193. To differentiate these costs, the NARUC CAM favors the minimum-size method (assumes a utility can build a minimally sized distribution network to serve the minimum electric load requirements of its customers), and the zero-intercept method (uses regression analysis of distribution network components to identify theoretical costs of equipment that serve no load).¹⁴⁸

194. For purposes of classifying distribution costs, the Basic Customer and P&A methods are fundamentally flawed.

195. The fundamental assumption underlying the Basic Customer method defies cost causation, as the method fails to recognize that both the number of customers and the need to serve peak demand make up the costs of the distribution system.

196. The P&A method is similarly flawed because because it automatically assumes that customer energy use will drive the cost of transformers and distribution lines, however, without a corresponding increase in peak demand, increased energy use will not increase the cost of the line.¹⁴⁹

197. The method overclassifies costs of conductors and transformers to energy.¹⁵⁰

198. The NARUC CAM explicitly states in regard to the classification and allocation of distribution network costs that the distribution network has no associated energy component.¹⁵¹

199. Therefore, the Basic Customer and P&A methods are inappropriate for classifying distribution costs.

¹⁴⁶ Ex. XLI-3 at 18:13-19:7 (Ly Direct); Ex. XLI-9 at 14:6-8 (Ly Surrebuttal).

¹⁴⁷ NSP Initial Br. at 247.

¹⁴⁸ Ex. XLI-3 at 21:21-22:11 (Ly Direct).

¹⁴⁹ Ex. DOC-16, Zajicek Direct at 23:8-12.

¹⁵⁰ XLI Ex. 6 at 14:8-12 (Ly Rebuttal).

¹⁵¹ Ex. XLI-9 at 16:16-21 (Ly Surrebuttal).

200. While the Company's use of the Minimum System Method is more appropriate than use of the Basic Customer and P&A methods, the Company should apply either the Minimum System or the Zero-Intercept methodologies, rather than arbitrarily blend the two.

201. Because the results in this proceeding effectively represent the results of a zero-intercept study, the Company's classification proposal in this instance is sufficiently reasonable.

b. OAG CCOSs

202. I find that the OAG CCOSs are unreliable and have no probative value in this proceeding.

203. Like the Company, the OAG continues to support use of the stratification methodology, which is an obsolete methodology.¹⁵²

204. The OAG also proposes an updated D10S allocator for use by the Company, updates which are flawed (i.e., twelve coincident peak "12 CP" allocator).¹⁵³

205. The OAG takes issue with the D10S allocator as used by the Company because (1) "the hours Xcel chose to represent "peak" load are not coincident with MISO's system peak or even Xcel's own system peak because they fall on weekends the hours Xcel chose to represent "peak" load are not coincident with MISO's system peak or even Xcel's own system peak because they fall on weekends," (2) "Xcel's D10S allocator is not based on historical data," and (3) "Xcel's D10S allocator is unduly sensitive to the choice of a single peak hour."¹⁵⁴

206. The OAG conducted its own rendition of the D10S allocator, which is based on the sum of all loads in Xcel's load forecasts for 2025 and 2026 at the hours of 3 and 4 p.m. on weekdays between June 21 and August 26, then dividing the class load totals by "the sum of the system loads for the same hours to yield the OAG's Alternate D10S Allocator."¹⁵⁵

207. XLI's analysis of these hours showed 77 hours (82%) of the total hours selected by the OAG "fall significantly below the system peak."¹⁵⁶ The resulting average load presented by the OAG's hours is just 82% of peak load.¹⁵⁷

¹⁵² OAG Initial Br. at 56-58.

¹⁵³ OAG Initial Br. at 58-59.

¹⁵⁴ OAG Initial Br. at 59-60.

¹⁵⁵ OAG Initial Br. at 60-61.

¹⁵⁶ Ex. XLI-6 at 5:15-16 (Ly Rebuttal).

¹⁵⁷ Ex. XLI-6 at 5:17-18 (Ly Rebuttal).

208. The Company is a summer-peaking system, and therefore it would be nonsensical to design the system to only meet year-round average demand, which would surely lead to a failure to meet its customers' actual peak demands during the summer.¹⁵⁸

209. Use of the 12CP allocator as recommended by the OAG would also be redundant, because the E8760 allocator appropriately recognizes reliability risks throughout the year, assigning costs to customers on that basis.¹⁵⁹

210. I find that the OAG's alternate D10S Allocator is flawed, because it relies on data that does not represent actual peak demand or the impact of the Company's system peak.¹⁶⁰

211. For these reasons, I find that the OAG CCOSSs are inconsistent with standard practice and cost-causation, and therefore inapt for this proceeding.

c. AED-4CP CCOSS

212. I find that the AED-4CP CCOSS provided by XLI is just and reasonable and the only CCOSS in the record that should inform revenue allocation in this case.

213. The AED-4CP methodology is a variation of the Average and Excess Demand allocation methodology, and the National Association of Regulated Utility Commissioners ("NARUC") Manual recognizes this methodology as one that considers energy usage and more appropriately reflects cost causation.¹⁶¹

214. The AED-4CP is recognized explicitly in the NARUC CAM as considering energy usage in developing allocation factors, and as a method that more appropriately reflects cost causation.¹⁶²

215. The AED-4CP methodology recognizes two critical cost drivers: "(1) off-peak loads do not drive a utility's capacity needs to the same degree as on-peak loads; and (2) very high-load-factor loads are quite flat, and have significantly lower variability than low-load-factor loads."¹⁶³

216. The method recognizes the Company operates its generating fleet as an integrated system, since the AED-4CP method "recognizes that load-following resources are an essential

¹⁵⁸ Ex. XLI-3 at 19:10-17 (Ly Direct).

¹⁵⁹ Ex. XLI-3 at 20:5-11 (Ly Direct).

¹⁶⁰ Ex. DOC-18 at 11 (Zajicek Surrebuttal).

¹⁶¹ Ex. XLI-3 at 11:12-15 (Ly Direct).

¹⁶² Ex. XLI-3 at 11:12-15 (Ly Direct).

¹⁶³ Ex. XLI-3 at 12:11-16 (Ly Direct).

attribute of a reliable generation fleet and further, that certain customer classes require more load-following resources than other classes.”¹⁶⁴

217. Several other jurisdictions have adopted the AED-4CP method, including Arizona, Colorado, Kansas, Missouri, New Mexico, and Texas (note, NSPM affiliates, Public Service Company of Colorado and Southwestern Public Service Company, operate in three of these jurisdictions).¹⁶⁵

218. The AED-4CP was also accepted by the Commission in Minnesota Power’s 2021 rate case.¹⁶⁶

219. Despite the Company’s concerns that AED-4CP does not allocate production plant costs based on weighted hourly marginal energy costs, XLI’s CCOSs need not consider marginal energy costs, since doing so would result in marginal energy costs causing production plant costs.¹⁶⁷

220. The Company has not provided persuasive evidence that stratification is a more appropriate allocation methodology than AED-4CP.

221. Given its prevalence in states where the Company operates, the Commission’s own adoption of the methodology, and evidence outlining the validity of the AED-4CP, I find that the XLI CCOS should be the only one used to inform revenue allocation in this proceeding.

REVENUE ALLOCATION

222. Electricity is a significant operating expense for industrial customers who face increased domestic and global competition, which limits industrial customers’ ability to pass on higher electricity costs.¹⁶⁸

223. Because C&I customers have a finite ability to pass on higher electricity costs, and are impacted significantly by interclass subsidies on the Company’s system.¹⁶⁹

224. Minimizing interclass subsidies is important and provides benefits to the Company and its customers by promoting efficiency, stability, and conservation, while ensuring all customers have just and reasonable rates.¹⁷⁰ The avoidance of interclass subsidies comports with Minn. Stat. § 216B.03.

¹⁶⁴ Ex. XLI-3 at 13:15-18 (Ly Direct).

¹⁶⁵ Ex. XLI-3 at 14:16-19 (Ly Direct).

¹⁶⁶ Ex. XLI-3 at 15:3-4 (Ly Direct).

¹⁶⁷ Ex. XLI-9 at 7:14-17 (Ly Surrebuttal).

¹⁶⁸ Ex. XLI-6 at 22:15-20 (Ly Rebuttal).

¹⁶⁹ XLI Initial Br. at 46-47.

¹⁷⁰ XLI Initial Br. at 48.

225. Ratemaking principles and cost causation dictate that base revenues should reflect the actual costs for a utility to provide service to customer classes, as doing so provides the foundation for cost-based rates and send appropriate price signals to ratepayers.

226. Cost of service is an explicit factor the Commission considers when setting rates, which the public utility requesting the rate increase bears the burden to prove.¹⁷¹

227. The Commission has supported moving rates to cost.¹⁷²

228. The Company's contention that its proposal to allocate its requested base revenue increase will move customer classes 20% toward cost-based rates is flawed.

229. In fact, C&I Demand customers' subsidies to the Residential and Lighting class would increase under the proposal.¹⁷³

230. The proposal would fail to comply with the requirements of Minn. Stat. § 216C.05, which directs the achievement of retail electricity rates that are at least 5% below the national average for each customer class. For example, the current average monthly bill for certain large industrial customers is 13% above the national average, which would increase to 22% with the proposal in the Company's MYRP.¹⁷⁴

231. The revenue allocation in this proceeding should move customers closer to cost of service under a valid CCOSS.

232. Moving customer rates closer to cost provides benefits to the Company and its customers, and comports with Commission precedent.

233. XLI's CCOSS is the only one that would satisfactorily move customer rates closer to cost.

234. Given the Company's serious departure from the state's goal to set rates at least 5% below the national average for all customer classes, revenue allocation should be based on cost of service.

¹⁷¹ *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order at 50 (Feb. 28, 2023) (eDocket No. 20232-193486-01).

¹⁷² Ex. XLI-3 at 28:18-19 (Ly Direct).

¹⁷³ Ex. XLI-3 at 31:12-16 (Ly Direct).

¹⁷⁴ Minn. Stat. § 216C.05 (2024); Ex. XLI-3 at 32:5-9 (Ly Direct).

RATE DESIGN

I. Proposed Large Load Tariff

A. Findings of Fact

235. The Company proposed a new tariff to serve large load customers (“Data Center Tariff”) in Docket No. E002/M-25-289, wherein it proposes to (1) treat new large loads as sub-classes within the C&I Demand class and (2) allocate any additional revenues required from Large General Time of Day Service and Large Peak Controlled Time of Day Service customers as a result of the incremental cost test based on the test year base revenue allocation.¹⁷⁵

236. The Company has yet to explain (1) how these new sub-classes would be recognized in the CCOSS, and (2) has not justified its proposal to use base rate revenues to allocate incremental revenues that may be recovered from new large load customers.¹⁷⁶

237. Customer classes should be defined so as to group together customers with similar usage characteristics, with primary differentiating characteristics being “size, how and when electricity is used (i.e., load factor and coincidence factor), whether service is firm or curtailable, and delivery voltage.”¹⁷⁷

238. Concerning to me is Large General Time of Day customers will generally be much larger, accruing electrical demands of at least 100 megawatts.¹⁷⁸

239. Further, data centers run nonstop, and operate at very high load factors (i.e., 90%+). data centers run nonstop, and operate at very high load factors (i.e., 90%+).

240. Given the wide variance of customer types within the C&I demand class, the establishment of a new, distinct Large General Time of Day Service class separate from the existing C&I Demand class would most appropriately account for the unique characteristics, electrical demand, and load features of such large load customers.¹⁷⁹

241. The Company did not provide sufficient evidence to justify its proposal to use base rate revenues to allocate incremental revenues that may be recovered from new large load customers.

242. The incremental costs in the Company’s Incremental Cost Test would be comprised of “energy costs based on forecast fuel rates, capacity costs based on the potential need for resource additions consistent with the Company’s latest Integrated Resource Plan, and the net increase in MISO-related costs, adjusted for the impact of any jurisdictional cost allocation increase,” but a

¹⁷⁵ Ex. XLI-9 at 21:4-11 (Ly Surrebuttal).

¹⁷⁶ XLI Initial Br. at 52-53.

¹⁷⁷ Ex. XLI-9 at 21:16-20 (Ly Surrebuttal).

¹⁷⁸ Ex. XLI-9 at 22:2-4 (Ly Surrebuttal).

¹⁷⁹ Ex. XLI-9 at 22:11-14 (Ly Surrebuttal).

significant amount of the incremental base rate costs would directly relate to production and transmission plant and related expenses.¹⁸⁰

243. As a result, using base rate revenue to allocate the incremental revenues would defy cost causation principles.

244. I find that the Commission should direct that any incremental revenues collected from new large load customers be allocated to customer classes the way NSP allocates its production and transmission plant, to ensure cost allocation for new large load customers is consistent with cost causation.¹⁸¹

CONCLUSIONS OF LAW

REVENUE REQUIREMENT ISSUES

I. Return on Equity (“ROE”)

245. Two Supreme Court cases guide evaluation of a fair ROE: *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia*¹⁸² (“*Bluefield*”), and *Federal Power Commission v. Hope Natural Gas Co.*¹⁸³ (“*Hope*”).

246. Neither the *Hope* and *Bluefield* decisions nor Minnesota law require the Commission to provide investors with above average returns. Utilities are only allowed an opportunity to earn a return commensurate with risk. The law does not provide the Company a guarantee of a return.¹⁸⁴

247. Minnesota law requires that customer rates be just and reasonable.¹⁸⁵

248. The Company failed to satisfy its affirmative burden to show that its proposed ROE is reasonable. And any doubt as to the reasonableness of the Company’s proposal must be resolved in favor of ratepayers.¹⁸⁶

249. The Company’s reduced risk profile, along with its billing and customer service issues, warrant a 50- and 10- basis point reduction, respectively, to its ROE.

¹⁸⁰ Ex. XLI-9 at 23:12-19 (Ly Surrebuttal).

¹⁸¹ Ex. XLI-9 at 23:12-19 (Ly Surrebuttal).

¹⁸² 262 U.S. 679 (1923).

¹⁸³ 320 U.S. 591 (1944).

¹⁸⁴ XLI Initial Br. at 13; *see* Ex. XLI-2 at 17:6-9 (LaConte Direct); Ex. Xcel-24 at 42:19-21 (Nowak Rebuttal).

¹⁸⁵ Minn. Stat. § 216B.03.

¹⁸⁶ Minn. Stat. § 216B.03.

II. Annual Incentive Pay (“AIP”) and Long-Term Incentive Compensation

250. Rates must be just and reasonable.¹⁸⁷

251. The Company bears the burden to demonstrate its proposal to increase its AIP cap to 20% will result in just and reasonable rates for its customers.

252. The Company fails to satisfy its affirmative burden of proof in this proceeding, which requires it to show that it is just and reasonable for ratepayers to bear the proposed increases.

III. Operations & Maintenance Expense (“O&M”)

253. The Company bears the burden to demonstrate its proposal will result in just and reasonable rates for its customers, and that it is just and reasonable for ratepayers to carry these costs.

254. The Company failed to show its request to increase its Energy Supply O&M and Transmission O&M costs tracks with its historical spending. Therefore, it is not just and reasonable for ratepayers to bear this cost.

IV. Excess Liability Insurance

255. The Company bears the burden to demonstrate its proposal will result in just and reasonable rates for its customers, and that it is just and reasonable for ratepayers to carry these costs.

256. The Company failed to meet its burden to establish that rate-basing these increased ELI costs is appropriate.

257. A reduction to the Company’s ELI expense will facilitate recognition of the increased wildfire risk for all utilities, while protecting NSP customers from an outsized portion of Xcel Energy Inc.’s total ELI expense.

258. The Commission should limit NSP’s allowed ELI expense to ensure NSP customers do not subsidize customers in other jurisdictions that have experienced significant wildfires.

V. Depreciation Expense

259. Adopting the Department’s proposal regarding the King Plant and Sherco Unit 3 could lead to intergenerational inequity and result in rate shock, and thus be inconsistent with Minn. Stat. 216B.16, subd. 6.

¹⁸⁷ Minn. Stat. § 216B.03.

260. The Company's proposal to maintain the current depreciation rates for both the King Plant and Sherco Unit 3 satisfies its burden of proof, as it would result in just and reasonable rates for ratepayers.

VI. Customer Care O&M

261. The Company bears the burden to demonstrate its proposal will result in just and reasonable rates for its customers, and that it is just and reasonable for ratepayers to carry these costs.

262. Recovery of Customer Care O&M expenses from ratepayers without providing them with basic levels of customer care would defy just and reasonable ratemaking.

263. The Company has failed to meet its burden of proof to demonstrate that it should recover Customer Care O&M expenses while failing to meet its statutory obligations for customer service.

CLASS COST OF SERVICE STUDY ("CCOSS")

264. The CCOSS is a requirement under state law for any utility rate case filing.¹⁸⁸

265. The Company bears the burden to demonstrate its revenue allocation method will result in just and reasonable rates for ratepayers.

266. The Company's chosen allocation method, stratification, is obsolete and renders the Company's CCOSS unreliable.

267. The Company failed to satisfy its affirmative burden of proof, which would require it to prove the validity of the Company CCOSS as a judicial fact and then demonstrate that the Company CCOSS is a just and reasonable starting point to determine revenue apportionment.

268. Evidence demonstrates that the OAG CCOSSs fail to rely on reliable methods for revenue allocation to a degree that departs the legal standard for just and reasonable rates.

REVENUE ALLOCATION

269. Minnesota law requires that rates be just and reasonable.¹⁸⁹

¹⁸⁸ Minn. R. 7825.4300, subp. C.

¹⁸⁹ Minn. Stat. § 216B.03.

270. “To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05.” This is a “statutory directive.”¹⁹⁰

271. The Company’s evidence supporting its proposed revenue allocation fails to satisfy its affirmative burden of proof, as well as statutory mandates, and is unpersuasive.

272. The Company failed to provide sufficient evidence to show that certain customers absorbing larger increases to support Residential customers is consistent with Minnesota law or reasonable (i.e., the second prong of its burden of proof).

RATE DESIGN

273. The Company has not satisfied its burden of proof to show that its new large load proposal will result in just and reasonable rates for ratepayers, and will not unduly burden existing C&I Demand customers.

RECOMMENDATIONS

REVENUE REQUIREMENT ISSUES

II. Return on Equity (“ROE”)

274. Based upon evidence in the record and application of the burden of proof, the Company has failed to satisfy its burden of proof with respect to its 10.30% ROE proposal.

275. I find that evidence in the record supports an ROE of 8.96% or lower, to account for the risk mitigation measures in place at the Company and customer service issues experienced by the Company’s ratepayers.

III. Annual Incentive Pay (“AIP”) and Long-Term Incentive Compensation

276. The Company’s request to increase the AIP cap from 15% to 20% should be rejected because the Company failed to show that employees’ performance benefits ratepayers. Therefore, it is not just and reasonable for ratepayers to bear this cost.

277. The Company’s request to include long-term incentive compensation in rate base should be denied consistent with previous decisions, and because this expense provides no affirmative benefit to ratepayers.

¹⁹⁰ *In the Matter of a Petition of Northern States Power, doing business as Xcel Energy, for Approval of General Time-of-Use Service Tariff*, PUC Docket No. E-002/M-20-86, Order to Conduct Pilot Programs for General Service Time-of-Use Rates, and Setting Procedural Schedule at 11 (July 16, 2021).

IV. Operations & Maintenance Expense (“O&M”)

278. The Company’s proposed Energy Supply O&M and Transmission O&M costs should be reduced to reflect historical spending and its ability to recover costs through its true-up mechanism.

279. The Company’s request to increase its Energy Supply O&M and Transmission O&M costs in rate base should be denied.

V. Excess Liability Insurance

280. The Company’s requested ELI expense should be limited to ensure NSP customers are not subsidizing customers in other jurisdictions.

VI. Depreciation Expense

281. The Department’s proposal should be denied because it is inconsistent with Minnesota law and will not create just and reasonable rates for ratepayers.

VII. Customer Care O&M

282. The Commission should disallow the Company’s request for customer care O&M expenses in the amount of \$27.3 million in 2025 and \$27.1 million in 2026 in their entirety unless and until the Company can demonstrate it has remedied its customer service and billing issues.

CLASS COST OF SERVICE STUDY (“CCOSS”)

283. XLI’s AED-4CP CCOSS is just and reasonable and should be the only CCOSSs to inform revenue allocation in this proceeding.

284. The Company should re-run its CCOSS, using the final approved revenue requirement and the AED-4CP to determine the final revenue allocation in this case.

285. The OAG CCOSSs rely on methodologies that are inappropriate for determining revenue allocation, and should be given little weight.

REVENUE ALLOCATION

286. Because the Company failed to satisfy its burden of proof and its proposed revenue allocation is inconsistent with both its stated goals and Minnesota law, it should be rejected.

287. The revenue allocation decided in this case should move all customer classes to cost of service.

288. The Commission should adopt the AED-4CP CCOSS produced by XLI for both the initial and subsequent years of the MYRP, because it is the only one that recognizes explicit state energy policy and appropriately considers the disproportionate harm the Company’s current rate structure has inflicted upon C&I Demand customers.

RATE DESIGN

289. The Commission should direct the Company to file an updated CCOSS addressing customer differences once it sees an increase of 8% to 10% of current MWh sales from new data center load. Such a filing should be made in its active general rate case pending at that time, or otherwise in this docket.

290. The Commission should clearly direct the Company to create a new, distinct subclass separate from the existing C&I Demand class to account for new large load customers.

Dated: _____

By: _____

The Honorable Joseph Meyer
Administrative Law Judge
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620

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