

**BEFORE THE MINNESOTA COURT OF ADMINISTRATIVE HEARINGS
600 North Robert Street
Saint Paul, Minnesota 55101**

**FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
Saint Paul, Minnesota 55101-2147**

**IN THE MATTER OF THE APPLICATION OF
NORTHERN STATES POWER COMPANY
FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE
IN MINNESOTA**

**CAH Docket No. 28-2500-40515
MPUC Docket No. E-002/GR-24-320**

**PROPOSED FINDINGS OF FACT, CONCLUSIONS OF LAW, AND
RECOMMENDATION OF
NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY**

February 25, 2026

**Eric F. Swanson
Winthrop & Weinstine, P.A.
225 South Sixth Street, Suite 3500
Minneapolis, Minnesota 55402**

**Ian M. Dobson
Northern States Power Company
d/b/a Xcel Energy
414 Nicollet Mall
Minneapolis, Minnesota 55401**

Attorneys for Xcel Energy

TABLE OF CONTENTS

	Page
STATEMENT OF THE ISSUES	2
SUMMARY OF CONCLUSIONS	5
FINDINGS OF FACT	5
I. SUMMARY OF THE APPLICATION AND CURRENT REQUEST	5
II. PARTIES	6
III. SUMMARY OF PUBLIC COMMENTS	7
IV. JURISDICTION	8
V. PROCEDURAL BACKGROUND	9
VI. CASE OVERVIEW	22
VII. LEGAL STANDARDS	27
A. Cost Of Capital And Return On Equity	28
B. Revenue Requirements.....	30
C. Revenue Allocation And Rate Design	32
VIII. UNDISPUTED OR RESOLVED ISSUES	32
A. Cost Of Capital.....	32
1. Capital Structure.....	33
2. Cost Of Long-Term Debt.....	33
3. Cost Of Short-Term Debt.....	34
B. Revenue Related Issues.....	34
1. 2025 Sales Forecast Update	34
2. 2025 Late Fee Revenue	34
3. Capacity Revenue Baseline And True-Up	35
4. Prairie Island Capacity Revenues	36
C. Expense or Rate Base Issues	36
1. Community Solar Gardens.....	36
2. Customer Advances	37
3. Nuclear Decommissioning Accrual/Nuclear End-of- Life Accrual	37

4.	Transmission, Distribution, And General (TD&G) Depreciation	38
5.	Distributed Intelligence My Energy Connection (MEC) 3.0	38
6.	Distributed Intelligence	38
7.	Employee Expenses	39
8.	Electric Vehicle Program	39
9.	Generation Capacity Revenues	40
10.	Hosting Capacity	40
11.	Luverne Battery Reallocation	41
12.	Nuclear Production Tax Credit	41
13.	Solar Production Tax Credits - Allocation.....	42
14.	Federal Production Tax Credits	42
15.	Remaining Lives And Net Salvage Rates - Production	43
16.	Remaining Lives - Nuclear	44
17.	TCR Rider Removal FERC Reclassification	44
18.	TCR Rider Removal Update	45
19.	Service Quality	45
20.	Sherco Inventory Write Off	45
21.	Wildfire Mitigation Pole Loading Clearance (PLC) Update	46
22.	Wildfire	46
23.	Research And Experimentation Federal And State Tax Credits	47
24.	North Dakota Investment Tax Credits	48
25.	Distribution Communications Infrastructure	48
26.	Bad Debt Expense Adjustment	49
27.	Discrete Capacity Project Investments	49
28.	Fault Location And Isolation Service Restoration (FLISR)	50
29.	Property Tax True-Up	51
D.	Class Cost Of Service Study	52

E.	Revenue Apportionment And Rate Design.....	52
1.	Rate Design Proposals.....	52
2.	Conservation Cost Recovery Charge	52
3.	Excess Footage Charges, Winter Construction Charges, And Dedicated Switching.	53
F.	Additional Issues	54
1.	Reporting Requirements.....	54
2.	Fuel Clause Rider	55
3.	ATO/MTO Dual Feeder Service.....	55
4.	Coal Combustion Residuals Tracker.....	56
5.	Bad Debt Expense Tracker.....	58
6.	PowerOn Auto Enrollment.....	59
7.	MYRP Issues.....	59
IX.	DISPUTED ISSUES	60
A.	Overall Cost Of Capital – Return On Equity	60
1.	Xcel’s Proposed ROE	61
2.	XLI’s Proposed ROE	65
3.	The Department’s Proposed ROE.....	66
4.	CUB’s Proposed ROE.....	68
5.	Analysis And Recommendation.....	68
6.	Recommended Overall Cost Of Capital.....	75
B.	Revenue Requirement Issues	76
1.	Revenues	76
a.	Late Payment Fees	76
b.	Reconnection Fees	78
2.	Rate Base And Expense Items	80
a.	Energy Supply O&M	80
b.	Transmission O&M.....	83
c.	Distribution O&M.....	87
d.	Customer Care O&M.....	89
e.	Liquidated Damages	91

f.	Compensation And Benefits	93
	(i) Base Pay.....	93
	(a) Base Pay Amount.....	93
	(b) Future Rate Case Compliance	98
	(ii) Incentive Compensation.....	98
	(a) Annual Incentive Plan (AIP) Compensation	99
	(b) AIP Cap Amount	100
	(c) AIP Cap Calculation	103
	(d) Long-Term Incentive (LTI) Compensation	104
	(iii) Executive Compensation	109
	(iv) Limited Availability Benefits	114
	(v) Misc. Benefit, Life, LTD Expenses	115
	(vi) Non-Qualified Expenses	117
g.	FERC Account 923 (Outside Services Employed Expense)	118
h.	Insurance Premium Expenses	121
i.	Prepaid Pension And Accrued Liabilities	123
j.	Allocations	129
	(i) General Allocator.....	129
	(ii) Interchange Agreement Allocator.....	131
	(iii) Wildfire Allocations.....	136
k.	Sherco Unit 3 And Allen S. King Coal Plants Remaining Lives	138
l.	Sherco 3 Restoration Costs	141
m.	Riverside Generating Unit	141
n.	Rate Case Expenses	143
o.	Time-of-Use Rate Implementation Costs	147
p.	Extreme Heat/Poor Air Quality Reconnection Program.....	153
q.	Property Tax.....	158

r.	Board Of Directors Expense	161
s.	Organizational Dues (EEI, Chamber Of Commerce).....	163
(i)	EEI Dues	163
(ii)	Chambers Of Commerce.....	166
t.	Employee Recognition Awards	167
u.	Investor Relations Expenses	170
v.	Distribution Targeted Undergrounding.....	170
w.	Distribution Capacity Investments.....	173
x.	Distribution Communications Infrastructure	175
y.	Virtual Power Plants	176
z.	Equity Considerations In Distribution Operations And Planning.....	178
aa.	Good Neighbor Plan (NOx) Tracker Proposal.....	180
C.	Class Cost of Service Study	181
1.	Compliance – Capital Structure	182
2.	Classification Of Fixed Production Plant.....	183
3.	Allocation Of Demand-Related Production Costs (D10S Allocator).....	185
4.	Allocation Of Demand-Related Transmission Costs.....	186
5.	Classification And Allocation Of Shared Distribution Costs.....	187
a.	Minimum System Method	188
b.	Basic Customer Method.....	189
c.	Peak-And-Average Method	190
d.	Demand Adjustment	190
e.	Findings And Conclusions On Shared Distribution Costs	191
6.	Classification And Allocation Of AMI.....	191
7.	Classification Of Other Production O&M	193
8.	Allocation Of Economic Development Discounts.....	194
9.	CCOSS Conclusion.....	195

D.	Revenue Apportionment And Rate Design.....	195
1.	Revenue Apportionment	196
a.	Class Revenue Apportionment	196
b.	2025 And 2026 Revenue Apportionment	200
2.	Rate Design	201
a.	Residential And Small Commercial Customer Charges.....	201
b.	Street Lighting.....	203
c.	Low-Income Discount Rate	204
3.	Tariff Changes.....	208
a.	Residential Arrears Management Program (RAMP).....	208
b.	Super Large Customer Tariff	211
c.	Disconnection Moratorium And Randomized Control Trial.....	212
(i)	Disconnection Moratorium	212
(ii)	Randomized Control Trial	214
E.	Additional Issues	215
1.	Definition Of Energy Justice.....	215
2.	Recognition Of Energy Affordability And Elimination Of Energy Insecurity As Public Interest	216
	CONCLUSIONS OF LAW	216
	RECOMMENDATION.....	217
	NOTICE	217

FIGURE

Figure 1. Average Residential Monthly Bill National And MN, ND, SD, IA, WI, MI IOUs (EIA 2023 Preliminary Data)	26
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TABLES

Table 1. Comparison Of Annual Changes In Average Bills	25
Table 2. Xcel Energy ROE Analytical Results	64
Table 3. XLI ROE Analytical Results	65
Table 4. Department Constant Growth And Two-Growth DCF Analyses	67
Table 5. Summary Of Parties' Two-Growth DCF Analyses.....	70
Table 6. 2025 Overall Cost Of Capital.....	75
Table 7. 2026 Overall Cost Of Capital.....	76
Table 8. 2024 Corporate Scorecard	100
Table 9. Comparison Of CCOSS.....	195
Table 10. Revenue Apportionment and Factors State of Minnesota Jurisdiction (\$ Thousands)	197
Table 11. Proposed Revenue Apportionment with Company Adjustments.....	199
Table 12. Enrollment In Company Affordability Programs.....	206

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Authority to Increase Rates for Electric
Service in Minnesota

CAH Docket No. 28-2500-40515
MPUC Docket No. E-002/GR-24-320

The above-entitled matter came on for an evidentiary hearing before the Honorable Joseph C. Meyer, Administrative Law Judge, on December 17-18, 2025, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota, and also remotely via Webex and Telephone. Public hearings were held on September 15-17, 2025, in Stillwater, St. Cloud, by virtual means, and St. Paul, respectively, and on September 22-25, 2025, in Faribault, Edina, by virtual means, Minneapolis, and Welch, respectively. Public comments were received until the close of the evidentiary hearing.

Post-hearing briefs were filed on January 28, 2026, and responsive 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.

The parties to this proceeding are: Northern States Power Company, doing business as Xcel Energy (Company or Xcel Energy or NSPM); the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC); the Office of Minnesota Attorney General - Residential Utilities Division (OAG); the Citizens Utility Board of Minnesota (CUB); Xcel Large Industrials (XLI); the Energy CENTS Coalition (ECC); Walmart Inc. (Walmart); the Joint Intervenors (Joint Intervenors); and the Suburban Rate Authority (SRA).

Appearances were made by the following: For Xcel Energy, Ian Dobson, Northern States Power Company – Minnesota, d/b/a Xcel Energy; for Xcel Energy, Eric Swanson and Elizabeth Schmiesing, Winthrop & Weinstine, P.A.; for Xcel Energy, Valerie Herring and Elizabeth Brama, Taft Stettinius & Hollister, LLP; for Xcel Energy, Ryan Barlow, Moss & Barnett; for the Department, Richard Dornfeld, Katherine Arnold, Amrit Hundal, and Stephen Melchionne, Assistant Attorneys General; for the OAG, Peter Scholtz, Joey Cherney, and Wendy Raymond, Assistant Attorneys General; for CUB, Brian Edstrom, Senior Regulatory Advocate; for XLI, Andrew Moratzka and Eden Fauré, Stoel Rives, LLP; for ECC, George Shardlow, Executive Director; for Walmart, Colette Brashears,

Kutak Rock, LLP; and for the Joint Intervenors, Erica McConnell and Bradley Klein, Environmental Law and Policy Center; for SRA, Joe Sathe, Kennedy & Graven.

Ashley Marcus and Robert Manning appeared for the Minnesota Public Utilities Commission (Commission).

STATEMENT OF THE ISSUES

On November 1, 2024, Xcel Energy filed its Application for a Proposed Increase to Electric Rates in Minnesota (Initial Filing). The Initial Filing outlines a two-year multi-year rate plan (MYRP) addressing rates for 2025 and 2026. The Company originally proposed a general rate increase of \$353.3 million, or 9.6 percent for 2025 and a proposed subsequent increase of \$137.5 million, or 3.6 percent, would take effect in 2026.¹

The Notice of and Order for Hearing listed the issues to be addressed over the course of the rate case as the following:

- A. The standard rate case issues,² including the impacts of data centers.
- B. Whether it is appropriate to use the proposed hypothetical capital structure or whether an alternate capital structure should be adopted.
- C. Reasons for the significant changes of the following costs since the last rate case:
 1. Customer Accounting – \$16.5 million.
 2. Customer Service and Information – \$34.0 million increase.
 3. Administrative and General – \$67.8 million increase.
 4. Depreciation – \$112.9 million increase.

¹ The Company substantially reduced its requested increase through the course of this proceeding, as discussed below.

² The standard rate case issues are: 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? and 3) Are the Company's proposed capital structure and return on equity reasonable? *In the Matter of the Application of Minnegasco, a Division of NorAm Energy Company, for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-95-700, NOTICE OF AND ORDER FOR HEARING at 3 (Oct. 4, 1995).

- D. The increase in the distribution budget with a focus on how the increased spending will impact reliability.
- E. How much Top 10 executive compensation costs should be recovered in rates?
- F. What grid reinforcement program and associated costs should be approved.
- G. 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.
- H. Develop a full record that ensures decisions made in Docket E-002/CI-24-318 are properly reflected in the 2026 Test Year.
- I. Future ADMS functionalities, lifespan, and costs.
- J. 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.
- K. Should Xcel's proposed 2025 and 2026 sales true-ups be approved.
- L. 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 inter-generational 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.

SUMMARY OF CONCLUSIONS

The hearing record demonstrates that Xcel Energy will experience a revenue shortfall of approximately \$208 million for 2025 and an incremental \$157 million for 2026.³ Xcel Energy is entitled to recover this revenue shortfall through an adjustment of its retail electric rates.

The capital structure, cost of debt, and return on equity reflected in the findings below are reasonable and should be used in determining an appropriate overall rate of return.

Modifying Xcel Energy's retail electric rates in the manner described in the findings and conclusions below, including those related to rate design, will result in just and reasonable rates that serve the public interest.

Providing for recovery of expenses described in the findings and conclusions below is reasonable, appropriate, and supported by the hearing record.

Based upon the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. SUMMARY OF THE APPLICATION AND CURRENT REQUEST

1. The Company proposes a two-year MYRP, with a 2025 test year and a 2026 plan year. The Company structured its MYRP proposal consistent with its prior MYRP, presenting a traditional full cost of service for both the test year and plan year and utilizing the true-up and customer protection measures previously approved by the Commission – the plan year sales true-up, the property tax true-up and the capital true-up, together with compliance filings that provide ongoing regulatory oversight.

2. No party objected to the proposed term or basic structure of the MYRP. Thus, this case has centered on traditional rate case issues, including the need for and reasonableness of the Company's investments and expenses, determining a reasonable return on those investments, and appropriately assigning the Company's costs and the responsibility for covering those costs to the various customer classes.

³ The Company's rebuttal revenue requirements were \$208.4 million in 2025 and an incremental \$156.9 million in 2026. Ex. Xcel-19 at 3 (Halama Rebuttal). The Company later agreed to additional adjustments for Wildfire and Prairie Island Capacity Revenues, not reflected in these figures but that the Administrative Law Judge recommends be adopted.

3. The Company stated that increases in the core costs of doing business as a vertically-integrated utility drove the need for this filing, including: energy supply investments, transmission and distribution capital investments, increased operations and maintenance (O&M) expenses across these same business areas, the general increased costs of doing business, and the Company's cost of capital.⁴

4. The Company further stated that the MYRP was necessary to position it to continue its work on certain key matters, including: (1) further transforming its generation fleet, to progress toward the "carbon-free by 2040" standard for Minnesota's electric utilities, including retiring thousands of megawatts of coal generation in a span of about six years and adding substantial renewable resources to its fleet; (2) creating a more advanced distribution grid that continues to reliably serve customers, while enabling further transformation of the overall energy delivery system and better meeting new customer demands; and (3) assisting in continued beneficial electrification and the electrification of Minnesota's transportation system.⁵

5. Over the course of the proceeding, the Company incorporated new information and the impact of new regulatory decisions into its overall rate request. Additionally, the parties resolved several financial issues. In Rebuttal Testimony, the Company reflected this new information and the impact of these resolved issues and reduced its revenue increase request by over \$125 million, requesting an increase of \$208.4 million in 2025 and an incremental \$156.9 million in 2026.⁶

6. Following Rebuttal Testimony, the Company agreed to two further adjustments to its request, related to its wildfire mitigation efforts⁷ and capacity revenues for the Prairie Island Nuclear Generating Plant (PINGP),⁸ discussed in Section VIII below, further reducing its revenue increase request.

II. PARTIES

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

⁴ Exhibit (Ex.) Xcel-15 at 22-23 (Liberkowski Direct); Ex. Xcel-17 at 10-19 and Schedule 6 (Halama Direct).

⁵ Ex. Xcel-15 at 3-4 (Liberkowski Direct).

⁶ Ex. Xcel-16 at 20 (Liberkowski Rebuttal); Ex. Xcel-19 at 4-29 (Halama Rebuttal).

⁷ Ex. Xcel-95 (Xcel Energy correspondence regarding wildfire issue).

⁸ The Company agreed to this adjustment and listed it as an issue not in dispute in its Issues Matrix, filed January 23, 2026. (eDocket No. 20261-227337-01).

8. The Department represents the interests of the State's ratepayers in rate proceedings.⁹ Department staff reviews the testimony and schedules filed by the Applicant and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

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

10. CUB is a non-profit advocate for Minnesota's residential utility consumers.

11. XLI includes Flint Hills Resources Pine Bend, LLC, Marathon Petroleum Corporation, USG Interiors, Inc. and the Builders Association of Minnesota.

12. ECC is a 501(c)(3) nonprofit advocate and service provider that works to ensure that low- and fixed-income utility customers have access to affordable energy.

13. Walmart is an American multinational retail corporation that operates a chain of supercenters, retail department stores, and grocery stores in the United States and 23 other countries.

14. Joint Intervenors in this proceeding includes Cooperative Energy Futures (CEF), Environmental Law & Policy Center (ELPC), Minnesota Interfaith Power & Light (MNIPL), and Vote Solar.

15. SRA is a municipal joint powers association. Its members are suburban municipalities within the Twin Cities metropolitan area, most served by Xcel Energy.

III. SUMMARY OF PUBLIC COMMENTS

16. Over 5,000 written public comments have been received to date. The public comments generally addressed the following topics:

1. general opposition to any rate increase at this time, as customers are experiencing hardship due to inflation and other pressures;
2. general opposition to any rate increase, given the Company's perceived financial health;
3. general opposition to any rate increase, due to concern regarding customers on fixed-incomes, low-income ratepayers and energy burden;

⁹ Minn. Stat. § 216A.07, subd. 3 (2020); Minn. R. 7829.0800, subp. 3 (2021).

4. general opposition to any rate increase, due to concerns with executive compensation;
5. general opposition to any rate increase, due to a belief that renewable energy resources have decreased production costs or are subsidized;
6. general opposition to any rate increase, due to a belief that the Company is not invested enough in renewable energy resources;
7. general support for a rate increase, due to the Company's investments in renewable energy resources;
8. general opposition to any rate increase, due to opposition to investments in renewable energy resources;
9. general opposition to any rate increase, due to opposition to fossil fuel use for electricity generation; and
10. general opposition to an increase in the Residential Customer Charge;

17. Seventy-nine people provided oral comments at the nine public hearings in this proceeding. Public commenters generally addressed the following topics:

1. general opposition to any rate increase at this time, as customers are experiencing hardship due to inflation and other pressures;
2. general opposition to any rate increase, given the Company's perceived financial health;
3. general opposition to any rate increase, due to concern regarding customers on fixed-incomes, low-income ratepayers and energy burden;
4. general opposition to investment in renewable energy resources; and
5. general opposition to any rate increase, due to opposition to data center development.

IV. JURISDICTION

18. The Commission has general jurisdiction over Xcel Energy under Minn. Stat. §§ 216B.01 and 216B.02. The Commission has specific jurisdiction over proposed rate changes under Minn. Stat. § 216B.16.

19. The case was properly referred to the Office of Administrative Hearings (now Court of Administrative Hearings (CAH)) under Minn. Stat. §§ 14.48-14.62 and Minn. R. 1400.0200, et seq. for contested case proceedings.

V. PROCEDURAL BACKGROUND

20. The Company filed its Application for Authority to Increase Rates for Electric Service in Minnesota on November 1, 2024, requesting a two-year MYRP addressing rates for 2025 and 2026.

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

- 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?
- Should this matter be sent to the Office of Administrative Hearings for a contested case hearing and if so, what should be the scope of the hearing?
- Are there other issues or concerns related to this matter?¹⁰

22. November 12, 2024, the Department filed initial comments recommending the Commission accept the Company's filing as complete and refer this matter to the CAH for a contested case proceeding. The Department also recommended the Commission limit the Company's interim rate recovery.¹¹

23. CUB also filed initial comments on November 12, 2024, along with their petition to intervene in this matter.¹²

24. OAG filed initial comments on November 12, 2024, opposing the Company's request for interim rate recovery.¹³

¹⁰ Notice of Comment Period on Completeness and Procedures (Nov. 5, 2024) (eDocket No. 202411-211632-01).

¹¹ Comments of the Minnesota Department of Commerce (Nov. 12, 2024) (eDocket No. 202411-211839-01).

¹² Citizens Utility Board of Minnesota Initial Comments and Petition to Intervene (Nov. 12, 2024) (eDocket No. 202411-211851-02).

¹³ Comments of the Office of the Attorney General in Opposition to Xcel's Interim-Rate Proposal (Nov. 12, 2024) (eDocket No. 202411-211845-02).

25. On November 18, 2024, the Department,¹⁴ Electrify America,¹⁵ the OAG¹⁶ and the Company¹⁷ filed reply comments.

26. The filing came before the Commission on December 12, 2024.¹⁸

27. On December 30, 2024, the Commission issued an Order accepting the Company's filing and suspending the proposed rates.¹⁹

28. In a separate Order, the Commission set the Company's interim rates.²⁰

29. In a third Order, the Commission referred the case for contested case proceedings.²¹

30. On January 22, 2025, Administrative Law Judge (ALJ) Joseph C. Meyer held a prehearing conference via Microsoft Teams.²²

31. On January 22, 2025, ECC submitted a Petition to Intervene.²³

32. On January 24, 2025, XLI submitted a Petition to Intervene.²⁴

33. On January 27, 2025, the ALJ issued a Protective Order regulating the use and disclosure of nonpublic data.²⁵

¹⁴ DOC Correspondence (Nov. 18, 2024) (eDocket No. 202411-212074-01).

¹⁵ Reply Comments of Electrify America (Nov. 18, 2024) (eDocket No. 202411-212053-01).

¹⁶ Reply Comments of the Office of the Attorney General – Residential Utilities Division (Nov. 18, 2024) (eDocket No. 202411-212075-02).

¹⁷ Reply Comments of Xcel Energy (Nov. 18, 2024) (eDocket No. 202411-212101-01).

¹⁸ NOTICE OF ORAL ARGUMENT TIMES AND PROCEDURES (Dec. 11, 2024) (eDocket No. 202412-212899-01).

¹⁹ ORDER ACCEPTING FILING AND SUSPENDING RATES (Dec. 30, 2024) (eDocket No. 202412-213389-01).

²⁰ ORDER SETTING INTERIM RATES (Dec. 30, 2024) (eDocket No. 202412-213390-01).

²¹ NOTICE OF AND ORDER FOR HEARING (Dec. 30, 2024) (eDocket No. 202412-213391-01).

²² ORDER ON PREHEARING CONFERENCE (Jan. 13, 2025) (eDocket No. 20251-213881-01).

²³ Energy CENTS Coalition Petition to Intervene (Jan. 22, 2025) (eDocket No. 20251-214232-01).

²⁴ Xcel Large Industrials Petition to Intervene (Jan. 24, 2025) (eDocket No. 20251-214380-02).

²⁵ PROTECTIVE ORDER and PROTECTIVE ORDER FOR HIGHLY CONFIDENTIAL TRADE SECRET DATA (Jan. 27, 2025) (eDocket No. 20251-214424-01).

34. On January 31, 2025, the ALJ issued the First Prehearing Order and established the following schedule of proceedings:

Document or Event	Due Date	Description
Deadline for Intervention	April 30, 2025	All petitions for intervention shall be served and filed by this date.
Supplemental Direct Testimony, Xcel Energy	March 17, 2025	Supplemental Direct Testimony shall be served and filed by this date.
Direct Testimony, Intervenors	August 22, 2025	Direct Testimony shall be served and filed by this date.
Initial Settlement Discussions	Week of September 2 or September 8	The parties will aim to schedule settlement discussions during these weeks.
Rebuttal Testimony, All Parties	October 10, 2025	Rebuttal Testimony shall be served and filed by this date.
Completion of Discovery on Direct and Rebuttal testimonies, deadline for objections to Admissibility of pre-filed Direct and Rebuttal Testimony, and deadline for challenges to the qualifications of witnesses	November 21, 2025	All responses to discovery requests on Direct and Rebuttal testimonies shall be served by this date. All objections to pre-filed Direct and Rebuttal testimonies and challenges to the qualifications of witnesses shall be served and filed by this date.
Surrebuttal Testimony, All Parties	November 25, 2025	Surrebuttal Testimony shall be served and filed by this date.
Deadline for Completion of Surrebuttal Discovery	December 12, 2025	All responses to discovery requests on Surrebuttal Testimony shall be served by this date.

Document or Event	Due Date	Description
Public Hearings	TBD	The Applicant and Commission Staff will arrange for and schedule public hearings. At least one of the public hearings will be conducted virtually.
Corrections to Pre-Filed Testimonies	December 4, 2025	All revisions and corrections to pre-filed testimony are due by this date.
Deadline for Objections to Admissibility of Surrebuttal Testimonies	December 5, 2025	All objections to pre-filed Surrebuttal Testimony shall be served and filed by this date.

Document or Event	Due Date	Description
<p>Service and Filing of Proposed Witness Lists, Proposed Exhibit Lists, and Proposed Exhibits</p>	<p>December 8, 2025</p>	<p>The parties shall serve and file, in the eDockets system, their proposed witness lists, proposed exhibit lists, and proposed exhibits. Proposed exhibit lists shall be clearly titled as: “[Party Name’s] Proposed Exhibit List.”</p> <p>The parties shall also circulate among themselves via email, their proposed exhibit lists. The parties shall include the Administrative Law Judge and the Court Reporter in the email circulation of their proposed exhibit lists. The proposed exhibit lists shall be in the template form provided by the court reporter so that it can be compiled by Applicant into a Master Exhibit List.</p> <p>*At the conclusion of the hearing, Applicant shall prepare the Master Exhibit List using the template provided by the court reporter. The Master Exhibit List shall be given to the court reporter and filed in eDockets. The Master Exhibit list shall contain live links to the documents in eDockets and include the eDockets document number.</p>

Document or Event	Due Date	Description
Settlement/Prehearing Status Conference	December 15, 2025	A second prehearing status conference will be held where the parties can address the status of settlement negotiations and evidentiary hearing logistics.
Evidentiary Hearings	December 17-19, 2025	An evidentiary hearing will be held at the Minnesota Public Utilities Commission, 121 7th Pl E, #350, St Paul, MN 55101, commencing at 9:30 a.m. each day.
Deadline for Filing Public Comments	December 30, 2025	All public comments must be eFiled or received by the Commission by 4:30 p.m. on this date.
Draft Issues Matrix	January 23, 2026	The Company shall serve and file a draft issues matrix.
Initial Briefs	January 28, 2026	The parties shall serve and file their Initial Briefs.
Response to Issues Matrix	February 18, 2026	The parties shall serve and file any replies to the issues matrix filed by the Company.
Reply Briefs and Proposed Findings of Fact, Conclusions of Law, and Recommendations	February 25, 2026	The parties shall serve and file their Reply Briefs and Proposed Findings of Fact, Conclusions of Law, and Recommendations.
Administrative Law Judge Report	April 30, 2026	
Administrative Law Judge Report Exceptions	May 15, 2026	

Document or Event	Due Date	Description
Commission Order	July 31, 2026 ²⁶	

35. No parties filed an objection to the petition to intervene of XLI and on February 10, 2025, ALJ Meyer granted the petition.²⁷

36. No parties filed an objection to the petition to intervene of ECC and on February 14, 2025, ALJ Meyer granted the petition.²⁸

37. 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.²⁹

38. On March 31, 2025, SRA submitted its Petition to Intervene.³⁰

39. No parties filed an objection to the petition to intervene of SRA and on April 15, 2025, ALJ Meyer granted the petition.³¹

40. On April 29, 2025, Walmart submitted its Petition to Intervene.³²

41. On April 30, 2025, the Joint Intervenors submitted their applications for Pro Hac Vice Admission.³³

²⁶ FIRST PREHEARING ORDER (Jan. 31, 2025) (eDocket No. 20251-214744-01).

²⁷ ORDER GRANTING UNOPPOSED INTERVENTION PETITION OF XLI (Feb. 10, 2025) (eDocket No. 20252-215166-01).

²⁸ ORDER GRANTING UNOPPOSED INTERVENTION PETITION OF ECC (Feb. 14, 2025) (eDocket No. 20252-215402-01).

²⁹ See Xcel Exs. 18, 27, 37, 39, 48 and 79.

³⁰ Suburban Rate Authority Petition to Intervene (Mar. 31, 2025) (eDocket No. 20253-217053-01).

³¹ ORDER GRANTING UNOPPOSED INTERVENTION PETITION OF SRA (Apr. 15, 2025) (eDocket No. 20254-217644-01).

³² Walmart Inc. Petition to Intervene (Apr. 29, 2025) (eDocket No. 20254-218272-02).

³³ Application for Pro Hac Vice Admission of Bradley Klein (eDocket No. 20254-218401-02); Application for Pro Hac Vice Admission of Erica S. McConnell (eDocket No. 20254-218401-03) (Apr. 30, 2025).

42. On April 30, 2025, the Joint Intervenors submitted their Petition to Intervene.³⁴

43. On April 30, 2025, XLI submitted correspondence notifying the Commission, the ALJ and parties that they had incorporated a new member, Building Owners and Managers Association (BOMA) Greater Minneapolis, into the consortium.³⁵

44. No parties filed an objection to the petitions to intervene of Walmart and the Joint Intervenors, and on May 19, 2025, ALJ Meyer granted the petitions and Pro Hac Vice admission.³⁶

45. On June 3, 2025, Walmart submitted its application for Pro Hac Vice admission.³⁷

46. On June 9, 2025, ALJ Meyer granted the Pro Hac Vice Admission of Walmart.³⁸

47. On July 25, 2025, the OAG and DOC jointly filed a motion with the CAH for an order to compel the Company to produce certain documents in response to an information request.³⁹

48. 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.⁴⁰

³⁴ Petition to Intervene of Cooperative Energy Futures, Minnesota Interfaith Power & Light, Environmental Law & Policy Center, and Vote Solar (Apr. 30, 2025) (eDocket No. 20254-218395-01).

³⁵ Correspondence adding Building Owners and Managers Association of Greater Minneapolis (BOMA) to the XLI group (Apr. 30, 2025) (eDocket No. 20254-218394-01).

³⁶ 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).

³⁷ Application for Pro Hac Vice Admission of Colette N. Brashears (June 3, 2025) (eDocket No. 20256-219712-01).

³⁸ ORDER GRANTING APPLICATION FOR PRO HAC VICE ADMISSION OF COLETTE N. BRASHEARS (June 9, 2025) (eDocket No. 20256-219531-02).

³⁹ Office of Attorney General – Residential Utilities Division and Department of Commerce’s Notice of Motion and Motion to Compel Discovery (July 25, 2025) (eDocket No. 20257-221445-01).

⁴⁰ *See* Ex. Xcel-11.

49. On August 8, 2025, the Company filed its response to the OAG and DOC motion to compel discovery.⁴¹

50. On August 19, 2025, ALJ Meyer held a motion hearing via Microsoft Teams.⁴²

51. On August 22, 2025, SRA, CUB, Joint Intervenors, Walmart, XLI, OAG and DOC submitted its Direct Testimony.⁴³

52. On August 25, 2025, ECC submitted its Direct Testimony.⁴⁴

53. On August 27, 2025, XLI submitted errata corrections to its Direct Testimony of Billie LaConte and Jonathan Ly.⁴⁵

54. On August 29, 2025, ALJ Meyer issued an order on the motion to compel of the DOC and OAG.⁴⁶

55. On September 5, 2025, ALJ Meyer held a prehearing conference via Microsoft Teams.⁴⁷

56. On September 15-17, 2025, public hearings were held in Stillwater, St. Cloud, Virtual and St. Paul, respectively.⁴⁸

57. On September 22-25, 2025, public hearings were held in Faribault, Edina, Virtual, Minneapolis and Welch, respectively.⁴⁹

58. On September 29, 2025, XLI submitted errata corrections to its Direct Testimony.⁵⁰

⁴¹ Xcel Energy Reply in Opposition to Motion to Compel Discovery (Aug. 8, 2025) (eDocket No. 20258-221905-01).

⁴² ORDER FOR MOTION HEARING (Aug. 11, 2025) (eDocket No. 20258-221943-01).

⁴³ See eDocket Nos. 20258-222359-01, 20258-222358-02-05, 20258-222357-01-02, 20258-222356-01, 20258-222355-02, 20258-222343-02-03, 20258-222348-02-07, 20258-222345-01-07, 20258-222346-01-11.

⁴⁴ See eDocket No. 20258-222360-01.

⁴⁵ See eDocket No. 20258-222480-01

⁴⁶ ORDER GRANTING IN PART AND DENYING IN PART MOTION TO COMPEL (Aug. 29, 2025) (eDocket No. 20258-222555-01).

⁴⁷ ORDER FOR PREHEARING CONFERENCE (Sept. 3, 2025) (eDocket No. 20259-222664-01).

⁴⁸ See eDocket Nos. 202511-224975-01-04.

⁴⁹ See eDocket Nos. 202511-224975-05-09.

⁵⁰ See eDocket Nos. 20259-223371-01, 20259-223371-03-05.

59. On October 1, 2025, the Company submitted correspondence regarding 2026 Interim Rates.⁵¹

60. 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.⁵²

61. On October 10, 2025, SRA, the Company, XLI, Joint Intervenors, DOC and OAG filed Rebuttal Testimony.⁵³

62. 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 Benjamin Halama Rebuttal Testimony.⁵⁴

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

64. On October 27, 2025, ALJ Meyer issued an order for motion hearing on OAG objection and motion to strike portions of Benjamin Halama Rebuttal Testimony.⁵⁶

65. On October 31, 2025, initial comments on the Company's interim rate request were filed by OAG,⁵⁷ ECC⁵⁸ and DOC,⁵⁹ and jointly by CUB and XLI.⁶⁰

⁵¹ Xcel Energy Letter Regarding 2026 Interim Rates (Oct. 1, 2025) (eDocket No. 202510-223492-01).

⁵² Notice of Comment Period on Interim Rate Request (Oct. 8, 2025) (eDocket No. 202510-223704-01).

⁵³ See eDocket Nos. 202510-223812-01-02, 202510-223801-02-12, 202510-223804-01-16, 202510-223807-01-07, 202510-223798-02-03, 202510-223796-01, 202510-223779-01-02, 202510-223776-02-03.

⁵⁴ 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).

⁵⁵ Xcel Energy Errata (Oct. 24, 2025) (eDocket No. 202510-224273-01).

⁵⁶ ORDER FOR MOTION HEARING (Oct. 27, 2025) (eDocket No. 202510-224308-01).

⁵⁷ Comments of the Office of the Attorney General – Residential Utilities Division (Oct. 31, 2025) (eDocket No. 202510-224548-01).

⁵⁸ Energy CENTS Coalition Initial Comment (Oct. 31, 2025) (eDocket No. 202510-224517-01).

⁵⁹ Initial Comments of the Minnesota Department of Commerce (Oct. 31, 2025) (eDocket No. 202510-224510-01).

⁶⁰ Initial Comments of the Citizens Utility Board of Minnesota and Xcel Large Industrials (Oct. 31, 2025) (eDocket No. 202510-224520-02).

66. 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.⁶¹

67. On November 4, 2025, the DOC filed their response supporting OAG's objection and motion to strike portions of Benjamin Halama's Rebuttal Testimony.⁶²

68. On November 5, 2025, ALJ Meyer held a motion hearing via Microsoft Teams.⁶³

69. On November 10, 2025, the DOC⁶⁴ and the Company⁶⁵ filed reply comments to the Company's interim rate request.

70. On November 12, 2025, ALJ Meyer issued an order denying the OAG's motion to strike.⁶⁶

71. On November 25, 2025, SRA, ECC, CUB, the Company, Joint Intervenors, OAG, XLI and DOC filed Surrebuttal Testimony.⁶⁷

72. 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.⁶⁸

⁶¹ 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).

⁶² Minnesota Department of Commerce's Response Supporting OAG-RUD's Objection and Motion to Strike Portions of the Rebuttal Testimony of Benjamin Halama (Nov. 4, 2025) (eDocket No. 202511-224653-01).

⁶³ Hearing Transcript (Nov. 5, 2025) (eDocket No. 202511-224780-01).

⁶⁴ Minnesota Department of Commerce Reply Comments – 2026 Interim Rates (Nov. 10, 2025) (eDocket No. 202511-224790-01).

⁶⁵ Xcel Energy Reply Comments – 2026 Interim Rates (Nov. 10, 2025) (eDocket No. 202511-224825-01).

⁶⁶ ORDER DENYING MOTION TO STRIKE (Nov. 12, 2025) (eDocket No. 202511-224861-01).

⁶⁷ See eDocket Nos. 20511-225305-02-03, 202511-225302-02, 202511-225-300-02-05, 202511-225298-02-04, 202511-225295-01-02, 202511-225286-02-05, 202511-225282-02-04, 202511-225277-01-15.

⁶⁸ See eDocket Nos. 202512-225546-01-02.

73. On December 4, 2025, the OAG filed errata corrections to the Direct Testimony of Katherine Hinderlie.⁶⁹

74. On December 4, 2025, the DOC 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.⁷⁰

75. On December 5, 2025, the Company filed a notice of motion and motion to strike portions of Jonathan Ly's Surrebuttal Testimony.⁷¹

76. On December 8, 2025, ALJ Meyer ordered parties wishing to respond to the Company's motion to file responses by December 12, 2025 and set a Motion Hearing for December 15, 2025.⁷²

77. On December 9, 2025, the Company submitted a reconciliation filing in accordance with the September 16, 2025 Electric Rate Case Virtual Public Hearing.⁷³

78. On December 11, 2025, XLI filed a response to the Company's motion to strike part of XLI witness Jonathan Ly's Surrebuttal Testimony.⁷⁴

79. On December 11, 2025, the Company filed a motion for relief regarding a procedural and due process issue.⁷⁵

80. On December 11, 2025, the DOC responded to the Company's motion for relief filed on December 11, 2025.⁷⁶

81. On December 11, 2025, ALJ Meyer 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, 2025.⁷⁷

⁶⁹ See eDocket No. 202512-225543-01.

⁷⁰ See eDocket No. 202512-225534-02.

⁷¹ Notice of Motion and Motion to Strike along with the Memorandum in Support of Motion to Strike (Dec. 5, 2025) (eDocket No. 202512-225566-01).

⁷² ORDER ON STATUS CONFERENCE (Dec. 8, 2025) (eDocket No. 202512-225611-01).

⁷³ Reconciliation Filing – September 16, 2025 Virtual Public Hearing (Dec. 9, 2025) (eDocket No. 202512-225673-01).

⁷⁴ Response of Xcel Large Industrials (Dec. 11, 2025) (eDocket No. 202512-225778-02).

⁷⁵ Xcel Energy's 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).

⁷⁶ Minnesota Department of Commerce Correspondence (Dec. 11, 2025) (eDocket No. 202512-225770-01).

⁷⁷ ORDER FOR PROCEDURE ON MOTION FOR RELIEF (Dec. 11, 2025) (eDocket No. 202512-225750-01).

82. 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.⁷⁸

83. ALJ Meyer 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, 2025.⁷⁹

84. On December 16, 2025, the Company submitted Responsive Testimony of Nicholas N. Paluck regarding rate design.⁸⁰

85. 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.⁸¹

86. On January 23, 2026, the Company filed its Issues Matrix.⁸²

87. On January 28, 2026, SRA,⁸³ Joint Intervenors,⁸⁴ OAG,⁸⁵ CUB,⁸⁶ XLI,⁸⁷ Walmart⁸⁸ and DOC⁸⁹ filed their Initial Briefs.

⁷⁸ Xcel Energy Correspondence (Dec. 12, 2025) (eDocket No. 202512-225803-01).

⁷⁹ 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).

⁸⁰ Responsive Testimony of Nicholas N. Paluck (Dec. 16, 2025) (eDocket No. 202512-225929-01).

⁸¹ See Evidentiary Hearing Transcript (Tr.) Volumes (Vol.) 1-2.

⁸² Issues Matrix of Xcel Energy (Jan. 23, 2026) (eDocket No. 20261-227337-01).

⁸³ Initial Brief of the Suburban Rate Authority (Jan. 28, 2026) (eDocket No. 20261-227541-01).

⁸⁴ Initial Brief of the Joint Intervenors (Jan. 28, 2026) (eDocket No. 20261-227538-01).

⁸⁵ Initial Brief of the Office of the Attorney General – Residential Utilities Division (Jan. 28, 2026) (eDocket No. 20261-227537-02).

⁸⁶ Initial Brief of the Citizens Utility Board of Minnesota (Jan. 28, 2026) (eDocket No. 20261-227535-02).

⁸⁷ Post-Hearing Brief of the Xcel Large Industrials (Jan. 28, 2026) (eDocket Nos. 20261-227526-02-03).

⁸⁸ Initial Post-Hearing Brief of Walmart Inc. (Jan. 28, 2026) (eDocket No. 20261-227525-01).

⁸⁹ Initial Brief of the Minnesota Department of Commerce (Jan. 28, 2026) (eDocket Nos. 20261-227521-01-02).

88. On January 28, 2026, the Company filed its Initial Brief.⁹⁰

89. On January 29, 2026, the Company filed errata corrections to its Initial Brief.⁹¹

90. 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.

91. On February 25, 2026, Xcel Energy, SRA, Joint Intervenors, OAG, CUB, XLI, Walmart and DOC filed their Reply Briefs and Proposed Findings.

VI. CASE OVERVIEW

92. The Company stated that this multiple factors necessitated this MYRP, including it work to: (1) further transform its generation fleet, to progress toward Minnesota’s “carbon-free by 2040” standard for electric utilities, including retiring thousands of megawatts of coal generation in a span of about six years and adding substantial renewable resources to its fleet; (2) create a more advanced distribution grid that continues to reliably serve customers, while better meeting new customer demands; and (3) assisting in continued beneficial electrification and the electrification of Minnesota’s transportation system.⁹² The Company also stated the MYRP reflected the necessary investments to keep its core plants, substations, poles and wires operating reliably, its need for revenues that reflect the overall increased cost of business, and its need for a reasonable overall cost of capital.⁹³

93. Regarding its work to achieve Minnesota’s “carbon-free by 2040” standard, the Company explained that its retirement of its major coal plants has required working closely with its host communities and employees to minimize the disruption of this transformation, while also completing the largest build-out of wind resources in its history, including over 2,800 MW in new or repowered facilities.⁹⁴ In addition, the Company noted that it is building the largest solar project in the Upper Midwest, with Sherco Solar adding

⁹⁰ Initial Brief of Northern States Power Company d/b/a Xcel Energy (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 ALJ was immediately notified and the Company asked that the Initial Brief be accepted as timely filed. (Jan. 28, 2026) (eDocket No. 20261-227543-01).

⁹¹ Northern States Power Company d/b/a Xcel Energy Errata to Initial Brief (Jan. 29, 2026) (eDocket Nos. 20261-227580-01-02).

⁹² Ex. Xcel-15 at 3-4 (Liberkowski Direct).

⁹³ Ex. Xcel-15 at 19-20, 22-23 (Liberkowski Direct).

⁹⁴ Ex. Xcel-15 at 4, 10-11 (Liberkowski Direct).

an additional 710 MW of renewable generation, and that, by the end of this MYRP, wind and solar will provide approximately 40 percent of the electricity for Xcel Energy customers in this region.⁹⁵ Additionally, the Company continues investing in its nuclear fleet, which provides a critical source of baseload, carbon-free energy.⁹⁶

94. While these asset additions are substantial, and impact customers' bills,⁹⁷ this work is required to meet the State's energy goals. Moreover, the Company noted that the overall impact of these additions on customer bills requires looking beyond the impact of this rate case. For example, while these substantial renewable energy additions can impact base rates, they also mean the Company continues to lessen the use of its fossil fuel facilities, reducing fuel costs.⁹⁸ Those reduced costs are passed on to customers in the fuel cost adjustment (FCA) going forward, helping to control bill increases.⁹⁹

95. Regarding the Company's work on the distribution grid reflected in this case, the Company continues work on its long-term strategic plan to transform its distribution system to advance the efficiency and reliability of service and to safely integrate more distributed energy resources (DERs) into its system.¹⁰⁰ To date, that work has allowed the Company (which manages a little less than half of all electrical accounts in the State) to incorporate far more interconnected distributed solar capacity than all other utilities in the State combined, and over 20 times the amount of any other Minnesota utility.¹⁰¹ While doing this critical forward-looking work, the Company must also invest and incur costs to keep its core substations, poles and wires operating reliably into the future, and those investments and expenses are also reflected in this rate case, as are the increased costs of doing business.¹⁰² The record demonstrates that the Company's distribution investments alone account for over \$115 million of its MYRP rate request.¹⁰³

96. The Company also stated that certain investments during this MYRP period are targeted to further advance the clean energy transition by preparing the grid for greater electrification and new customer loads and assisting in the continuing electrification of the

⁹⁵ Ex. Xcel-15 at 11 (Liberkowski Direct).

⁹⁶ See Ex. Xcel-41 at 12-13 (Church Direct).

⁹⁷ Company witness Halama identifies the revenue requirements impact of these investments, with the Company's nuclear and wind investments alone accounting for nearly \$70 of its 2025 MYRP request. Ex. Xcel-17 at 14 and Schedule 6 (Halama Direct).

⁹⁸ Ex. Xcel-15 at 12 (Liberkowski Direct).

⁹⁹ Ex. Xcel-15 at 12 (Liberkowski Direct).

¹⁰⁰ Ex. Xcel-15 at 12 (Liberkowski Direct).

¹⁰¹ Ex. Xcel-15 at 12 (Liberkowski Direct).

¹⁰² Ex. Xcel-15 at 22-23 (Liberkowski Direct); Ex. Xcel-17 at 10-20 and Schedule 6 (Halama Direct).

¹⁰³ Ex. Xcel-17 at 12 and Schedule 6 (Halama Direct).

State's transportation system.¹⁰⁴ The Company noted its continued support of electric vehicle (EV) adoption through investments in its EV programs and pilots and stated that distributed energy resources (DERs), greater electrification, and new customer loads will require the Company's distribution equipment to be robust enough to maintain proper voltage levels as the stresses on that system change., requiring investments in the Company's Asset Health and Reliability category.¹⁰⁵

97. Finally, the Company stated that it the Company cannot transform its fleet, address its aging infrastructure, improve the customer experience, and continue to provide safe, reliable, and environmentally responsible energy without significant investments. The Company stated it will have an ongoing need to access capital, and, if it is to maintain affordability of its service, that capital must come at a reasonable cost. The Company stated that its proposed capital structure and return on equity would enable the necessary access to the capital markets and would allow the Company to maintain its strong credit ratings, keeping costs of debt lower and providing long-term energy affordability.¹⁰⁶

98. Intervenors objected to the overall size of the requested rate increase, recommending, among other adjustments, significant denials of recovery for core business costs, including substantial reductions in base pay to Company employees and substantial reductions to energy supply, transmission, distribution and customer service O&M expenses. Intervenors also objected to the Company's proposed increase to its return on equity and raised concerns regarding the overall affordability of the Company's service.

99. When discussing affordability concerns, Intervenor testimony often focused on the Company's rates set in general rates cases and raised concern about the number and amounts of rate increases customers have experienced.¹⁰⁷ While the Company acknowledged its past rate increases, it stated that assessing the overall affordability of the Company's service requires looking at the monthly bills customers actually pay.¹⁰⁸ That monthly bill reflects not just the rates set in general rate cases, but also factors such as usage and fuel costs.

100. The record demonstrates that, since 2014, electric utility customers nationally, in the upper Midwest and in Minnesota have all seen greater increases in their

¹⁰⁴ Ex. Xcel-34 at 5-6 (Mensen Direct).

¹⁰⁵ Ex. Xcel-34 at 6 (Mensen Direct).

¹⁰⁶ Ex. Xcel-15 at 19-20 (Liberkowski Direct).

¹⁰⁷ *See, e.g.*, Ex. DOC-1 at 19-20 (Johnson Direct). The Company would note that these rate increases have all been reviewed and approved by the Commission as being necessary for the continued supply of safe, reliable service.

¹⁰⁸ Ex. Xcel-16 at 14 (Liberkowski Rebuttal).

monthly bill, compared to the Company’s customers and this holds true across all customer classes.¹⁰⁹

Table 1. Comparison Of Annual Changes In Average Bills¹¹⁰

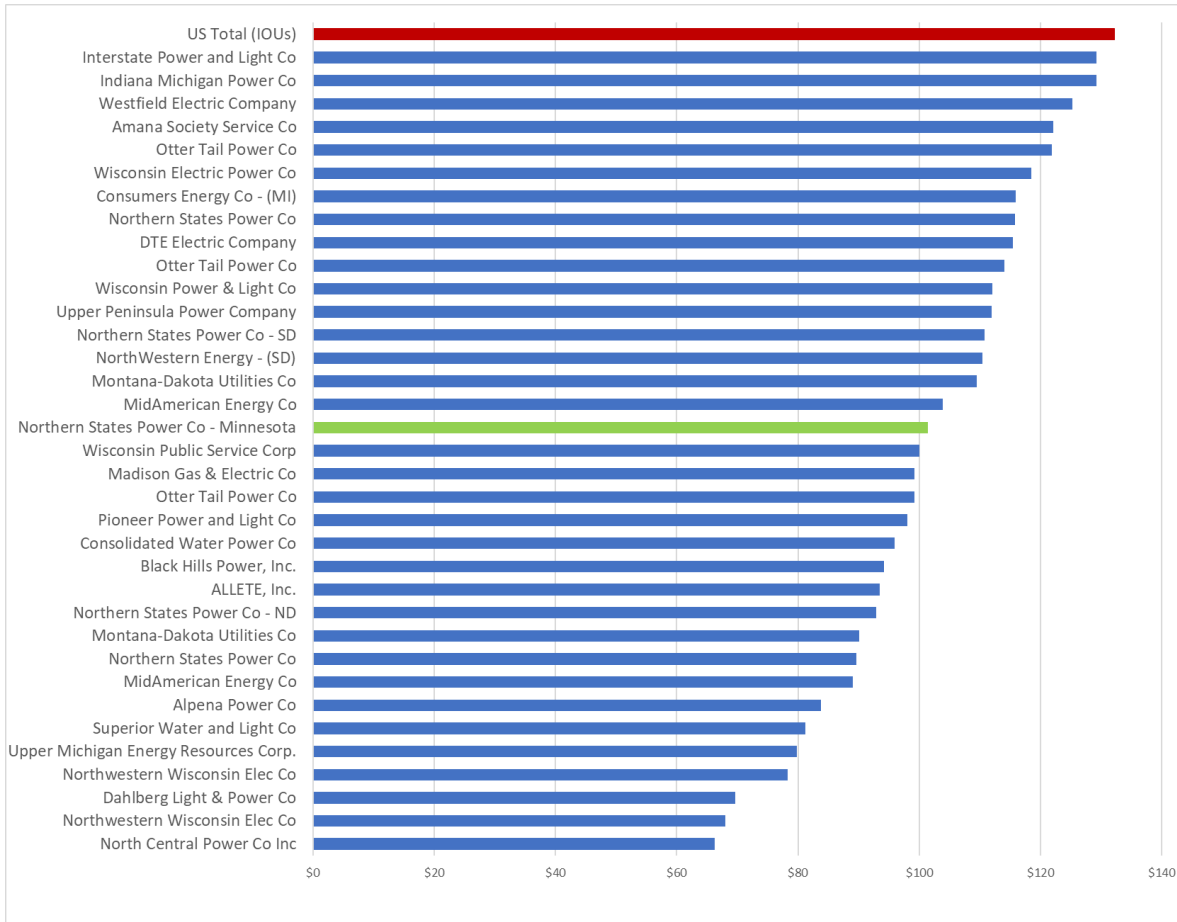
2014-2024 Compound Annual Growth Rate	NSP- MN	National	MN	Upper Midwest
Bills				
Residential	1.76%	2.38%	2.52%	2.11%
Commercial	0.99%	1.25%	1.91%	1.41%
Industrial	-0.25%	1.64%	3.43%	9.00%
Retail	0.90%	1.57%	3.05%	1.47%

101. The record further demonstrates that even with the recent rate increases, Xcel Energy’s customers’ bills continue to be well below the national average:

¹⁰⁹ Ex. Xcel-16 at 14 (Liberkowski Rebuttal).

¹¹⁰ Ex. Xcel-16 at 14 and Schedule 1E (Liberkowski Rebuttal).

**Figure 1. Average Residential Monthly Bill
National And MN, ND, SD, IA, WI, MI IOUs
(EIA 2023 Preliminary Data)¹¹¹**



102. In addition, the record demonstrates the considerable effort the Company, Commission and stakeholders have engaged in, and continue to engage in, to address the affordability challenges being felt by its most energy-burdened customers.¹¹² That work includes, among other efforts, the PowerON Electric Affordability program (PowerON), Medical Affordability Program (MAP), Gas Affordability Program (GAP), Electric Low-Income Discount (LID), Low-Usage Affordability Credit (LUAC), Automatic Bill Credit (ABC) Pilot Program, past work with the Equity Stakeholder Advisory Group (ESAG);

¹¹¹ Ex. Xcel-15 at 16-17 (Liberkowsky Direct).

¹¹² See, e.g., Ex. Xcel-15 at 17 (Liberkowsky Direct); Ex. Xcel-38 at 23-35 (Lindgren/Howard Direct) (Ms. Howard fully adopted the prefiled Direct and Supplemental Direct Testimony of Ms. Lindgren. Ex. Xcel-81 at 2 (Howard Rebuttal)); Ex. Xcel-70 at 10-12, 28-35 (Martin Direct).

and ongoing work with our Environmental Justice Accountability Board.¹¹³ In addition, for those customers who may not meet the income qualifications for some of these dedicated programs, the Company has worked to offer options such as Flexible Payment Arrangements, Budget Billing, and Customer Due Date billing to provide increased flexibility and control to customers¹¹⁴ and the Payment Plan Credit Program, funded by shareholders with \$17.5 million in initial funding, offering forgiveness of up to 75 percent of the overdue amount on eligible customers' balances.¹¹⁵ And in this case, the Company proposes RAMP, discussed further below, in response to the Commission's January 23, 2025 Order in the Company's Safety, Reliability and Service Quality docket.¹¹⁶

103. As further addressed below, the affordability concerns raised by Intervenors and by public commenters deserve to be taken seriously and should be considered among other non-cost factors in designing rates. However, the record demonstrates that Xcel Energy has outperformed other utilities in addressing the overall affordability of its electric bills and affordability concerns cannot justify denial of the reasonable and necessary costs of providing service.

VII. LEGAL STANDARDS

104. Minnesota Statutes Chapter 216B governs the ALJ's and Commission's consideration of this matter and sets forth the goals of State regulation, as well as the process to be followed and the factors to be considered in setting rates. Chapter 216B generally provides:

Every rate made, demanded, or received by any public utility . . . 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. . . . Any doubt as to reasonableness should be resolved in favor of the consumer.¹¹⁷

105. Specifically addressing rate setting and general rate cases such as this proceeding, the Minnesota Supreme Court has explained that, in reviewing and deciding upon rate change requests, "the [Commission's] charter is broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers to

¹¹³ Ex. Xcel-38 at 23-27 (Lindgren/Howard Direct); Ex. Xcel-70 at 10-12; 30-32 (Martin Direct).

¹¹⁴ Ex. Xcel-38 at 30-32 (Lindgren/Howard Direct).

¹¹⁵ Ex. Xcel-38 at 32-33 (Lindgren/Howard Direct).

¹¹⁶ Ex. Xcel-39, entire (Lindgren/Howard Supplemental Direct).

¹¹⁷ Minn. Stat. § 216B.03 (emphasis added).

ensure that rates are ‘just and reasonable.’”¹¹⁸ In so holding, the Court specifically referenced the requirements of Minn. Stat. § 216B.16, 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.*¹¹⁹

106. Chapter 216B further provides that the burden of proof to show that a rate change is just and reasonable shall be on the public utility seeking the change.¹²⁰ For a utility to meet this burden, the utility must demonstrate the facts at issue by a preponderance of the evidence.¹²¹

A. Cost Of Capital And Return On Equity

107. 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 *Bluefield* and *Hope* cases, stretching back over 100 years ago. The Court stated:

What annual rate will constitute just compensation depends upon many circumstances and *must be determined by the exercise of a fair and enlightened judgment*, having regard to all relevant facts.¹²²

The Court 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. (Citation omitted.) By that standard the return to the equity owner should be *commensurate with returns on investments in other enterprises having*

¹¹⁸ *In the Matter of the Request of Interstate Power Company For Authority To Change Its Rates For Gas Service In Minnesota*, 574 N.W.2d 408, 411 (Minn. 1998) (citing Minn. Stat. § 216B.16, subd. 6) (emphasis added).

¹¹⁹ Minn. Stat. § 216B.16, subd. 6 (emphasis added).

¹²⁰ *Id.*, subd. 4.

¹²¹ Minn. R. 1400.7300, subp. 5; *In the Matter of the Petition of Minnesota Power and Light Company, d/b/a Minnesota Power, for Authority to Change its Schedule of Rates in Minnesota*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989) (review denied).

¹²² *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692, 43 S. Ct. 675, 679 (1923) (*Bluefield*) (emphasis added).

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.¹²³

108. In cases such as *Hibbing Taconite Co. v. Minnesota Public Service Commission (Hibbing)*, the Minnesota Supreme Court adopted the *Bluefield* and *Hope* requirements for rate setting in Minnesota, including *Bluefield's* observation 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.¹²⁴

109. The *Hibbing* court explained that in determining the appropriate return, the Commission “is bound to follow certain legal criteria” and acts in its quasi-judicial capacity as a fact-finder, weighing the evidence as would a judge in a court trial. Specifically, the Commission’s task is to review the evidence and:

establish a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk, will allow the company to attract new capital as required, and will maintain the company's financial integrity.

110. In weighing that evidence, the Commission “must balance the interests of the utility against the interests of the utility’s customers.”¹²⁵

¹²³ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944) (*Hope*) (emphasis added).

¹²⁴ *Hibbing Taconite Co. v. Minnesota Public Service Commission*, 302 N.W.2d 5, 10 (Minn. 1980) (citing *Bluefield*, 262 U.S. at 690, 43 S. Ct. at 678).

¹²⁵ *Id.* at 10 (emphasis added), citing *Minneapolis Street Railway Co. v. City of Minneapolis*, 86 N.W.2d 657, 676 (Minn. 1957). In so holding, the Hibbing Court explicitly rejected and found impermissible a prior Commission policy labeled the “*North Central doctrine*” whereby the Commission focused on the testimony of the witness recommending the lowest rate of return to determine if it was basically sound and capable of being adopted, before considering higher recommendations. The Court observed that this policy was presumably intended to comply with the general statement in Minn. Stat. § 216B.03 that “any doubt as to reasonableness should be resolved in favor of the consumer.” However, the Court found the North Central doctrine an impermissible means to achieve that end, finding instead that the Commission must consider the entirety of the evidence and balance the interests of the utility against those of the customer, rather than simply pegging a return on the basis of one expert’s testimony. *Id.* at 10-11.

B. Revenue Requirements

111. Regarding other “revenue requirements” issues such as the recovery of expenses, Minnesota courts have stated that, here too, the Commission acts in its quasi-judicial capacity.¹²⁶ Minnesota courts have further explained that on such issues, such as recovery of expenses, “under normal ratemaking policy, *a utility is entitled to recover necessary, ongoing expenses incurred in the business of providing utility service.*”¹²⁷ The cost of furnishing utility service includes items such as labor-related costs, materials and supplies, taxes, insurance, and depreciation.¹²⁸

112. Along with determining the Company’s necessary revenues, the Commission must provide for the allocation of the revenue responsibilities among customer classes (revenue apportionment) and the appropriate rates (rate design) that yields those allocated revenues when applied to test year billing determinants. Minnesota courts have consistently held that when making rate design decisions, the Commission acts in its “quasi-legislative” capacity, rather than in a “quasi-judicial” capacity, reflecting the policy nature of rate design determinations. Minnesota courts have also consistently held that, in allocating revenue responsibility and designing rates, the Commission considers both cost and non-cost factors.¹²⁹

113. DOC argues that when deciding the many financial, revenue and rate design issues in a rate case, the Commission need not consider those issues on a discrete basis, calling such consideration “a matter of convenience, not legal necessity,” and that “the Commission’s sole obligation is to set a rate with a non-confiscatory net effect,” citing a 1942 U.S. Supreme Court case that involved Federal Power Commission (FPC) regulation of natural gas utilities.¹³⁰ The Administrative Law Judge disagrees.

114. *Federal Power Commission v. Natural Gas Pipeline Co. of America* (*Federal Power Comm’n*) concerned the FPC’s first time application of the Natural Gas Act of 1938 (NGA)¹³¹ to the subject companies.¹³² The NGA provided for federal regulation of natural gas providers and specifically provided that the FPC “may order a [rate] decrease where

¹²⁶ See, e.g., *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 251 N.W.2d 350, 358 (Minn. 1977).

¹²⁷ *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).

¹²⁸ See *Minnegasco v. Minnesota Public Utilities Commission*, 549 N.W.2d 904, 909 (Minn. 1996).

¹²⁹ See, e.g., *St. Paul Area Chamber of Commerce*, 251 N.W.2d at 358.

¹³⁰ DOC Initial Brief at 10, citing *Federal Power Comm’n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. 575, 585 (1942).

¹³¹ Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. § 717 et seq. (NGA).

¹³² *Federal Power Comm’n v. Nat. Gas Pipeline Co. of Am.*, 120 F.2d 625 (7th Cir. 1941).

existing rates are unjust . . . unlawful, or are not the lowest reasonable rates.”¹³³ While the *Federal Power Comm’n* Court noted that “the ‘lowest reasonable rate’ is one which is not confiscatory in the constitutional sense,” this simply recognizes the basic constitutional prohibition against takings. It does not provide guidance as to the proper analysis under Minnesota States Chapter 216B. Moreover, after observing this constitutional minimum, the *Federal Power Comm’n* Court proceeded to examine the record evidence supporting each of the FPC’s discrete financial findings challenged by the utilities to determine whether they were supported by substantial evidence.¹³⁴ Consistent with a long line of Minnesota case law, the Commission must similarly examine the various issues in this case under the appropriate legal standard as set forth above.

115. CUB similarly implies that cost and non-cost factors must be considered throughout the rate setting process, regardless of whether the issue concerns financial, revenue allocation and rate design matters, primarily relying on another case involving FPC regulation under the NGA.¹³⁵ Again, the Administrative Law Judge disagrees.

116. *In re Permian Basin Area Rates (Permian Basin)*, relied on by CUB, concerned the FPC’s regulation of natural gas producers. The Court noted that “the number both of independent producers and of jurisdictional sales is large, and the administrative burdens placed upon the Commission by an individual company costs of service standard were therefore extremely heavy. In consequence, the Commission’s regulation of producers’ sales became increasingly laborious, until, in 1960, it was described as the ‘outstanding example in the federal government of the breakdown of the administrative process.’¹³⁶ The Court thus found the FPC “has . . . labored with obvious difficulty to regulate a diverse and growing industry under the terms of an ill-suited statute” and that the FPC has the constitutional and statutory authority to adopt a system of “area regulation,” as opposed to examining each producer’s cost of service¹³⁷—a scenario distinct from ratemaking under Minnesota Statutes Chapter 216B.

117. CUB also implies that Minnesota Courts have fully adopted the reasoning of *Permian Basin*, citing *St. Paul Chamber*, and again implying that cost and noncost factors must be considered throughout the rate setting process.¹³⁸ However, the *St. Paul Chamber* Court stated that it adopted the *Permian Basin* reasoning:

as the standard in Minnesota *when courts are called upon to review the allocation of rate increases among consumer classes.*

¹³³ NGA at §5(a); *Federal Power Comm’n*, 315 U.S. at 585.

¹³⁴ See *Federal Power Comm’n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. at 586-599.

¹³⁵ CUB Initial Brief at 7-8 (citing *In re Permian Basin Area Rates*, 390 U.S. 747 (1968)).

¹³⁶ *Permian Basin*, 390 U.S. at 757-758.

¹³⁷ *Permian Basin*, 390 U.S. at 756.

¹³⁸ CUB Initial Brief at 8.

Combining this rule with that adopted above for factual determinations, we may summarize as follows:

(a) When the Public Service Commission acts in a judicial capacity as a factfinder, receives evidence in order to make factual conclusions, and weighs that evidence as would a judge in a court trial, it will be held on review to the substantial-evidence standard.

(b) When the Public Service Commission acts in a legislative capacity as in rate increase allocations, balancing both cost and noncost factors and making choices among public policy alternatives, its decisions will be upheld unless shown to be in excess of statutory authority or resulting in unjust, unreasonable, or discriminatory rates by clear and convincing evidence.¹³⁹

C. Revenue Allocation And Rate Design

118. In contrast to the legal requirements for determining a fair return or the cost of service, the Commission and courts have long recognized the appropriateness of considering ability to pay, among other non-cost factors, in revenue allocation and rate design determinations.¹⁴⁰

119. All parties agree that in allocating revenue responsibility among the rate classes and in designing rates within those classes, the Commission considers both cost and non-cost factors and acts in its “quasi-legislative” capacity, rather than in a “quasi-judicial” capacity, reflecting the policy nature of rate design determinations. As the *St. Paul Chamber* Court noted, on these issues the Commission’s “careful balancing of public policies and private needs is not a matter for the courts, unless statutory authority has been exceeded or discretion abused.”¹⁴¹

VIII. UNDISPUTED OR RESOLVED ISSUES

A. Cost Of Capital

120. A utility’s overall cost of capital is determined by its capital structure (the percentages of its total capital comprised of equity, long-term debt and short-term debt) and the costs associated with those various components of its capital structure. Only Xcel Energy and the Department provided testimony regarding the Company’s capital structure and costs of debt, and do not dispute the capital structure, cost of long-term debt or cost of short-term debt to be used in determining the Company’s revenue requirement for 2025 and 2026.

¹³⁹ *St. Paul Chamber*, 251 N.W.2d at 358

¹⁴⁰ *St. Paul Chamber*, 251 N.W.2d at 357.

¹⁴¹ *St. Paul Chamber*, 251 N.W.2d at 357.

1. Capital Structure

121. The Company proposed the following capital structures for the 2025 test year and the 2026 plan year:¹⁴²

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%

122. The Department recommended use of the Company's proposed capital structure in determining the Company's overall cost of capital in this proceeding, noting that it reflects the Company's actual capital structure, which has been relatively constant for many years, and that the Commission has approved a 52.50 percent Common Equity ratio in all Company rate cases since 2008.¹⁴³

123. The Company's proposed capital structure is reasonable and should be used for ratemaking purposes in this proceeding.

2. Cost Of Long-Term Debt

124. The Company proposed costs of long-term debt for 2025 and 2026 of 4.51 and 4.53 percent, respectively, calculating those costs as the sum of all expected interest and related amortization expenses, divided by the 13-month average of debt outstanding.¹⁴⁴

¹⁴² Ex. Xcel-21 at 4 (Wehner Direct).

¹⁴³ Ex. DOC-12 at 32 (Addonizio Direct).

¹⁴⁴ Ex. Xcel-21 at 30-31 and Schedules 4 and 5 (Wehner Direct).

125. The Department reviewed the Company's and others' debt issuances and concluded the Company's proposed costs of long-term debt were reasonable.¹⁴⁵

126. The Company's proposed costs of long-term debt for 2025 and 2026 are reasonable and should be used for ratemaking purposes in this proceeding.

3. Cost Of Short-Term Debt

127. 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.¹⁴⁶

128. The Department reviewed the Company's proposed costs for short-term debt and concluded they were reasonable.¹⁴⁷

129. The Company's proposed costs of short-term debt for 2025 and 2026 are reasonable and should be used for ratemaking purposes in this proceeding.

B. Revenue Related Issues

1. 2025 Sales Forecast Update

130. Given the timeline of this proceeding, and consistent with past practice in Xcel Energy rate cases, the Company recommended that 2025 final rates be set using 2025 actual sales.¹⁴⁸

131. The Department agreed that it is reasonable to set 2025 final rates using 2025 actual sales,¹⁴⁹ and no other party provided testimony on this issue.

132. It is just and reasonable to set 2025 final rates using 2025 actual sales, as proposed by the Company.

2. 2025 Late Fee Revenue

133. 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), discussed below. This

¹⁴⁵ Ex. DOC-12 at 33-38 (Addonizio Direct).

¹⁴⁶ Ex. Xcel-21 at 32-36 and Schedules 13-15 (Wehner Direct).

¹⁴⁷ Ex. DOC-12 at 38-39 (Addonizio Direct).

¹⁴⁸ Ex. Xcel-29 and 13-16 (Levine Direct); Ex. Xcel-30 at 1-2 (Levine Rebuttal).

¹⁴⁹ Ex. DOC-15 at 2-4 (Shah Surrebuttal).

increased the Company's revenue requirement by \$6.1 million and \$5.8 million in 2025 and 2026, respectively.¹⁵⁰

134. 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 2026.¹⁵¹

135. 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.¹⁵² The parties continue to dispute the appropriate ratemaking treatment of 2026 late fee revenues.

136. It is reasonable 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 Department.

3. Capacity Revenue Baseline And True-Up

137. In its Initial Filing, the Company included budgeted amounts for Midcontinent Independent System Operator (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.¹⁵³

138. By the time of Intervenor Direct Testimony, the MISO Planning Reserve Auction had occurred and additional bilateral contracts were available. The Department therefore recommended updating the baseline for capacity revenues reflecting these changes.¹⁵⁴

139. The Company agreed with the Department's updated capacity revenue numbers in its Rebuttal Testimony, lowering its revenue requirement accordingly.¹⁵⁵

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

¹⁵⁰ Ex. Xcel-18 at 7-8 and Schedules 11, 12 (Halama Supplemental Direct).

¹⁵¹ Ex. DOC-19 at 66-68 (Bahn Direct).

¹⁵² Ex. Xcel-19 at 14-15 (Halama Rebuttal).

¹⁵³ Ex. Xcel-17 at 19, 78 and Schedules 11 and 12 (Halama Direct).

¹⁵⁴ Ex. DOC-5 at 9-14 and Schedule 3 (Golden Direct).

¹⁵⁵ Ex. Xcel-19 at 12-13 (Halama Rebuttal).

4. Prairie Island Capacity Revenues

141. 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 be reflected in this case, such as incorporating the impact of any derating by MISO on the Company's capacity revenues.¹⁵⁶

142. The Company provided Rebuttal Testimony, estimating lost capacity revenues for 2025 of approximately \$171,000 due to this outage.¹⁵⁷

143. The Department recommended an adjustment increasing revenues in both 2025 and 2026 by \$171,000 to reflect these lost revenues,¹⁵⁸ and the Company agreed to this adjustment.

144. The Company's cost of service for both 2025 and 2026 should be adjusted to include \$171,000 in lost revenues due to the PINGP outage.

C. Expense or Rate Base Issues

1. Community Solar Gardens

145. 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.¹⁵⁹

146. The Department agreed with this adjustment,¹⁶⁰ and no other party filed testimony regarding it.

147. 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 Department.

¹⁵⁶ *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 (Nov. 15, 2024) (eDocket No. 20251-214793-01).

¹⁵⁷ Ex. Xcel-82 at 4-13 and Schedules 1-5 (Detmer Rebuttal).

¹⁵⁸ Ex. DOC-2 at 23-25 (Johnson Surrebuttal).

¹⁵⁹ Ex. Xcel-19 at 4-5 and Schedules 3A-3B at 2 (Halama Rebuttal).

¹⁶⁰ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

2. Customer Advances

148. In Rebuttal Testimony, the Company adjusted its customer advances to reflect a more current 13-month period.¹⁶¹

149. In Surrebuttal Testimony, the Department agreed this adjustment is appropriate.¹⁶²

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

3. Nuclear Decommissioning Accrual/Nuclear End-of-Life Accrual

151. The Company's Initial Filing included the then-approved amounts for the accruals related to nuclear decommissioning and end-of-life nuclear fuel.¹⁶³

152. 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, issued after the Company filed this case.¹⁶⁴

153. 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. RP-24-67, resulting in annual decommissioning accrual amount of zero for 2025 and 2026.¹⁶⁵

154. 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.¹⁶⁶

¹⁶¹ Ex. Xcel-19 at 5 and Schedules 3A and 3B (Halama Rebuttal).

¹⁶² Ex. DOC-2 at 31 and Schedule 1 (Johnson Surrebuttal).

¹⁶³ Ex. Xcel-68 at 51, 53 (Johnson Direct).

¹⁶⁴ Ex. DOC-5 at 2-5 (Golden Direct).

¹⁶⁵ Ex. Xcel-19 at 5-7 and Schedules 3A and 3B (Halama Rebuttal); Ex. Xcel-86 at 5-7 (Moeller Rebuttal)

¹⁶⁶ Ex. Xcel-19 at 9-11 and Schedules 3A and 3B (Halama Rebuttal); Ex. Xcel-86 at 5-7 (Moeller Rebuttal)

155. The Department agreed with the Company's proposed adjustments for these items.¹⁶⁷

156. The nuclear decommissioning and end-of-life nuclear fuel accrual amount adjustments agreed to by the Company and Department are reasonable and should be approved.

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

157. 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.¹⁶⁸

158. The Department agreed with the Company's rebuttal adjustment for this item.¹⁶⁹

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

5. Distributed Intelligence My Energy Connection (MEC) 3.0

160. 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.¹⁷⁰

161. The Department reviewed and agreed with the Company's proposed adjustment.¹⁷¹

162. The Company's rebuttal adjustment for the MEC 3.0 project is reasonable and should be approved, as agreed to by the Company and Department.

6. Distributed Intelligence

163. In Rebuttal Testimony, the Company removed one non-NSPM distributed intelligence project that was inadvertently included in the MYRP Forecast resulting in a

¹⁶⁷ Ex. DOC-6 at 2-4 (Golden Surrebuttal); Ex. DOC-2 at Schedule 1 (Johnson Surrebuttal).

¹⁶⁸ Ex. Xcel-19 at 7 and Schedules 3A and 3B (Halama Rebuttal); Ex. Xcel-86 at 7-10 (Moeller Rebuttal).

¹⁶⁹ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁷⁰ Ex. Xcel-19 at 7-8 and Schedules 3A and 3B (Halama Rebuttal).

¹⁷¹ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

decrease to overall revenue requirement deficiency of approximately \$0.2 million in 2025 and 2026.¹⁷²

164. The Department reviewed and agreed with the Company's proposed adjustment.¹⁷³

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

7. Employee Expenses

166. 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.¹⁷⁴

167. The Department reviewed and agreed with the Company's proposed adjustment.¹⁷⁵

168. The Company's adjustment for employee expenses is reasonable and should be approved, as agreed to by the Company and Department.

8. Electric Vehicle Program

169. 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.¹⁷⁶

170. The Department reviewed and agreed with the Company's proposed adjustment.¹⁷⁷

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

¹⁷² Ex. Xcel-19 at 8 and Schedules 3A and 3B (Halama Rebuttal).

¹⁷³ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁷⁴ Ex. Xcel-18 at 6 and Schedule 13 (Halama Supplemental Direct); Ex. Xcel-19 at 9 and Schedules 3A and 3B (Halama Rebuttal); Ex. Xcel-27 at 1-3 (Robinson Rebuttal).

¹⁷⁵ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁷⁶ Ex. Xcel-19 at 11-12 and Schedules 3A and 3B (Halama Rebuttal).

¹⁷⁷ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

9. Generation Capacity Revenues

172. The Company's Initial Filing included baseline capacity revenues in line with historic revenues.¹⁷⁸

173. Following the Company's Initial Filing, MISO conducted another Planning Reserve Auction resulting in greater revenues for the Company and the Department recommended updating the baseline capacity revenues to reflect this new information, reducing the Company's revenue requirement.¹⁷⁹

174. 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 Planning Resource Auction results.¹⁸⁰

175. 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 Department.

10. Hosting Capacity

176. In its Initial Filing, the Company included capital additions for hosting capacity beginning in 2026 because it was expected that the frameworks being developed in the two dockets referenced above might result in specific projects being identified for implementation in 2026.

177. Joint Intervenors recommended not including the hosting capacity dollars in the 2026 plan year at this time, given the lack of specifically identified projects.¹⁸¹

178. In Rebuttal Testimony, the Company stated that it now does not expect that to have specific hosting capacity projects identified for implementation in 2026 and proposed removing the hosting capacity dollars from rate base.¹⁸²

179. The Department agreed with the Company's proposed removal of hosting capacity capital additions.¹⁸³

¹⁷⁸ Ex. Xcel-17 at 19, 44-45 (Halama Direct).

¹⁷⁹ Ex. DOC-5 at 9-14 (Golden Direct).

¹⁸⁰ Ex. Xcel-19 at 12-13 and Schedules 3A and 3B (Halama Rebuttal); Ex DOC-6 at 4-5 (Golden Surrebuttal).

¹⁸¹ Ex. JIN-1 at 25 (Kenworthy Direct).

¹⁸² Ex. Xcel-35 at 26 (Mensen Rebuttal); Ex. Xcel-19 at 13 and Schedules 3A and 3B (Halama Rebuttal).

¹⁸³ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

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

11. Luverne Battery Reallocation

181. 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 to perform the 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.¹⁸⁴

182. 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 increasing the rebuttal revenue requirement.¹⁸⁵

183. The Department reviewed and agreed with the Company's proposed adjustment.¹⁸⁶

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

12. Nuclear Production Tax Credit

185. As the Company indicated in its Initial Filing, 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.¹⁸⁷

¹⁸⁴ Ex. Xcel-69 at 44-45 (Johnson Direct).

¹⁸⁵ Ex. Xcel-86 at 8-9 (Moeller Rebuttal); Ex. Xcel-19 at 15-16 and Schedules 3A and 3B (Halama Rebuttal).

¹⁸⁶ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁸⁷ Ex. Xcel-17 at 57 (Halama Direct).

186. 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.¹⁸⁸

187. 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.¹⁸⁹

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

13. Solar Production Tax Credits - Allocation

189. 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 RES Rider, i.e., based on the Minnesota jurisdictional energy allocator due to their variable nature.¹⁹⁰

190. The Company proposed a rebuttal adjustment to correct this allocation.¹⁹¹

191. The Department reviewed and agreed with the Company's proposed adjustment.¹⁹²

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

14. Federal Production Tax Credits

193. 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 Renewable Energy Standard (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 filing.¹⁹³

¹⁸⁸ Ex. Xcel-19 at 16 (Halama Rebuttal) Ex. DOC-7 at 6-8 (Uphus Direct).

¹⁸⁹ Ex. Xcel-19 at 16-17 and Schedules 3A and 3B (Halama Rebuttal); Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁹⁰ Ex. Xcel-17 at 57 (Halama Direct); Ex. Xcel-19 at 17 (Halama Rebuttal).

¹⁹¹ Ex. Xcel-19 at 17 and Schedules 3A and 3B (Halama Rebuttal).

¹⁹² Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁹³ Ex. Xcel-17 at 103-104 (Halama Direct).

194. The Department agreed with the Company's proposed treatment of PTCs but recommended using the Company's updated PTC forecast, developed after the Initial Filing.¹⁹⁴

195. The Company agreed to use the updated forecast and adjusting the baseline PTCs accordingly, also incorporating the solar PTC allocation adjustment discussed above.¹⁹⁵

196. The Department reviewed and agreed with the Company's proposed adjustment.¹⁹⁶

197. 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, as agreed to by the Company and Department.

15. Remaining Lives And Net Salvage Rates - Production

198. 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.¹⁹⁷

199. 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.¹⁹⁸

200. The Department recommended no life extension for these hydro facilities in the ARL docket, and the Company did not object to this recommendation.¹⁹⁹

201. 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.²⁰⁰

¹⁹⁴ Ex. DOC-7 at 5-8 (Uphus Direct).

¹⁹⁵ Ex. Xcel-19 at 18-19 and Schedules 3 and 3B (Halama Rebuttal).

¹⁹⁶ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

¹⁹⁷ Ex. Xcel-69 at 33 (Johnson Direct); Ex. Xcel-18 at 20-21 (Halama Rebuttal).

¹⁹⁸ Ex. Xcel-19 at 20-21 (Halama Rebuttal).

¹⁹⁹ Ex. Xcel-86 at 3-4 (Moeller Rebuttal); Ex. Xcel-19 at 20-21 and Schedules 3A and 3B (Halama Rebuttal).

²⁰⁰ Ex. Xcel-19 at 20-21 and Schedules 3A and 3B (Halama Rebuttal).

202. The Department reviewed and agreed with the Company's proposed adjustment.²⁰¹

203. The Company's adjustment for Remaining Lives and Net Salvage Rates - Production is reasonable and should be approved, as agreed to by the Company and Department.

16. Remaining Lives - Nuclear

204. After the Initial Filing in this matter the Commission issued its Order in the Company's 2024-2024 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.²⁰²

205. The Department recommended adjusting the Company's cost of service to reflect these life extensions and the Company agreed to this adjustment.²⁰³

206. 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.

17. TCR Rider Removal FERC Reclassification

207. The Company proposed a rebuttal adjustment to correct for a misclassification in FERC accounts related to AMI meters.²⁰⁴

208. The Department reviewed and agreed with the Company's proposed adjustment.²⁰⁵

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

²⁰¹ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

²⁰² Ex. DOC-23 at 14 (Jones Direct).

²⁰³ 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).

²⁰⁴ Ex. Xcel-19 at 23 and Schedules 3A and 3B (Halama Rebuttal).

²⁰⁵ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

18. TCR Rider Removal Update

210. In Rebuttal Testimony, the Company adjusted the 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.²⁰⁶

211. The Department reviewed and agreed with the Company's proposed adjustment.²⁰⁷

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

19. Service Quality

213. 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-24-27.²⁰⁸

214. The Department reviewed and agreed with the Company's proposed adjustment.²⁰⁹

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

20. Sherco Inventory Write Off

216. In its Initial Filing, the Company proposed to include a one-time \$8.1 million obsolete inventory write-off in 2026 from the retirement of Sherco Unit 1.²¹⁰

217. The Department recommended to amortize the write-off amount of \$8.1 million over three years and revise the revenue requirement to reflect the three year amortization beginning in 2025.²¹¹

218. The Company agreed with the Department recommendation.²¹²

²⁰⁶ Ex. Xcel-19 at 23 and Schedules 3A and 3B (Halama Rebuttal).

²⁰⁷ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

²⁰⁸ Ex. Xcel-19 at 23 and Schedules 3A and 3B (Halama Rebuttal).

²⁰⁹ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

²¹⁰ Ex. Xcel-45 at 58-59 (Capra Direct).

²¹¹ Ex. DOC-1 at 39-40 (Johnson Direct).

²¹² Ex. Xcel-19 at 25-26 and Schedules 3A and 3B (Halama Rebuttal).

219. 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 and should be approved.

21. Wildfire Mitigation Pole Loading Clearance (PLC) Update

220. 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.²¹³

221. 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 Mr. Halama.²¹⁴

222. In Rebuttal Testimony, the Company proposed an adjustment to reconcile the cost of service calculations of Mr. Halama to the amounts presented by Ms. Sherwood and Ms. Bloch.²¹⁵

223. The Department reviewed and agreed with the Company's proposed adjustment.²¹⁶

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

22. Wildfire

225. Wildfire mitigation is a core component of providing utility service.²¹⁷ While the Company and Department disagree regarding the overall scope of wildfire risk faced by the Company in Minnesota,²¹⁸ they reached general alignment that the Company should

²¹³ 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).

²¹⁴ Ex. Xcel-48 at 4 (Sherwood Supplemental Direct); Ex. Xcel-18 at 5 (Halama Supplemental Direct); Ex. Xcel-19 at 25-26 and Schedules 3A and 3B (Halama Rebuttal).

²¹⁵ Ex. Xcel-19 at 25-26 and Schedules 3A and 3B (Halama Rebuttal).

²¹⁶ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal).

²¹⁷ Ex. Xcel-84 at 21 (McGregor Rebuttal).

²¹⁸ Ex. Xcel-47 at 2-23 (Sherwood Direct); Ex. Xcel-84 at 12-21 (McGregor Rebuttal); Ex. DOC-9 at 10-20 (Borden Direct).

begin implementing wildfire mitigation activities, including smaller-scale and foundational programs, as well as larger-scale programs in higher-risk areas.²¹⁹

226. The overall costs for the larger-scale wildfire programs presented in the Department's Direct Testimony and Surrebuttal Testimony are reasonable for inclusion in the 2025 test year and 2026 plan year. This results 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 from the Company's Rebuttal Testimony position.²²⁰ The 2025 test year and 2026 plan year also should include the smaller-scale and foundational programs (and costs), as proposed by the Company.²²¹

227. The Company is in the process of developing more sophisticated modeling to support future wildfire mitigation activities.²²² The Company should work with interested stakeholders to identify an appropriate proceeding in which to present the results of this more sophisticated modeling, as well as a formalized wildfire mitigation plan.²²³ That future proceeding could also consider the best way to recover wildfire-related costs.²²⁴ Since Integrated Distribution Plans have their own cadence focused on planning, not cost recovery,²²⁵ it is premature to proscribe that future wildfire-related filings should be subsumed into the IDP process.²²⁶

23. Research And Experimentation Federal And State Tax Credits

228. 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 2026 plan year. The Company calculated the R&E credit amounts using an adjusted average of the qualified research expenses (QREs) for tax years 2020 through 2022.²²⁷

²¹⁹ Ex. Xcel-95 at 2 (Xcel Energy Correspondence Regarding Wildfire Issue) (citing Ex. DOC-9 at 3:1-4 (Borden Direct) and Ex. DOC-10 at 10:4-8 (Borden Surrebuttal). The Joint Intervenors support this resolution. *See* JIN Initial Brief at 39-40 (citing Ex. JIN-4 at 21 (Kenworthy Surrebuttal)).

²²⁰ Ex. Xcel-95 at 1-2 (Xcel Energy Correspondence Regarding Wildfire Issue).

²²¹ Ex. Xcel-48 at 2-9 and Schedule 1 (Sherwood Supplemental Direct); Ex. Xcel-84 at 2 (McGregor Rebuttal); Ex. DOC-9 at 3:1-4 (Borden Direct).

²²² Ex. Xcel-84 at 13 (McGregor Rebuttal).

²²³ Ex. Xcel-84 at 23 (McGregor Rebuttal).

²²⁴ Ex. Xcel-16 at 29 (Liberkowski Rebuttal).

²²⁵ Ex. Xcel-16 at 28 (Liberkowski Rebuttal).

²²⁶ *Contra* JIN Initial Brief at 41-42.

²²⁷ Ex. Xcel-17 at 57 (Halama Direct); Ex. Xcel-19 at 41-42 and Schedule 4 (Halama Rebuttal).

229. The Department initially proposed an adjustment to these tax credit amounts based on using tax years 2022 through 2024.²²⁸ 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.²²⁹

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

24. North Dakota Investment Tax Credits

231. The Company included a proportional share of its North Dakota investment tax credits (ITCs) in its test year and plan year, consistent with the Commission's order in the Company's last rate case.²³⁰

232. The Department originally proposed an adjustment to these tax credit amounts.²³¹ However, upon review of further information provided by the Company in Rebuttal Testimony, the Department agreed no adjustment was appropriate.²³²

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

25. Distribution Communications Infrastructure

234. The Company included capital additions for certain fiber buildout projects for the teleprotection of its distribution system.²³³ In its Rebuttal Testimony, the Company explained that 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 that requires a consistent, reliable, and secure communications channel, which the fiber buildout projects provide.²³⁴

235. Joint Intervenors originally recommended an adjustment removing these projects from the MYRP.²³⁵ However, upon review of additional information provided in

²²⁸ Ex. DOC-7 at 12-14 (Uphus Direct).

²²⁹ Ex. DOC-8 at 5-6 (Uphus Surrebuttal).

²³⁰ Ex. Xcel-17 at 128 (Halama Direct).

²³¹ Ex. DOC-7 at 8-12 (Uphus Direct).

²³² Ex. Xcel-19 at 41-42 and Schedule 4 (Halama Rebuttal); Ex. DOC-8 at 4 (Uphus Surrebuttal).

²³³ Ex. Xcel-36 at 101-104 (Mensen Direct).

²³⁴ Ex. Xcel-35 at 27-33 (Mensen Rebuttal).

²³⁵ Ex. JIN-1 at 26-30 (Kenworthy Direct).

the Company's Rebuttal Testimony, Joint Intervenors no longer recommended removing these projects from the MYRP.²³⁶

236. Based on the record of this proceeding, the fiber buildout projects proposed in the MYRP are reasonable and rate recovery should be allowed.

26. Bad Debt Expense Adjustment

237. The Company's Initial Filing included bad debt expense for the 2025 test year and 2026 plan year at 0.50 percent and 0.53 percent of commodity revenues, respectively.²³⁷

238. The Department originally recommended an adjustment to lower the bad debt ratios to 0.45 and 0.50 percent for 2025 and 2026, respectively, based on a three-year historical average of 2022 through 2024.²³⁸

239. In response, the Company explained that 2022 bad debt expense was not consistent with other Company history, that year-to-date actual data for 2025 showed actual bad debt tracking extremely close to the Company's 2025 forecast and that the Company has consistently underestimated its bad debt expense in prior years.²³⁹

240. After reviewing the Company's Rebuttal Testimony and responses to Information Requests, the Department agreed that 2025 actual bad debt experience was tracking extremely close to the Company's forecast and no longer recommended an adjustment.²⁴⁰

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

27. Discrete Capacity Project Investments

242. In its Initial Filing, the Company's Distribution business area proposed certain discrete capacity projects to come into service during the MYRP.²⁴¹

²³⁶ Ex. JIN-4 at 17-18 (Kenworthy Surrebuttal).

²³⁷ Ex. Xcel-17 at 74 (Halama Direct); Ex. Xcel-38 at 35-46 (Lindgren Direct).

²³⁸ Ex. DOC-23 at 19-20 (Jones Direct).

²³⁹ Ex. Xcel-81 at 3-4 (Howard Rebuttal).

²⁴⁰ Ex. Xcel-24 at 8-9 and Schedule 2 (Jones Surrebuttal).

²⁴¹ Ex. Xcel-34 at 88-91 (Mensen Direct).

243. Joint Intervenors initially recommended against approval of these projects absent further justification.²⁴²

244. The Company provided additional information on these projects in its Rebuttal Testimony.²⁴³ In its Initial Brief, Joint Intervenors stated that based on this further information they no longer opposed rate recovery for these projects.²⁴⁴

245. The record supports approval of rate recovery for the Company's discrete capacity projects, as agreed to by the Company and Joint Intervenors.

28. Fault Location And Isolation Service Restoration (FLISR)

246. 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).²⁴⁵ 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).²⁴⁶ 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, 2032.²⁴⁷

247. Based on the Company's testimony, the Department concluded that the Company complied with the FLISR filing requirements related to a FLISR PIM,²⁴⁸ 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).²⁴⁹ The Department also recommended that the Company continue to evaluate the FLISR PIM as part of future rate cases when FLISR is fully deployed.²⁵⁰

²⁴² Ex. JIN-1 at 23-24 (Kenworthy Direct).

²⁴³ Ex. Xcel-35 at 19-25 (Mensen Rebuttal)

²⁴⁴ JIN Initial Brief at 42-43.

²⁴⁵ Ex. Xcel-34 at 109 (Mensen Direct).

²⁴⁶ Ex. Xcel-34, Schedule 4 (Mensen Direct).

²⁴⁷ Ex. Xcel-34 at 118 and Schedule 4 (Mensen Direct).

²⁴⁸ Ex. DOC-7 at 23 (Uphus Direct).

²⁴⁹ Ex. DOC-7 at 24 (Uphus Direct).

²⁵⁰ Ex. DOC-7 at 24 (Uphus Direct).

248. 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.²⁵¹

249. The Administrative Law Judge recommends the Commission find that the Company complied with the filing requirements related to a FLISR PIM and that the Commission 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 the PBR proceeding and as part of future rate cases when FLISR is fully deployed.

29. Property Tax True-Up

250. The Company proposed to use a true-up mechanism to ensure that customers pay only the property taxes that are actually incurred.²⁵² 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.²⁵³

251. 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;²⁵⁴ any over-recovery would be refunded, or, symmetrically, any under-recovery would be charged, through an appropriate mechanism at that time;²⁵⁵ and the Company proposed that the true-up would stay in place until its next rate case.²⁵⁶

252. 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.²⁵⁷ This true-up process has been in place for years, and the Company believes it has worked well to date.²⁵⁸

²⁵¹ Ex. Xcel-35 at 42 (Mensen Rebuttal); Ex. DOC-8 at 7-8 (Uphus Surrebuttal).

²⁵² Ex. Xcel-51 at 22 (Kowalowski Direct).

²⁵³ Ex. Xcel-51 at 22 (Kowalowski Direct).

²⁵⁴ Ex. Xcel-51 at 13, 22 (Kowalowski Direct).

²⁵⁵ Ex. Xcel-51 at 22 (Kowalowski Direct).

²⁵⁶ Ex. Xcel-51 at 23 (Kowalowski Direct).

²⁵⁷ Ex. Xcel-51 at 10, 11, 22 (Kowalowski Direct).

²⁵⁸ Ex. Xcel-51 at 22, 23 (Kowalowski Direct).

253. The Department initially recommended to modify the Company's proposed property tax true-up.²⁵⁹ The Department recommended that the true-up be limited such that "the Company is not allowed to recover the property tax expense if it exceeds 5% of the Commission approved amount to be included in the MYRP."²⁶⁰ But in its Surrebuttal Testimony, the Department changed its position and supported the Company's proposed property tax true-up.²⁶¹ The Company's proposed property tax true-up process is reasonable and is supported in the record, and should be adopted.

D. Class Cost Of Service Study

254. The Company explained that the D60Sub allocator is used to allocate the costs of distribution substations that serve multiple customer classes, and demonstrated that it had removed peak loads related to substations dedicated to specific customers.²⁶² No party raised concerns with the calculation of the D60Sub allocator and the record demonstrates that it should be approved.

E. Revenue Apportionment And Rate Design

1. Rate Design Proposals

255. The Company provided a rate design proposal for each customer class and schedules to demonstrate how the rates would be calculated once a revenue requirement is determined.²⁶³ Other than the disputed issues discussed below, parties did not dispute the Company's rate design proposals and they should be approved.

2. Conservation Cost Recovery Charge

256. 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.²⁶⁴ The record demonstrates that the Company's recommendation to change the CCRC is reasonable and it should be approved.

²⁵⁹ Ex. DOC-23 at 13 (Jones Direct).

²⁶⁰ Ex. DOC-23 at 13 (Jones Direct).

²⁶¹ Ex. DOC-24 at 4-5 (Jones Surrebuttal).

²⁶² Ex. Xcel-73 at 28-26 (Barthol Direct).

²⁶³ Ex. Xcel-76 at 13-24 (Paluck Direct).

²⁶⁴ Ex. Xcel-73 at 50-51 (Barthol Direct).

3. Excess Footage Charges, Winter Construction Charges, And Dedicated Switching.

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

258. 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.²⁶⁵

259. 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 winter construction charges because of increases in material, labor, and equipment costs, and provided cost analysis to support its proposal.²⁶⁶

260. 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.²⁶⁷

261. 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.²⁶⁸

262. 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,²⁶⁹ which the Company provided in its Rebuttal Testimony.²⁷⁰ 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.²⁷¹

²⁶⁵ Ex. Xcel-73 at 52 and Schedule 11 (Barthol Direct).

²⁶⁶ Ex. Xcel-73 at 52-53 and Schedule 11 (Barthol Direct).

²⁶⁷ Ex. Xcel-73 at 53-54 and Schedule 11 (Barthol Direct).

²⁶⁸ Ex. Xcel-73 at 54 (Barthol Direct).

²⁶⁹ Ex. DOC-19 at 53-54 (Bahn Direct).

²⁷⁰ Ex. Xcel-74 at 40-42 (Barthol Rebuttal).

²⁷¹ Ex. DOC-20 at 15-16 (Bahn Surrebuttal).

263. 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.

F. Additional Issues

1. Reporting Requirements

264. 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 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.²⁷² No party provided testimony regarding this proposal. Therefore, the record supports the Company's proposal to discontinue the deferral of emission allowances with no adjustment in this proceeding.

265. 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 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.²⁷³ No party provided testimony regarding compliance with this requirement. Based on the information provided by the Company, the record supports discontinuance of further reporting related to HomeSmart.

266. 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.²⁷⁴ No party objected to this Company request. Therefore, the record supports that the Company should be allowed to discontinue reporting on TBT leases in future rate cases.

267. 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.

²⁷² Ex. Xcel-17 at 130 (Halama Direct).

²⁷³ Ex. Xcel-17 at 130 (Halama Direct).

²⁷⁴ Ex. Xcel-17 at 131 (Halama Direct).

Since this provision has not been triggered in many years, the Company proposed to discontinue this reporting in future rate cases.²⁷⁵ No party objected to this Company request. Therefore, the record supports that the Company should be allowed to discontinue this reporting.

2. Fuel Clause Rider

268. The Company updated the Fuel Adjustment Factor section of the Fuel Clause Rider to be consistent with test year 2025 information. The Fuel Adjustment Factor Ratios by Service Category were updated to test year 2025 based on corresponding updates to Class Cost Ratios, TOU Ratios, and TOD Ratios. These updates were determined using the method approved by the Commission in the Company's previous rate cases.²⁷⁶ The Department reviewed the Company's update and agreed with that it is appropriate.²⁷⁷ The Company's updates to the Fuel Clause Rider, as agreed to by the Company and Department, are reasonable and should be approved.

3. ATO/MTO Dual Feeder Service

269. ATO/MTO 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 a ATO/MTO switch, allows the alternate feeder to 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.²⁷⁸

270. 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.²⁷⁹

271. The Company proposed to implement a charge for new ATO/MTO Dual Feeder Service customers to cover the cost associated with reserving alternate feeder

²⁷⁵ Ex. Xcel-17 at 132 (Halama Direct).

²⁷⁶ Ex. Xcel-76 at 24 (Paluck Direct)

²⁷⁷ Ex. DOC-19 at 51 (Bahn Direct).

²⁷⁸ Ex. Xcel-34 at 195 (Mensen Direct).

²⁷⁹ Ex. Xcel-34 at 195 (Mensen Direct).

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.²⁸⁰ 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.²⁸¹

272. 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.²⁸²

273. 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.²⁸³ In Surrebuttal Testimony, the Department confirmed that the Company and the Department are in agreement on reporting in the next rate case.²⁸⁴

274. The Administrative Law Judge recommends that the Commission 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 Administrative Law Judge recommends that the Commission approve that 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.

4. Coal Combustion Residuals Tracker

275. The Company proposed a tracker for costs of complying with the U.S. Environmental Protection Agency's amended regulations governing how coal ash, also known as coal combustion residue (CCR), is managed.²⁸⁵

²⁸⁰ Ex. Xcel-34 at 196 (Mensen Direct).

²⁸¹ Ex. Xcel-34 at 196 (Mensen Direct).

²⁸² Ex. DOC-7 at 27 (Uphus Direct).

²⁸³ Ex. Xcel-35 at 51 (Mensen Rebuttal).

²⁸⁴ Ex. DOC-8 at 8 (Uphus Direct).

²⁸⁵ Ex. Xcel-61 at 14, 30 (West Direct); Ex. Xcel-17 at 117-118 (Halama Direct); Ex. Xcel-69 at 53-55 (Johnson Direct).

276. Company witness Jeffrey West explained that the CCR regulations were first promulgated by the EPA in 2015 under the Resource Conservation and Recovery Act (RCRA), and have been subsequently amended and interpreted by the EPA.²⁸⁶ The purpose of the CCR regulations is to regulate the ongoing management of coal ash from inception to disposal at active landfills and impoundments.²⁸⁷

277. Mr. West described amendments to the CCR regulation, specifically that the EPA's 2024 regulations significantly expanded the scope of the CCR regulations, which increased the number of locations and sites subject to these regulations. The revised rules are commonly referred to as the "Legacy CCR Rule." 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.²⁸⁸

278. Mr. West provided a summary of the potential impacts to the Company from the Legacy CCR rule, which defines a systematic approach to CCR that begins with an initial investigation, which may lead to final remediation and closure in some cases. Each action is determined by the results of the previous steps in the process. The first step includes desktop-type reviews of approximately 35 current and former electric generating facilities at a cost of \$4 to \$6 million between. The desktop reviews will identify sites that will need further investigation to determine if further work, including groundwater and/or other remediation, may be needed. The location and costs of future remediation is currently uncertain but could be in the tens of millions of dollars. Those units that are found to have impacted groundwater, as defined by the CCR regulations, would be subject to the additional costs for corrective action necessary to meet groundwater protection standards. These activities and any cost estimates are unknown at this time.²⁸⁹

279. Mr. West further testified that future changes to the CCR regulations or changes to the EPA's interpretation of those regulations could occur, and that 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.²⁹⁰ Company witness Halama further testified that the uncertainty of these costs make a tracker the appropriate mechanism for cost recovery of these costs.²⁹¹

280. Department witness Andrew Golden recommended approval of the Company's CCR tracker and that the Company be required to provide adequate support for its Legacy CCR expenses. Mr. Golden also recommended that the Company not be able

²⁸⁶ Ex. Xcel-61 at 15 (West Direct).

²⁸⁷ Ex. Xcel-61 at 16 (West Direct).

²⁸⁸ Ex. Xcel-61 at 17 (West Direct).

²⁸⁹ Ex. Xcel-61 at 28 (West Direct).

²⁹⁰ Ex. Xcel-61 at 28 (West Direct).

²⁹¹ Ex. Xcel-17 at 118 (Halama Direct).

to include any internal labor costs in the tracker because those costs would not be considered incremental costs.²⁹²

281. In response to Mr. Golden's recommendation, Mr. West testified that the Company might need to hire resources for CCR compliance that would be incremental costs not otherwise be captured in the Company's forecast. Mr. West explained that 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 may not be able to handle this workload and additional resources may need to be obtained. Mr. West also explained that 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.²⁹³

282. In surrebuttal, Mr. Golden testified that he found Mr. West's explanation of the potential need for additional labor and resources beyond the Company's existing capacity to be reasonable, and agreed that such costs could be considered incremental costs. As a result, Mr. Golden revised his recommendation to no longer exclude internal labor costs, but instead require the Company to justify and support how any incremental labor costs incurred were incremental beyond internal labor costs and outside services already collected through rate case recovery.²⁹⁴

283. The Administrative Law Judge recommends that the Commission approve the Company's requested CCR tracker and that it 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.

5. Bad Debt Expense Tracker

284. In the Company's Annual Safety, Reliability, and Service Quality Report docket, MPUC 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. Annual Safety, Reliability, and Service Quality Report.²⁹⁵

²⁹² Ex. DOC-5 at 26 (Golden Direct).

²⁹³ Ex. Xcel-60 at 3-4 (West Rebuttal).

²⁹⁴ Ex. DOC-6 at 7-8 (Golden Surrebuttal).

²⁹⁵ Ex. Xcel-17 at 119-120 (Halama Direct); Ex. ECC-1 at 11-13 (Shardlow Direct); Ex. ECC-2 at 1-2 (Shardlow Surrebuttal).

285. CUB and ECC both supported the Company's proposal and no other party commented.²⁹⁶

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

6. PowerOn Auto Enrollment

287. In its Direct Testimony, ECC proposed to expand PowerOn assistance by implementing auto-enrollment of the Company's LIHEAP-enrolled, electric only customers.²⁹⁷

288. The Company and CUB supported this ECC proposal.²⁹⁸

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

7. MYRP Issues

290. The Company proposed a two-year term for the MYRP, with a 2025 Test Year and 2026 Plan Year.²⁹⁹ No other party filed testimony or took a position on the term of the MYRP. The two-year term is reasonable and should be approved.

291. 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.³⁰⁰ 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.³⁰¹ The 2026 Sales True-Up, as agreed to by the Company and Department, is reasonable and should be approved.

292. 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.³⁰² The Department

²⁹⁶ Ex. CUB-3 at 24-25

²⁹⁷ Ex. ECC-1 at 11-13 (Shardlow Direct).

²⁹⁸ 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).

²⁹⁹ Ex. Xcel-15 at 2-5 (Liberkowski Direct).

³⁰⁰ 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).

³⁰¹ Ex. DOC 19 at 9-17 (Bahn Direct); Ex. DOC-20 at 4 (Bahn Surrebuttal).

³⁰² Ex. Xcel-15 at 40 (Liberkowski Direct); Ex. Xcel-19 at 67-68 (Halama Rebuttal).

agreed the Capital True-Up was appropriate and should be continued.³⁰³ No other party filed testimony or took a position on this issue. The Capital True-Up, as agreed to by the Company and Department, is reasonable and should be approved.

IX. DISPUTED ISSUES

A. Overall Cost Of Capital – Return On Equity

293. A utility's overall cost of capital is determined by its capital structure (the percentages of its total capital comprised of equity, long-term debt and short-term debt) and the costs associated with those various components of its capital structure. Only Xcel Energy and the Department provided testimony regarding the Company's capital structure and costs of debt, and do not dispute the capital structure, cost of long-term debt or cost of short-term debt to be used in determining the Company's revenue requirement for 2025 and 2026. Therefore, the only remaining cost of capital issue in this proceeding concerns the return on equity (ROE) to be authorized.

294. Under both court and Commission precedent, in setting an allowed ROE the Commission seeks to establish a return that is:

- Adequate to allow the Company to attract the capital that is necessary to provide safe and reliable service (the capital attraction standard);
- Sufficient to ensure the Company's ability to maintain its financial integrity (the financial integrity standard); and
- At a level that is comparable to returns required on investments of similar risk (the comparability standard).³⁰⁴

295. To determine a recommended reasonable return consistent with these fundamental standards, the Commission has long relied on expert witnesses' analytical modeling methods, particularly the results of a Two-Growth Discounted Cash Flow (DCF) analysis. These analyses can inform both a reasonable range of ROEs and inform the Commission determination of an allowed ROE within that range.

296. The following parties filed testimony presenting analyses and recommending a specific ROE: Xcel Energy, Department, CUB and XLI. In addition, Walmart and CUB provided general testimony on ROE, recommending the Commission approve an ROE no higher than the Company's currently approved 9.25 percent.

³⁰³ Ex. DOC-1 at 52 (Johnson Direct).

³⁰⁴ Ex. Xcel-24 at 10 (Nowak Direct).

1. Xcel's Proposed ROE

297. Xcel Energy cost of capital expert witness Mr. Nowak provided a full analysis of the appropriate return on common equity for the Company, developed through the use of multiple market-based financial models, consistent with both financial literature and regulatory precedent.³⁰⁵

298. Because the Company is not publicly traded, witness Nowak first established a “proxy group” of companies for which market data is available, consistent with past Commission practice, by applying several screening criteria to identify companies that possess a set of business and operating characteristics similar to Xcel Energy’s Minnesota electric utility operations.³⁰⁶

299. While no proxy group will be identical in risk to the Company, use of these criteria can identify a group of vertically-integrated electric utilities that is reasonably comparable to the financial and operational characteristics of the Company’s electric utility operations.³⁰⁷ For example, the proxy group screening criterion requiring an investment grade credit rating ensures that the proxy group companies are, like the Company, in sound financial condition.³⁰⁸ Because credit ratings take into account both the regulatory environment in which the utility operates and its business and financial risks, the ratings provide a broad measure of investment risk for investors.³⁰⁹ Establishment of a proxy group that meets these key criteria ensures that the cost of equity analysis will be consistent with the *Hope* and *Bluefield* standards, requiring returns commensurate with returns on investments of similar risk.³¹⁰

300. While Mr. Nowak’s screening criteria for the proxy group did not change from his Direct Testimony to his Rebuttal Testimony, his Rebuttal Testimony removed two companies from the proxy group due to recent mergers and acquisitions and added one company that now met his criteria.³¹¹

301. Among the parties to this proceeding that used a proxy group for its cost of equity analyses, any minor difference in the companies included in the final group analyzed by each party (for example, CUB and XLI adopted the Company’s Direct Testimony proxy group for their analyses and did not update the group as did witness Nowak) are not significant for purposes of determining a fair and reasonable ROE. Rather, the disparate

³⁰⁵ Ex. Xcel-24 at 9-10, 34-35 (Nowak Direct).

³⁰⁶ Ex. Xcel-24 at 30-34 (Nowak Direct).

³⁰⁷ Ex. Xcel-24 at 32 (Nowak Direct).

³⁰⁸ Ex. Xcel-24 at 32 (Nowak Direct).

³⁰⁹ Ex. Xcel-24 at 32, 53-54 (Nowak Direct).

³¹⁰ See, Ex. Xcel-24 at 32-34 (Nowak Direct).

³¹¹ Ex. Xcel-25 at 12 (Nowak Rebuttal).

recommendations result from the different approaches or underlying philosophies of their respective witnesses.

302. To develop his ROE recommendation, Mr. Nowak applied the following analytical models to his proxy group companies:

- Constant Growth DCF, based on the theory that a stock's current price represents the present value of all expected future cash flows, which for purposes of the model, are assumed to be equal to all expected future dividends. In a Constant Growth DCF analysis, the cost of common equity is then equal to the expected dividend yield plus the dividend growth rate.³¹²
- Two Growth DCF, long and consistently relied upon by the Commission, which moderates the effect of substantially high or low near-term growth estimates on the DCF results by identifying companies with a growth rate outside the range determined by the proxy group plus or minus one standard deviation and, for those companies, applying the Constant Growth DCF model earnings growth for the first five years (i.e., short-term growth rate), and the proxy group average growth rate plus one standard deviation for companies with a high growth rate and the proxy group average minus one standard deviation for companies with a low growth rate.³¹³
- CAPM, which adds a risk-free rate of return with a market risk premium, adjusted to reflect the systematic risk of the individual security relative to the market, as measured by the Beta coefficient.³¹⁴
- Bond Yield Plus Risk Premium, which compares the risk premium implied by historical authorized ROEs compared to prevailing interest rates at the time of prior regulatory decisions. The analysis incorporates more than 30 years of 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.³¹⁵
- Expected Earnings Analysis, a comparable earnings analysis that calculates the earnings that investors expect to receive on the book value of a stock,

³¹² Ex. Xcel-24 at 35-36 (Nowak Direct).

³¹³ Ex. Xcel-24 at 40-42 (Nowak Direct).

³¹⁴ Ex. Xcel-24 at 43-44 (Nowak Direct).

³¹⁵ Ex. Xcel 24 at 47 49 (Nowak Direct); Ex. Xcel 25 at 40 41, 75 (Nowak Rebuttal).

using an accounting-based approach that relies on investment analysts' projections of earnings on book equity.³¹⁶

303. In addition to the results of these analytical analyses, Mr. Nowak testified that 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. Therefore, the Company's regulatory environment and its business and financial risks must also be taken into consideration when determining where the Company's cost of equity falls within the range of results.³¹⁷

304. Mr. 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.³¹⁸ 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.³¹⁹

305. Review of the mechanisms available to both Xcel Energy 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.³²⁰ 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.³²¹

306. Finally, Mr. Nowak considered the effect of "flotation costs," or the costs associated with the sale of new issuances of common stock.³²² Mr. Nowak's analysis

³¹⁶ Ex. Xcel-24 at 49-51 (Nowak Direct). This Expected Earnings Analysis was not relied on as one of Mr. Nowak's primary analyses, but was considered in his overall analysis as one benchmark of reasonableness. Ex. Xcel-24 at 3-4 (Nowak Direct); Ex. Xcel-25 at 42-44 (Nowak Rebuttal).

³¹⁷ Ex. Xcel-24 at 53 (Nowak Direct).

³¹⁸ Ex. Xcel-24 at 54-57 and Schedule 11 (Nowak Direct).

³¹⁹ Ex. Xcel-24 at 56 (Nowak Direct).

³²⁰ Ex. Xcel-24 at 55 and Schedule 11 (Nowak Direct); Ex. Xcel-25 at 79-80 (Nowak Rebuttal).

³²¹ Ex. Xcel-24 at 55 and Schedule 11 (Nowak Direct).

³²² Ex. Xcel-24 at 60-62 and Schedule 10 (Nowak Direct).

indicated that consideration of flotation costs results in a seven to eight basis point addition to the ROE analytical results, a figure with which the Department agreed.³²³

307. The results of Mr. Nowak’s initial analyses and his recommended ROE were as follows:³²⁴

Table 2. Xcel Energy ROE Analytical Results

	Average	Median
<i>Primary Analyses</i>		
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%
<i>Benchmark Analysis</i>		
Expected Earnings	10.71%	10.12%
<i>Other Considerations</i>		
Flotation Costs	0.07%	0.07%
Recommended Range	10.0% - 11.0%	
Recommended ROE	10.30%	

308. Mr. Nowak’s analysis established a recommended range for ROE of 10.00 to 11.00 – a range starting below the lowest average or mean analytical result of 10.34 percent (the Two-Growth DCF analysis long relied on by the Commission), and ending below the highest ROEs indicated by the analytical results.³²⁵ 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.³²⁶

³²³ Ex. Xcel-24 at 61 and Schedule 10 (Nowak Direct); Ex. DOC-12 at 57 (Addonizio Direct).

³²⁴ Ex. Xcel-24 at 4-5 (Nowak Direct).

³²⁵ Ex. Xcel-24 at 5 (Nowak Direct).

³²⁶ Ex. Xcel-24 at 5 (Nowak Direct).

309. Mr. 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.³²⁷ 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, Mr. Nowak continued to recommend an ROE of 10.30 percent, which continued to be below his now updated Two-Growth DCF analysis.³²⁸

2. XLI’s Proposed ROE

310. XLI witness Ms. LaConte also conducted multiple analyses, developing the following estimated ROEs for the Company:³²⁹

Table 3. XLI ROE Analytical Results

Component	Low	Mean	High
Constant Growth DCF	9.36%	10.38%	11.84%
Two-Growth DCF		9.58%	
Multi-Stage DCF	8.29%	8.58%	8.91%
CAPM Historical MRP		10.15%	
CAPM Projected MRP		11.09%	
Average		9.80%	

311. In developing her ROE recommendation, Ms. LaConte gave no weight to her CAPM results, so rather than basing her recommendation on this 9.80 percent average, she averaged the seven DCF results, resulting in a starting point for her recommendation of 9.56 percent.³³⁰

312. Ms. LaConte described her analysis as using “standard methods that have been used for years to determine the appropriate ROE for utilities.”³³¹ However, Ms. LaConte did not apply these same methods in the Company’s last rate case. In that case,

³²⁷ Ex. Xcel-25 at 13 and Schedules 2-8 (Nowak Rebuttal).

³²⁸ Ex. Xcel-25 at 13, 84 (Nowak Rebuttal).

³²⁹ Ex. XLI-1 at 15-18 (LaConte Direct).

³³⁰ Ex. XLI-1 at 18 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 327 (LaConte).

³³¹ Ex. XLI-1 at 18 (LaConte Direct).

Ms. LaConte did not present a Multi-Stage DCF.³³² Instead, she performed three, not two, CAPM analyses and performed a risk premium analysis not presented in this proceeding.³³³

313. In addition, Ms. LaConte’s application of the Two-Growth DCF analysis, incorporating a long-term gross domestic product (GDP) growth rate differs from the Commission’s preferred two-growth approach,” used by the Company, which has never incorporated a long-term GDP growth rate into the analysis.³³⁴ As Mr. Nowak testified, if Ms. LaConte’s Two-Stage DCF model were conformed to the Commission’s preferred methodology, her ROE estimates would increase by nearly 80 basis points, to 10.36 percent—in line with the Two-Stage DCF results of both the Company and Department.

314. After setting a baseline ROE of 9.56, Ms. LaConte recommends a 50 basis point ROE reduction due to the Company’s alleged “reduced financial risk compared to the companies in the proxy group.”³³⁵ Ms. LaConte also recommends a separate 10 basis point reduction due to her allegation that the Company “is not meeting its requirement to provide reliable billing and customer service.”³³⁶

3. The Department’s Proposed ROE

315. The Department recommends the Commission set an ROE of 9.25 percent for the Company, based on the testimony of Department witness Mr. Addonizio.³³⁷ While Mr. Addonizio developed several traditional and commonly accepted ROE estimation methodologies including using Constant Growth DCF, Two-Growth DCF, and CAPM models for his testimony, he stated that he used a Multi-Stage DCF analysis to “anchor” his ROE recommendation.³³⁸

316. The Multi-Stage DCF model, as employed by Mr. Addonizio, attempts to estimate ROE by incorporating a generic, long-term overall GDP growth estimate into the analysis, assuming that, beyond the initial years of the analysis, the dividends for all of the proxy group companies will grow at the same rate as the U.S. GDP.³³⁹ Development Of The Department’s Recommended ROE

317. Mr. Addonizio’s updated Multi-Stage DCF analysis, resulted in mean ROE estimates of just 8.35 percent and 8.74 percent but he does not recommend either of these

³³² See Ex. Xcel-100 at 15 (LaConte 21-630 Direct); Tr. Vol. 2 (Dec. 18, 2025) at 328 (LaConte).

³³³ Cf. Ex. Xcel-100 at 15 (LaConte 21-630 Direct) and Ex. XLI-1 at 18 (LaConte Direct).

³³⁴ Ex. Xcel-25 at 71 (Nowak Rebuttal).

³³⁵ Ex. XLI-1 at 28 (LaConte Direct).

³³⁶ Ex. XLI-1 at 28 (LaConte Direct).

³³⁷ Ex. DOC-13 at 2 (Addonizio Surrebuttal).

³³⁸ Ex. DOC-12 at 87 (Addonizio Direct).

³³⁹ Ex. Xcel-25 at 24 (Nowak Rebuttal); Ex. DOC-12 at 46 (Addonizio Direct).

for the Company’s allowed ROE, instead recommending no change from the Company’s currently approved ROE of 9.25 percent.³⁴⁰

318. Underlying Mr. Addonizio’s recommendation is his view that the “cost of equity,” which he estimates using his Multi-Stage DCF analysis, is fundamentally different than a utility’s allowed ROE, and that “allowed ROEs [set by regulatory commissions] typically exceed the cost of equity,” a practice he cannot explain.”³⁴¹

319. Mr. Addonizio recommended maintaining the Company’s currently-approved 9.25 percent ROE, to avoid a recommendation that would be “significantly out of line with other recent allowed ROEs” and after considering recent trends in the cost of capital, the “gap” between his Multi-Stage DCF cost of equity and recent allowed ROEs, and the absolute level of recent allowed ROEs.³⁴²

320. In addition to his Multi-Stage DCF analyses, Mr. Addonizio presented an analysis of the cost of equity consistent with the Commission’s preferred Two-Growth DCF approach in both his Direct and Surrebuttal testimonies, and also presented a Constant Growth DCF analysis, previously used by the Commission.³⁴³ His results yielded the following implied ROEs:

Table 4. Department Constant Growth And Two-Growth DCF Analyses³⁴⁴

	Mean Low ROE	Mean Average ROE	Mean High ROE
Constant Growth Direct	10.57%	10.90%	11.24%
Constant Growth Rebuttal	10.12%	10.59%	11.06%
Two-Growth Direct	10.58%	10.81%	11.03%
Two-Growth Rebuttal	10.22%	10.57%	10.95%

321. Mr. Addonizio did not recommend using these results, stating that he believes they rely on unrealistically high equity analyst growth rate assumptions.³⁴⁵

³⁴⁰ Ex. DOC-13 at 4 (Addonizio Surrebuttal).

³⁴¹ Ex. DOC-12 at 70-71, 75 (Addonizio Direct).

³⁴² Ex. DOC-12 at 85 (Addonizio Direct).

³⁴³ Ex. DOC-12 at 53 and Schedules 17-20 (Addonizio Direct); Ex. DOC-13 at 5 and Schedules 8-11 (Addonizio Surrebuttal).

³⁴⁴ Ex. DOC-12 at 53 (Addonizio Direct); Ex. DOC-13 at 5 (Addonizio Surrebuttal).

³⁴⁵ See Ex. DOC-12 at 48-49 (Addonizio Direct).

4. CUB's Proposed ROE

322. CUB cost of capital witness Dr. Kihm argues that allowed ROE determinations in rate case are “outside the realm of financial issues and in the public policy arena.”³⁴⁶

323. While Dr. Kihm stresses the need for ROE determinations to be policy-based, in developing his ROE recommendation, he first develops DCF and CAPM analyses that he states establish a cost of equity for the Company of 7.7 percent, which he uses to establish the low end of a range of reasonable ROEs.³⁴⁷ For the high end of his range, Dr. Kihm uses his estimate of the cost of equity for the S&P 500 of 9.3 percent³⁴⁸.

324. Similar to Mr. Addonizio, Dr. Kihm testifies that there is a distinction between “cost of equity” and an authorized ROE.³⁴⁹ Therefore, he does not base his recommendation on his analytical results, but states that the Commission should apply the principal of “gradualism” by moving Xcel Energy’s ROE closer to his determined cost of equity by lowering the ROE from 9.25 percent to 9.0 percent.³⁵⁰

5. Analysis And Recommendation

325. Parties have provided multiple analytical models and results for estimating the Company’s cost of equity, with results for the Company’s cost of equity ranging from a single estimate below 6 percent (the Department’s updated “Low GDP Growth” CAPM analysis with a 10-year growth transition period) to several estimates above 11 percent, with a high estimate of 11.84 percent (XLI’s “High” Constant Growth DCF).

326. 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.³⁵¹

327. The Commission has never relied on a Multi-Stage DCF model in determining the allowed ROE for a Minnesota utility.³⁵²

³⁴⁶ Ex. CUB-1 at 44 (Kihm Direct).

³⁴⁷ Ex. CUB-1 at 37, 44 (Kihm Direct).

³⁴⁸ Ex. CUB-1 at 29-30, 44 (Kihm Direct).

³⁴⁹ *See, e.g.*, Ex. CUB-1 at 12, 38 (Kihm Direct).

³⁵⁰ Ex. CUB-1 at 45, 47 (Kihm Direct).

³⁵¹ Ex. Xcel-25 at 10-11 and Table 2 (Nowak Rebuttal).

³⁵² Ex. Xcel-25 at 27-28 (Nowak Rebuttal); Tr. Vol. 2 (Dec. 18, 2025) at 464 (Addonizio).

328. Credit rating agencies place a high value on transparency, predictability and consistency in regulatory outcomes.³⁵³ These agencies also emphasize the importance of balanced and constructive outcomes in utility rate proceedings, and such outcomes can result in lower costs of debt, benefitting utility customers.³⁵⁴

329. The ALJ concurs with the Commission's finding in Xcel Energy's most recent rate case that:

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.³⁵⁵

330. The Two-Growth DCF analyses in this record show the following costs of equity for the Company:

³⁵³ Ex. Xcel-20 at 20 and Schedule 8 at 10, Schedule 9 at 6-8 (Wehner Direct).

³⁵⁴ Ex. Xcel-20 at 21 (Wehner Direct).

³⁵⁵ *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*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 89 (July 17, 2023).

Table 5. Summary Of Parties’ Two-Growth DCF Analyses

	Low	Average	High	Median
Two-Growth – Company Direct ³⁵⁶		10.34%		10.43%
Two-Growth – Company Rebuttal ³⁵⁷		10.38%		10.52%
Two-Growth – DOC Direct ³⁵⁸	10.58%	10.81%	11.03%	
Two-Growth – DOC Surrebuttal ³⁵⁹	10.22%	10.57%	10.95%	
Two-Growth - XLI ³⁶⁰		9.58%		
Two-Growth – XLI (conformed) ³⁶¹		10.36%		

331. Each of these Two-Growth analyses indicates the appropriateness of any increase in the Company’s currently allowed 9.25 percent ROE.

332. Several other factors support an upward adjustment to the Company’s current ROE, including:

- 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 utility 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 2025.³⁶²
- Since the Company’s 2021 rate case was filed, every subsequent authorized ROE for a vertically integrated electric utility in the country has been higher than the Company’s authorized ROE of 9.25 percent.³⁶³

³⁵⁶ Ex. Xcel-24 at 4 (Nowak Direct).

³⁵⁷ Ex. Xcel-25 at 13 (Nowak Rebuttal).

³⁵⁸ Ex. DOC-12 at 54 (Addonizio Direct).

³⁵⁹ Ex. DOC-13 at 5 (Addonizio Surrebuttal).

³⁶⁰ Ex. XLI-1 at 18 (LaConte Direct).

³⁶¹ Ex. Xcel-25 at 72 (Nowak Rebuttal).

³⁶² Ex. Xcel-25 at 3 (Nowak Rebuttal).

³⁶³ Ex. Xcel-25 at 3-4 (Nowak Rebuttal) (conforming XLI witness LaConte’s Two-Growth analysis, which used long-term GDP growth estimates in developing the second stage, to the Commission’s consistent methodology).

- 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 2025.³⁶⁴
- The 30-year Treasury yield, along with the trailing 18-month average authorized ROEs, has continued to increase since the Company’s last rate case, in which the Commission authorized the 9.25 percent ROE, as shown in the following chart:³⁶⁵
- In both the prior case and the current case, the Department provided Two-Growth DCF analyses consistent with the Commission’s preferred ROE analytical approach. The mean result from the Department’s Surrebuttal Two-Growth DCF analysis in this case is 10.57 percent,³⁶⁶ nearly a 70 basis point increase relative the Department’s Surrebuttal Two-Growth DCF analysis in the Company’s last case.³⁶⁷
- Over the past three years, national average ROEs for vertically integrated utilities have ranged from 9.74 percent to 9.84 percent.³⁶⁸

333. Both the Department and CUB urge the Commission to reject the Two-Stage DCF results and instead rely on a Multi-Stage DCF model that incorporates long-term GDP estimates into the growth determination and yields analytical results for estimating Xcel Energy’s ROE that are more the 100 basis points below any authorized ROE for any vertically integrated electric utility in the decades of available data.³⁶⁹

334. GDP is not a market-based or forward-looking measure – it simply measures the monetary value of the total output of goods and services, across all private industry and government sectors in the United States economy.³⁷⁰ The use of such a generic economy-

³⁶⁴ 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.)

³⁶⁵ Ex. Xcel-25 at 4, 10 (Nowak Rebuttal).

³⁶⁶ Ex. DOC-13 at 5 (Addonizio Surrebuttal).

³⁶⁷ See Ex. Xcel-25 at 23 (Nowak Rebuttal) (filed prior to the Department filing its Surrebuttal Testimony in this case).

³⁶⁸ Ex. XLI-1 at 15 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 320-321 (LaConte).

³⁶⁹ Ex. Xcel-25 at 3 (Nowak Rebuttal).

³⁷⁰ See Ex. DOC-12 at 49 (Addonizio Direct).

wide measure is not appropriate for analyzing ROEs for mature companies such as utilities.³⁷¹

335. There is no reason to expect that an individual corporation competing for capital as a going concern will limit, or have investors expect it to limit, its earnings or dividend growth to GDP.³⁷² A measure of *aggregate* economic growth is not reasonable to reflect growth expectations for individual companies.³⁷³ As an aggregate number, long-term U.S. GDP growth estimates necessarily reflect companies growing both faster and slower than the average.³⁷⁴ Some companies will fall short of, and others will exceed the growth of the economy for an extended period of time.

336. Long-term U.S. GDP growth projections do not reflect current market conditions that affect earnings growth for individual utilities.³⁷⁵

337. Observation of actual utility experience demonstrates that utility growth is not limited by U.S. GDP growth. From 2010 through the end of July 2025, the S&P 500 Utilities Index had a compound annual growth rate (“CAGR”) of 6.71 percent, when looking at price-only growth (comparable to the analyst growth rates used in a traditional Two-Growth DCF analysis).³⁷⁶ This CAGR is much more comparable to the analyst growth rates used in the both the Company’s and the Department Constant Growth and Two-Stage DCF analyses (over 6 percent) than the terminal growth rate of 3.87 percent used by Mr. Addonizio in his Multi-Stage analysis.³⁷⁷ Additionally, 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, and other sectors of the economy have grown both significantly faster (for example, educational services, health care and social assistance) and significantly slower (for example agriculture, forestry, fishing and hunting) than the overall U.S. GDP growth rate.³⁷⁸

338. The Department asserts that use of the long-term U.S. GDP growth rate is reasonable, in part, because “no company can grow faster than the economy as a whole in perpetuity, as the company would eventually be larger than the entire economy, which is obviously not possible.”³⁷⁹ However, a company’s total value and the U.S. GDP is not a meaningful comparison, as evidenced by the fact that the market capitalization of the S&P

³⁷¹ Ex. Xcel-25 at 23-24 (Nowak Rebuttal).

³⁷² Ex. Xcel-25 at 24 (Nowak Rebuttal).

³⁷³ Ex. Xcel-25 at 24 (Nowak Rebuttal).

³⁷⁴ Ex. Xcel-25 at 24 (Nowak Rebuttal).

³⁷⁵ Ex. Xcel-25 at 24 (Nowak Rebuttal).

³⁷⁶ Ex. Xcel-25 at 25 (Nowak Rebuttal).

³⁷⁷ Ex. Xcel-25 at 25, 27 (Nowak Rebuttal).

³⁷⁸ Ex. Xcel-25 at 25-26 (Nowak Rebuttal).

³⁷⁹ Ex. DOC-12 at 48-49 (Addonizio Direct).

500 companies is approximately double that of the U.S. GDP.³⁸⁰ Additionally, this hypothetical of a company growing larger than the entire economy exaggerates the prospects of such an outcome. For NSPM's electric rate base of approximately \$13 billion to exceed the value of the GDP of the United States (approximately \$29 trillion) would require more than two centuries of sustained growth at Mr. Addonizio's proxy group average near-term growth rate, compared to the overall U.S. economy growing at his projected U.S. GDP growth rate for those same 200-plus years.³⁸¹

339. The ALJ finds persuasive Company witness Mr. Nowak's testimony that:

Rather than question the reasonableness of the inputs and assumptions of [their Multi-Stage] models, they conclude that the cost of equity is below the current level of authorized ROEs. However, the suggestion that utility commissions have systematically overestimated the cost of equity in setting allowed returns is inconsistent with reasonable market-based models.³⁸²

In other words, using reasonable, market-based models, as the Department did in its Two-Growth DCF, eliminates the need for the Commission to set aside analytical results and fundamentally change how it determines the allowed ROE.

340. Divorcing the authorized ROE from a reasoned interpretation of reasonable and reliable cost of equity models would introduce considerable uncertainty into the ROE determination process and would depart from the *Hope*, *Bluefield* and *Hibbing* principles that require a utility be allowed the opportunity to earn an ROE that is comparable to returns required on investments of similar risk.³⁸³

341. Given their own departure from their analytical results, the ALJ does not find the Department or CUB testimony to produce a reliable means of meeting the *Hope*, *Bluefield* and *Hibbing* standards for establishing an appropriate ROE.

342. The ALJ also does not recommend XLI's testimony on ROE persuasive. Ms. LaConte significantly changed her approach to developing a baseline ROE recommendation in this case from the approach taken in the Company's prior rate case. In both cases she based her baseline ROE recommendation solely on DCF results. However, in the current case, Ms. LaConte included three different Multi-Stage DCF results, an analysis she did not perform in the last case. And each of these analyses presented an ROE estimate below 9.00 percent. Moreover, Ms. LaConte changed how she utilized the results of her analyses to inform her recommendations. In the Company's last rate case Ms. LaConte looked to the mid-point of her DCF results, meaning she looked only at the low

³⁸⁰ Ex. Xcel-25 at 24 (Nowak Rebuttal).

³⁸¹ Ex. Xcel-25 at 24-25 (Nowak Rebuttal).

³⁸² Ex. Xcel-25 at 3 (Nowak Rebuttal).

³⁸³ Ex. Xcel-25 at 3 (Nowak Rebuttal).

result and the high result and calculated the mid-point between those numbers.³⁸⁴ In the current case, however, Ms. LaConte did *not* base her recommendation on the mid-point of her DCF analysis, but based it on the simple average of all DCF results. This change resulted in her giving significant weight to the three sub-9.00 percent Multi-Stage DCF results.³⁸⁵

343. Had Ms. LaConte instead more closely aligned her approach to that taken just three years ago and looked at the mid-point of her DCF analyses in this case, even including her Multi-Stage DCF results, her starting point would have been 10.07 percent.³⁸⁶ And, had Ms. LaConte instead *replicated* her approach from the Company's last rate case and not included the new Multi-Stage DCF analysis, her starting point would have been 10.60 percent – 30 basis points higher than recommended by the Company.³⁸⁷

344. The record also does not support Ms. LaConte's proposed 50 basis point risk adjustment. Ms. LaConte acknowledged that the source document for her Schedule 10, offered in support of this adjustment, is a now three-and-a-half year old report, "S&P Global Regulatory Focus Topical Special Report – Adjustment Clauses: A State by State Overview (S&P Report or Report)."³⁸⁸

345. The S&P Report includes summary charts similar to Ms. LaConte's Schedule 10, as well as accompanying text, and a comparison of Schedule 10 with the Report reveals numerous errors in Ms. LaConte's schedule and in her accompanying testimony. For example, while Ms. LaConte testified that Schedule 10 lists adjustment clauses for her proxy group,³⁸⁹ she in fact included companies not in her proxy group.³⁹⁰ In addition, in her Schedule 10, Ms. LaConte claims the Company has a full decoupling mechanism.³⁹¹ It does not and the S&P Report notes that, stating that the Company has a partial decoupling mechanism³⁹² with a 3 percent cap.³⁹³

³⁸⁴ Tr. Vol. 2 (Dec. 18, 2025) at 330-331 (LaConte)

³⁸⁵ Ex. XLI-1 at 18 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 327 (LaConte).

³⁸⁶ $(8.29 \text{ percent} + 11.84 \text{ percent})/2 = 10.065 \text{ percent}$. At hearing, Ms. LaConte did not perform this calculation, but confirmed that the mid-point of her DCF analyses would be "roughly 10 percent." Tr. Vol. 2 (Dec. 18, 2025) at 331 (LaConte).

³⁸⁷ $(9.36 \text{ percent} + 11.84 \text{ percent})/2 = 10.60 \text{ percent}$.

³⁸⁸ Tr. Vol. 2 (Dec. 18, 2025) at 323-324 (LaConte). The Company introduced the full S&P Report into the record at hearing. Tr. Vol. 2 (Dec. 18, 2025) at 324 (introducing Ex. Xcel-99).

³⁸⁹ Ex. XLI-1 at 29 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 321-322 (LaConte).

³⁹⁰ Tr. Vol. 2 (Dec. 18, 2025) at 322-323 (LaConte).

³⁹¹ Ex. XLI-1 at Schedule 10 at 2 (LaConte Direct); Tr. Vol. 2 (Dec. 18, 2025) at 325 (LaConte).

³⁹² Ex. Xcel-99 at 10.

³⁹³ Ex. Xcel-99 at 22.

346. Ms. LaConte also acknowledged that she did not examine any of the sales true-ups or decoupling mechanisms for the other companies listed in her Schedule 10 or in the S&P Report.³⁹⁴ Therefore, she did not know whether those companies had the same kind of limitations on recovery as the Company.³⁹⁵

347. The ALJ finds that the Company’s recommended ROE of 10.30 percent, near the lower end of its range of ROE from 10.00 to 11.00 percent, and slightly below its Two-Growth DCF analyses, to reasonably represent the Company’s ROE. Based on this record, a 10.30 percent ROE will provide the Company a return commensurate with those being earned by companies of comparable risk, balances the interests of customers and shareholders, conservatively reflects current market conditions and will maintain the financial integrity of the Company while allowing it to access capital at reasonable rates, providing long-term benefits to its customers.

6. Recommended Overall Cost Of Capital

348. Incorporating the recommended 10.30 percent return on common equity into the agreed upon capital structure, and applying the agreed upon costs of long-term and short term debt, results in the following overall cost of capital for 2025 and 2026:

Table 6. 2025 Overall Cost Of Capital

	Ratio	Cost	Weighted Cost
Short-term debt	0.79%	5.31%	0.04%
Long-term Debt	46.71%	4.51%	2.11%
Common Equity	52.50%	10.30%	5.41%
Weighted Average Cost of Capital			7.56%

³⁹⁴ Tr. Vol. 2 (Dec. 18, 2025) at 326-327 (LaConte).

³⁹⁵ Tr. Vol. 2 (Dec. 18, 2025) at 326-327 (LaConte).

Table 7. 2026 Overall Cost Of Capital

	Ratio	Cost	Weighted Cost
Short-term debt	1.00%	3.38%	0.03%
Long-term Debt	46.50%	4.53%	2.11%
Common Equity	52.50%	10.30%	5.41%
Weighted Average Cost of Capital			7.55%

B. Revenue Requirement Issues

349. While the parties resolved a number of issues impacting the test year and plan year revenue requirements, several issues remain unresolved. These Findings address disputed revenue issues first, followed by disputed issues concerning the Company’s planned investments (rate base issues) and expenses.

1. Revenues

a. Late Payment Fees

350. Xcel Energy collects late payment fees when customers do not make timely payments on their utility bills pursuant to Minnesota Rule 7820.5500. Xcel Energy anticipates collecting \$6.1 million in late payment fees in 2025 and \$5.8 million in 2026.³⁹⁶

351. The Commission ordered Xcel Energy to propose a program to use interest payments and fees from late bill payments to mitigate costs for low-income customers. Xcel Energy proposed the Residential Arrears Management Program, or RAMP, which is discussed in the Tariff Changes section of this Recommendation, including the intervenors’ positions on RAMP.³⁹⁷

352. As for the revenue requirement impact of RAMP, the Company originally proposed to dedicate the entirety of its projected test year and plan year late payment fee revenue to RAMP, increasing its revenue requirement accordingly.³⁹⁸

353. The Department noted that the Commission order in this case will not be issued until mid-2026, so recommended including the full 2025 late payment fee revenues

³⁹⁶ Xcel-39 at 4 (Lindgren Supplemental Direct).

³⁹⁷ *In the Matter of Xcel Energy’s 2023 Safety, Reliability and Service Quality Annual Report*, Docket No. E002/M-24-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS at Order Point No. 33 (Jan. 13, 2025).

³⁹⁸ Ex. Xcel-18 at 7-8 (Halama Supplemental Direct).

(\$6.1 million) and one-half of the 2026 late payment fee revenues (\$2.9 million) in Other Operating Revenues for the 2025 test year and 2026 plan year, respectively, and reducing the Company's revenue requirement accordingly.³⁹⁹

354. CUB recommended that the Commission order the Company to eliminate late payment fees for residential customers. In support of its recommendation, CUB argued that the Company failed to prove its late payment fees are just and reasonable because the Company did not substantiate those fees in this proceeding. CUB also argued that late payment fees have little effect on the timeliness of residential customer payments. CUB's proposal to waive late payment fees would eliminate the funding for RAMP and increase the revenue requirement for all Xcel Energy customers.⁴⁰⁰

355. The Company agreed with the Department's recommended adjustment for the 2025 test year, but explained that it anticipates using the full 2026 late payment fee revenues for RAMP if the Commission approves the program, so does not agree with the Department's proposed 2026 plan year adjustment and continues to recommend initial funding of RAMP at the full \$5.8 million level.⁴⁰¹

356. 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 tariffs. The Commission previously approved Xcel Energy's existing tariffs, determining them to be just and reasonable, and CUB's argument that the Company's late payment fees are unsupported by evidence is an attempt to impermissibly shift the burden of proof back onto the Company.⁴⁰²

357. The Company argued that, notwithstanding that it does not bear the burden of proof to demonstrate its existing rates are reasonable, 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 this 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.⁴⁰³

³⁹⁹ Ex. DOC-19 at 67, 70 (Bahn Direct).

⁴⁰⁰ CUB Initial Brief at 28-29.

⁴⁰¹ Ex. Xcel-19 at 14-15 (Halama Rebuttal); Ex. Xcel-81 at 9-10 (Howard Rebuttal).

⁴⁰² Xcel Energy 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)).

⁴⁰³ Ex. Xcel-71 at 49 (Martin Rebuttal).

358. As discussed in the Tariff Changes section, the Administrative Law Judge recommends the Commission approve RAMP, as proposed by the Company. The Administrative Law Judge further recommends that, if approved, the Company's proposal to fund RAMP with the expected late payment fees for the entirety of the 2026 plan year is reasonable and best supports the establishment of this new program by ensuring sufficient funding to provide an appropriate level of relief to qualifying ratepayers.

359. The Administrative Law Judge recommends rejecting CUB's proposal to eliminate late fees. As the party opposing existing rates, CUB bears the burden of proof to demonstrate the existing late fees are unjust and unreasonable. CUB did not meet this burden and did not introduce evidence refuting Xcel Energy's evidence that the absence of late fees during the COVID-19 pandemic moratorium resulted in an increase in past due payments and arrears.

b. Reconnection Fees

360. Xcel Energy charges a reconnection fee based on the actual cost of reconnection pursuant to Minnesota Rule 7820.2600. The reconnection fee is \$13.50 for customers with Advanced Metering Infrastructure (AMI) and \$95 (effective as of January 1, 2026) for customers who opted out of AMI and receive manual meter reading. These costs are real, 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.⁴⁰⁴

361. CUB witness Ms. Levenson-Falk recommended that the Commission should require Xcel Energy to eliminate the collection of reconnection fees for all residential customers. Ms. Levenson-Falk acknowledged that Minnesota regulations allow utilities to charge reconnection fees for valid disconnections, but argued that affordability concerns persist and the imposition of reconnection fees creates a barrier for customers to regain electricity service. Ms. Levenson-Falk argued that the elimination of reconnection fees will make restoration of service more affordable for households and could reduce barriers for customers to enter into agreements for the payment of arrears. Ms. Levenson-Falk referenced the Company's estimate in its 2023 Annual Safety, Reliability, and Service Quality Report that it would cost approximately \$485,000 to eliminate reconnection fees.⁴⁰⁵

362. CUB also argued that eliminating reconnection fees is in the public interest and is thus within the Commission's authority to eliminate. CUB witness Ms. Levenson-Falk

⁴⁰⁴ Ex. Xcel-71 at 25-27 (Martin Rebuttal); CUB-3 at 14 (Levenson-Falk Direct).

⁴⁰⁵ Ex. CUB-3 at 15-16 (Levenson-Falk Direct).

further argued that waiving these fees would align with the definition of equity adopted by Company witness Mr. Martin and Department witness Dr. Hirasuna.⁴⁰⁶

363. 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.⁴⁰⁷

364. ECC witness George Sharlow noted that ECC supports Ms. Levenson-Falk's recommendation to eliminate reconnection fees.⁴⁰⁸

365. The Company responded 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. Company witness Mr. Martin recognized that although the immediate cost shift was likely to be small, the estimates the 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.⁴⁰⁹

366. Xcel Energy argued that CUB's recommendation to eliminate disconnection fees should be rejected. In the alternative, Xcel Energy 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.⁴¹⁰

367. The Administrative Law Judge finds that Minnesota Rule 7820.2600 permits a utility to charge a reconnection fee based on the cost of reconnection as stated in the utility's tariff on file with the Commission. Under this authority, Xcel Energy is permitted to charge a reconnection fee of \$13.50 for customers with AMI technology and \$95 for customers who opted out of AMI technology. The Administrative Law Judge disagrees with CUB's position that the Commission may fully eliminate these fees for residential customers that are provided for in Minnesota Rules because it would be in the public interest.

⁴⁰⁶ Ex. CUB-8 at 16 (Levenson-Falk Surrebuttal) (citing Ex. DOC-21 at 6 (Hirasuna Direct) and Ex. Xcel-71 at 7 (Martin Rebuttal)).

⁴⁰⁷ CUB Initial Brief at 37.

⁴⁰⁸ Ex. ECC-2 at 5 (Sharlow Surrebuttal).

⁴⁰⁹ Ex. Xcel-71 at 27 (Martin Rebuttal).

⁴¹⁰ Xcel Energy Initial Brief at 61.

368. The Administrative Law Judge recommends that the Commission reject Cub's proposal to eliminate reconnection fees for all residential customers. Reconnection fees are based on the real costs of reconnection that, absent recovery from the disconnected customer, would result in an increase in to the Company's revenue requirement and be recovered from all Xcel Energy customers. In effect, this means that customers who have remained current on their bills, including most low-income customers, would incur the additional costs caused by customers who have been disconnected. Although the current estimate of these costs would result in a relatively small impact on customers' bills, the number of reconnections each year is variable and the impact on customers who have remained current could increase if reconnections increase.

369. In the alternative, the Administrative Law Judge recommends that the Commission waive late fees for low-income customers only. The criteria to be used to determine low-income qualification for reconnection fee waiver should be developed by the Company and impacted stakeholders.

2. Rate Base And Expense Items

370. Intervenors object to including various investments and expenses in the Company's cost of service. Minnesota Statutes guide the Commission's consideration of such matters by requiring the Commission "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."⁴¹¹

a. Energy Supply O&M

371. 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.⁴¹² In order to safely operate and maintain these generation facilities for the benefit of customers, Energy Supply incurs operation and maintenance (O&M) expenses for labor, overtime, chemicals, materials, outside services, rents, land easements, and employee expenses.⁴¹³

372. The Company's Energy Supply 2025 and 2026 O&M budgets for this rate case were developed as part of Energy Supply's annual budgeting process. The Energy Supply's annual O&M budgeting process begins with a review of historical O&M costs for each generation facility. These historical amounts are then adjusted to account for

⁴¹¹ Minn. Stat. § 216B.16, subd. 6 (emphasis added).

⁴¹² Ex. Xcel-44 at 1-2, 11 (Capra Direct).

⁴¹³ Ex. Xcel-46 at 2 (Capra Rebuttal).

known changes in the upcoming years such as new and retiring generation facilities, overhaul schedules, and plant improvements.⁴¹⁴

373. For 2025 and 2026, Energy Supply has budgeted \$167.5 million and \$192.4 million in O&M expenses (NSP Total Company).⁴¹⁵ Company witness Randy A. Capra provided nearly 40 pages of testimony describing the cost drivers for each of Energy Supply's O&M budget category for 2025 and 2026.⁴¹⁶

374. XLI proposes a 4.3 percent reduction to both Energy Supply's 2025 and 2026 O&M expenses based on a comparison of Energy Supply's actual O&M expenses to amounts approved in the Company's last rate case (Docket No. E002/GR-21-630).⁴¹⁷ The three-year average of the difference between the actual and approved amounts for 2022-2024 was 4.3 percent.⁴¹⁸

375. The Company provided three primary reasons to explain 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.⁴¹⁹

376. The Company explained that 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 2024.⁴²⁰ Due to permitting delays, the in-service dates for both of these projects was postponed for a year.⁴²¹ These delays reduced actual Energy Supply O&M expenses in 2023 and 2024 by \$0.9 and \$4.2 million, respectively.⁴²²

377. In addition, the Company provided evidence that actual O&M expenses for 2022-2024 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 2022-2024 from wind service providers.⁴²³ The waking

⁴¹⁴ Ex. Xcel-44 at 9 (Capra Direct).

⁴¹⁵ Ex. Xcel-46 at 4 (Capra Rebuttal). Energy Supply's 2025 and 2026 O&M expenses are \$122.3 million and \$140.7 million for 2025 and 2026 MN Jurisdiction net of Interchange Billings to NSPW basis; Ex. Xcel-44 at 64-65 (Capra Direct).

⁴¹⁶ Ex. Xcel-44 at 54-92 (Capra Direct).

⁴¹⁷ Ex. XLI-1 at 51 (LaConte Direct).

⁴¹⁸ Ex. XLI-1 at 51 (LaConte Direct).

⁴¹⁹ Ex. Xcel-46 at 4-5 (Capra Rebuttal).

⁴²⁰ Ex. Xcel-46 at 4-5 (Capra Rebuttal).

⁴²¹ Ex. Xcel-46 at 5 (Capra Rebuttal).

⁴²² Ex. Xcel-46 at 4-5 (Capra Rebuttal).

⁴²³ Ex. Xcel-46, Schedule 2 (Capra Rebuttal).

damage payment and over \$7 million of the liquidated damage payments were returned to customers through the RES Rider.⁴²⁴

378. XLI also questioned the reasonableness of Energy Supply's 2025 and 2026 O&M budgets because they are higher than 2024 actual O&M expenses.⁴²⁵ The Company explained that 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.⁴²⁶ Further, Company witness Capra explained that 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 Allen S. King Plant Unit 1 (\$1.2 million).⁴²⁷

379. XLI did not take issue with any of these O&M expense drivers or the amounts budgeted by the Company in 2025 and 2026 to address each of these drivers.⁴²⁸

380. XLI's proposal for Energy Supply's O&M expenses does not account for the reasons that the Company's expenses were lower than budgeted in 2022-2024, nor does it account for the current needs of the Company's generation facilities.

381. XLI argued that its proposed adjustment to Energy Supply's 2025 and 2026 O&M budgets would not impact the Company's ability to recover its costs because the Company can be made whole through its true-up mechanism.⁴²⁹ While Xcel Energy has proposed continuation of its capital true-up mechanism, Xcel Energy does not have an O&M true-up mechanism⁴³⁰ so reducing the Company's 2025 and 2026 Energy Supply O&M budgets risks the Company not being able to recover its costs of operating and maintaining its generation facilities.

382. The Company has met its burden to establish that its forecasted Energy Supply O&M budgets for 2025 and 2026 are just and reasonable. The Company fully supported its 2025 and 2026 budgeted amounts and explained the difference between its budget and actual expenses in 2022-2024.

⁴²⁴ Ex. Xcel-46, Schedule 2 (Capra Rebuttal); Ex. Xcel-46 at 5 (Capra Rebuttal).

⁴²⁵ Ex. XLI-1 at 51 (LaConte Direct).

⁴²⁶ Ex. Xcel-46 at 7 (Capra Rebuttal).

⁴²⁷ Ex. Xcel-46 at 7 (Capra Rebuttal).

⁴²⁸ Ex. XLI-7 at 13-15 (LaConte Surrebuttal).

⁴²⁹ Ex. XLI-7 at 14 (LaConte Surrebuttal).

⁴³⁰ Ex. Xcel-15 at 29-30 (Liberkowski Direct).

383. The Commission allow Xcel Energy to recover its proposed Energy Supply O&M expenses for 2025 and 2026, and reject XLI's recommended adjustments.

b. Transmission O&M

384. The Company's proposed Transmission O&M expense budget is \$18.9 million for 2025 and \$19.4 million for 2026 (State of Minnesota Electric Jurisdiction).⁴³¹

385. The Department and XLI each recommend that the Company's proposed Transmission O&M expense budgets for 2025 and 2026 should be reduced.

386. The Department recommends using Transmission's 2024 actual O&M expense of \$17.4 million as Transmission's 2025 and 2026 O&M expense budgets.⁴³² The Department's recommendation reduces the Company's Transmission's 2025 O&M expense budget by \$1.5 million and Transmission's 2026 O&M expense budget by \$2.0 million.⁴³³

387. The Department notes that Transmission's actual O&M expense declined year-over-year during the period covered by the Company's last electric rate case (2022-2024).⁴³⁴

388. The Company explained that there internal reorganizations within the Company that impacted Transmission's actual O&M expense from 2022-2024.⁴³⁵ 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.⁴³⁶ 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.⁴³⁷

389. In 2024, certain North American Electric Reliability Corporation and Midcontinent Independent System Operator, Inc. ("MISO") related administrative fees and facility study costs were also shifted out of Transmission and into ISP.⁴³⁸ This resulted in

⁴³¹ Ex. Xcel-43 at 2 (Berklund Rebuttal); Ex. DOC-5 at Schedule 1 (Golden Direct) (Xcel Energy Response to DOC IR 157).

⁴³² Ex. DOC-5 at 8-9 (Golden Direct).

⁴³³ Ex. DOC-5 at 8 (Golden Direct)

⁴³⁴ Ex. DOC-5 at 9 (Golden Direct).

⁴³⁵ Ex. Xcel-43 at 4 (Berklund Rebuttal).

⁴³⁶ Ex. Xcel-43 at 4 (Berklund Rebuttal).

⁴³⁷ Ex. Xcel-43 at 4-5 (Berklund Rebuttal).

⁴³⁸ Ex. Xcel-43 at 5 (Berklund Rebuttal).

a \$2.1 million decrease in Transmission’s 2024 actual O&M expense compared to the approved 2024 O&M expense amount.⁴³⁹

390. Further, the Company 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.⁴⁴⁰

391. The Company discussed that all of these changes were taken into account when developing Transmission’s 2025 and 2026 O&M expense budgets.⁴⁴¹ Company witness David Berklund explained that in developing its budgets (including for 2025 and 2026), Transmission uses a bottoms-up approach.⁴⁴² 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.⁴⁴³ 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.⁴⁴⁴ 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.⁴⁴⁵

392. The Department also asserts that the reduction in Transmission’s actual O&M expense from 2022-2024, due to the Company’s internal reorganization changes, resulted in a “significant” reduction in O&M expense that should be carried forward into 2025 and 2026.⁴⁴⁶

393. The Company explained that there is no need to carry these reductions forward because Transmission already accounted for the impact of these changes when developing its 2025 and 2026 O&M expense budgets.⁴⁴⁷ The Company presented evidence that Transmission’s 2025 O&M expense budget is 10 percent lower than its 2022 actual O&M expense and Transmission’s 2026 O&M expense budget is 8 percent lower than its 2022 actual O&M expense.⁴⁴⁸ 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.⁴⁴⁹ 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

⁴³⁹ Ex. Xcel-43 at 5 (Berklund Rebuttal).

⁴⁴⁰ Ex. Xcel-43 at 5 (Berklund Rebuttal).

⁴⁴¹ Ex. Xcel-43 at 5 (Berklund Rebuttal).

⁴⁴² Ex. Xcel-43 at 3 (Berklund Rebuttal).

⁴⁴³ Ex. Xcel-43 at 3 (Berklund Rebuttal).

⁴⁴⁴ Ex. Xcel-43 at 3 (Berklund Rebuttal).

⁴⁴⁵ Ex. Xcel-43 at 3 (Berklund Rebuttal).

⁴⁴⁶ Ex. DOC-5 at 9 (Golden Direct).

⁴⁴⁷ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁴⁸ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁴⁹ Ex. Xcel-43 at 3 (Berklund Rebuttal).

identical to 2024 actual O&M expense (\$17.4 million).⁴⁵⁰ This demonstrates that Transmission has already appropriately accounted for these changes in its rate forecasts and budgets.⁴⁵¹

394. Lastly, the Department notes that Transmission's internal labor costs declined from 2022-2024.⁴⁵² Although Transmission's internal labor costs declined in 2023 and 2024, as discussed above, this was due to the Company's internal reorganization changes, which shifted approximately \$1.5 million in internal labor costs from Transmission to ISP.⁴⁵³ Company witness Berklund explained that this was a one-time event that will not reoccur in 2025 or 2026; thus, it is not appropriate to use Transmission's 2024 actual O&M expense to determine its 2025 and 2026 O&M expense budgets.⁴⁵⁴

395. In addition, 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.⁴⁵⁵ 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.⁴⁵⁶ 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 actuals.⁴⁵⁷

396. Further, in addition to internal labor costs, the Company's Transmission's 2025 and 2026 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.⁴⁵⁸

397. The Company also discussed the increase in capital investments in 2025 and 2026, including numerous transmission projects approved by the Midcontinent Independent System Operator, Inc. (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.⁴⁵⁹ Company witness Berklund explained that "[c]apital investments are a key driver of O&M for Transmission."⁴⁶⁰ As shown in his

⁴⁵⁰ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁵¹ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁵² Ex. DOC-5 at 8 (Golden Direct).

⁴⁵³ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁵⁴ Ex. Xcel-43 at 6 (Berklund Rebuttal).

⁴⁵⁵ Ex. Xcel-42 at 84 (Berklund Direct); Ex. Xcel-43 at 6-7 (Berklund Rebuttal).

⁴⁵⁶ Ex. Xcel-43 at 7 (Berklund Rebuttal).

⁴⁵⁷ Ex. Xcel-43 at 7 (Berklund Rebuttal).

⁴⁵⁸ Ex. Xcel-43 at 7-8 (Berklund Rebuttal).

⁴⁵⁹ Ex. Xcel-43 at 8 (Berklund Rebuttal).

⁴⁶⁰ Ex. Xcel-43 at 9 (Berklund Rebuttal).

testimony, there will be a substantial increase in Transmission capital investments in 2025 and 2026 compared to 2024, demonstrating the reasonableness of Transmission’s modest increases in O&M expenses of \$1.5 million in 2025 and \$2.0 million in 2026 compared to 2024 actuals.⁴⁶¹

398. XLI recommends reducing Transmission’s O&M expenses by 16.2 percent in 2025 and 2026, or approximately \$3.1 million each year.⁴⁶² XLI determined this reduction by comparing Transmission’s 2022-2024 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.⁴⁶³ XLI’s recommendation results in Transmission’s 2025 and 2026 O&M expense budgets (\$15.8 million for 2025 and \$16.3 million for 2026) being lower than Transmission’s 2024 actual O&M expense (\$17.4 million) (State of Minnesota Electric Jurisdiction).⁴⁶⁴

399. XLI’s recommendation is unpersuasive for the same reasons as the Department’s recommendation. That is, Transmission’s 2022-2024 actual O&M expense was lower than the approved amounts in the Company’s last electric rate case due to internal reorganization changes. As discussed above, these changes were taken into account when developing Transmission’s 2025 and 2026 O&M expense budgets, and as a result, the 2025 and 2026 budgets reflect modest increases in O&M expenses of \$1.5 million in 2025 and \$2.0 million in 2026 compared to 2024 actuals.⁴⁶⁵ Also, as previously discussed, 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,⁴⁶⁶ which XLI acknowledged.⁴⁶⁷

400. XLI also recommends that “NSP should be required to reduce the Transmission O&M expense in this proceeding, which will shift the burden to recover potentially higher expenses through its true-up mechanism to NSP.”⁴⁶⁸ Here, XLI appears to be referring to the Company’s capital true-up,⁴⁶⁹ which is designed to cover variances in capital spending, not O&M expense.⁴⁷⁰ Thus, this recommendation should not be adopted.

401. Finally, XLI argues that, regarding Transmission O&M expense, “customers are at a disadvantage if the utility uses a projected test year because it may lead to excessive

⁴⁶¹ Ex. Xcel-43 at 9-10 (Berklund Rebuttal).

⁴⁶² Ex. XLI-1 at 53 (LaConte Direct).

⁴⁶³ Ex. XLI-1 at 52 (LaConte Direct).

⁴⁶⁴ Ex. Xcel-43 at 10-11 (Berklund Rebuttal).

⁴⁶⁵ Ex. Xcel-43 at 11 (Berklund Rebuttal).

⁴⁶⁶ Ex. Xcel-42 at 84 (Berklund Direct); Ex. Xcel-43 at 6-7, 11 (Berklund Rebuttal).

⁴⁶⁷ Ex. XLI-1 at 52 (LaConte Direct).

⁴⁶⁸ XLI Initial Brief at 26.

⁴⁶⁹ XLI Initial Brief at 26 (citing Ex. XLI-8 at 15:14-18 (LaConte Surrebuttal)).

⁴⁷⁰ Ex. Xcel-15 at 37-39 (Liberkowski Direct).

rates due to forecasting errors, as demonstrated above, or biased projections.”⁴⁷¹ This concern is unwarranted, however, because a lower actual O&M expense for Transmission does not necessarily mean that customers will pay higher rates than they would have otherwise.⁴⁷² At the evidentiary hearing, Company witness Berklund testified that Xcel Energy manages O&M at the Company level, and Transmission is only a portion of that.⁴⁷³ Therefore, while O&M expense for Transmission could run lower than forecasted, other business units could experience pressures that require O&M expense greater than forecasted, and the net result at the Company level could be closer to the authorized budget, which would be used for customers.⁴⁷⁴ According to the Company, it needs this flexibility to effectively manage its O&M at the Company level.⁴⁷⁵

402. The Administrative Law Judge finds that the Company’s 2025 and 2026 Transmission O&M expense budgets are reasonable and that the Company should be permitted to recover its requested O&M amounts. The Department and XLI’s recommendations to reduce the Company’s 2025 and 2026 Transmission O&M expense budgets should not be adopted.

c. Distribution O&M

403. The Department recommends setting the Company’s Distribution 2025 and 2026 vegetation management budget using 2024 actuals with a 3 percent increase for each year, which results in a \$5.8 million reduction to Distribution’s 2025 O&M budget and an \$8.3 million reduction to Distribution’s 2026 O&M budget.⁴⁷⁶ Vegetation management is the only component of Distribution’s 2025 and 2026 O&M budget that the Department challenges as unreasonable.

404. The Department stated the following three reasons for its recommendation: (1) Distribution’s 2025 and 2026 vegetation management budgets are higher than actual vegetation management costs for 2022-2024;⁴⁷⁷ (2) Distribution’s actual vegetation management costs for 2022- 2024 were lower than the amounts approved for recovery for these same years as part of the Company’s last electric rate case;⁴⁷⁸ and (3) actual vegetation management costs for 2025 through September 30, 2025 were lower than budgeted.⁴⁷⁹

⁴⁷¹ Ex XLI-7 at 15 (LaConte Surrebuttal).

⁴⁷² Tr. Vol. 1 (Dec. 17, 2025) at 233 (Berklund).

⁴⁷³ Tr. Vol. 1 (Dec. 17, 2025) at 233-34 (Berklund).

⁴⁷⁴ Tr. Vol. 1 (Dec. 17, 2025) at 234 (Berklund).

⁴⁷⁵ Xcel Energy Initial Brief at 73.

⁴⁷⁶ Ex. DOC-7 at 20 (Uphus Direct).

⁴⁷⁷ Ex. DOC-7 at 17 (Uphus Direct).

⁴⁷⁸ Ex. DOC-7 at 19 (Uphus Direct).

⁴⁷⁹ Ex. DOC-8 at 11 (Uphus Surrebuttal).

405. With respect to the reasonableness of the 2025 and 2026 vegetation management budgets, Company witness Marty D. Mensen testified 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.⁴⁸⁰ 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.⁴⁸¹

406. Regarding actual vegetation management costs for 2022-2024 being lower than the amounts approved in the Company's last rate case, the Company explained that this shows how the Company appropriately manages its overall O&M budget to address the highest priority needs of its customers.⁴⁸² The year with the greatest deviation between the budget and the rate case approved amount is 2023. The Company explained that in 2023, vegetation management work planned for that year needed to be postponed to reallocate resources to storm restoration work.⁴⁸³ 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 (2019-2022).⁴⁸⁴ 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.⁴⁸⁵

407. The Company explained that actual vegetation management costs for 2025 through September 30, 2025 was lower 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.⁴⁸⁶ Consequently, this led to vegetation management O&M costs through September 2025 being lower than initially budgeted.⁴⁸⁷

⁴⁸⁰ Ex. Xcel-35 at 44-45 (Mensen Rebuttal).

⁴⁸¹ Ex. Xcel-35 at 45 (Mensen Rebuttal); Ex. DOC-7 at Schedule 1 at 50-51 (Uphus Direct).

⁴⁸² Ex. Xcel-35 at 47 (Mensen Rebuttal).

⁴⁸³ Ex. Xcel-35 at 47 (Mensen Rebuttal).

⁴⁸⁴ Ex. Xcel-35 at 47 (Mensen Rebuttal).

⁴⁸⁵ Ex. Xcel-35 at 47 (Mensen Rebuttal).

⁴⁸⁶ Ex. DOC-8, Schedule 1 at 3 (Uphus Surrebuttal) (Xcel Energy Response to DOC IR 2175).

⁴⁸⁷ Ex. DOC-8, Schedule 1 at 3 (Uphus Surrebuttal) (Xcel Energy Response to DOC IR 2175).

408. The Company explains that it manages its Distribution O&M budget on an overall basis that allows for fluctuations between costs in different budget categories.⁴⁸⁸ The Department's recommendation to apply a 3 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.⁴⁸⁹ The Department's proposed adjustment would set Distribution's O&M budget for 2025 at \$106.7 million whereas Distribution's actual O&M expenses for 2024 were \$109.9 million on a State of Minnesota Electric Jurisdiction basis.⁴⁹⁰

409. That result would be unreasonable, as the Company explained the need for additional O&M spending in 2025 and 2026 to support increases in internal labor costs and AGIS O&M to support the AMI meter deployment in 2025.⁴⁹¹ In addition, this leaves no room in the Distribution O&M budget to address unanticipated events such as the higher than expected storm restoration costs similar to what occurred in 2023.

410. The Administrative Law Judge finds that the Commission should allow Xcel Energy to recover its vegetation management expenses for 2025 and 2026 as proposed by the Company and reject the Department's proposed adjustment.⁴⁹²

d. Customer Care O&M

411. Consistent with treatment in prior rate cases, the Company explained that it developed the 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 of the 2025 test year and \$27.1 million for the 2026 plan year.⁴⁹³

412. 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. Company witness Ms. Lindgren provided testimony and data showing that, although the Customer Care O&M budget is decreasing overall, this does not reflect a decreased focus on customer care, and that from 2024 to 2025, the Company anticipates an increase in Customer Care labor costs of approximately \$1.1 million attributable to employee headcount and annual wage

⁴⁸⁸ Ex. Xcel-35 at 48 (Mensen Rebuttal); Ex. Xcel-26 at 29 (Robinson Direct).

⁴⁸⁹ Xcel Energy Initial Brief at 76.

⁴⁹⁰ Xcel Energy Initial Brief at 76.

⁴⁹¹ Ex. Xcel-34 at 144 (Mensen Direct).

⁴⁹² Ex. Xcel-35 at 47 (Mensen Rebuttal).

⁴⁹³ Ex. Xcel-38 at 9, 14 (Lindgren Direct).

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.⁴⁹⁴

413. XLI recommended complete denial of all Customer Care expenses in both 2025 and 2026, in addition to a 10-basis point reduction in the Company's ROE. In support of this recommendation, XLI witness Ms. LaConte argued that some members of the Building Owners and Managers Association of Greater Minneapolis (BOMA) encountered significant customer service and billing issues that Xcel Energy struggled to resolve in a timely manner.⁴⁹⁵

414. BOMA also raised these complaints in a July 7, 2025 letter to the Company and in a public comment filed on July 2, 2025 in this matter.⁴⁹⁶

415. Company witness Ms. Howard explained that Xcel Energy has repeatedly requested, including throughout this proceeding, that BOMA identify which members are continuing to experience billing and customer service issues that remain unresolved. Ms. Howard stated that BOMA has not provided this information despite these repeated requests.⁴⁹⁷

416. Due to XLI's and BOMA's reticence to provide this information, the Company implemented alternative means to identify impacted BOMA members and respond to BOMA's concerns. According to Ms. Howard, the 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.⁴⁹⁸

417. No other party challenged the Company's proposed Customer Care O&M expense and no party, including XLI, objected to the Company's calculation of that expense.

418. The Administrative Law Judge rejects XLI's proposal to remove the entire Customer Care O&M expense from the revenue requirement and to lower the Company's ROE by 10-basis points for two reasons. First, as the Company explained, BOMA and XLI have not been forthcoming with the identity of the BOMA members encountering billing and customer service issues to allow Xcel Energy to investigate and provide a resolution. Second, there is no record support for removing the entirety of the Customer Care O&M expense, which is inclusive of departments and costs wholly unrelated to XLI's and

⁴⁹⁴ Ex. Xcel-38 at 10, 16 (Lindgren Direct).

⁴⁹⁵ Ex. XLI-2 at 1, 59-64 (LaConte Direct).

⁴⁹⁶ Ex. Xcel-81 at 6-7 (Howard Rebuttal); BOMA Public Comment (July 2, 2025).

⁴⁹⁷ Ex. Xcel-81 at 7 (Howard Rebuttal).

⁴⁹⁸ Ex. Xcel-81 at 6 (Howard Rebuttal).

BOMA's concerns. Because XLI did not introduce evidence assessing the portion of this O&M expense that is reasonably related to these issues, there is no record by which the Administrative Law Judge could determine the appropriate reduction in O&M expense, if such a reduction were warranted.

419. The Administrative Law Judge finds that the Company's Customer Care O&M expense is reasonable, demonstrates the Company's successes in lowering costs while increasing its workforce to support its customers, and is necessary to support an appropriate level of service.

e. Liquidated Damages

420. 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.⁴⁹⁹ Specifically, Xcel Energy 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.⁵⁰⁰ If the contractual Measured Average Availability (MAA) is less than the PAA for a given production period, liquidated damages are owed to Xcel Energy.⁵⁰¹ For wind facilities that are being recovered in the RES Rider, all liquidated damage payments are credited back to customers through this rider.⁵⁰²

421. The Department recommended that Energy Supply's O&M expenses include an estimate of liquidated damages in 2025 and 2026 based on a four-year average of liquidated damages from 2022-2025 (annualized for 2025) after accounting for amounts already refunded in the Company's RES Rider.⁵⁰³ The Department's recommendation would reduce Energy Supply's O&M expenses for both 2025 and 2026 by \$945,694.⁵⁰⁴

422. Xcel Energy explained 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.⁵⁰⁵

⁴⁹⁹ Ex. Xcel-46 at 9 (Capra Rebuttal).

⁵⁰⁰ Ex. Xcel-46 at 9 (Capra Rebuttal).

⁵⁰¹ Ex. Xcel-46 at 9 (Capra Rebuttal).

⁵⁰² Ex. Xcel-46 at 9 (Capra Rebuttal).

⁵⁰³ Ex. DOC-2 at 18 (Johnson Surrebuttal).

⁵⁰⁴ Ex. DOC-2 at 18 (Johnson Surrebuttal). This amount is MN Jurisdictional Net of Interchange Billings to NSPW.

⁵⁰⁵ Xcel Energy Initial Brief at 82.

423. According to the Company, 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.⁵⁰⁶ 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.⁵⁰⁷

424. The Company also provided evidence showing that its liquidated damage amounts have been declining in recent years.⁵⁰⁸ This is because the Company has been working with service providers to improve the operational performance of its facilities.⁵⁰⁹ These efforts have resulted in declining liquidated damage payments in both 2024 and 2025.⁵¹⁰

425. Further, the Company explained 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.⁵¹¹ 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.⁵¹² 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.⁵¹³ Indeed, from 2022-2024 nearly 70 percent or \$7 million in liquidated damages was credited back to customers through the RES Rider.⁵¹⁴ As the Company does not have 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 2022-2024 amounts that the Department uses to calculate its proposed adjustment.⁵¹⁵

426. The Administrative Law Judge finds that, given the substantial variability in liquidated damages amounts and the Company's demonstration that liquidated damages have been declining, and are expected to continue to decline, the Department's proposed O&M adjustment based on historical liquidated damage amounts should not be adopted.

⁵⁰⁶ Ex. Xcel-46 at 12 (Capra Rebuttal).

⁵⁰⁷ Ex. Xcel-46 at 12 (Capra Rebuttal).

⁵⁰⁸ Ex. Xcel-46 at 12 (Capra Rebuttal); Ex. DOC-2 at Schedule 5 at 3 (Johnson Surrebuttal) (Xcel Energy Response to DOC IR 3109).

⁵⁰⁹ Ex. Xcel-46 at 11-12 (Capra Rebuttal).

⁵¹⁰ Ex. Xcel-46 at 12 (Capra Rebuttal); Ex. DOC-2 at Schedule 5 at 3 (Johnson Surrebuttal) (Xcel Energy Response to DOC IR 3109).

⁵¹¹ Ex. Xcel-46 at 13 (Capra Rebuttal).

⁵¹² Ex. Xcel-46 at 13 (Capra Rebuttal).

⁵¹³ Ex. Xcel-46 at 13 (Capra Rebuttal).

⁵¹⁴ Ex. Xcel-46 at 10-11 (Capra Rebuttal).

⁵¹⁵ Ex. Xcel-46 at 13 (Capra Rebuttal).

f. Compensation And Benefits

427. Together, NSPM and Xcel Energy Services Inc. employ over 7,000 employees, including over 2,000 bargaining unit (union) employees.⁵¹⁶

428. These employees include line workers, customer service representatives, engineers, accountants, and power plant operators who are all necessary to provide safe and reliable electric service to NSPM's 1.5 million electric customers in Minnesota, North Dakota, and South Dakota.⁵¹⁷

429. The Company provides a market-competitive compensation and benefits package to its employees, referred to as its "Total Rewards Program."⁵¹⁸ The total compensation portion of the Total Rewards Program consists of base pay, the Annual Incentive Program (AIP), Long-Term Incentive (LTI) Program, and an employee recognition program.⁵¹⁹

430. Employee health and wellness portion of the Total Rewards Program consists of medical, pharmacy, dental, disability, vision, and life insurance coverage for our active employees and their families, plus employee time-off, long-term disability, workers' compensation and medical benefits for retirees.⁵²⁰

431. Retirement portion of the Total Rewards Program consists of defined pension plans and defined contribution 401(k) savings plans.⁵²¹

(i) Base Pay

(a) Base Pay Amount

432. The Company seeks recovery of base pay expense for 2025 and 2026.⁵²² 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.⁵²³ For the Company's bargaining-unit employees, base wages and

⁵¹⁶ Ex. DOC-3, Schedule 4 at 7 (Kehrwald Direct); Ex. DOC-3, Schedule 12 at 1 (Kehrwald Direct) (Xcel Energy Response to DOC IR Revised 125).

⁵¹⁷ Ex. Xcel-15 at 6 (Liberkowsky Direct).

⁵¹⁸ Ex. Xcel-62 at 6 (Ly Direct).

⁵¹⁹ Ex. Xcel-62 at 7 (Ly Direct).

⁵²⁰ Ex. Xcel-62 at 7 (Ly Direct).

⁵²¹ Ex. Xcel-62 at 7 (Ly Direct).

⁵²² Ex. Xcel-62 at 8 (Ly Direct).

⁵²³ Ex. Xcel-62 at 8-13 (Ly Direct).

overtime constitute their entire compensation because bargaining-unit employees are not eligible for other forms of compensation.⁵²⁴

433. 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 3.0 percent for both bargaining and non-bargaining employees, and included forecasted amounts for overtime and paid time off.⁵²⁵

434. The Company's projected 3.0 percent base pay increase for bargaining-unit employees is based on the applicable collective bargaining agreement.⁵²⁶

435. The Company's projected 3.0 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.⁵²⁷ 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 2025.⁵²⁸

436. The Company's 2025 and 2026 base pay budgets include forecasted overtime associated with planned outages and overhauls at generation facilities.⁵²⁹ For 2025, the base pay budget includes planned outages at two nuclear facilities.⁵³⁰ For 2026, the base pay budget includes a planned outage at Sherco Unit 3.⁵³¹ Because overtime varies based on outage and overhaul schedules, total base pay expense does not necessarily increase in a linear 3.0 percent pattern from year to year.⁵³²

437. The 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.⁵³³

⁵²⁴ Ex. Xcel-62 at 9-10 (Ly Direct). Bargaining employees are eligible for recognition awards based on exceptional performance.

⁵²⁵ Ex. Xcel-62 at 11-12 (Ly Direct).

⁵²⁶ Ex. Xcel-62 at 12 (Ly Direct); Ex. Xcel-63 at 7 (Ly Rebuttal).

⁵²⁷ Ex. Xcel-62 at 12 (Ly Direct); Ex. Xcel-63 at 7-8 (Ly Rebuttal).

⁵²⁸ Ex. Xcel-63 at 7 (Ly Rebuttal).

⁵²⁹ Ex. Xcel-28 at 26-27 (Robinson Rebuttal).

⁵³⁰ Ex. Xcel-28 at 26-27 (Robinson Rebuttal).

⁵³¹ Ex. Xcel-28 at 27 (Robinson Rebuttal).

⁵³² Ex. Xcel-63 at 6 (Ly Rebuttal).

⁵³³ Ex. Xcel-28 at 26 (Robinson Rebuttal); Ex. DOC-3, MBK-D-4 at 8 (Kehrwald Direct) (DOC IR No. 122 Second Supplement Attachment C).

438. The Department recommends an adjustment that would limit the Company's base pay expense for 2025 and 2026 to a 3.0 percent annual increase over the 2024 base pay amount approved in the Company's last electric rate case.⁵³⁴ The Department's proposed adjustments would reduce the Company's requested base pay expense by \$19.1 million in 2025 and \$11.7 million in 2026 resulting in base pay amounts of \$348.16 million in 2025 and \$358.61 million in 2026 on a State of Minnesota Electric Jurisdictional basis.⁵³⁵

439. In Surrebuttal, the Department offered an alternative approach that starts with an average of actual base pay expense for 2022–2024 and then applies a 3.8 percent increase to 2025 and a 0.8 percent increase for 2026.⁵³⁶

440. The Department's principal rationale for its proposed adjustments is that the Company did not provide forecasted full-time equivalent (FTE) counts for the State of Minnesota Electric Jurisdiction for 2025 and 2026 or jurisdiction-specific FTE counts tied to the base pay amounts approved in the Company's last electric rate case.⁵³⁷ The Department asserts that without this information it cannot analyze the reasonableness of the Company's proposed base pay expense on a per-employee basis.⁵³⁸

441. 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.⁵³⁹

442. The Company stated that there are two main reasons that it allocates labor costs rather than FTEs.⁵⁴⁰ The first reason is because NSPM uses Xcel Energy Services, Inc. (XES) to deliver enterprise-wide functions such as human resources, technology, finance, and legal.⁵⁴¹ These enterprise-wide services are provided at cost to all Xcel Energy operating companies, including NSPM.⁵⁴² When these XES employees are performing enterprise-wide work, a portion of their labor costs are allocated to NSPM's State of

⁵³⁴ Ex. DOC-4 at 7 (Kehrwald Surrebuttal).

⁵³⁵ Ex. DOC-4 at 22 (Kehrwald Surrebuttal). The Department's base pay adjustment overlaps with its proposed adjustment to Transmission O&M expenses. If both adjustments are adopted, the Department's base pay adjustment needs to be reduced to \$17.6 million in 2025 and \$9.7 million in 2026. Ex. DOC-4 at 22 (Kehrwald Surrebuttal).

⁵³⁶ Ex. DOC-4 at 25-26 (Kehrwald Surrebuttal).

⁵³⁷ Ex. DOC-4 at 10 (Kehrwald Surrebuttal).

⁵³⁸ DOC Initial Brief at 44-45.

⁵³⁹ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴⁰ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴¹ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴² Ex. Xcel-28 at 28 (Robinson Rebuttal).

Minnesota Electric Jurisdiction.⁵⁴³ 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.⁵⁴⁴ The second reason provided by the Company is because, 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.⁵⁴⁵ These multiple allocations make it impossible to accurately correlate FTE counts to base pays amounts at the State of Minnesota Electric Jurisdictional level.⁵⁴⁶

443. The Department argued that the Company should be able to provide forecasted FTE counts because it uses FTE counts in its General Allocator calculations.⁵⁴⁷ The Company explained that the General Allocator methodology referenced by the Department uses historical FTE counts at the NSPM and XES level and does not include forecasted jurisdiction-specific FTE counts of the type requested by the Department.⁵⁴⁸

444. The Department also argued that without forecasted FTE counts, it could not judge the reasonableness of the Company's base pay amounts because the Company may have plans to cut its workforce and unreasonably increase per employee base pay.⁵⁴⁹ The Company countered this argument by providing actual FTE counts for both NSPM and Xcel Energy Services, Inc. for 2022, 2023, 2024, and through July 31, 2025.⁵⁵⁰ 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 2024.⁵⁵¹ The Company also stated in response to discovery that it had no plans for a restructuring or layoffs in either 2025 or 2026.⁵⁵²

⁵⁴³ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴⁴ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴⁵ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴⁶ Ex. Xcel-28 at 28 (Robinson Rebuttal).

⁵⁴⁷ Ex. DOC-4 at 13 (Kehrwald Surrebuttal).

⁵⁴⁸ Ex. Xcel-49 at 13-14 (Doyle Direct); While the Company uses actual FTE counts in its General Allocator calculation those FTE counts are based only on FTE hours that are directly charged to an operating company and exclude any hours allocated from XES. This results in an understatement of the total FTEs that support the State of Minnesota Electric Jurisdiction.

⁵⁴⁹ Ex. DOC-4 at 10-11 (Kehrwald Surrebuttal).

⁵⁵⁰ Ex. DOC-3 at Schedule 13 at 1 (Kehrwald Direct) (Xcel Energy Response to DOC IR 183).

⁵⁵¹ Ex. DOC-3 at Schedule 13 at 1 (Kehrwald Direct) (Xcel Energy Response to DOC IR 183).

⁵⁵² Ex. DOC-3 at Schedule 5 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 164).

445. 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 2023.⁵⁵³ In response to the Department's questioning, the Company provided three 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 4.0 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).⁵⁵⁴

446. 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.⁵⁵⁵ The Company explained that the Company's 2024 base pay budget in its last rate case was developed in 2021 and did not sufficiently account for significant inflation in the labor market that occurred after this budget was developed.⁵⁵⁶ Specifically, the Company paid a 6.1 percent increase to bargaining unit employees in 2023 based on their new union contracts and paid a 4.0 percent increase to non-bargaining unit employees to maintain market-competitive salaries.⁵⁵⁷ These higher than forecasted base pay increases in 2023 compounded into 2024, causing actual 2024 base pay amounts to exceed the amounts approved in the last rate case.

447. The record reflects that the Company's base pay budgets for 2025 and 2026 were developed from current wage and headcount data and incorporate known and measurable obligations, including contractual wage increases, market-based wage trends for non-bargaining employees, and planned overtime requirements.⁵⁵⁸ The record does not reflect that the Department identified any specific input, assumption, or component of the Company's base pay forecast that is inflated, imprudent, or unreasonable.

448. The absence of forecasted jurisdiction-level FTE counts does not, by itself, undermine the reasonableness of the Company's base pay budgets where the Company allocates labor costs to the jurisdiction and the record contains other evidence supporting the forecasted base pay expense, including budget-development methodology, market and contractual wage information, headcount stability, and historical comparisons.

⁵⁵³ Ex. DOC-3 at 9 (Kehrwald Direct).

⁵⁵⁴ 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*

⁵⁵⁵ Ex. DOC-4 at 20 (Kehrwald Surrebuttal).

⁵⁵⁶ Ex. Xcel-28 at 30-31 (Robinson Rebuttal).

⁵⁵⁷ Ex. Xcel-63 at 6 (Ly Rebuttal).

⁵⁵⁸ Ex. Xcel-28 at 26-27 (Robinson Rebuttal); Ex. Xcel-63 at 7 (Ly Rebuttal).

449. Based on the foregoing, the Company’s requested base pay budgets for 2025 and 2026 are reasonable and should be adopted, and the Department’s proposed base pay adjustments should be rejected.

(b) Future Rate Case Compliance

450. In addition to recommending an adjustment to the Company’s base pay amounts for 2025 and 2026, the Department also recommended requiring the Company to provide FTE counts and base pay amounts as part of a total compensation schedule with its initial filing in all future rate cases.⁵⁵⁹

451. The Company provided testimony that forecasted FTE counts are not available on a State of Minnesota Electric Jurisdiction basis because the Company allocates labor counts not specific employees. The Company also explained that this information would provide limited insight into the reasonableness of the Company’s base pay budgets given the capital and O&M split and because the Company does not budget FTEs on a State of Minnesota Electric Jurisdiction basis.⁵⁶⁰

452. Given that the data requested is not available and of limited relevance, the Administrative Law Judge finds that the Department’s proposed compliance requirement related to FTE counts should not be adopted.

(ii) Incentive Compensation

453. Incentive compensation, also known as “pay-at-risk,” is a component of an employee’s total compensation.⁵⁶¹ It is considered “pay-at-risk” because this form of compensation is not earned unless pre-established business goals are achieved.⁵⁶² Xcel Energy has two incentive compensation programs: AIP and LTI.⁵⁶³ AIP is Xcel Energy’s short-term incentive compensation program and LTI is Xcel Energy’s long-term incentive compensation program.⁵⁶⁴

454. To support recovery for its AIP and LTI compensation, the Company provided a third-party compensation study, the 2024 Willis Towers Watson Compensation

⁵⁵⁹ Ex. DOC-4 at 22 (Kehrwald Surrebuttal).

⁵⁶⁰ Ex. Xcel-28 at 32 (Robinson Rebuttal).

⁵⁶¹ Ex. Xcel-62 at 13 (Ly Direct).

⁵⁶² Ex. Xcel-62 at 13 (Ly Direct).

⁵⁶³ Ex. Xcel-62 at 7 (Ly Direct).

⁵⁶⁴ Ex. Xcel-62 at 7 (Ly Direct).

Study (2024 WTW Study).⁵⁶⁵ This study found that 100 percent of companies offer an AIP and 100 percent offer an LTI program.⁵⁶⁶

455. In addition, the 2024 WTW Study determined that both AIP and LTI compensation are necessary for the compensation paid to Company employees to reach market competitive compensation levels.⁵⁶⁷ Specifically, without AIP and LTI compensation, Xcel Energy's total compensation amounts are between 16.7 percent to 19.9 percent below the total compensation amounts offered by other peer utilities.⁵⁶⁸

456. The Company argued that incentive compensation also provides benefits for customers by tying a portion of compensation to performance of specific customer-centric metrics.⁵⁶⁹ As such, the Company explained that incentive compensation reduces fixed labor costs because it is only paid out if these specific performance targets are met.⁵⁷⁰ The Company also explained that incentive pay reduces benefit-related expenses such as 401K match, pension benefits, and life insurance premiums because these expenses are tied to base pay amounts.⁵⁷¹

(a) Annual Incentive Plan (AIP) Compensation

457. All exempt, non-bargaining employees are eligible for AIP, subject to certain employment requirements.⁵⁷² Each eligible employee has a targeted annual incentive opportunity expressed as a percentage of their base pay.⁵⁷³

458. For each employee, AIP compensation is based on a combination of achievement of individual performance goals and the Company's achievement of corporate Key Performance Indicators (KPIs).⁵⁷⁴ Each of these goals is focused on metrics that benefit customers such as reliability, safety, and customer satisfaction, as illustrated by the 2024 corporate KPIs in the table below.

⁵⁶⁵ Ex. Xcel-62 at Schedule 5 (Ly Direct).

⁵⁶⁶ Ex. Xcel-64 Schedule 5 at 11-12 (Ly Direct).

⁵⁶⁷ Ex. Xcel-64 Schedule 5 at 20 (Ly Direct).

⁵⁶⁸ Ex. Xcel-64 Schedule 5 at 20 (Ly Direct).

⁵⁶⁹ Ex. Xcel-62 at 14-15 (Ly Direct).

⁵⁷⁰ Ex. Xcel-62 at 16 (Ly Direct).

⁵⁷¹ Ex. Xcel-62 at 17 (Ly Direct).

⁵⁷² Ex. Xcel-62 at 15 (Ly Direct).

⁵⁷³ Ex. Xcel-62 at 15 (Ly Direct).

⁵⁷⁴ Ex. Xcel-62 at 15 (Ly Direct).

Table 8. 2024 Corporate Scorecard⁵⁷⁵

Key Performance Indicator	2024 Goal			
	Threshold	Target	Maximum	Weight
Customer Satisfaction <i>(JD Power residential survey)</i>	30 th percentile	38 th percentile	50 th percentile	20%
Public Safety <i>(gas emergency response)</i>	92.0%	96.5%	98.5%	20%
Electric System Reliability <i>(SAIDI)</i>	100	94	92	20%
Employee Safety <i>(safety culture)</i>	Declining 77-79	Steady/ Improving 80-82	Significant Improvement 83	20%
Diversity, Equity & Inclusion <i>(index)</i>	100	200	300	10%
Wind Availability <i>(equivalent availability factor)</i>	94.0%	96.0%	97.0%	10%

459. AIP compensation is needed for the Company’s compensation amounts to be in line with other employers in the labor market. Without AIP compensation, Xcel Energy’s total cash compensation would be between 12.1 percent to 14.3 percent below the market total cash compensation offered by similar utility employers.

460. In this proceeding, Xcel Energy requested two changes to its AIP cost recovery: (1) increasing the cap on AIP compensation from 15 percent of base pay to 20 percent; and (2) applying the 20 percent cap to the aggregate of all employees’ salaries instead of on an individual basis.⁵⁷⁶

461. The Department and XLI oppose both of the Company’s proposed changes to its AIP cost recovery.⁵⁷⁷

(b) AIP Cap Amount

462. The Company argued that its existing 15 percent AIP cap was established in the early 1990s and does not reflect current compensation trends that are more heavily weighted toward incentive compensation.⁵⁷⁸ Xcel Energy noted that employers, including the Company, have moved a greater percentage of compensation into incentive programs

⁵⁷⁵ Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct).

⁵⁷⁶ Ex. Xcel-62 at 17-18 (Ly Direct).

⁵⁷⁷ Ex. DOC-3 at 56 (Kehrwald Direct); Ex. XLI-1 at 47 (LaConte Direct).

⁵⁷⁸ Ex. Xcel-63 at 9 (Ly Rebuttal).

because they drive employee performance and reduce fixed costs.⁵⁷⁹ For Xcel Energy, this means that the market-based AIP targets for many jobs have exceeded 15 percent.⁵⁸⁰

463. The Company noted that this change in compensation trends was one of the reasons that the ALJ in the Company's last electric rate case recommended increasing the Company's AIP cap to 20 percent. Specifically, the ALJ "was persuaded that it would be reasonable to increase the cap to 20 percent of base pay because market-rate compensation practices have evolved to include more incentive-based compensation in recent years."⁵⁸¹

464. The Company further argued that increasing the Xcel Energy's AIP cap to 20 percent would also 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.⁵⁸² The Commission adopted this 20 percent cap because "without AIP, Minnesota Power's total cash compensation for eligible employees would be below the market rate."⁵⁸³ The Company noted that the same rationale applies to Xcel Energy because without AIP compensation, the Company's total cash compensation is 12.1 to 13.0 percent below market level compensation amounts.⁵⁸⁴

465. The Company noted that the Commission has approved 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.⁵⁸⁵

⁵⁷⁹ Ex. Xcel-63 at 9 (Ly Rebuttal); Ex. Xcel-67 at 9-10 (Mustich Rebuttal).

⁵⁸⁰ Ex. Xcel-63 at 9 (Ly Rebuttal).

⁵⁸¹ *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*, Docket No. E002/M-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 18 (July 17, 2023).

⁵⁸² *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 33 (Mar. 12, 2018).

⁵⁸³ *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 33 (Mar. 12, 2018).

⁵⁸⁴ Ex. Xcel-62 at 31 (Ly Direct).

⁵⁸⁵ *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*, Docket No. G008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 23-24, 71 (June 3, 2016).

466. Both the Department and XLI argue against the Company's proposed increase in its AIP cap by alleging that the earnings-per-share (EPS) threshold component of the Company's AIP shows that this compensation is aligned with shareholder interests.⁵⁸⁶ These parties note that if the EPS threshold is not met that there is no AIP payout for employees even if other KPIs are met.⁵⁸⁷

467. The Company responded by explaining that EPS threshold is simply a gating criteria designed to ensure that the Company is performing at a minimum sustainable financial level before AIP compensation is paid.⁵⁸⁸ This is a conservative approach that protects customers from the utility having to payout AIP compensation in years of financial underperformance.⁵⁸⁹ The Company also provided evidence that the AIP goals themselves are customer-focused—advancing the clean energy transition, improving the customer experience, maintaining affordable bills, and ensuring safety and reliability.⁵⁹⁰ In addition, 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.⁵⁹¹

468. Parties also pointed to the EPS modifier as evidence that the Company's AIP compensation is aligned more with shareholders than customers.⁵⁹² The Company explained that the EPS modifier would not apply to the AIP compensation amount that the Company is requesting in this proceeding because the EPS modifier is only used to adjust AIP payments to above target amounts in certain circumstances.⁵⁹³ Since the Company is only requesting recovery of its AIP target amounts, any costs above the AIP target amount due to the application of EPS modifier are borne by shareholders – not customers.⁵⁹⁴

469. The Administrative Law Judge finds that the Company has met its burden to demonstrate that increasing the cap on AIP to 20 percent is reasonable. The Company has demonstrated that AIP compensation is essential to achieving market-competitive levels of compensation, it drives employee performance on customer-centric metrics, is consistent with market compensation trends, and is in line with the AIP caps approved by the Commission for other utilities.

⁵⁸⁶ Ex. DOC-3 at 56 (Kehrwald Direct); Ex. XLI-2 at 46 (LaConte Direct).

⁵⁸⁷ DOC Initial Brief at 50; XLI Initial Brief at 21.

⁵⁸⁸ 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.”).

⁵⁸⁹ Ex. Xcel-67 at 10-11 (Mustich Rebuttal).

⁵⁹⁰ Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).

⁵⁹¹ Ex. Xcel-62 at 20-21 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).

⁵⁹² Ex. DOC-4 at 35-36 (Kehrwald Surrebuttal); Ex. XLI-7 at 16 (LaConte Surrebuttal).

⁵⁹³ Tr. Vol. 1 (Dec. 17, 2025) at 181:13-24 (Ly).

⁵⁹⁴ Tr. Vol. 1 (Dec. 17, 2025) at 181:13-24 (Ly).

(c) AIP Cap Calculation

470. The amount of AIP expense that the Company is requesting recovery for in this proceeding is calculated using individual employee's market-based AIP target for their respective job and then applying the Company's proposed 20 percent AIP cap.⁵⁹⁵ The Company requests approval to calculate any AIP refund amount based on this aggregate rate case approved amount, rather than recalculating each employee's payout to the proposed 20 percent AIP cap.⁵⁹⁶

471. The Company urged calculation of a AIP cap on an aggregate because applying the cap individually after the approved AIP amount is determined would distort the intent of the program by creating arbitrary limits on certain employees' payouts regardless of their actual performance.⁵⁹⁷ The Company stated that this could weaken the link between pay and performance, reduce fairness within the plan, and undermine its effectiveness in motivating employees to achieve customer-focused results.⁵⁹⁸

472. The Company also stated that recalculating the proposed 20 percent cap on an individual basis only further reduces the Company's ability to recover the actual AIP compensation paid to employees.⁵⁹⁹

473. Both the Department and XLI opposed the Company's proposed change to the AIP cap calculation by arguing that it could lead the Company to concentrate its AIP payouts on a few employees, which could incentivize employees to prioritize shareholder interests.⁶⁰⁰

474. The Company countered that it cannot change these payout ranges during a given year to consolidate AIP payouts to a few employees because each employee's potential AIP payout range is set forth in the Company's AIP plan document.⁶⁰¹ The Company explained that the only discretion that the Company has in administering AIP is limited to determining where within that AIP payout range a particular employee's AIP payout should be set based on achievement of both individual and corporate performance metrics.⁶⁰²

⁵⁹⁵ Ex. Xcel-63 at 17-18 (Ly Rebuttal)

⁵⁹⁶ Ex. Xcel-62 at 17-18 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).

⁵⁹⁷ Ex. Xcel-63 at 18 (Ly Rebuttal).

⁵⁹⁸ Ex. Xcel-63 at 18 (Ly Rebuttal).

⁵⁹⁹ Xcel Energy Initial Brief at 102.

⁶⁰⁰ Ex. DOC-3 at 27-28 (Kehrwald Direct); Ex. XLI-1 at 3 (LaConte Direct); Ex. DOC-4 at 45 (Kehrwald Surrebuttal).

⁶⁰¹ Ex. Xcel-62 at 15 (Ly Direct).

⁶⁰² Ex. Xcel-62 at 15 (Ly Direct).

475. The Administrative Law Judge finds that the Company has met its burden to demonstrate that administering the AIP cap on an aggregate basis is just and reasonable. Administering AIP on the approved aggregate AIP amount provides the Commission and customers with assurance that the total AIP expense remains bound and cost-controlled, while allowing the Company the flexibility to allocate employee awards in a manner that best reflects both corporate achievements and individual contributions.

(d) Long-Term Incentive (LTI) Compensation

476. In this proceeding, the Company seeks recovery of two components of its LTI compensation—environmental LTI and time-based LTI—which make up approximately 40 percent of the Company’s total LTI target-level compensation expense.⁶⁰³ The Company has not requested recovery of the remaining 60 percent of LTI.⁶⁰⁴

477. Historically, the Commission has denied utility requests to recover LTI compensation.⁶⁰⁵ The Commission has reasoned that, because LTI programs are designed chiefly to serve shareholders’ interests, shareholders should pay for the programs, rather than customers.⁶⁰⁶

478. Environmental LTI is measured by the reduction in carbon dioxide emissions below 2005 levels associated with the Company’s electric service. If the Company does not meet its environmental goals, the environmental LTI is not paid out and the employee does not receive their full amount of market-based compensation.⁶⁰⁷

479. Time-based LTI requires a three-year vesting period to ensure that eligible employees engage in long-term planning for the benefit of the Company and that they remain at the Company long enough to see those plans through. Retaining employees with the knowledge and skills necessary to guide, manage, and operate a utility is a crucial component in providing a high level of service to customers and achieving operational efficiency, both of which benefit customers.⁶⁰⁸

480. The Company is not seeking recovery of relative Total Shareholder Return (TSR) LTI, which constitutes approximately 60 percent of the total LTI grant value.

⁶⁰³ Ex. Xcel-62 at 23-24 (Ly Direct).

⁶⁰⁴ Ex. Xcel-62 at 23-24 (Ly Direct).

⁶⁰⁵ Ex. DOC-3 at 16-17 (Kehrwald Direct).

⁶⁰⁶ *See, e.g., 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*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 15 (July 17, 2023).

⁶⁰⁷ Ex. Xcel-62 at 24 (Ly Direct).

⁶⁰⁸ Ex. Xcel-62 at 27 (Ly Direct).

Relative TSR is similar to the types of LTI that the Commission has denied recovery in the past because it is aligned with shareholder interests.⁶⁰⁹

481. The Company explained that while it could structure its compensation to provide all compensation as base pay, providing a portion of compensation through LTI allows the Company to tie compensation to achievement of specific goals which have been structured to provide significant benefits to customers.

482. Xcel Energy's Environmental LTI goal is focused on reducing carbon emissions below 2005 levels and incentivizes employees to work on implementation of renewable resources, promoting energy efficiency programs, and improving plant operations to reduce carbon output.⁶¹⁰ As reduction of carbon emissions is a long-term goal of both Xcel Energy and the State of Minnesota, the environmental LTI maintains employee attention by tying a portion of their compensation to working towards this goal.⁶¹¹

483. Time-based LTI requires employees to stay with the Company throughout a three-year vesting period in order to receive this portion of their compensation.⁶¹² This benefits customers by helping to retain qualified and experienced employees and reducing costs associated with hiring and training new employees.⁶¹³

484. Recognizing the Commission's prior decisions disallowing recovery of LTI, the Company provided an analysis of market competitive compensation data. Based on that market data, Xcel Energy confirmed that the levels of Target Total Direct Compensation were reasonable and consistent with market-based total compensation levels. Additionally, the market review confirmed that the Company's overall compensation philosophy and incentive compensation plan designs were consistent with utilities specifically, and industry generally.⁶¹⁴

⁶⁰⁹ Ex. Xcel-62 at 23-24 (Ly Direct).

⁶¹⁰ Ex. Xcel-62 at 24 (Ly Direct).

⁶¹¹ Ex. Xcel-62 at 24 (Ly Direct).

⁶¹² Ex. Xcel-62 at 27 (Ly Direct).

⁶¹³ Ex. Xcel-62 at 27 (Ly Direct) ("Based on a review of employees who received LTI grants as a portion of their market-based compensation over three consecutive years, over 96 percent of the employees remained with the Company through the three-year vesting cycle."); Ex. Xcel-67 at 7 (Mustich Rebuttal).

⁶¹⁴ 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).

485. The Department recommended the Commission deny Xcel Energy's request to recover any portion of its LTI. The Department disagreed that these LTI programs were distinguishable from similar programs that the Commission has denied.⁶¹⁵

486. XLI joined the Department's opposition to including LTI compensation costs.⁶¹⁶

487. The Department observed that the Company already provides significant and comprehensive benefits to its employees which include AIP (or short-term incentive compensation), pension, 401(k) matching, health and dental, life insurance, long-term disability, legacy retiree medical and recognition awards, all of which are included for recovery from customers in this proceeding.⁶¹⁷

488. With respect to Environmental LTI, both the Department noted that the environmental LTI goals that Xcel Energy is incentivizing are based on the collective performance of Xcel Energy, rather than on the performance of NSPM Electric.⁶¹⁸ Additionally, both the Department and XLI observe that the Environmental LTI goals are based on environmental goals that are generally aligned, and in some cases less ambitious than Minnesota's carbon-free standard outlined in statute. In light of this, the Department concluded it does not make sense for customers to provide incentives to the utility for following state law.⁶¹⁹

489. The Department and XLI also note that because LTI is delivered through stock awards, it may encourage employees to prioritize shareholder interests over customer interests.⁶²⁰

490. Finally, the Department noted its concern regarding the amount of LTI compensation allocated to the Company's ten highest-paid employees, especially in light of the lack of identified limits on LTI awards and the substantial incentive compensation levels observed in recent years, including instances where total incentive compensation significantly exceeded base salary.⁶²¹

491. In response, the Company explained that offering a portion of total market-based compensation as incentive compensation provides benefits to customers. The Company reasoned this promotes superior employee performance—by aligning compensation with results and showing employees the connection between their

⁶¹⁵ Ex. DOC-3 at 14-18 (Kehrwald Direct); Ex. DOC-4 at 26-31 (Kehrwald Surrebuttal).

⁶¹⁶ Ex. XLI-1 at 49 (LaConte Direct).

⁶¹⁷ Ex. DOC-3 at 16-17 (Kehrwald Direct).

⁶¹⁸ Ex. DOC-3 at 17 (Kehrwald Direct).

⁶¹⁹ Ex. DOC-3 at 17 (Kehrwald Direct); Ex. XLI-1 at 48-49 (LaConte Direct).

⁶²⁰ Ex. DOC-3 at 17 (Kehrwald Direct); Ex. XLI-1 at 48 (LaConte Direct).

⁶²¹ Ex. DOC-3 at 40 (Kehrwald Direct).

performance and their pay; and by reducing fixed labor costs— because base pay is tied to a variety of benefit-related expenses, if all pay was provided as base pay, benefit costs would also be higher.⁶²²

492. Further, the Company explained that 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.⁶²³

493. The Company also explained that to effectively attract and retain qualified employees needed to provide continuous safe and reliable electric service to customers, the Company’s overall compensation package must be competitive in the marketplace.⁶²⁴ Without AIP and LTI compensation, Xcel Energy’s total compensation amounts are between 16.7 percent to 19.9 percent below the total compensation amounts offered by other peer utilities.⁶²⁵ As a result, LTI compensation is not an optional add-on or “bonus,” rather it is an essential part of the providing a market competitive compensation package. Without LTI compensation, the Company’s total rewards package would not be market competitive and the Company would be at a severe disadvantage in the labor market.

494. In response to the Department’s and XLI’s assertion that the Company’s Environmental LTI goals are already mandated by state statutory emissions-reduction requirements, the Company explained that its Environmental LTI goals are broader and promote investments not just in carbon-free generation but also in energy efficiency and demand-side management. In addition, Xcel Energy’s LTI goals require year-over-year reductions in carbon emissions, not just achievement of carbon-free generation targets every five years starting in 2030 like Minnesota’s carbon-free standard.⁶²⁶

495. In response to the Department’s criticism that Xcel Energy’s Environmental LTI goal is based on Xcel Energy’s collective performance rather than the performance of NSPM,⁶²⁷ the Company explained that because NSPM is a large part of Xcel Energy,

⁶²² Ex. Xcel-62 at 23-27 (Ly Direct); Ex. Xcel-63 at 21 (Ly Rebuttal); Ex. Xcel-66 at 10-11 (Mustich Direct); Ex. Xcel-67 at 9-10 (Mustich Rebuttal).

⁶²³ Ex. Xcel-26 at 21-22 and Schedule 7 (Ly Direct) (2021 WorldatWork Incentive Pay Practices).

⁶²⁴ Ex. Xcel-63 at 21 (Ly Rebuttal).

⁶²⁵ Ex. Xcel-64 Schedule 5 at 20 (Ly Direct).

⁶²⁶ Minn. Stat. § 216B.1691, subd. 2g (80 percent by 2030; 90 percent by 2035; and 100 percent by 2040).

⁶²⁷ Ex. DOC-3 at 17 (Kehrwald Direct).

NSPM is essential to achieving real progress on carbon emissions reductions across the Xcel Energy. In addition, given the interrelated nature of the electric system and the fact that carbon emissions of neighboring states impact Minnesota customers, an Xcel Energy performance target is important to ensuring that achievement of these carbon reduction goals is meaningful.⁶²⁸

496. The Company also explained that its time-based LTI goals provide material benefits for customers. By requiring a three-year vesting period, time-based LTI promotes workforce stability, reduces turnover, reduces hiring and training costs, and ensures that experienced and skilled employees remain with the Company. And Xcel Energy's time-based LTI has had the desired effect as the Company demonstrated that more than 96 percent of employees receiving time-based LTI grants remained with the Company through the vesting period, providing needed continuity in the leadership of the Company.⁶²⁹

497. In response to the Department's concern that LTI compensation is delivered in the form of stock, the Company explained the fact that LTI compensation is paid in the form of stock does not change the performance metrics to which these pieces of compensation are tied. Not only that but providing company stock as a form of compensation is a common practice among publicly traded companies and for good reason. Providing compensation in the form of stock gives employees a stake in the success of the company and incentivizes them to work for the long-term financial health and stability of the Company, which benefits both the Company and customers.

498. Finally, in response to the Department's criticism that LTI compensation is paid to the top executives of the Company,⁶³⁰ Xcel Energy explained these are the employees that are driving key strategic decisions and providing leadership on how to implement the Company's carbon-free transition such that it is appropriate to tie their compensation to achievement of these goals. The Company provided support that it is standard market practice for the compensation of top executives to be more heavily weighted towards incentive compensation rather than base pay.⁶³¹ And there is good reason for that as incentive compensation ties pay to measurable results that benefit both the Company and its customers.⁶³²

499. The Administrative Law Judge recommends that the Commission approve the environmental LTI and time-based LTI components of the Company's overall LTI compensation. The Company provided employment market and compensation design evidence by way of a compensation study and third-party compensation data regarding modern compensation practices. As noted by the Company, the recovery analysis should

⁶²⁸ Ex. Xcel-63 at 22 (Ly Rebuttal).

⁶²⁹ Ex. Xcel-62 at 27 (Ly Direct).

⁶³⁰ DOC Initial Brief at 46.

⁶³¹ Ex. Xcel-67 at 8 (Mustich Rebuttal).

⁶³² Ex. Xcel-67 at 9 (Mustich Rebuttal).

focus on whether the Company’s overall compensation is reasonable. The Company has demonstrated that if its employees do not receive LTI, their compensation falls below their market-based level of compensation and is thus unreasonable.

(iii) Executive Compensation

500. 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?”⁶³³

501. In this proceeding, Xcel Energy 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.⁶³⁴ These 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.⁶³⁵ 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).⁶³⁶

502. 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 Xcel Energy’s total direct compensation amounts for its top ten highest paid employees to that 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.”⁶³⁷

503. In addition, the Company supplied testimony from a third-party executive compensation expert with over 35 years of experience in designing and evaluating employee compensation programs.⁶³⁸ 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.”⁶³⁹

⁶³³ *In re Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota*, E-002/GR-24-320, NOTICE OF AND ORDER FOR HEARING at 2 (Dec. 30, 2024).

⁶³⁴ Ex. DOC-3, Schedule 18 at 6 (Kehrwald Direct).

⁶³⁵ Ex. Xcel-63 at 29 (Ly Rebuttal).

⁶³⁶ Ex. Xcel-63 at 29 (Ly Rebuttal).

⁶³⁷ Ex. Xcel-66, Schedule 2 at 10 (Mustich Direct).

⁶³⁸ Ex. Xcel-66, Schedule 1 (Mustich Direct).

⁶³⁹ Ex. Xcel-66 at 9 (Mustich Direct).

504. The Department and the OAG both recommended that the Company not be allowed to recover any of its compensation costs for its top ten highest paid employees.⁶⁴⁰ Both parties argued the Company did not carry its burden to show that recovery of these compensation costs from customers is reasonable.⁶⁴¹

505. The Department and the OAG did not offer their own executive compensation study but instead critiqued the Company's Executive Compensation Study.

506. The Department argued the Executive Compensation Study should have used a peer group with revenues similar to that of NSPM rather than Xcel Energy.⁶⁴² Company witness Mustich explained that the chosen peer group is appropriate because of the enterprise-wide responsibilities of the top ten highest paid employees.⁶⁴³ Company Mustich also testified that if the Department's suggestion was followed, and the Executive Compensation Study was redone based on revenues of NSPM, the market level compensation amount for a CEO running a company of that size would be \$6.8 million and that this amount is 2.5 times greater portion than that of Xcel Energy's CEO salary that is allocated to the State of Minnesota Electric Jurisdiction.⁶⁴⁴

507. The Department and OAG also criticized the Executive Compensation Study for not identifying whether any of the peer utilities had any restrictions placed on the rate recovery of their executive compensation.⁶⁴⁵ Company witness Mustich testified that whether a company seeks or gains rate recovery of its top ten employees compensation does not impact what the company must pay its executive employees.⁶⁴⁶ The Company argued that a market-competitive compensation package is necessary to attract and retain qualified executives.⁶⁴⁷

508. The Department further argued that the Executive Compensation Study was flawed because it examined incentive compensation at the target amount even though executives could be paid higher amounts depending on performance.⁶⁴⁸ The Company responded that its request in this case is limited to incentive compensation at target and any

⁶⁴⁰ DOC Initial Brief at 51; OAG Initial Brief at 25.

⁶⁴¹ DOC Initial Brief at 51; OAG Initial Brief at 24.

⁶⁴² Ex. DOC-3 at 7 (Kehrwald Direct).

⁶⁴³ Ex. Xcel-67 at 3 (Mustich Rebuttal).

⁶⁴⁴ Ex. Xcel-67 at 4 (Mustich Rebuttal).

⁶⁴⁵ Ex. Xcel-67 at 5 (Mustich Rebuttal).

⁶⁴⁶ Ex. Xcel-67 at 5 (Mustich Rebuttal).

⁶⁴⁷ Ex. Xcel-66 at 8 (Mustich Direct).

⁶⁴⁸ DOC Initial Brief at 52.

compensation paid out above these target amounts are paid for by shareholders, not customers.⁶⁴⁹

509. The Department and OAG also argued the Company should not be allowed to recover any of its compensation costs for its top ten highest paid employees because they allege that these employees are focused on shareholder interests as opposed to ratepayer interests.⁶⁵⁰ These parties argued that the Company failed to provide any “evidence showing how these top ten executives’ work could be apportioned between shareholders and ratepayers.”⁶⁵¹

510. To determine what portion of time these executive employees spend on shareholder versus customers interests, the Department and the OAG requested that the Company produce calendar entries for 2022, 2023, 2024, and 2025; performance evaluations for 2022, 2023, and 2024; and job descriptions for the Company’s top ten highest paid employees.⁶⁵² Xcel Energy objected to the discovery requests that sought calendar entries and performance evaluations on the grounds that these requests were overly broad, unduly burdensome, irrelevant, and, with regard to the performance evaluations, that the probative value of the information is outweighed by its tendency to oppress or harass.⁶⁵³ After the Department and the OAG brought a motion to compel, the Administrative Law Judge narrowed the materials that were to be produced and ordered the Company to produce calendars for 2023 and 2024 for the Company’s top ten highest paid employees, exclusive of any calendars for people who held the role of general counsel at the time and performance evaluations for 2024.⁶⁵⁴

511. After a review of these calendars and performance evaluations, the OAG argued that that recovery of executive compensation should be denied because the calendar and performance evaluations provided by the Company demonstrate a “primacy of shareholder interests.”⁶⁵⁵ Specifically, the OAG witness Katherine Hinderlie pointed to

⁶⁴⁹ See e.g., Ex. Xcel-62 at 17 (Ly Direct) (“We are requesting recovery of only the target-level of AIP amount, subject to a 20 percent recovery cap.”).

⁶⁵⁰ Ex. OAG-1 at 22 (Hinderlie Direct); Ex. DOC-3 at 41 (Kehrwald Direct).

⁶⁵¹ DOC Initial Brief at 51.

⁶⁵² Ex. OAG-3 at 13 (Hinderlie Surrebuttal); Ex. DOC-4, Schedule 12 (Kehrwald Surrebuttal) (Xcel Energy Response to DOC IR 1168); ORDER GRANTING IN PART AND DENYING IN PART MOTION TO COMPEL (Aug. 29, 2025) (eDocket No. [20258-222555-01](#)).

⁶⁵³ Xcel Energy Reply in Opposition to Motion to Compel Discovery (Aug. 8, 2025) (eDocket No. [20258-221905-01](#)).

⁶⁵⁴ ORDER GRANTING IN PART AND DENYING IN PART MOTION TO COMPEL (Aug. 29, 2025) (eDocket No. [20258-222555-01](#)).

⁶⁵⁵ OAG Initial Brief at 33.

portions of these calendars and performance evaluations that focus on the financial health of the Company or that are related to Xcel Energy's annual shareholder meeting.⁶⁵⁶

512. The Company argued that the Department and OAG focus on trying to split the time of executives into shareholder and customers focused tasks is unsound because it assumes that there is some bright line distinction between the work that these executives perform on behalf of customers versus shareholders.⁶⁵⁷ Company witness Ly explained that the work of these employees, and that of all of the Company's employees, is in furtherance of operating the utility and providing electric and gas service to customers.⁶⁵⁸

513. The Company also argued that calendars and performance evaluations provide limited insight into the customer benefits provided by the Company's top executives. The Company stated that neither an employee's calendar nor their performance evaluation provide an accurate depiction of the work that is being done on a day-to-day basis for the benefit of customers.⁶⁵⁹

514. The Department and OAG also argued that these executive employees are more focused on shareholder rather than customer interests because executive compensation is "heavily dependent on incentive compensation."⁶⁶⁰

515. The Company countered by providing evidence demonstrating that it is common in the labor market to structure executive compensation with a greater percentage of incentive compensation rather than base pay.⁶⁶¹ Based on the peer companies, incentive compensation makes up nearly 90 percent of compensation for CEOs.⁶⁶² Company witness Mustich testified that customers also benefit by the Company providing a greater percentage of executive compensation as incentive pay.⁶⁶³ Company witness Mustich explained that 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.⁶⁶⁴ 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 which would harm customers.⁶⁶⁵

⁶⁵⁶ See e.g., Ex. OAG-4 at 15, 19 (Hinderlie Surrebuttal).

⁶⁵⁷ Ex. Xcel-63 at 28 (Ly Rebuttal).

⁶⁵⁸ Ex. Xcel-63 at 28 (Ly Rebuttal).

⁶⁵⁹ Xcel Energy Reply in Opposition to Motion to Compel Discovery (Aug. 8, 2025) (eDocket No. [20258-221905-01](#)).

⁶⁶⁰ Ex. OAG-1 at 24 (Hinderlie Direct); see also DOC-3 at 24 (Kehrwald Direct).

⁶⁶¹ Xcel Energy Initial Brief at 112.

⁶⁶² Ex. Xcel-67 at 9 (Mustich Rebuttal).

⁶⁶³ Ex. Xcel-67 at 9-10 (Mustich Rebuttal); Ex. Xcel-63 at 33-34 (Ly Rebuttal).

⁶⁶⁴ Xcel Energy Initial Brief at 112.

⁶⁶⁵ Ex. Xcel-67 at 9 (Mustich Rebuttal).

The Company also stated that increasing fixed base salaries would increase other costs that are tied to base salaries such as disability insurance premiums.⁶⁶⁶

516. The Company also pointed out that its incentive compensation is focused on customer centric metrics.⁶⁶⁷ The Company's AIP measures performance with metrics that promote customer satisfaction, safety, reliability, inclusion, and wind availability.⁶⁶⁸ The time-based portion of LTI helps reduce attrition at high-level ranks of the organization and thereby reduces hiring and training costs.⁶⁶⁹ Environmental LTI promotes consistent progress in the reduction of carbon emissions.⁶⁷⁰ The Company stated that these metrics demonstrate that incentive compensation focuses and awards Xcel Energy's executives for achievement of goals that directly benefit its customers.⁶⁷¹

517. The OAG further suggests that the Commission "could create a performance incentive mechanism that would allow rate recovery of a portion of executive compensation if Xcel meets Commission-defined affordability metrics."⁶⁷² The OAG recommends that these possible performance incentive mechanisms could be explored in a new docket.⁶⁷³

518. The Company opposed the OAG's recommendation to punt a decision on recovery of executive compensation to a new docket as the Company argued that the Company has fully supported its executive compensation request in this case.

519. The Administrative Law Judge finds that the Company has met its burden to demonstrate that its fully its request to recover the compensation costs for its top ten highest paid employees is reasonable. The Company was the only party to provide a study that demonstrated that the compensation for these employees is in line with the compensation amounts and structure provided by other utility employers. The Company also provided evidence that these employees provide benefits to customers by providing strategic leadership for the Company. The Company also provided evidence that the majority of the compensation for these employees is provided as incentive compensation that is tied to achievement of customer-focused metrics.

520. The Administrative Law Judge also finds that the Company's request is consistent with Minnesota law. Specifically, Minnesota law requires the Commission to "give due consideration to the public need for adequate, efficient, and reasonable service

⁶⁶⁶ Ex. Xcel-62 at 17 (Ly Direct).

⁶⁶⁷ Xcel Energy Initial Brief at 112.

⁶⁶⁸ Ex. Xcel-67 at 7 (Mustich Rebuttal).

⁶⁶⁹ Ex. Xcel-63 at 23-24 (Ly Rebuttal).

⁶⁷⁰ Ex. Xcel-63 at 23-24 (Ly Rebuttal).

⁶⁷¹ Xcel Energy Initial Brief at 112.

⁶⁷² OAG Initial Brief at 35.

⁶⁷³ OAG Initial Brief at 35.

and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service.”⁶⁷⁴ Despite the fact that the Company demonstrated that its executive compensation costs are reasonable and are a necessary cost of service, the Company requested that only a portion of the executive compensation be recovered from customers in this rate case.⁶⁷⁵ Shareholders were assigned nearly 40 percent of the State of Minnesota Electric Jurisdiction portion of the Company’s top ten highest paid employees.⁶⁷⁶ The remaining 60 percent is appropriate to recover from customers given the benefits that customers receive from having qualified, skilled executives whose compensation is structured to advance customer-focused metrics.

521. In contrast, the recommendations from the Department and the OAG to deny recovery of all of the Company’s compensation costs for its top ten highest paid employees fails to consider the utility’s need to recover a necessary cost of service.⁶⁷⁷

522. In conclusion, the Company should be allowed to recover the portion of its executive compensation costs included in the Company’s rate request as it is fully supported by substantial evidence.

(iv) Limited Availability Benefits

523. Limited availability benefits are another component of the Company’s market-competitive compensation and benefits package, and include physicals and financial, tax, and estate planning services for executive employees.⁶⁷⁸ The costs for these limited availability benefits are \$103,003 (State of Minnesota Electric Jurisdiction) in both 2025 and 2026.⁶⁷⁹

524. The Department recommended disallowing recovery of costs associated with these limited availability benefits. The Department asserted that that these benefits should not be recovered because they are provided to employees that are already “highly compensated,” and the Department questions the customer benefit provided by these limited availability benefits.⁶⁸⁰

525. The Company explained that the fact that these limited availability benefits are provided to employees that “are already well compensated” is irrelevant as to whether they are a necessary part of a market-competitive compensation and benefits package. The Company provided undisputed evidence to show that these limited availability benefits are

⁶⁷⁴ Minn. Stat. § 216B.16, subd. 6.

⁶⁷⁵ Ex. Xcel-63 at 29 (Ly Rebuttal).

⁶⁷⁶ Ex. Xcel-63 at 29 (Ly Rebuttal).

⁶⁷⁷ Xcel Energy Initial Brief at 113.

⁶⁷⁸ Ex. Xcel-64 at 36 (Ly Rebuttal).

⁶⁷⁹ Ex. DOC-3 at 50 (Kehrwald Direct).

⁶⁸⁰ Ex. DOC-3 at 50 (Kehrwald Direct).

included in a majority of other utilities' compensation and benefits packages and thus are a reasonable and necessary cost of service. The Company's third-party executive compensation expert Mustich testified that 72 percent of the utilities in Xcel Energy's peer group provide financial, tax, and estate planning services to their executives and approximately 50 percent provide executive physicals.⁶⁸¹ If the Company failed to provide commensurate benefits in line with those offered by other employers, it risks both losing existing employees to these other utility employers and struggling to attract qualified employees to fill open positions.

526. The Company also explained that these limited availability benefits also provide benefits to customers by reducing executive turnover.⁶⁸² Executive turnover is expensive because it involves paying recruitment and transition costs and can also be disruptive to Company operations.⁶⁸³ 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.⁶⁸⁴ Specifically, executive physicals help maintain the health of these employees while financial, tax, and estate planning services allow employees the ability to focus on the core operations of the Company without distraction.

527. The Administrative Law Judge recommends that the Commission approve recovery for limited availability benefits. The Company has shown that these benefits are both a necessary cost of service and provide benefits to customers, thus it is reasonable to recover these costs from customers.

(v) Misc. Benefit, Life, LTD Expenses

528. 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 2026.⁶⁸⁵

529. The Department recommends using the average of 2022-2024 actual miscellaneous benefit, life, and LTD expense and applying an inflator based on the average annual increase from 2021 to 2024 to calculate the 2025 and 2026 amounts.⁶⁸⁶ The Department's recommendation reduces the Company's miscellaneous benefit, life, and LTD expense by \$551,597 for 2025 and \$490,067 for 2026.⁶⁸⁷ The Department states that "using an average of actuals smooths the variability in the expense while applying an

⁶⁸¹ Ex. Xcel-67 at 11-12 (Mustich Rebuttal).

⁶⁸² Ex. Xcel-63 at 37 (Ly Rebuttal).

⁶⁸³ Ex. Xcel-63 at 37 (Ly Rebuttal).

⁶⁸⁴ Ex. Xcel-67 at 11-12 (Mustich Rebuttal).

⁶⁸⁵ Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

⁶⁸⁶ Ex. DOC-3 at 43 (Kehrwald Direct).

⁶⁸⁷ Ex. DOC-3 at 44 (Kehrwald Direct).

inflator based on the actual change over time in the expense recognizes the general increasing trajectory of this expense over time.”⁶⁸⁸

530. The Company states that it adequately supported the amount of miscellaneous benefit, life, and LTD expense for 2025 and 2026.⁶⁸⁹ 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.⁶⁹⁰ Schedules 2 and 15 of witness Schrubbe’s Direct Testimony also provide 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.⁶⁹¹

531. The Company also explains that the Company’s forecasts of its pension and benefit costs, including miscellaneous benefit, life, and LTD expense, “are formulaic, are calculated in accordance with accounting rules and standards, and are based on actuarial assumptions specific to the Company.”⁶⁹² Further, Xcel Energy’s approach to forecasting its costs in this rate case is consistent with longstanding practice and precedent in the Company’s prior rate cases before the Commission.⁶⁹³

532. The Department provides no discernible basis in past Commission practice or precedent for its recommendation to use the average of 2022-2024 actuals and apply an inflator based on the average annual increase from 2021 to 2024. In addition, at the evidentiary hearing, Department witness Kehrwald agreed that “in a representative test year some actual costs will be higher than forecast and others will be lower” and that “the purpose of [this rate] case is not to make up for any past actual costs that were higher or lower than forecasted in prior rate cases.”⁶⁹⁴

533. Moreover, the Company presented evidence that recovery of its miscellaneous benefit, life, and LTD expense is reasonable. Company witness Ly explained that Xcel Energy’s health and wellness benefits are necessary because, without them, “the Company would not be able to attract, retain, and motivate qualified employees. For any employer like Xcel Energy, providing health and wellness coverage to employees is a necessity rather than optional.”⁶⁹⁵ Similarly, Company witness Schrubbe explained that it is appropriate for customers to pay for active health and welfare benefits as “they reflect a reasonable and necessary level of expense.”⁶⁹⁶ Witness Schrubbe discussed that

⁶⁸⁸ Ex. DOC-3 at 44 (Kehrwald Direct).

⁶⁸⁹ Xcel Energy Initial Brief at 117.

⁶⁹⁰ See Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

⁶⁹¹ See Ex. Xcel-57 at 8, 84-85, Schedules 2 and 15 (Schrubbe Direct).

⁶⁹² Ex. Xcel-57 at 7-8 (Schrubbe Direct).

⁶⁹³ Ex. Xcel-17 at 21-25 (Halama Direct).

⁶⁹⁴ Tr. Vol. 2 (Dec. 18, 2025) at 453-54 (Kehrwald).

⁶⁹⁵ Ex. Xcel-62 at 36 (Ly Direct).

⁶⁹⁶ Ex. Xcel-57 at 89 (Schrubbe Direct).

“[e]mployees expect their employer to provide a reasonable level of health and welfare benefits, and any employer that does not do so is at a significant disadvantage in the labor market.”⁶⁹⁷ The Company states that its compensation and benefits are required to attract, retain, and motivate employees to provide quality service to customers.⁶⁹⁸

534. The Administrative Law Judge finds that the Company’s 2025 and 2026 miscellaneous benefit, life, and LTD expense is reasonable and that the Company should be permitted to recover \$3,976,149 for 2025 and \$3,990,839 for 2026. The Department’s recommendation to reduce the Company’s 2025 and 2026 miscellaneous benefit, life, and LTD expense should not be adopted.

(vi) Non-Qualified Expenses

535. The Company requested recovery of its non-qualified expense in the amount of \$44,662 for 2025 and \$48,394 for 2026.⁶⁹⁹ Xcel Energy’s non-qualified expense is comprised of the costs of the Company’s matching contributions under Xcel Energy’s Deferred Compensation Plan.⁷⁰⁰

536. The Department recommends recovery of Xcel Energy’s non-qualified expense be disallowed and argues that the Company “has not shown any reasonable basis” that it should be allowed to recover these costs from customers.⁷⁰¹

537. The Company provided support for the amount of non-qualified expense for 2025 and 2026, including Table 2 and Schedule 2 of Company witness Schrubbe’s Direct Testimony.⁷⁰²

538. The Company also presented evidence that recovery of its non-qualified expense is reasonable. The Company explained 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.”⁷⁰³ 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

⁶⁹⁷ Ex. Xcel-57 at 89 (Schrubbe Direct).

⁶⁹⁸ Ex. Xcel-57 at 89 (Schrubbe Direct).

⁶⁹⁹ Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

⁷⁰⁰ Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

⁷⁰¹ Ex. DOC-3 at 48 (Kehrwald Direct).

⁷⁰² See Ex. Xcel-57 at 7, Table 2 (Schrubbe Direct).

⁷⁰³ Ex. DOC-3, Schedule 25 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 120).

employees.⁷⁰⁴ Company witness Ly stated that it is important that Xcel Energy'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.⁷⁰⁵ At the evidentiary hearing, Department witness Kehrwald acknowledged the Company's explanation provided in discovery of the importance of the Deferred Compensation Plan, as well as the fact that an attachment to her own testimony indicates that such benefits help attract and retain top talent.⁷⁰⁶

539. Witness Kehrwald asserts that the Commission has disallowed recovery of non-qualified expense in past rate cases, and therefore disallowance is also appropriate here.⁷⁰⁷ However, the Commission is not bound by the decisions cited by witness Kehrwald, and 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.

540. The Administrative Law Judge finds that the Company's 2025 and 2026 non-qualified expense is reasonable and that the Company should be permitted to recover \$44,662 for 2025 and \$48,394 for 2026. The Department's recommendation to disallow the Company's 2025 and 2026 non-qualified expense should not be adopted.

g. FERC Account 923 (Outside Services Employed Expense)

541. The Company's recovery request in this rate case is based on budgets that are developed using a bottom-up analysis of the needs and priorities of each business area.⁷⁰⁸ The Company's budgeting process is not based on individual FERC accounts.⁷⁰⁹ Nevertheless, the Department sought to limit the Company's recovery for certain O&M expenses, across multiple business areas, that are tracked in one specific FERC account, FERC Account 923.⁷¹⁰

542. 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.⁷¹¹ 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,

⁷⁰⁴ Ex. DOC-3, Schedule 25 at 2 (Kehrwald Direct) (Xcel Energy Response to DOC IR 120).

⁷⁰⁵ Ex. Xcel-62 at 35 (Ly Direct).

⁷⁰⁶ Tr. Vol. 2 (Dec. 18, 2025) at 457-59 (Kehrwald); Ex. DOC-3 at Schedule 24 (Kehrwald Direct).

⁷⁰⁷ Ex. DOC-3 at 47 (Kehrwald Direct).

⁷⁰⁸ Ex. Xcel-26 at 6-7 (Robinson Direct); Ex. Xcel-28 at 19 (Robinson Rebuttal).

⁷⁰⁹ Ex. Xcel-28 at 19 (Robinson Rebuttal).

⁷¹⁰ Ex. DOC-5 at 17 (Golden Direct).

⁷¹¹ See Uniform System of Accounts, 18 C.F.R. part 101, Account 923.

General Counsel, Human Resources and Employee Services, Technology Services, and Corporate Other.⁷¹²

543. The Company estimates the amount in FERC Account 923 for the 2025 test year at \$26.8 million, and for the 2026 plan year it is estimated at \$25.9 million.⁷¹³ The Department argued that these amounts were too high because the Company had over-recovered in FERC Account 923 in 2022-2024.⁷¹⁴ The Department recommended limiting the Company's 2025 recovery in FERC Account 923 to the 2024 actual figure plus 7.5 percent for inflation, and limiting the Company's 2026 recovery to the 2025 amount plus another 7.5 percent.⁷¹⁵ This would result in reductions of \$4.3 million for the 2025 test year and \$1.7 million for the 2026 plan year.⁷¹⁶

544. Because the Company does not budget by FERC Account, it is illogical to focus on just one FERC Account when analyzing the Company's spending.⁷¹⁷ The Company's forecasted O&M—at a Company-wide level—for 2025 and 2026 is the best reflection of the anticipated O&M for those years.⁷¹⁸ Focusing on just one FERC account while ignoring others serves no purpose other than to arbitrarily limit the Company's overall recovery.⁷¹⁹

545. It is especially unwarranted for the Department to focus on FERC Account 923, because it is a catch-all account.⁷²⁰ Because FERC Account 923 includes expenses and special projects from numerous business areas, there is no compelling reason why expenses in it would be directly comparable from one year to the next. The Company has experienced ups and downs in spending on many categories in FERC Account 923 in prior years.⁷²¹ The net effect for FERC Account 923 was that it ended up below forecasted amounts, but there are “undoubtedly other FERC accounts that show the Company under-recovered during the same period.”⁷²²

546. The essence of the Department's argument about FERC Account 923 is that the Company did not provide a detailed description of the reasons why the 2025 and 2026 forecasts for that account will be higher than in past years.⁷²³ But, as explained above, the

⁷¹² Ex. Xcel-28 at 20 (Robinson Rebuttal).

⁷¹³ Ex. DOC-5, Schedule 4 (Golden Direct).

⁷¹⁴ Ex. DOC-5 at 15 (Golden Direct).

⁷¹⁵ Ex. DOC-5 at 17 (Golden Direct).

⁷¹⁶ Ex. DOC-6 at 14 (Golden Surrebuttal).

⁷¹⁷ Ex. Xcel-28 at 23 (Robinson Rebuttal).

⁷¹⁸ Ex. Xcel-28 at 23 (Robinson Rebuttal).

⁷¹⁹ Ex. Xcel-28 at 19 (Robinson Rebuttal).

⁷²⁰ Ex. Xcel-28 at 19 (Robinson Rebuttal).

⁷²¹ Ex. Xcel-28 at 20-21 (Robinson Rebuttal).

⁷²² Ex. Xcel-28 at 20 (Robinson Rebuttal).

⁷²³ Ex. DOC-6 at 14 (Golden Surrebuttal).

Company's budgets and rate case presentation is not organized by FERC Account. Instead, the 2025 and 2026 expenses that are tracked in FERC Account 923 are incorporated into the O&M requests for the Company's business areas. 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.⁷²⁴ The Company provided extensive testimony supporting each of these areas of increased O&M,⁷²⁵ so there is no need for a separate explanation of the increase for the subparts of these expenses that are tracked in FERC Account 923.

547. The Department's argument about FERC Account 923 in this case is nearly identical to its argument in a recent Minnesota Power rate case.⁷²⁶ Just as in this case, the Department looked back at spending in FERC Account 923 in years preceding Minnesota Power's test year, argued that Minnesota Power had overestimated the amount in FERC Account 923 in those past years, and sought to limit Minnesota Power's recovery to the actual expense incurred in the previously completed year plus a small percentage.⁷²⁷ Minnesota Power argued that the use of multi-year averages in this way "fails to accurately capture the reality of the test year" and that its forecasts considered factors that multi-year averages do not reasonably capture.⁷²⁸ The ALJ found that because Minnesota Power's budget process had carefully considered its system, its needs, and known impacts, the record supported its forecasted expenses in FERC Account 923.⁷²⁹ The Commission agreed. The situation here is nearly identical, and the same outcome is warranted.

548. For these reasons, the Department's recommendations to limit the Company's recovery for expenses tracked in FERC Account 923 is rejected.

⁷²⁴ Ex. Xcel-28 at 23 (Robinson Rebuttal).

⁷²⁵ See generally Exs. Xcel-33 (Scheller Direct) and Xcel-47 (Sherwood Direct).

⁷²⁶ *In re Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Feb. 28, 2023).

⁷²⁷ *In re Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 23 (Feb. 28, 2023).

⁷²⁸ *In re Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 24 (Feb. 28, 2023).

⁷²⁹ *In re Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 25 (Feb. 28, 2023).

h. Insurance Premium Expenses

549. The Company seeks to recover its insurance premium costs for 2025 and 2026. The Minnesota jurisdictional allocation is:

2025	\$34.2 million
2026	\$37.6 million ⁷³⁰

550. Company witness Mr. Robert Miller explained that insurance costs are impacted by the insurance market conditions and the Company's exposure metrics that are evaluated annually. To determine insurance market conditions, the Company consults with insurance brokers to identify if markets will be trending up, trending down, or staying flat. The Company then evaluates its exposure metrics, such as number of employees, miles of pipes and wires, and changes to the value of insurable assets.⁷³¹

551. 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.⁷³²

552. Because not all distributions and credits are fully known at the time the Company forecasts its insurance budget, the Company proposed the implementation of a symmetrical true-up that would both prevent under-recovery of insurance premium expense and over-recovery due to receipt of credits that were not accounted for in the Company's forecast.⁷³³

553. Company witness Mr. Miller 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,⁷³⁴ and

⁷³⁰ Ex. Xcel-54 at 19 (Miller Direct).

⁷³¹ Ex. Xcel-54 at 20 (Miller Direct).

⁷³² Ex. Xcel-54 at 20 (Miller Direct).

⁷³³ Ex. Xcel-56 at 11-12 (Miller Rebuttal).

⁷³⁴ Ex. Xcel-54 at 23 (Miller Direct).

2. increased utility industry losses, including losses due to events such as wildfires and gas explosions, which impact the Company's Excess Liability premiums.⁷³⁵

554. Mr. Miller explained that “hardening market” means that insurance capacity is reducing, which allows insurance companies to increase premiums pursuant to basic supply and demand principles. This hardening in the insurance market impacted the Company's 2025 premiums. Mr. Miller also explained that if there is no additional claims activity, the market may soften somewhat between 2025 and 2026.⁷³⁶

555. Mr. Miller also described an underwriting change in 2023 resulting 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.⁷³⁷

556. Mr. Miller described how Xcel Energy, Inc.'s insurance brokers assign loss loading and wildfire loading to Xcel Energy Insurance, Inc.'s various operating companies to allocate the cost of such premiums to those operating companies that had been subject to wildfire losses and face higher wildfire risk, ensuring that premium expense is appropriately allocated among Xcel Energy's jurisdictions.⁷³⁸

557. The Department did not raise any concerns regarding the type or amount of insurance obtained by the Company. Department witness Holly Jones, however, recommended setting the Company's 2025 recovery based on its actual 2024 experience, adjusted by a percentage recommending the historical average of the Company's premium experience from 2020-2024, and applying the percentage increase from 2025 to 2026 provided by the Company to arrive at the recovery for 2026.⁷³⁹

558. XLI similarly did not raise any concerns regarding the type or amount of insurance obtained by the Company. XLI witness Billie LaConte expressed that the increase from 2024 to 2025 and 2026 was substantial⁷⁴⁰ and that she was concerned 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.⁷⁴¹ Ms. LaConte recommended that the Company's recovery of Excess Liability insurance premium costs be based on an average increase, but Ms. LaConte

⁷³⁵ Ex. Xcel-54 at 30 (Miller Direct).

⁷³⁶ Ex. Xcel-54 at 22-23 (Miller Direct).

⁷³⁷ Ex. Xcel-56 at 4-5, 8 (Miller Rebuttal).

⁷³⁸ Ex. Xcel-56 at 15-16 (Miller Rebuttal).

⁷³⁹ Ex. DOC-23 at 25-26 (Jones Direct).

⁷⁴⁰ Ex. XLI-2 at 54-55 (LaConte Direct).

⁷⁴¹ Ex. XLI-2 at 57 (LaConte Direct).

proposed a different averaging period than did Department witness Ms. Jones, choosing the period from 2022-2024.⁷⁴²

559. The Company updated its Excess Liability Insurance Premium information in Mr. Miller's 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.⁷⁴³ The similarity between the Company's updated forecast and its initial forecast demonstrates that the Company's initial forecast is proving to be accurate.

560. The Company 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.⁷⁴⁴ This reduction in the Company's allocated Excess Liability Premium demonstrates that the loss and wildfire loading conducted by the Company's brokers is appropriately allocating risk among Xcel Energy, Inc.'s jurisdictions.

561. The Administrative Law Judge recommends that the Department's and XLI's proposed adjustments should be rejected. The record in this proceeding demonstrates the accuracy and thoroughness of the Company's insurance premium expense forecasting methodology, and Company witness Mr. Miller explained the reasons for the predicted upward trend in the Company's insurance premiums. The validity of the Company's methods was proven out by the extremely small variance between the Company's forecast and its updated July 2025 forecast. The application of loss loading and wildfire loading ensures that the Company is not paying more than its fair share of premium expense.

562. The Administrative Law Judge recommends that the Commission establish a symmetrical true up for insurance costs to ensure that the Company neither over-recovers nor under-recovers its prudently-incurred insurance costs.

i. Prepaid Pension And Accrued Liabilities

563. In this case, Xcel Energy 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).⁷⁴⁵

564. Xcel Energy explained that 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

⁷⁴² Ex. XLI-2 at 57-58 (LaConte Direct).

⁷⁴³ Ex. Xcel-56 at 2-3 (Miller Rebuttal).

⁷⁴⁴ Ex. Xcel-56 at 3-4 (Miller Rebuttal).

⁷⁴⁵ Xcel Energy Initial Brief at 135; Ex. Xcel-57 at 84 (Schrubbe Direct).

expense than it has contributed to those plans, which results in accrued liabilities.⁷⁴⁶ 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.⁷⁴⁷

565. Company witness Schrubbe supported the amount of the Company's prepaid pension asset, including presenting the cumulative contribution and cumulative expense amounts that make up the prepaid pension asset.⁷⁴⁸ These amounts were not disputed by any party. It is also undisputed that Xcel Energy's prepaid pension asset represents the difference between the Company's cumulative contributions to the pension trust and the cumulative recognized pension expense.⁷⁴⁹

566. Xcel Energy explained that it is reasonable for the Company to earn a WACC return on the prepaid pension asset for several reasons.

567. First, Xcel Energy states that the prepaid pension asset benefits both the Company and customers because the pension benefit that gives rise to the prepaid pension asset helps the Company attract and retain employees needed to provide safe and reliable electric service to customers.⁷⁵⁰ Witness Schrubbe explained that for over 50 years, Xcel Energy's pension plan has provided a market-competitive benefit that has allowed the Company to attract and retain employees who have helped build, operate, and maintain the electric system that continues to provide safe and reliable electric service.⁷⁵¹ Company witness Ly also explained that Xcel Energy's pension plan helps the Company manage an orderly transition of employees into retirement, which provides an opportunity for the Company to effectively manage its workforce at the end of employees' careers, appropriately prepare for knowledge transfer, and manage training and succession planning,⁷⁵² and is critical to ensuring the provision of safe and reliable electric service.⁷⁵³

568. Second, Xcel Energy states that recovery of the Company's operating costs related to pension expenses does not compensate the Company in any way for the prepayments that have created the prepaid pension asset.⁷⁵⁴ It is a well-established regulatory principle that prepayments should be included in rate base.⁷⁵⁵ This is because

⁷⁴⁶ Ex. Xcel-57 at 55 (Schrubbe Direct).

⁷⁴⁷ Ex. Xcel-57 at 55-66 (Schrubbe Direct).

⁷⁴⁸ See Ex. Xcel-57 at 59-63 and Schedules 12-14 (Schrubbe Direct).

⁷⁴⁹ See Ex. Xcel-58 at 12 (Schrubbe Rebuttal).

⁷⁵⁰ Xcel Energy Initial Brief at 135; Ex. Xcel-57 at 69 (Schrubbe Direct); Ex. Xcel-58 at 27-28 (Schrubbe Rebuttal).

⁷⁵¹ Ex. Xcel-57 at 24-25 (Schrubbe Direct).

⁷⁵² Ex. Xcel-62 at 41 (Ly Direct).

⁷⁵³ Ex. Xcel-58 at 28-29 (Schrubbe Rebuttal).

⁷⁵⁴ Xcel Energy Initial Brief at 136.

⁷⁵⁵ Ex. Xcel-57 at 68 (Schrubbe Direct).

the prepayment reflects a timing difference between when the Company pays (prepays) an amount for an item and when customers contribute to the cost of that item, and a return on the asset or liability compensates the prepaying party for providing the funds.⁷⁵⁶

569. Xcel Energy explained that with respect to its prepaid pension asset, 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.⁷⁵⁷ 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.⁷⁵⁸ A white paper by The Brattle Group affirms: “The key point is that funding a pension trust requires committing corporate resources that could otherwise be deployed elsewhere, and this trade-off defines the opportunity cost of capital. Hence such funds merit a return (to the extent they are not treated as period cost).”⁷⁵⁹

570. According to the Company, investors are entitled to be compensated for the loss of these alternative options for utilizing funds in a productive manner.⁷⁶⁰ Witness Schrubbe also explained that Xcel Energy does not recover in rates the pension contributions – just the pension expense – a return on the cumulative difference between the two is critical to the Company and its investors.⁷⁶¹ Further, at the evidentiary hearing, witness Schrubbe testified that this is especially important because the pension trust and the prepaid pension asset as a whole will remain in use for many years to come.⁷⁶²

571. Third, Xcel Energy states that the Company’s prepaid pension asset provides significant financial benefits to customers, reducing the cost of the pension expense that is paid by customers each year.⁷⁶³ It is undisputed that customers benefit, and have benefited, from the Company’s prepaid pension asset through the reduction in pension expense charged to customers.⁷⁶⁴

572. Witness Schrubbe explained that 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).⁷⁶⁵ The EROA is multiplied by the value of the assets in the pension trust, and the product of this calculation is subtracted from the

⁷⁵⁶ Ex. Xcel-57 at 68-69 (Schrubbe Direct).

⁷⁵⁷ Ex. Xcel-58 at 2 (Schrubbe Rebuttal).

⁷⁵⁸ Ex. Xcel-58 at 21 (Schrubbe Rebuttal).

⁷⁵⁹ Ex. Xcel-58 at 21 and Schedule 1 at 4 (Schrubbe Rebuttal).

⁷⁶⁰ Ex. Xcel-58 at 21 (Schrubbe Rebuttal).

⁷⁶¹ Ex. Xcel-58 at 22 (Schrubbe Rebuttal).

⁷⁶² Ex. Xcel-97 at 1 (Schrubbe Revised Witness Summary).

⁷⁶³ Xcel Energy Initial Brief at 137.

⁷⁶⁴ Ex. Xcel-58 at 13 (Schrubbe Rebuttal).

⁷⁶⁵ Ex. Xcel-57 at 69 (Schrubbe Direct).

annual pension cost.⁷⁶⁶ Therefore, the return on the prepaid pension asset reduces the annual qualified pension cost charged to customers on a dollar-for-dollar basis.⁷⁶⁷

573. The gains on the prepaid pension asset from investing the pension funds in the marketplace enable the Company to provide the pension benefit at a lower cost than would have been possible without these gains, and in turn reduce the annual pension expense paid by customers.⁷⁶⁸ Here, Xcel Energy presented evidence that 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 2026.⁷⁶⁹

574. In addition, customers receive the benefit of earnings on the entire amount of the assets in the pension trust, not just the amount that is recognized in annual pension cost.⁷⁷⁰ The pension plan amount on which customers earn a return is also much larger than the amount on which the Company is proposing they pay a return.⁷⁷¹ This is because, as explained above, 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).⁷⁷² Witness Schrubbe stated, "In this case, the Company is proposing to include the Company's prepayments of pension expense as an addition to rate base, and to treat the customers' prepayments of FAS 106 and FAS 112 as a reduction to rate base."⁷⁷³

575. In Xcel Energy's appeal of the denial of a return on the prepaid pension asset in the Company's 2022-2024 MYRP, the Minnesota Court of Appeals held that the prepaid pension asset should earn a return so long as the asset consists of shareholder derived funds.⁷⁷⁴ On this record, there is no debate that the prepaid pension asset consists solely of shareholder (Company) supplied funds. Witness Schrubbe explained that customers pay only annual pension expense through rates, which is by definition subtracted out of the calculation of the prepaid pension asset⁷⁷⁵ (cumulative contributions by investors minus cumulative recognized pension expense).⁷⁷⁶ The Company also indicated that it has never

⁷⁶⁶ Ex. Xcel-57 at 69 (Schrubbe Direct).

⁷⁶⁷ Ex. Xcel-57 at 69 (Schrubbe Direct).

⁷⁶⁸ Ex. Xcel-57 at 25 (Schrubbe Direct).

⁷⁶⁹ Ex. Xcel-57 at 73, Table 16 (Schrubbe Direct).

⁷⁷⁰ Ex. Xcel-57 at 70 (Schrubbe Direct).

⁷⁷¹ Ex. Xcel-57 at 71 (Schrubbe Direct).

⁷⁷² Ex. Xcel-57 at 72 (Schrubbe Direct).

⁷⁷³ Ex. Xcel-57 at 64 (Schrubbe Direct).

⁷⁷⁴ *See 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).

⁷⁷⁵ Ex. Xcel-57 at 81 (Schrubbe Direct).

⁷⁷⁶ Ex. Xcel-58 at 12 (Schrubbe Rebuttal).

had negative pension expense for the NSPM prepaid pension asset for which it seeks rate base treatment.⁷⁷⁷ Further, the market returns on the prepaid pension asset directly reduce pension expense, solely benefiting customers.⁷⁷⁸ Because the prepaid pension asset consists of cumulative pension contributions that exceed cumulative pension expense, the asset necessarily consists of shareholder-supplied funds.

576. The Department agrees that it is undisputed that the Company is entitled to a return on the value of the prepaid pension asset.⁷⁷⁹ However, the Department argues that the Company's interest in the prepaid pension asset lacks value and the Commission should deny a return.⁷⁸⁰ Specifically, the Department asserts that the Company "only has a contingent reversionary interest in pension trust property of nominal or no value."⁷⁸¹ In support, the Department cites law and treatises regarding property interests in pension trusts.⁷⁸²

577. The Department's recommendation is unpersuasive. As an initial point, the Department confuses the Company's request. The Company explained that it is not seeking to recover either the pension fund or the prepaid pension asset; rather, it is seeking to earn a return on the cumulative contributions to the pension fund made by the Company that exceed the cumulative pension expense paid by customers – i.e., to compensate investors for the use of their money to fund employee pensions.⁷⁸³ Thus, the Company's interest in pension trust itself has no bearing here.

578. The Department's recommendation is also unsupported by law. The Department relies almost entirely on law and treatises regarding property interests in pension trusts,⁷⁸⁴ which have no applicability in this case where the Company is not seeking recovery of either the pension fund or the prepaid pension asset. The Department's position is also contrary to Minnesota case law regarding prepaid pension assets. As previously explained, the Minnesota Court of Appeals held that the prepaid pension asset should earn a return so long as the asset consists of shareholder derived funds, and it is undisputed that the prepaid pension asset consists solely of shareholder (Company) supplied funds.

579. Alternatively, the Department recommends that if the Commission decides nonetheless to grant Xcel Energy a return, the rate of return should not exceed the

⁷⁷⁷ Ex. Xcel-57 at 83 and Schedule 14 (Schrubbe Direct).

⁷⁷⁸ Ex. Xcel-57 at 81 (Schrubbe Direct).

⁷⁷⁹ DOC Initial Brief at 61 (citing *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, 2025 WL 249995, at *9).

⁷⁸⁰ DOC Initial Brief at 61.

⁷⁸¹ DOC Initial Brief at 61.

⁷⁸² See DOC Initial Brief at 61-63.

⁷⁸³ Xcel Energy Initial Brief at 135, 141-42; Ex. Xcel-58 at 6 (Schrubbe Rebuttal).

⁷⁸⁴ See DOC Initial Brief at 61-63.

Company's long-term cost of debt.⁷⁸⁵ The Department provides the following reasons for its recommendation: (1) prepaid pension lacks the characteristics of other rate base assets;⁷⁸⁶ and (2) limiting the return to the long-term costs of debt would allow the Company to recover its cost of service and discourage the Company from making excessive contributions above the minimum necessary threshold required by the Employee Retirement Income Security Act.⁷⁸⁷

580. Xcel Energy maintains that the most appropriate outcome would be for the Company to earn a WACC return on the prepaid pension asset, similar to other items included in rate base, such as ADIT.⁷⁸⁸ The Company also explained that its assets, including the prepaid pension asset, are financed with a mix of debt and equity, which further warrants recovery of a return reflecting both components.⁷⁸⁹

581. Notably, the Company stated that it "continually looks for ways to reduce the number of contested issues in rate proceedings. To this end, the Company accepts the Department's surrebuttal adjustment as a compromise on the prepaid pension asset and the prepaid retiree medical and other post-employment benefit liabilities."⁷⁹⁰ The Company further clarified that this agreement is solely for purposes of this individual proceeding, and not as precedent or agreeing to any underlying principle.⁷⁹¹

582. The Administrative Law Judge finds that Xcel Energy's request to include its prepaid pension asset in rate base and to earn a return at the Company's WACC request is reasonable. As demonstrated by the Company, the prepaid pension asset is a shareholder funded service-producing asset that benefits customers and employees, and therefore belongs in rate base, consistent with Minnesota law.

583. In the alternative, under the specific facts of this case and in light of Xcel Energy's agreement with the Department's recommendation for the Company to earn a return at its cost of long-term debt on the prepaid pension asset, allowing the Company to earn a return at its cost of long-term debt in this case only is reasonable. The Administrative Law Judge notes that the Department continues to advocate for no return.⁷⁹² However, this position is unreasonable, particularly when the Department's only testimony regarding the

⁷⁸⁵ DOC Initial Brief at 64; Ex. DOC-11 at 15 (Hunt Surrebuttal).

⁷⁸⁶ Ex. DOC-11 at 7 (Hunt Surrebuttal).

⁷⁸⁷ DOC Initial Brief at 65; Ex. DOC-11, Schedule 6 (Hunt Surrebuttal).

⁷⁸⁸ Ex. Xcel-97 at 1 (Schrubbe Revised Witness Summary).

⁷⁸⁹ Ex. Xcel-97 at 1-2 (Schrubbe Revised Witness Summary).

⁷⁹⁰ Ex. Xcel-97 at 2 (Schrubbe Revised Witness Summary).

⁷⁹¹ Ex. Xcel-97 at 2 (Schrubbe Revised Witness Summary).

⁷⁹² See DOC Initial Brief at 61-65.

prepaid pension asset provides that earning a return at the Company's cost of long-term debt on the prepaid pension asset is within the range of reasonableness.⁷⁹³

j. Allocations

(i) General Allocator

584. The Company requests to change its allocation method to account for employee work in its Minnesota jurisdiction from full-time equivalents to using the number of employees.⁷⁹⁴

585. For purposes of allocating costs that cannot otherwise be direct assigned to an operating company or non-regulated subsidiary, the Company's General Allocator is used by employees.⁷⁹⁵ The General Allocator formula uses either FTE Hours (for NSPM) or Number of Employees (for all other jurisdictions), as a factor, in addition to Total Assets and Revenues, to establish the allocator amount.⁷⁹⁶

586. The Number of Employees factor is based on the number of employees for each operating company, with common officers from XES assigned to Xcel Energy to ensure that no customer of a regulated utility is responsible for costs to support nonregulated activities.⁷⁹⁷ The FTE Hours methodology is based on the number of productive labor hours of all operating company and XES employees, including indirect labor hours that are allocated using a ratio that includes the Number of Employees factor.⁷⁹⁸ FTE Hours in the General Allocator is used only for the Minnesota jurisdiction regulated utility, as all other operations of Xcel Energy, Inc. use the Number of Employees methodology.⁷⁹⁹ While several allocators for NSPM use the FTE Hours methodology currently, the largest impact is on the Company's General Allocator.⁸⁰⁰

⁷⁹³ See Ex. DOC-11 at 15-19 (Hunt Surrebuttal).

⁷⁹⁴ Ex. Xcel-49 at 26 (Doyle Direct).

⁷⁹⁵ Ex. Xcel-49 at 10 (Doyle Direct); Ex. Xcel-50 at 10-11 (Doyle Rebuttal). The General Allocator cannot be used by employees of NSPM. Ex. Xcel-49 at 18 (Doyle Direct).

⁷⁹⁶ Ex. Xcel-49 at 13-14 (Doyle Direct).

⁷⁹⁷ Ex. Xcel-49 at 13-14 (Doyle Direct).

⁷⁹⁸ Ex. Xcel-49 at 13-14 (Doyle Direct).

⁷⁹⁹ The General Allocator is calculated in all jurisdictions other than Minnesota through three equally weighted factors: Total Assets, Revenues, and Number of Employees. In Minnesota, however, the General Allocator uses FTE Hours instead of Number of Employees. So, from an accounting perspective, because all other operating companies and non-regulated affiliates use the Number of Employees methodology, the calculation for Minnesota must be performed manually and certain costs get excluded as they are based on Number of Employees. Ex. Xcel-49 at 13-14 (Doyle Direct).

⁸⁰⁰ Ex. Xcel-49 at 15 (Doyle Direct).

587. 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 Energy securities filing or an XES Human Resources employee developing enterprise-wide policies; in all other circumstances, XES employees must direct assign their time to the proper regulated operating company or non-regulated affiliate.⁸⁰¹ Because NSPM has the largest number of employees, the costs of XES to support NSPM (through Human Resources, Employee Communications, and other employee-focused areas) incur the largest time and labor amounts.⁸⁰²

588. Since 2011, the Commission has required Xcel to use Full Time Equivalent (FTE) hours in its General Allocator. Following Xcel's 2008 rate case, the Commission investigated Xcel's three-part allocation method, which used the number of employees as its labor component.⁸⁰³ As part of its investigation, the Commission required Xcel to file "an analysis of 99 work orders submitted in the rate case, providing detailed analysis of the cost-allocation process used for each one."⁸⁰⁴ The Commission ultimately ordered Xcel to use FTEs instead of the number of employees.⁸⁰⁵

589. The Company's actual experience with the FTE Hours methodology is that costs that are incurred to support NSPM's regulated operations are not allocated to Minnesota Customers. Therefore, while the Commission's original focus on ordering the FTE Hours methodology in 2011 was driven by concerns about allocating non-regulated operations costs to the regulated utility, using the FTE hours methodology actually results in operations costs of the regulated utility being borne by non-regulated affiliates and other operating companies.⁸⁰⁶ The Company concluded that this result is fundamentally inconsistent with Minn. Stat. 216B.16, subd. 6.

590. The Department objected to the Company's request, citing back to the Commission's 2011 Order in Docket No. E,G002/AI-10-690.⁸⁰⁷ Additionally, the Department objected because use of the Number of Employees methodology would increase costs to Minnesota electric ratepayers in the test year and potentially in future

⁸⁰¹ Ex. Xcel-49 at 16-17 (Doyle Direct).

⁸⁰² Ex. Xcel-49 at 24-25 (Doyle Direct).

⁸⁰³ See *In re Northern States Power Company's Cost Allocation Procedures and General Allocator*, Docket No. E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (Mar. 15, 2011) (2011 General Allocator Order).

⁸⁰⁴ 2011 General Allocator Order at 2 (citing *In re Application of Northern States Power Company d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, E002/GR-08-1065, FINDINGS OF FACT AND CONCLUSIONS OF LAW, AND ORDER at 20 (Oct. 23, 2009).

⁸⁰⁵ 2011 General Allocator Order at 4.

⁸⁰⁶ Ex. Xcel-49 at 18-19 (Doyle Direct).

⁸⁰⁷ Ex. DOC-1 at 34 (Johnson Direct).

years.⁸⁰⁸ The Department argued that this was an “over allocation of costs to Minnesota” customers.⁸⁰⁹ However, as the Company pointed out, this increase in costs to Minnesota customers when using the Number of Employees methodology in the General Allocator is not an “over allocation” of costs but is actually an increase because Minnesota customers are not currently allocated the full cost for regulated operations when the FTE Hours methodology is used.⁸¹⁰

591. Given the Company’s actual experience with the FTE Hours methodology, and the fact that its use results in other operating companies and non-regulated affiliates paying the costs to support NSPM’s operations, the Company’s request to return to the Number of Employees methodology for purposes of calculating its allocators is a reasonable and appropriate request.

(ii) Interchange Agreement Allocator

592. Northern States Power Company-Minnesota (NSPM) and Northern States Power Company-Wisconsin (NSPW) operate a single integrated electric generation and transmission system, which jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the NSP System are owned by the two separate legal entities (NSPM and NSPW), with the ownership boundary at the Minnesota/Wisconsin border. Under the Interchange Agreement, each operating company bills the other operating company for their share of the joint costs using energy requirements as the basis for sharing variable costs (i.e., an energy allocator) and peak demand as the basis for sharing capital related and other fixed costs (i.e., a demand allocator).⁸¹¹

593. In this case, the Company forecasted 2025-2026 Interchange revenue and expenses using 2025-2026 NSPM and NSPW budget information.⁸¹² The demand allocator was computed based on average monthly coincident peak demands for the NSPM and NSPW systems based on three years of data.⁸¹³ In Supplemental Direct filed March 17,

⁸⁰⁸ Ex. DOC-2 at 11 (Johnson Surrebuttal).

⁸⁰⁹ Ex. DOC-1 at 38-39 (Johnson Direct).

⁸¹⁰ Ex. Xcel-49 at 18-19 (Doyle Direct).

⁸¹¹ Ex. Xcel-17 at 60-62 (Halama Direct).

⁸¹² 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).

⁸¹³ 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.”).

2025, the Company explained it had discovered an error in the computation of the interchange demand allocator and provided a corrected demand allocator calculation.⁸¹⁴

594. 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 the Federal Energy Regulatory Commission (FERC) in May 2025 in FERC Docket ER25-1620-000. This update would increase the 2025 revenue requirement by \$272,723.⁸¹⁵

595. The Department further recommended the Commission require Xcel Energy to apply the 2025 Interchange demand allocator accepted by FERC in May 2025 to 2026 costs and revenues, decreasing the 2026 revenue deficiency by \$2,940,237.⁸¹⁶

596. The Department explained that “Xcel’s proposed 2026 Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators. In contrast, the 2025 Interchange Agreement includes more current period updated demand allocators that include updated transmission loss allocators that have been approved by FERC.”⁸¹⁷

597. In response to the Company’s assertion that applying the 2025 demand allocator to 2026 was not appropriate because the 2025 allocator is not representative of the 2026 test year cost of service, the Department stated that it asked the Company to explain what other components of the Interchange Agreement billings changed for 2026, and that the Company listed other items but did not provide any actual updates to those. As a result, the Department concludes there are no other changes to other elements of the Interchange Agreement for 2026 that are warranted.⁸¹⁸

598. As shown in Schedule 17 to the Supplemental Direct Testimony of Mr. Halama, for the 2025 test year, the demand allocator was computed based on 18 months of actuals (through June 2024) and 18 months of projected peak demands (through December 2025). The same forecasted and actual data was utilized to compute the allocator accepted

⁸¹⁴ Ex. Xcel-18 at 6-7 and Schedule 17 (Halama Supplemental Direct).

⁸¹⁵ Ex. DOC-1 at 29-33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).

⁸¹⁶ Ex. DOC-1 at 33 (Johnson Direct); Ex. DOC-2 at 7 (Johnson Surrebuttal).

⁸¹⁷ Ex. DOC-2 at 6 (Johnson Surrebuttal); *see also* Ex. DOC-1 at 32 (Johnson Direct) (“Xcel’s proposed 2026 Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators. In contrast, the 2025 Interchange Agreement includes the updated transmission loss allocators that have been approved by FERC. As a result, I conclude it is more reasonable to use the updated transmission demand allocators for 2026 rather than relying on older data.”).

⁸¹⁸ Ex. DOC-2 at 6 (Johnson Surrebuttal).

by FERC in Docket ER25-1620-000.⁸¹⁹ For the 2026 plan year, the demand allocator was computed using six months of actuals (through June 2024) and forecasts through December 2026.⁸²⁰ No additional months of actual peak demand were included in the FERC-approved 2025 demand allocator.⁸²¹

599. The Company explained that at the time it filed Supplemental Direct, it had just submitted its annual Interchange Agreement update to FERC for 2025; no 2026 update had been filed as the data for the 2026 update was not yet available.⁸²² The Company also explained that for 2025, 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.⁸²³ Using the updated transmission loss multiplier would *increase* the Company's 2025 revenue requirement by \$272,723; however, the Company did not include this update in the 2025 test year due to timing and did not request to incorporate the increase to the 2025 revenue requirement.

600. The Company explained that application of the 2025 Interchange Agreement demand allocator to 2026 as proposed by the Department would not be representative of the 2026 plan year cost of service and therefore is not an appropriate basis for the calculation of 2026 plan year costs and revenues.⁸²⁴ The 2025 demand allocator is based on the 36-months of coincidental peak demands through December 2025.⁸²⁵ Instead of basing the 2026 demand allocator on January 2024-December 2026, as proposed by the Company, the Department's recommendation would remove all 2026 forecasted coincident

⁸¹⁹ Ex. DOC-1, Schedule 4 at 145 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A) (Appendix A to the FERC filing shows the specification of average monthly coincidental peak demands used to compute the 2025 demand allocator).

⁸²⁰ See Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator).

⁸²¹ Compare Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator) with Ex. DOC-1, Schedule 4 at 145 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A) (using the same actual peak demand data through June 2024).

⁸²² Xcel Energy Initial Brief at 154.

⁸²³ Ex. DOC-1, Schedule 4 at 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A). The transmission loss multiplier submitted to FERC on March 14, 2025 was updated based on data from 2020-2023 whereas the transmission loss multiplier utilized in the Company's supplemental direct testimony was based on data from 2019-2022.

⁸²⁴ Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160).

⁸²⁵ See Ex. Xcel-18 at Schedule 17 (Halama Supplemental Direct) (Interchange Demand Allocator); Xcel Energy Initial Brief at 155.

peak demand data from the determination of 2026 interchange costs and revenues. The result would be to allocate the 2026 interchange costs and revenues on older data (January 2023-December 2025) that fails to accurately represent the 2026 plan year. While the Department was critical of the Company's proposed 2026 demand allocator because it "still used forecasted demand allocators for the months of July 2024 through December 2026 in its calculations," the Company explained that the 2025 demand allocator as accepted by FERC—which the Department suggested be used—also uses forecasted data beginning July 2024.⁸²⁶

601. The Company also argued that while the Department's stated concern is that "Xcel's proposed 2026 Interchange Demand allocators are based on forecasted data that includes older transmission loss allocators,"⁸²⁷ the Department's recommended adjustment to the 2026 plan year of \$2,940,237 does not simply reflect an update to the most recent transmission loss multipliers. Instead, the Department proposed that 2026 interchange costs and revenues be allocated using the 2025 demand allocator which only reflects forecasted peak demands through December 2025.

602. The Company explained that incorporating the updated transmission loss multiplier to reflect the most recent update accepted by FERC in May 2025 while continuing to include the 2026 coincident peak demand forecast would result in a *higher* allocation of costs to Minnesota in 2026 compared to the Company's proposed demand allocator as filed in supplemental direct.⁸²⁸ Utilizing the updated transmission loss multiplier data to compute the 2026 demand allocator would result in an increase to the 2026 revenue requirement of \$282,504.⁸²⁹ The impact of the updated loss multipliers on the 2025 and 2026 demand allocators is relatively insignificant because the multipliers decreased by approximately the same order of magnitude for both NSPM and NSPW.⁸³⁰ The transmission loss multiplier for NSPM decreased from 0.960 to 0.959 while the transmission loss multiplier for NSPW decreased from 0.952 to 0.950.⁸³¹

603. The Company also explained that the Department's proposal to apply the 2025 demand allocator in 2026 was not supported by recent trends in the Interchange Agreement demand allocators filed with and accepted by FERC, which reflect an upward

⁸²⁶ Xcel Energy Initial Brief at 154 (citing Ex. DOC-1 at 31 (Johnson Direct)).

⁸²⁷ Xcel Energy Initial Brief at 155 (quoting Ex. DOC-2 at 6 (Johnson Surrebuttal)).

⁸²⁸ Xcel Energy Initial Brief at 156-158.

⁸²⁹ Xcel Energy 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)).

⁸³⁰ See Ex. DOC-1, Schedule 4 at 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160).

⁸³¹ Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A).

trend in the allocation of costs to NSPM over recent years, further supporting the reasonableness of the Company's proposed 2026 demand allocator in this case.⁸³²

604. Finally, the Company explained that application of the 2025 Interchange Agreement demand allocator to 2026 is not representative of the 2026 plan year cost of service.⁸³³ 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.⁸³⁴ Selectively holding 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 2026.⁸³⁵ In response to the Department's criticism that the Company was provided with an opportunity to update the values for these components but failed to do so, the Company explained these inputs for 2026 were not yet known, but that the 2026 forecast reflects a reasonable and supported projection for 2026 based on the most current available data and analysis.

605. The Administrative Law Judge recommends that the Commission approve Xcel Energy's Interchange Agreement costs and revenues based on the corrected demand allocators as filed in the Company's Supplemental Direct Testimony. The record supports that application of the 2025 demand allocator to the forecasted 2026 interchange agreement costs and revenues would not accurately reflect the Company's 2026 cost of service and forecasted peak demands in the 2026 plan year. Further, Xcel Energy's proposed 2025 demand allocator (84.0551 percent to NSPM) reflects a reasonable forecast based on information that was available at the time it was prepared, and results in lower 2025 test year costs for Minnesota customers compared to using the FERC-approved allocator with updated transmission loss multipliers – a benefit to customers.

⁸³² See Xcel Energy Initial Brief at 156 (Figure 4) (citing Ex. XLI-1 at 86 (LaConte Direct) (Xcel Energy's Response to DOC IR 157, Attachment A)).

⁸³³ Ex. DOC-1, Schedule 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160).

⁸³⁴ Ex. DOC-2, Schedule 2 (Johnson Surrebuttal) (Xcel Energy's Response to DOC IR 3107); Tr. Vol. 2 (Dec. 18, 2025) at 384-392 (Johnson) (acknowledging the Company will need to provide updated information for 2026 because the interchange agreement changes every single year).

⁸³⁵ Ex. Xcel-19 at 61 (Halama Rebuttal); see also Ex. DOC-2, Schedule 2 (Johnson Surrebuttal) (Xcel Energy's Response to DOC IR 3107).

(iii) Wildfire Allocations

606. The Company proposes to allocate wildfire mitigation costs using the Total Plant Ration (TPR).⁸³⁶

607. The Department and OAG originally argued that using the TPR is inappropriate, and recommend removing \$3.3 million in 2025 and \$4.3 million in 2026 of indirect wildfire mitigation costs allocated to the Minnesota jurisdiction.⁸³⁷

608. During the initial briefing period, the Department and OAG revised their recommendations, and then argued that indirect wildfire costs should be allocated based on the ratio of direct wildfire costs allocated from XES to NSPM.⁸³⁸ Specifically, the Department suggests that applying the 2025 direct cost allocation ratio to indirect costs results in a \$1.7 million reduction in indirect costs in the 2025 test year, and applying the 2026 direct cost allocation ratio results in a reduction of \$1.8 million in indirect cost allocation in the 2026 test year.⁸³⁹

609. The updated methodology used by the Department results in adjustments that are roughly the same as the Company's proposal.⁸⁴⁰

610. The OAG argues that the Company should not recover these costs because the Company did not meet its burden to provided total costs versus direct costs.⁸⁴¹

611. The Company provided the information necessary to make this calculation.⁸⁴²

612. NSPM adheres to a Commission approved fully distributed costing methodology. This framework was established in decades-old electric and gas rates

⁸³⁶ Ex. Xcel-50 at 13-14 (Doyle Rebuttal).

⁸³⁷ Ex. DOC-1 at 37 (Johnson Direct); Ex. OAG-7 at 19 (Lee Surrebuttal).

⁸³⁸ DOC Initial Brief at 73-74.

⁸³⁹ DOC Initial Brief at 73-74.

⁸⁴⁰ Xcel Energy Reply Brief at 104-05.

⁸⁴¹ Ex. OAG-5 at 29 (Lee Direct).

⁸⁴² Tr. Vol. 2 (Dec. 18, 2025) at 408:2-25 (Johnson).

cases⁸⁴³ and reaffirmed in the Commission's September 28, 1994 Order in Docket G,E999/CI-90-1008.⁸⁴⁴ The framework is used in all instances of the CAAM.⁸⁴⁵

613. The Company's cost assignment and allocation approach is structured around a hierarchical framework, which includes the following principles:⁸⁴⁶

- I. *Tariffed rate shall be used to value tariffed services provided.*
- II. *Costs shall be directly assigned to either regulated or non-regulated business & activities whenever possible.*
- III. *Costs that cannot be directly assigned to either regulated or non-regulated activities or jurisdictions will be described as common costs. Common costs shall be grouped into homogeneous cost categories designed to facilitate the proper allocation of costs between regulated and non-regulated activities or jurisdictions in accordance with the following principles:*
 - a. *Cost causation. All activities or jurisdictions that cause the cost to be incurred shall be allocated a portion of that cost. Direct assignment of a cost is preferred to the extent that the cost can be traced to the specific activity or jurisdiction.*
 - b. *Variability. If 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.*

⁸⁴³ 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*, 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*, Docket No. E-002/GR-92-1186, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Sep. 1, 1993)

⁸⁴⁴ 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).

⁸⁴⁵ Ex. Xcel-50 at 17 (Doyle Rebuttal).

⁸⁴⁶ Ex. Xcel-50 at 17-18 (Doyle Rebuttal).

- c. *Traceability. A 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.*
 - d. *Benefit. All activities or jurisdictions that benefit from a cost shall be allocated a portion of that cost.*
- IV. *Residual. The residual of costs left after either direct or indirect assignment or allocation shall be allocated based upon an appropriate general allocator as defined in this CAAM.*
- V. *Whenever neither direct or indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator.*

614. NSPM applies this framework to Wildfire Mitigation costs as follows:⁸⁴⁷

- Direct Charging: Costs are directly assigned to the NSPM Minnesota jurisdiction when the business activity is specific to that jurisdiction, in accordance with principle II above.
- Indirect Cost Allocation: For costs that cannot be directly assigned, the Company applies principle III.a (Cost Causation) above. Specifically, indirect costs are allocated using Total Plant, specifically electric transmission, and electric distribution, which are deemed the most cost causative methodologies available.

615. The Company is required to follow approved allocation methodologies.⁸⁴⁸ These reasonable allocation methodologies have been approved for many years. Making the proposed change by Department witness Johnson and OAG witness Lee would result in not following the historical framework in place.

k. Sherco Unit 3 And Allen S. King Coal Plants Remaining Lives

616. In the Company's most recent integrated resource plan (IRP) the Commission approved shortening the operating lives of the Sherco Unit 3 (Sherco 3) and Allen S. King (King) coal generating plants.⁸⁴⁹ King will be retired in December 2028,

⁸⁴⁷ Ex. Xcel-50 at 18 (Doyle Rebuttal).

⁸⁴⁸ Ex. Xcel-50 at 20 (Doyle Rebuttal).

⁸⁴⁹ ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS, Docket Nos. E002/RP-24-67 and E002/CN-23-212 (Apr. 21, 2025).

instead of June 2037, and Sherco 3 will be retired in December 2030 rather than December 2034.⁸⁵⁰

617. In this case, the Company proposes 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.⁸⁵¹

618. 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.⁸⁵²

619. In May 2025, after the Company filed its direct testimony, the Commission issued an order in the Early Retirement Docket. The Early Retirement Order established a four-tiered approach to determining ratemaking treatment of early-retired plants such as Sherco 3 and King. Tier 1 is a data-gathering phase. Data related to the plant, the impact of retirement on ratepayers and the utility's operation of the plant are considered in Tier 1. In Tier 2, the evaluation focuses on whether the early-retiring asset meets the criteria established for accelerated depreciation. In Tier 3, the evaluation asks whether accelerated depreciation would lead to rate shock. If this is the case, Tier 3 contemplates the creation of a regulatory asset with some type of return. Notably, discussion of the Tier 3 analysis specifically references minimizing cost to customers while also allowing utility recovery of prudently-invested capital retiring early due to environmental regulation. Tier 4 is reserved for unique assets, situations where an asset is operated imprudently, and plants that are not used and useful at the time of retirement.⁸⁵³

620. In her direct testimony, Department witness Ms. Holly Jones recommended that the depreciation lives of Sherco 3 and King be adjusted to match Sherco 3's and King's shortened operating lives in this case.⁸⁵⁴

621. The Department's proposal would increase the Company's revenue requirements in the 2025 test year and 2026 plan year by approximately \$58.8 million and \$55.4 million respectively.⁸⁵⁵

⁸⁵⁰ Ex. Xcel-17 at 76 (Halama Direct).

⁸⁵¹ Xcel-17 at 76 (Halama Direct).

⁸⁵² Xcel-69 at 41-42 (Johnson Direct); ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY-RETIRING GENERATING FACILITIES (May 14, 2025) (hereinafter, the EARLY RETIREMENT ORDER) at 1-2.

⁸⁵³ EARLY RETIREMENT ORDER AT 5, 7-8.

⁸⁵⁴ Ex. DOC-23 at 15-16 (Jones Direct).

⁸⁵⁵ Ex. Xcel-19 at 51 (Halama Rebuttal).

622. Company witness Halama testified that accelerated depreciation would significantly 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.⁸⁵⁶

623. OAG and XLI oppose the Department's proposal, contending that shortening the depreciable lives of the plants would result in rate shock and intergenerational inequity.⁸⁵⁷

624. OAG and XLI contend that rate shock would result from the increased revenue requirements in both 2025 and 2026.⁸⁵⁸

625. Both OAG and XLI testified that intergenerational inequity would result from the fact that future customers will benefit from the earlier adoption of cleaner resources but would not have been required to pay for the King and Sherco 3 plants.⁸⁵⁹

626. The Department focuses on potential intergenerational inequity resulting from future customers paying for a plant that is no longer used and useful.⁸⁶⁰

627. Mr. Halama applied the four-tiered analysis set forth in the Early Retirement Order and determined that the Company's regulatory asset proposal best balances the impacts to customers and the Company of the early retirement of the Sherco 3 and King plants.⁸⁶¹

628. Company witness Mark Moeller testified that the Company's proposal most appropriately aligns with state energy policy objectives and ensures the Company has an opportunity to recover its prudently incurred costs related to those facilities.⁸⁶²

629. The Commission recognized in the Early Retirement Order that if utilities are not permitted to fully recovering the costs of early retirement of coal-fired plants, utilities could be disincentivized from pursuing early retirement of these generation resources in order to more quickly decarbonize their energy fleets.⁸⁶³

⁸⁵⁶ Ex. Xcel-19 at 51-52 (Halama Rebuttal).

⁸⁵⁷ Ex. OAG-6 at 5-7, 9-10 (Lee Rebuttal); Ex. XLI-5 at 7-8 (LaConte Rebuttal).

⁸⁵⁸ Ex. OAG-6 at 5-6 (Lee Rebuttal); Ex. XLI-5 at 7-8 (LaConte Rebuttal).

⁸⁵⁹ Ex. OAG-6 at 5, 7 (Lee Rebuttal); Ex. XLI-5 at 7 (LaConte Rebuttal).

⁸⁶⁰ Ex. DOC-25 at 19 (Jones Surrebuttal).

⁸⁶¹ Ex. DOC-25 at 19 (Jones Surrebuttal).

⁸⁶² Ex. Xcel-86 at 4 (Moeller Rebuttal).

⁸⁶³ EARLY RETIREMENT ORDER at 2-3, 7.

630. The Administrative Law Judge recommends that the Commission take no action with respect to the depreciable lives of the Sherco 3 and King plants and instead establish a regulatory asset for each plant at the end of its operating life.

I. Sherco 3 Restoration Costs

631. The OAG recommended disallowing the remaining plant restoration costs, not covered by insurance, related to the restoration of Sherco Unit 3 restoration following a catastrophic failure of the Unit in 2011. The OAG stated that the Commission has now determined the Company acted imprudently, causing the outage. Therefore, OAG argued that although the restoration costs not covered by insurance have been included in the Company's rate base and depreciated since the Company's 2013 rate case, the remaining balance should now be disallowed.⁸⁶⁴

632. The Company stated that these costs, originally \$5.5 million and now \$2.4 million in 2025 and \$2.1 million in 2026, have been included in rates in each of the Company's rate cases since 2013 and this ratemaking treatment should not be changed.⁸⁶⁵

633. The Administrative Law Judge recommends that the Commission continue to provide the ratemaking treatment approved in 2013 and applied in each of the Company's succeeding rate cases.

m. Riverside Generating Unit

634. The Department proposes that the Riverside Generating Unit (Riverside) be removed from the Company's revenue requirement from May 1 of the 2025 test year through May of the 2026 plan year. The Department contends that Riverside will not be "used and useful" because it will be offline from approximately May 2025 through the end of May 2026 due to a mechanical outage.⁸⁶⁶

635. The Department recommends that if Riverside is removed from the Company's revenue requirement while it is offline that it be able to recover its property tax and depreciation expense associated with Riverside.⁸⁶⁷

⁸⁶⁴ Ex. OAG-5 at 22-25 (Lee Direct); OAG-7 at 16-19 (Lee Surrebuttal).

⁸⁶⁵ Ex. Xcel-16 at 21-22 (Liberkowsky Rebuttal); Ex. Xcel-19 at 34-35 (Halama Rebuttal).

⁸⁶⁶ Ex. DOC-1 at 48 (Johnson Direct). At the time of the hearing on this matter, all parties understood that Riverside was likely to come back online at the end of May, 2026. The Company has since learned that Riverside is likely to remain offline through 2026. Xcel Energy Reply Brief at 111, fn.405.

⁸⁶⁷ Ex. DOC-2 at 29-30 (Johnson Surrebuttal).

636. In his Surrebuttal Testimony, Department witness Johnson also recommended that the Commission refer the question of the Company's prudence with respect to its handling of the outage to a contested hearing.⁸⁶⁸

637. Riverside was in service during the early part of 2025.⁸⁶⁹

638. Company witness Nicholas Detmer testified that Riverside was included in the 2025-2026 capacity auction and generated capacity revenues of approximately \$26 million during that period.⁸⁷⁰ Department witness Mark Johnson acknowledges this fact.⁸⁷¹

639. Mr. Johnson testified that the 2025-2026 capacity revenues would be transferred to the Company's customers through the Company's established capacity tracker.⁸⁷²

640. Mr. Detmer also testified that Riverside will also be included in the 2026/2027 capacity auction, though the amount of revenue that will be generated is unknown.⁸⁷³

641. Company witness Amy Liberkowski testified that she was aware of no ratemaking principle that would support a resolution whereby Riverside was removed from the Company's revenue requirement, thereby prohibiting the company from recovering the costs of the plant, at the same time capacity revenues generated by Riverside were passed on to customers through the capacity tracker.⁸⁷⁴

642. Minnesota law establishes that a property need not be generating electricity to be "used and useful" if that property is providing some benefit to customers.⁸⁷⁵

643. The generation of capacity revenues is a benefit to the Company's customers, as those revenues are returned to customers through the Company's capacity tracker.⁸⁷⁶

644. The Administrative Law Judge recommends that the Commission determine that Riverside remains "used and useful" while it is offline due to its generation of capacity revenues, and deny the Department's request to remove Riverside from the Company's

⁸⁶⁸ Ex. DOC-2 at 29 (Johnson Surrebuttal).

⁸⁶⁹ Ex. Xcel-16 at 23 (Liberkowski Rebuttal).

⁸⁷⁰ Ex. Xcel-82 at 13-14 (Detmer Rebuttal).

⁸⁷¹ Ex. DOC-1 at 48 (Johnson Direct).

⁸⁷² Ex. DOC-1 at 48 (Johnson Direct).

⁸⁷³ Ex. Xcel-82 at 14 (Detmer Rebuttal).

⁸⁷⁴ Ex. Xcel-16 at 23-24 (Liberkowski Rebuttal).

⁸⁷⁵ *Senior Citizens Coalition of Northeastern Minnesota v. Minnesota Public Utilities Comm'n*, 355 N.W.2d 295, 300 (Minn. 1984)

⁸⁷⁶ Ex. DOC-1 at 48 (Johnson Direct).

revenue requirement. Alternatively, if the Commission determines that Riverside is not “used and useful” during the period it is offline, the Administrative Law Judge recommends that the Company be permitted to recover its property tax and depreciation expense, and that it be allowed to retain capacity revenues generated during the time Riverside is removed from the Company’s Revenue Requirement.

645. The Administrative Law Judge recommends that the Commission take no action on the Department’s request that this matter be referred to a contested case at this time because this request is premature. Stakeholders have had no opportunity to comment on the need for, and potential scope of, such a contested case.

n. Rate Case Expenses

646. The Company forecasted rate case expense in this case based on actual historical rate case expense from the most recent 2022-2024 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 over three years (2025-2027).⁸⁷⁷

647. The OAG proposed the Commission disallow recovery of 50 percent of rate case expense to reflect a 50/50 sharing of costs between shareholders and ratepayers.⁸⁷⁸ The OAG reasoned that it is “unreasonable for ratepayers to bear 100 percent of the burden of rate case expenses when the Company’s shareholders receive the benefits from the Company’s efforts to increase its rates.”⁸⁷⁹ Rate cases benefit shareholders by allowing the utility to increase its revenue requirement, which supports the utility’s ability to issue consistent dividends.⁸⁸⁰ In addition, specific expenses directly benefit shareholders, such as the utility’s cost-of-capital and return-on-equity witnesses that benefit shareholders by arguing for a higher return.⁸⁸¹

648. The OAG also argued that requiring a 50/50 split of rate case expense incentivizes efficiency and cost containment. The OAG argued that the Company chooses when to file a rate case and what issues to pursue, such that “the utility has discretion over the total cost incurred.”⁸⁸² The OAG also stated that if Xcel is allowed to recover all of its rate case costs from ratepayers, Xcel has no incentive to manage them. The OAG stated

⁸⁷⁷ 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).

⁸⁷⁸ Ex. OAG-5 at 15-22 (Lee Direct); Ex. OAG-7 at 13-16 (Lee Surrebuttal).

⁸⁷⁹ Ex. OAG-5 at 17 (Lee Direct).

⁸⁸⁰ Ex. OAG-5 at 17 (Lee Direct).

⁸⁸¹ Ex. OAG-5 at 18 (Lee Direct).

⁸⁸² Ex. OAG-5 at 16-17 (Lee Direct).

that Xcel’s rate case expense has continued to increase significantly, increasing 23 percent from the Company’s 2013 case to its 2015 case and 40 percent in the Company’s last case.⁸⁸³

649. The OAG also explained that other jurisdictions limit recovery of rate case expense, requiring a sharing between shareholders and customers.⁸⁸⁴ For example, the New Hampshire Public Utilities Commission requires a bidding process if rate case expense is estimated to be more than \$10,000.⁸⁸⁵ Both New Jersey and Missouri have ordered that only 50 percent of rate case expenses may be recovered from ratepayers, recognizing that shareholders benefit from rate cases.⁸⁸⁶ The Connecticut legislature has gone further and prohibited the recovery of any rate case expenses.⁸⁸⁷

650. The OAG recommended the Commission should follow these other states and recognize that splitting rate case expense between ratepayers and shareholders is both fairer and promotes efficiency. To accomplish this, the Commission should remove \$819,986 from both the 2025 test year and the 2026 plan year.⁸⁸⁸

651. The Company responded by noting that the purpose of rate case proceedings is not to increase the revenue requirement in order to issue dividends for the benefit of shareholders,⁸⁸⁹ 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.”⁸⁹⁰ 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 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.⁸⁹¹

⁸⁸³ Ex. OAG-7 at 16 (Lee Surrebuttal).

⁸⁸⁴ Ex. OAG-5 at 19-20 (Lee Direct).

⁸⁸⁵ Ex. OAG-5 at 19 (Lee Direct) (citing N.H. Code Admin. R. PUC 1905.04 (2024)).

⁸⁸⁶ Ex. OAG-5 at 20-21, Schedules 6 and 7 (Lee Direct) (attaching orders of the New Jersey Board of Public Utilities and Missouri Public Utilities Commission).

⁸⁸⁷ Ex. OAG-5, Schedule 9 (Lee Direct) (Conn. Gen. Stat. Ann. § 16-243p).

⁸⁸⁸ Ex. OAG-7 at 13 (Lee Surrebuttal).

⁸⁸⁹ Ex. OAG-5 at 17 (Lee Direct) (“Rate cases benefit shareholders by enabling the utility to increase the revenue requirement it collects from ratepayers, which supports the utility’s ability to issue consistent dividends.”); Ex. Xcel-19 at 44 (Halama Rebuttal).

⁸⁹⁰ Ex. DOC-1 at 5 (Johnson Direct).

⁸⁹¹ 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.”).

652. Additionally, the Company discussed the fact 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 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.⁸⁹² 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 twenty four witnesses filing intervenor direct and twenty two witnesses filing intervenor surrebuttal on a range of issues.⁸⁹³

653. The Company also explained that actual recent experience demonstrated how the factors beyond the Company's own costs and outside of the Company's control impact rate case expense. For the 2022-2024 electric 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.⁸⁹⁴

654. The Company explained efforts it takes to maintain reasonable rate case expense through disciplined budgeting and cost oversight consistent with all customer-funded operations.⁸⁹⁵ In response to the OAG's suggestion that the Company might be overpaying for legal and consulting services, Xcel Energy explained 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 Commission has consistently recognized the reasonableness of the Company's outside legal and expert witness expenses.⁸⁹⁶

⁸⁹² See Ex. Xcel-19 at 45-46 (Halama Rebuttal).

⁸⁹³ See Ex. Xcel-19 at 46 (Halama Rebuttal).

⁸⁹⁴ Ex. Xcel-19 at Schedule 5 (Halama Rebuttal) (Xcel Energy's Response to OAG IR No. 1009).

⁸⁹⁵ Ex. Xcel-19 at 45 (Halama Rebuttal).

⁸⁹⁶ Ex. Xcel-19 at 46-47 (Halama Rebuttal).

655. The Company discussed the fact that the Commission has consistently allowed utilities to recover reasonable and prudent rate case expenses through general rate cases.⁸⁹⁷ 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.”⁸⁹⁸

656. The Administrative Law Judge recommends the Commission approve recovery of the Company’s full forecasted rate case expense in this case. The Commission has consistently allowed utilities to recover reasonable and prudent rate case expenses through general rate cases as a necessary cost of regulated utility operations.⁸⁹⁹ The Company has demonstrated the reasonableness of the forecasted rate case expense and proposed amortization in this case. These expenses are a necessary component of regulated service, are incurred for the benefit of customers and the regulatory system as a whole, and

⁸⁹⁷ See *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*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 25 (June 9, 2014) (“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.”)

⁸⁹⁸ *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*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 4 (July 17, 2023).

⁸⁹⁹ See *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*, Docket No. G008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 25 (June 9, 2014) (“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.”)

should be recovered consistent with Minnesota cost-of-service ratemaking principles and Commission precedent.

o. Time-of-Use Rate Implementation Costs

657. On December 22, 2023, in Docket No. E002/M-23-524, the Company filed its proposal to implement a time-of-use (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 Docket No. E002/GR-21-630.⁹⁰⁰

658. 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.⁹⁰¹ 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 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

⁹⁰⁰ *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program*, 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*, 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).

⁹⁰¹ *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).

requirements.⁹⁰² The Company filed its 90-day compliance filing on August 14, 2025,⁹⁰³ which the Commission accepted by order dated February 23, 2026.⁹⁰⁴

659. As a result of the timing of the Commission's decisions regarding the residential TOU rate, 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 Mr. 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-23-524.⁹⁰⁵ However, at the time of Supplemental Direct Testimony, the Commission's written Order on the subject had not yet been issued.

660. The Commission issued the written Order for the Residential TOU design on May 15, 2025.⁹⁰⁶ 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."⁹⁰⁷ 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

⁹⁰² *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).

⁹⁰³ *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.")

⁹⁰⁴ *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 TARIFF MODIFICATIONS, APPROVING COMPLIANCE PLAN, AND SETTING ADDITIONAL REQUIREMENTS FOR RESIDENTIAL TIME-OF-USE RATE IMPLEMENTATION (Feb. 23, 2026).

⁹⁰⁵ Ex. Xcel-18 at n.2 (Halama Supplemental Direct).

⁹⁰⁶ *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).

⁹⁰⁷ *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).

2025 revenue deficiency by approximately \$20,000 and increased the 2026 deficiency by approximately \$329,000.⁹⁰⁸

661. In surrebuttal, the Department agreed with Xcel’s proposed rebuttal adjustment to the TOU rate implementation budget and proposed revenue deficiency increases.⁹⁰⁹

662. The OAG recommended the Commission disallow recovery of all TOU-related capital costs, reasoning first, that it was not clear that the costs added in rebuttal were incremental to costs that had already been included in the Company’s rate case and second, that the Company had not “shown that these costs are prudent and will be used and useful in utility service.”⁹¹⁰

663. Based on information provided in discovery, approximately \$1.4 million of the TOU-related capital costs are for Xcel Energy’s development of a new Rate Comparison Tool.⁹¹¹ The OAG explained that contrary to Xcel Energy’s implication that the Rate Comparison Tool arose from the Commission’s TOU order, the Commission never asked Xcel to develop the tool; Xcel decided to develop this tool on its own.⁹¹² What the tool will even do, much less how many people will ever use it, remains speculative. Furthermore, the OAG reasoned, the Rate Comparison Tool is not a TOU-specific tool—if it is ultimately developed, it will be available for all Xcel customers.⁹¹³ Finally, the OAG concluded that the in-service date for the tool remains uncertain, noting that a 2026 implementation is doubtful because the tool was only beginning its “design phase” as of October 2025.⁹¹⁴

664. The OAG also pointed out that the Company announced it was “developing” the Rate Comparison Tool in August 2024 long before the residential TOU rate was approved in May 2025 and two months before Xcel filed the instant rate request on November 1, 2024.⁹¹⁵ The OAG concludes as a result, the capital cost of developing the tool therefore did not and could not have arisen from the Commission’s TOU order. This fact, in turn, suggests that these costs are not incremental—there is a significant possibility

⁹⁰⁸ Ex. Xcel-19 at 27-29 and Schedules 3A and 3B (Halama Rebuttal).

⁹⁰⁹ Ex. DOC-2 at 31-32 and Schedule 1 (Johnson Surrebuttal); *see also In the Matter of the Petition of Xcel Energy for Approval of Residential Time of Use Rate Design*, Docket No. E002/M-23-524, Ex Parte Communication (Dec. 30, 2025).

⁹¹⁰ Ex. OAG-3 at 33, 39-40 (Hinderlie Surrebuttal).

⁹¹¹ Ex. OAG-3, KH-S-4 at 4 (Hinderlie Surrebuttal) (Xcel Energy’s Response to OAG IR No. 1051).

⁹¹² Ex. OAG-3 at 36 (Hinderlie Surrebuttal).

⁹¹³ Ex. OAG-3 at 37 (Hinderlie Surrebuttal).

⁹¹⁴ Ex. OAG-3 at 37-38 (Hinderlie Surrebuttal).

⁹¹⁵ Ex. OAG-3 at 34 (Hinderlie Surrebuttal).

that they were already included in the Company's initial filing and adding them in rebuttal would result in double counting these capital costs.⁹¹⁶

665. The OAG further reasoned even if the newly added costs of developing the Rate Comparison Tool were not duplicative, the tool may not ultimately be used and useful in providing utility service, and Xcel Energy has failed to provide any evidence to the contrary.⁹¹⁷ During the TOU docket, parties recommended shadow billing to give customers a clear side-by-side comparison of their actual bills and alternative-rate bills, but Xcel Energy instead proposed an online "Rate Analysis/Comparison Tool" that estimated future bills. The Commission expressed concerns about accessibility and accuracy and ordered Xcel Energy to assess the feasibility of shadow billing.⁹¹⁸ Based on these concerns, the OAG recommended the Commission deny \$171,810 of TOU-related capital costs in the 2025 test year and \$1,218,381 in the 2026 plan year that Xcel attributes to the Rate Comparison Tool.

666. Beyond the Rate Comparison Tool, the OAG argued that the Company had not provided sufficient explanation or support for any of its added TOU-related capital costs.⁹¹⁹ The Company simply alleged that it will incur these costs, without providing a reliable basis upon which to evaluate when or whether they will be incurred or whether they are reasonable. As a result, the OAG recommended the Company's request to recover \$659,641 in 2025 and \$2,458,859 in 2026 should be denied. If TOU-related capital costs do exist, the OAG reasoned, the Company can petition to recover them in its next rate case, assuming it demonstrates at that time that recovering them would be just and reasonable.⁹²⁰

667. In response, the Company explained that the capital costs included in rebuttal related to the TOU program are incremental to other costs proposed for recovery in this case. As explained in the Rebuttal Testimony of Mr. Halama, all of the capital costs that were added in rebuttal are new, incremental costs to those that had been included in the Company's initial filing: "Our initial rate case proposal included the O&M costs necessary to implement the rate but did not include the capital costs related to technical implementation. Development of a technical implementation plan was completed after the Commission approved our [TOU] rate proposal, which occurred after our initial filing in this rate case."⁹²¹ In response to discovery, the Company further affirmed that the costs

⁹¹⁶ Ex. OAG-3 at 34 (Hinderlie Surrebuttal).

⁹¹⁷ Ex. OAG-3 at 36-38 (Hinderlie Surrebuttal).

⁹¹⁸ Ex. OAG-3 at 33, 36-38 (Hinderlie Surrebuttal).

⁹¹⁹ Ex. OAG-3 at 39 (Hinderlie Surrebuttal).

⁹²⁰ Ex. OAG-3 at 39-40 (Hinderlie Surrebuttal).

⁹²¹ Ex. Xcel-19 at 27-28 (Halama Rebuttal).

incorporated in rebuttal are not duplicative of any costs already included in rates or proposed for recovery in this case.⁹²²

668. The Company further explained that the Commission ordered Xcel Energy to implement the TOU rate,⁹²³ and detailed how the proposed capital costs reflect necessary capital costs to comply with the Commission’s order in Docket No. E002/M-23-524. The Company explained that the capital costs are related to the technical implementation work including billing system configuration, software purchases, and work to develop and implement tools designed to provide customers with information and analysis to compare their energy bills under different rate options tailored to their specific energy usage.⁹²⁴ Detailed planning and development of the capital budget for TOU rate implementation was not completed until after the Commission’s issued its order approving the Residential TOU rate because the technical implementation work was dependent on what was approved by the Commission with respect to rate designs, billing, and other requirements.⁹²⁵

669. The Company also responded to the OAG’s suggestion that implementation of a Rate Comparison Tool instead of shadow billing was inconsistent with the Commission’s order implementing the TOU rate. The Commission’s TOU order unambiguously directed the Company to implement the approved TOU rate without shadow billing. Rather than requiring shadow billing at launch, the order instructs the Company to “evaluate the feasibility and cost of implementing shadow billing” as a potential future modification and to report on that evaluation in a filing due 15 months after implementation of the new TOU rate.⁹²⁶

⁹²² Ex. OAG-3 at KH-S-4 (Hinderlie Surrebuttal) (Xcel Energy’s Response to OAG IR No. 1051).

⁹²³ Ex. OAG-3 at 39 (Hinderlie Surrebuttal).

⁹²⁴ Ex. Xcel-19 at 27-29 (Halama Rebuttal).

⁹²⁵ Ex. Xcel-19 at 27-28 (Halama Rebuttal). As the OAG acknowledged, stakeholders in Docket No. E002/M-23-524 disagreed regarding “various aspects of the program including whether the program should be ‘opt-in’ or ‘opt-out,’ the specific times and rates of the TOU rate, and how the program should be marketed, evaluated, and tailored to set rate participants up for success in reducing their contributions to peak loads and bills.” Ex. OAG-3 at 30 (Hinderlie Surrebuttal).

⁹²⁶ *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) (Order Point No. 10 and Order Point No. 13). In directing the Company to identify the feasibility and cost of implementing shadow billing in a report to be filed 15 months after implementation of the new TOU rate, the Commission clearly did not intend shadow billing to be a component of the initial TOU rate implementation.

670. In responding to the OAG’s assertion that implementation of the Rate Comparison Tool unreasonable and may not provide value to customers, the Company also explained that an effective opt-in TOU rate requires a tool that allows customers to compare rates and understand the potential impacts of participation.⁹²⁷ Implementing an opt-in TOU rate without providing customers with such a comparison tool is not reasonable, as customers cannot make informed decisions about whether to opt in or not without a clear understanding of how the rate would affect their bills. While the Commission did not explicitly mandate the creation of this tool, it approved the residential TOU rate with the expectation that customers would have the information necessary to evaluate the rate.

671. The Company also responded to the OAG’s claim that the Rate Comparison Tool will not be used and useful, explaining that the tool would be launched to current TOU pilot participants in the first quarter of 2026 and all customers in the second quarter of 2026.⁹²⁸ Given the plan to implement the Rate Comparison Tool for all residential customers in the second quarter of 2026 in coordination with the launch of the Commission-ordered TOU Rate, this tool will be used and useful in the 2026 plan year in this case. The availability of the tool to all Residential customers also aligns with the Commission having ordered an *opt-in* TOU rate available to all Residential customers.

672. Finally, in response to the OAG’s claim that the remaining TOU-related capital costs are “too uncertain to reasonably include in rates at this time,”⁹²⁹ the Company referenced to the support that had been provided both in this proceeding and in Docket No. E002/M-23-524, where the Company provided details related to the timing of implementation, the customer enrollment process, space heating rates, the integration of net metering customers, and the tools that will be available to customers; a detailed communication plan including plans for customer care training, engagement with various

⁹²⁷ A number of parties filing comments in Docket No. E002/M-23-524 agreed that there needed to be some mechanism for customers to compare rates and understand the potential impacts of opting into the TOU rate.

⁹²⁸ Ex. OAG-3 at 37 (Hinderlie Surrebuttal); *see also 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 10 (Aug. 14, 2025) (“The Rate Comparison Tool will be available to customers on the current TOU pilot rate (MN Flex Pricing Pilot) in the first quarter of 2026 as part of the targeted communication to this group. The tool will be more widely available in the 2nd quarter of 2026 in coordination with the launch of the TOU rate. The Rate Comparison Tool will provide customers with a cost-based comparison of their bill on a rate other than what they are currently enrolled in. If a customer wishes to change to a different rate for which they are eligible, they may initiate that request digitally within the tool or connect with the Contact Center.”).

⁹²⁹ Ex. OAG-3 at 39 (Hinderlie Surrebuttal).

customer groups, and marketing of rates.⁹³⁰ Further, in Rebuttal Testimony in this case, the Company detailed the technical implementation work that would be completed to implement the Commission’s TOU Rate Order including setting up the three-part rate in the billing system, developing tools to analyze rate options and provide customers with self-service enrollment options, developing and implementing programs and changes to support the new rates, and purchasing and implementing software needed to support the new programs.⁹³¹ Finally, the Company noted that while its forecasted capital costs reflect a reasonable projection of necessary costs to be incurred through 2026 to comply with the Commission’s decisions in Docket No. E002/M-23-524, the capital true-up mechanism proposed in this case protects customers if actual capital costs in either 2025 or 2026 are lower than the level approved by the Commission.⁹³²

673. Based on the record developed in this case, the Administrative Law Judge recommends the Commission approve recovery of the Company’s TOU costs as proposed, including the capital costs proposed for recovery in rebuttal. The Commission ordered Xcel Energy to implement the TOU rate, which is the reason the Company must incur these costs. Further, the record in this case demonstrates the costs proposed reflect necessary, incremental capital costs to comply with the Commission’s decisions in Docket No. E002/M-23-524.

p. Extreme Heat/Poor Air Quality Reconnection Program

674. After this rate case was initiated, in response to a January 13, 2025 Order in Docket No. E002/M-24-27, the Company developed a plan to use Advanced Metering Infrastructure (AMI) to suspend disconnections during periods of poor air quality, and to reconnect previously disconnected customers during extreme heat and poor air quality (the “Reconnection Program”).⁹³³ Xcel Energy filed its proposed plan in compliance with the

⁹³⁰ *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 (Aug. 14, 2025). The Commission accepted the Company’s 90-day compliance filing by Order issued February 23, 2026. *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 TARIFF MODIFICATIONS, APPROVING COMPLIANCE PLAN, AND SETTING ADDITIONAL REQUIREMENTS FOR RESIDENTIAL TIME-OF-USE RATE IMPLEMENTATION (Feb. 23, 2026).

⁹³¹ Ex. Xcel-19 at 27-29 (Halama Rebuttal).

⁹³² Under the proposed capital true-up, the Company will make refunds if its aggregate capital-related revenue requirements in either 2025 or 2026 fall below the Commission-approved capital-related revenue requirements. Ex. Xcel-15 at 29 (Liberkowsky Direct).

⁹³³ This plan was developed in response to the Commission’s January 13, 2025 ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS in Docket No. E002/M-24-27, which required Xcel to propose a plan in its 2024 safety, reliability, and service

Commission's Order on April 1, 2025, detailing preliminary estimates of some of the costs the Company anticipated would need to be incurred to implement the Reconnection Program while noting the uncertainty in those cost assumptions and that other costs would need be incurred to implement the plan.⁹³⁴ The Company proposed a 16-month implementation timeframe from the date of the Commission's Order approving the plan to allow for necessary system upgrades and customer messaging.⁹³⁵

675. On July 25, 2025, over eight months after this rate case was filed, following record development on the Company's proposed Reconnection Program plan, the Commission issued an Order in Docket No. E002/M-25-27 approving the Company's Reconnection Program but requiring Xcel Energy to implement the Program effective May 1, 2026.⁹³⁶ The Order also directed the Company to consult with the Minnesota Department of Health and the Minnesota Pollution Control Agency to refine the details of the Reconnection Program implementation, including the specific triggers for reconnection and disconnection.⁹³⁷

676. In response to the Commission's Order and the accelerated timeline ordered for implementation of the Reconnection Program, the Company developed a scope of work and cost estimates and incorporated the forecasted incremental costs to be incurred in 2025

quality report due April 1, 2025, to restore power for involuntarily disconnected customers with AMI during a heat advisory, excessive heat warning, or when high air quality index alerts have been issued. *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 at Order Points Nos. 24 and 32 (Jan. 13, 2025).

⁹³⁴ *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, Xcel Energy Service Quality Annual Report, Part III: January 13, 2025 Order Compliance at 100-101 (Apr. 1, 2025) ("In this section we provide preliminary estimates of some of those costs to assist the Commission in weighing the benefits of implementing these plans against the costs.").

⁹³⁵ *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, Xcel Energy Service Quality Annual Report, Part III: January 13, 2025 Order Compliance at 101 (Apr. 1, 2025) ("The work listed is currently estimated to take approximately 72 weeks (or 16 months) once an Order is issued requiring these actions to be taken.").

⁹³⁶ *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, ORDER (July 25, 2025).

⁹³⁷ *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, ORDER at Order Points Nos. 4 and 5 (July 25, 2025).

and 2026 to comply with the Commission's July 25, 2025 Order in the rebuttal revenue requirement in this case.⁹³⁸

677. In surrebuttal testimony, the OAG recommended that the Commission deny recovery of all costs related to the Reconnection Program in this proceeding, concluding that Xcel had not shown the costs to be accurately forecasted or prudent to incur.⁹³⁹

678. In support of its recommendation, the OAG questioned the accuracy and reasonableness of the Company's forecasted Reconnection Program costs, noting that during notice and comment, the OAG was concerned about Xcel's cost estimates for the Reconnection Program. The Company estimated that the program would cost \$520,000, but provided very little support for this estimate, either in its filings or in response to discovery.⁹⁴⁰ The OAG further concluded that the Company failed to support the reasonableness of the assumptions used to estimate costs in Docket No. E002/M-25-27. For example, "Xcel's estimate of reconnecting 19,000 customer was almost 8,000 customers higher than the highest level of disconnected customers reported by Xcel in any month in 2024."⁹⁴¹ The OAG maintains that Xcel has not better supported its claimed costs in this rate case and emphasizes that the amount requested is now even higher.⁹⁴²

679. The OAG noted that the Company's proposed costs for the Reconnection Program in this case are many times greater than what Xcel Energy had represented in the docket in which this program was approved, and that the Company did not provide any explanation for the massive increase in either rebuttal testimony or discovery.⁹⁴³ The OAG sent discovery requesting an explanation for the cost increase and Xcel responded that the costs claimed in the rate case are the same as the costs Xcel claimed in Docket No. E002/M-25-27, which is not correct.⁹⁴⁴

680. The OAG also questioned whether the costs added in rebuttal for the Reconnection Program in this case were incremental to costs already proposed for recovery.⁹⁴⁵ In response to OAG's question about whether these costs were incremental to

⁹³⁸ Ex. Xcel-19 at 19-20 (Halama Rebuttal); Ex. Xcel-71 at 18-19, 33-34 (Martin Rebuttal).

⁹³⁹ Ex. OAG-3 at 40-50 (Hinderlie Surrebuttal).

⁹⁴⁰ Ex. OAG-3 at 42-43 (Hinderlie Surrebuttal).

⁹⁴¹ Ex. OAG-3 at 43 (Hinderlie Surrebuttal).

⁹⁴² Ex. OAG-3 at 44 (Hinderlie Surrebuttal).

⁹⁴³ Ex. OAG-3 at 46-47 (Hinderlie Surrebuttal). *Compare* Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Energy's Response to OAG IR No. 1061) with *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, Xcel Energy Reply Comments at 15 (June 3, 2025).

⁹⁴⁴ Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Energy's Response to OAG IR No. 1061).

⁹⁴⁵ Ex. OAG-3 at 43-44 (Hinderlie Surrebuttal).

those in the rate case, Xcel stated that they were but did not provide more specific information.⁹⁴⁶

681. The Company explained in Docket No. E002/M-25-27 that cost assumptions and estimates provided in that proceeding were preliminary, that not all costs had been forecasted, and that the Company had never created this kind of framework in its existing systems.⁹⁴⁷ As Xcel Energy explained 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 our predictions and cost estimates.”⁹⁴⁸

682. The Company was also clear in Docket No. E002/M-25-27 that expediting implementation of the Reconnection Program would come at a cost.⁹⁴⁹ Thus, the Company noted, it is not a surprise that the costs related to implementation of the Reconnection Program are, in fact, higher than the cost estimates provided in that proceeding. Further, the Commission “approved Xcel’s plan to institute this program with significant modifications from its original proposal.”⁹⁵⁰

683. In Docket No. E002/M-25-27, the OAG advocated for expedited implementation of the Reconnection Program.⁹⁵¹ The Company reasoned that it was disingenuous for the OAG to now suggest that the associated cost impacts are unreasonable or unexpected. In ordering the Company to implement the Reconnection Program, the

⁹⁴⁶ Ex. OAG-3 at 44 (Hinderlie Surrebuttal).

⁹⁴⁷ *In the Matter of Northern States Power Co. d/b/a Xcel Energy’s 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, Xcel Energy Reply Comments at 15 (June 3, 2025).

⁹⁴⁸ *See In the Matter of Northern States Power Co. d/b/a Xcel Energy’s 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, Xcel Energy Service Quality Annual Report, Part III: January 13, 2025 Order Compliance (Apr. 1, 2025); Xcel Energy Reply Comments (June 3, 2025).

⁹⁴⁹ *See* Minnesota Public Utilities Commission Agenda Meeting at 4:07:10-4:12:40, available at https://minnesotapuc.granicus.com/player/clip/2559?view_id=2&redirect=true (Jul. 17, 2025) (discussing the fact that accelerating implementation to May 1, 2026 was feasible but would increase the costs of the Reconnection Program).

⁹⁵⁰ Ex. OAG-3 at 41 (Hinderlie Surrebuttal).

⁹⁵¹ *In the Matter of Northern States Power Co. d/b/a Xcel Energy’s 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, OAG Letter (July 16, 2025) (supporting decision options 9 and 10, to require implementation effective May 1, 2026); OAG Comments at 2 (May 9, 2025) (recommending plan implementation on an expedited timeline).

Commission acknowledged that the program would require the Company to incur costs, that the total amount of those costs were not known at the time of the Commission's decision, and that accelerating implementation would increase those costs.⁹⁵² The Commission nevertheless concluded that the Company should move forward with implementation on the expedited schedule.

684. The Company explained it cannot implement the Reconnection Program as directed by the Commission on the timeline ordered without incurring the capital and O&M costs in 2025 and 2026 as reflected in the Company's rebuttal revenue requirement. Further, while the forecasted capital costs included in the Company's rebuttal revenue requirements reflect a reasonable projection of costs to be incurred through 2026 to comply with the Commission's July 25, 2026 Order, the capital true-up mechanism proposed in this case provides protection to customers if actual capital costs in either 2025 or 2026 are lower than the level approved by the Commission.⁹⁵³

685. In response to the OAG's questions regarding the Company's cost estimates,⁹⁵⁴ Xcel Energy explained in response to discovery, "The 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."⁹⁵⁵ 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."⁹⁵⁶

⁹⁵² *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27, ORDER (July 25, 2025); see also Minnesota Public Utilities Commission Agenda Meeting at 4:07:10-4:12:40, available at https://minnesotapuc.granicus.com/player/clip/2559?view_id=2&redirect=true (July 17, 2025) (discussing the fact that accelerating implementation to May 1, 2026 would increase the costs of the Reconnection Program).

⁹⁵³ Under the proposed capital true-up, the Company will make refunds if its aggregate capital-related revenue requirements in either 2025 or 2026 fall below the Commission-approved capital-related revenue requirements. Ex. Xcel-15 at 29 (Liberkowsky Direct).

⁹⁵⁴ Ex. OAG-3 at 43 (Hinderlie Surrebuttal).

⁹⁵⁵ Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Response to OAG IR 1061).

⁹⁵⁶ *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, 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

686. In responding to the OAG's assertion that the costs proposed for recovery might not be incremental,⁹⁵⁷ the Company explained the costs that were added to the 2025-2026 MYRP were new costs incorporated in rebuttal in response to the Commission's July 25, 2025 Order.⁹⁵⁸ The Company also confirmed, in response to discovery, that the proposed costs were incremental to those costs already included in supplemental direct.⁹⁵⁹ No costs related to the extreme heat and air quality reconnection program were included in the initially filed or supplemental direct 2025-2026 revenue requirements in this case because at the time the Company filed this case, it had not yet been ordered to develop such a plan, let alone to implement in during the 2026 plan year. The Commission's decision to require implementation of the Reconnection Program effective May 1, 2026 was issued July 25, 2025 and the Company incorporated these new costs in its rebuttal filed in October, 2025. It is unclear what additional information the OAG believes could be provided to prove the absence of these costs from the Company's initially filed MYRP revenue requirements.

687. The Administrative Law Judge recommends the Commission approve recovery of the Company's Reconnection Program costs as proposed in this case. The Company should not be disallowed recovery of costs required to implement an undertaking the Commission expressly permitted and directed it to pursue. The record supports that the Company relied on sound planning to comply with all applicable Commission directives related to implementation of the Reconnection Program.

q. Property Tax

688. The Company requested recovery of its forecasted property tax expense for the 2025 test year and 2026 plan year.

689. The Company's initial forecast for 2025 property tax expense, at the State of Minnesota electric jurisdiction level, was \$182.1 million.⁹⁶⁰ During the pendency of this case, the Company updated its forecast to reflect new developments and data: the Company resolved its 2025 property tax valuation with the Minnesota Department of Revenue (DOR); it received its valuations from North Dakota and South Dakota; and the actual 2024

meters in 2025 and accounts for the possibility that the number of disconnected customers in future years could be higher than 2024.

⁹⁵⁷ Ex. OAG-3 at 43-44 (Hinderlie Surrebuttal).

⁹⁵⁸ Ex. Xcel-19 at 19-20 (Halama Rebuttal).

⁹⁵⁹ Ex. OAG-3, Schedule 5 (Hinderlie Surrebuttal) (Xcel Energy Response to OAG IR 1061).

⁹⁶⁰ Ex. Xcel-51 at 3 (Kowalowski Direct). All property tax expense figures hereinafter are similarly at the State of Minnesota electric jurisdiction level.

effective local tax rate was determined.⁹⁶¹ The Company's updated forecast for 2025 was \$184.2 million.⁹⁶²

690. For 2026, the Company's initial forecast for property tax expense was \$194.3 million.⁹⁶³ As with the 2025 forecast, the 2026 forecast was updated to include the above-mentioned new developments and data.⁹⁶⁴ The Company's updated 2026 forecast was \$195.4 million.⁹⁶⁵

691. The only disputed issue relating to the Company's property tax expense is the baseline amount of property tax expense to be used for 2025 and 2026 (as noted *supra* these amounts will later be trued-up). The Company proposed to use its updated forecasts as the baseline.⁹⁶⁶ Even though the baseline amounts will be trued-up, it is still important that they be reasonably accurate in order to avoid wide swings in rates.⁹⁶⁷

692. The Department opposed the use of the Company's forecasted amounts as the baseline for 2025 and 2026.⁹⁶⁸ It advocated that the 2025 and 2026 baseline should be based on a 2 percent annual increase over the 2024 actual property tax expense; the result would be that the 2025 baseline would be \$178.9 million and the 2026 baseline would be \$182.4 million.⁹⁶⁹

693. The Department argued that the Company did not support its updated forecast for 2025 and 2026.⁹⁷⁰ But the Company provided detailed testimony explaining its forecast methodology and the data inputs it uses.

694. Specifically, the Company explained 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.⁹⁷¹ The Company further explained that 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

⁹⁶¹ Ex. Xcel-52 at 3-5 (Kowalowski Rebuttal).

⁹⁶² Ex. Xcel-52 at 3 (Kowalowski Rebuttal).

⁹⁶³ Ex. Xcel-51 at 3 (Kowalowski Direct).

⁹⁶⁴ Ex. Xcel-52 at 5-6 (Kowalowski Rebuttal).

⁹⁶⁵ Ex. Xcel-52 at 3 (Kowalowski Rebuttal).

⁹⁶⁶ Ex. Xcel-52 at 5-6 (Kowalowski Rebuttal).

⁹⁶⁷ *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*, Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 63 (Mar. 31, 2023).

⁹⁶⁸ Ex. DOC-23 at 9-11 (Jones Direct).

⁹⁶⁹ Ex. DOC-23 at 11 (Jones Direct); Ex. Xcel-52 at 10 (Kowalowski Rebuttal).

⁹⁷⁰ Ex. DOC-23 at 9 (Jones Direct).

⁹⁷¹ Ex. Xcel-51 at 9-22 (Kowalowski Direct); Ex. Xcel-52 at 13 (Kowalowski Rebuttal).

year to year, depending on inputs that the Company cannot control, the Company's forecast methodology uses the most recent available data.⁹⁷² 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.⁹⁷³

695. The Department did not identify any specific shortcomings in the Company's methodology. It is reasonable to conclude that the Company provided ample support for its updated forecasts.

696. The Department's main argument is that the Company has historically overestimated its property expense in recent years, and that the "historical trends" of the Company's past property tax expense should be the basis for forecasting the 2025 and 2026 property tax expense.⁹⁷⁴ The Department asserted that its proposed 2 percent annual increase was based on its review of the "historical trends."⁹⁷⁵

697. The Department's arguments on this point are without basis because there is no discernible "trend" in the Company's property tax expense over the past few years.⁹⁷⁶ Table 2 and Chart 2 in Department witness Jones' Direct Testimony set forth the year-over-year percentage change for the Company's property taxes for the last few years.⁹⁷⁷ They show that the property taxes went up 2.5 percent from 2020 to 2021, down 2.79 percent from 2021 to 2022, down 5.18 percent from 2022 to 2023, and up 6.35 percent from 2023 to 2024.⁹⁷⁸ These ups and downs do not demonstrate any sort of pattern or trend.⁹⁷⁹ There is no conclusion that can be drawn from looking at the changes from year to year.⁹⁸⁰

698. Moreover, the Department's recommended 2 percent increase has no apparent connection to the data the Department cited.⁹⁸¹ The Department stated that the 2 percent increase "was chosen as a reasonable midpoint among the range of recent year over year changes."⁹⁸² But it is not the mathematical midpoint and the Department did not explain how it was derived. It appears to be an arbitrary figure.

⁹⁷² Ex. Xcel-51 at 10 (Kowalowski Direct); Ex. Xcel-52 at 13 (Kowalowski Rebuttal).

⁹⁷³ Ex. Xcel-51 at 10-11 (Kowalowski Direct).

⁹⁷⁴ Ex. DOC-23 at 9-11 (Jones Direct).

⁹⁷⁵ Ex. DOC-23 at 11 (Jones Direct).

⁹⁷⁶ Ex. Xcel-52 at 15 (Kowalowski Rebuttal).

⁹⁷⁷ Ex. DOC-23 at 9-10 (Jones Direct).

⁹⁷⁸ Ex. DOC-23 at 9-10 (Jones Direct).

⁹⁷⁹ Ex. Xcel-52 at 15 (Kowalowski Rebuttal).

⁹⁸⁰ Ex. Xcel-52 at 15 (Kowalowski Rebuttal).

⁹⁸¹ Ex. Xcel-52 at 15 (Kowalowski Rebuttal).

⁹⁸² Ex. DOC-23 at 11 (Jones Direct).

699. The Company addressed 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.⁹⁸³ The Company explained that from 2020-2023, 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.⁹⁸⁴ And, the DOR’s Cap Rate—another driver of the property tax expense—increased as a result of the relatively high inflation in 2021-2023.⁹⁸⁵ The Company’s forecast does not make assumptions about whether these conditions will continue, so it appropriately balances the risks of over-recovery and under-recovery.⁹⁸⁶

700. In contrast, the Company showed that the Department’s recommendation implicitly assumes that the local effective tax rate will continue to decrease in 2025 and 2026.⁹⁸⁷ The Department provided no basis for this assumption and provided no argument on this point in surrebuttal.

701. In the Company’s previous rate case, the ALJ agreed with the Department that the Company’s methodology appeared to “favor over-recovery.”⁹⁸⁸ But the facts are different in this case. In the most recent year available (2024), the Company did not over-recover in the gas jurisdiction, and there is no evidence that the economic conditions that appear to have driven the over-recovery in 2021-2023 were present or will continue through 2025 and 2026.⁹⁸⁹

702. For these reasons, the Department’s recommendation is not persuasive. It is reasonable to use the Company’s updated 2025 and 2026 forecasts to set the baseline for the Company’s property tax expenses.

r. Board Of Directors Expense

703. As a Minnesota corporation, Xcel Energy is required under Minnesota law to have a Board of Directors.⁹⁹⁰

⁹⁸³ Ex. Xcel-52 at 18 (Kowalowski Rebuttal).

⁹⁸⁴ Ex. Xcel-52 at 18 (Kowalowski Rebuttal).

⁹⁸⁵ Ex. Xcel-52 at 19 (Kowalowski Rebuttal).

⁹⁸⁶ Ex. Xcel-52 at 19 (Kowalowski Rebuttal).

⁹⁸⁷ Ex. Xcel-52 at 16 (Kowalowski Rebuttal).

⁹⁸⁸ *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*, Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at 64 (Mar. 31, 2023).

⁹⁸⁹ Ex. Xcel-52 at 18-19 (Kowalowski Rebuttal).

⁹⁹⁰ Ex. Xcel-63 at 39 (Ly Rebuttal); Minn. Stat. § 302A.201, subd. 1.

704. The Department recommends the Company’s recovery of its Board of Directors expense be limited to 50 percent of this expense.⁹⁹¹ The Department’s recommendation would reduce the Company’s Board of Directors expense by \$608,897 for 2025 and \$661,153 for 2026.⁹⁹²

705. The Department argued that the Board of Directors’ financial interests are aligned with shareholders such that it is reasonable for shareholders to pay 50 percent of these expenses.⁹⁹³ The Company stated that the Board of Directors’ focus on the Company’s performance and financial well-being directly benefits customers.⁹⁹⁴ Company witness Ly explained that “[a]n effective and engaged board helps ensure that the Company operates reliably, maintains strong credit ratings, and secures access to capital at favorable rates—all of which lower financing costs that flow through to customers.”⁹⁹⁵

706. Department further argued that the Board of Directors’ ability to set its own compensation creates a conflict of interest, which poses a risk to customers’ interests.⁹⁹⁶

707. 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 review its Board of Directors’ compensation amounts and practices to confirm that they are in line with the market.⁹⁹⁷ In addition, Company witness Ly explained that although the Board of Directors formally approves its own compensation, safeguards are in place to mitigate against any conflict of interest.⁹⁹⁸ For example, as part of its 2024 review, the Governance, Compensation and Nominating Committee reviewed the market information provided by Meridian and recommended maintaining (not increasing) current compensation levels.⁹⁹⁹

708. The Department also questioned the Company’s Board of Directors expenses because the Company did not provide job descriptions for the Board of Directors.¹⁰⁰⁰

709. The Company explained that while the Company’s non-employee Board members do not have traditional job descriptions, their responsibilities are contained in the “Guidelines on Corporate Governance” and committee and board charters, which are

⁹⁹¹ Ex. DOC-4 at 65 (Kehrwald Surrebuttal).

⁹⁹² Ex. DOC-3 at 55 (Kehrwald Direct).

⁹⁹³ Ex. Xcel-63 at 40 (Ly Rebuttal).

⁹⁹⁴ Ex. Xcel-63 at 40 (Ly Rebuttal).

⁹⁹⁵ Ex. Xcel-63 at 40 (Ly Rebuttal).

⁹⁹⁶ Ex. DOC-3 at 52 (Kehrwald Direct).

⁹⁹⁷ Ex. Xcel-63 at 41 (Ly Rebuttal).

⁹⁹⁸ Ex. Xcel-63 at 42 (Ly Rebuttal).

⁹⁹⁹ Ex. Xcel-63 at 42-43 (Ly Rebuttal).

¹⁰⁰⁰ Ex. DOC-3 at 50 (Kehrwald Direct).

publicly available.¹⁰⁰¹ In addition, the Company's 2025 Proxy Statement outlined the Board of Directors' key responsibilities as well as the various committees that make up the Board and their responsibilities in supporting the Board's overall work.¹⁰⁰²

710. The Company pointed out that the Commission has historically approved the Company's request for Board of Directors expense in its entirety.¹⁰⁰³

711. The Company also stated that providing fair and market-competitive compensation is essential to attract and retain qualified directors.¹⁰⁰⁴

712. Xcel Energy's Board of Directors expense is reasonable. Consistent with prior Commission decisions, the Company should be allowed to recover 100 percent of this expense.

s. Organizational Dues (EEI, Chamber Of Commerce)

713. The Company's rate request includes certain dues that the Company pays in order to be a member of the Edison Electric Institute (EEI) and Chambers of Commerce.¹⁰⁰⁵

714. The OAG opposes cost recovery of dues paid to EEI.¹⁰⁰⁶ The OAG also argues that the Company should receive only 50 percent recovery for the Chamber of Commerce dues, on the basis that those dues should be considered economic development costs.¹⁰⁰⁷

(i) EEI Dues

715. EEI is an association that represents all U.S. investor-owned electric companies.¹⁰⁰⁸ 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.¹⁰⁰⁹ These figures exclude the lobbying-related portion of EEI dues.¹⁰¹⁰

716. The OAG opposes the Company's request for recovery of EEI dues for two reasons. First, the OAG argues the Company did not provide adequate information to demonstrate that customers derive a benefit from the non-lobbying portion of the dues paid

¹⁰⁰¹ Ex. Xcel-63 at 41 (Ly Rebuttal).

¹⁰⁰² Ex. Xcel-63 at 41 (Ly Rebuttal).

¹⁰⁰³ Ex. Xcel-63 at 43 (Ly Rebuttal).

¹⁰⁰⁴ Ex. Xcel-63 at 43 (Ly Rebuttal).

¹⁰⁰⁵ Ex. Xcel-28 at 5, 11 (Robinson Rebuttal).

¹⁰⁰⁶ Ex. OAG-7 at 7 (Lee Surrebuttal).

¹⁰⁰⁷ Ex. OAG-7 at 7 (Lee Surrebuttal).

¹⁰⁰⁸ Ex. Xcel-28 at 3 (Robinson Rebuttal).

¹⁰⁰⁹ Ex. Xcel-28 at 5 (Robinson Rebuttal).

¹⁰¹⁰ Ex. Xcel-28 at 3-6 (Robinson Rebuttal).

by the Company to EEI.¹⁰¹¹ Second, the OAG expressed concern that the EEI dues include costs that are attributable to lobbying-related activities, even though the OAG acknowledged that the Company used a Commission-approved method to remove the lobbying-related portion of the EEI dues.¹⁰¹²

717. In response to the OAG's first argument, the Company noted that its initial filing contained detailed data identifying numerous instances (particularly conferences) in which Company employees engaged with EEI.¹⁰¹³ In its direct testimony, the OAG requested that the Company provide additional information to support its request.¹⁰¹⁴ In response, the Company provided detailed information describing how EEI membership helps the Company serve its customers.¹⁰¹⁵ 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.¹⁰¹⁶ The Company cannot duplicate many of these services on its own.¹⁰¹⁷ The Company also referred the OAG to EEI's website, which lists EEI's varied and extensive activities and programs.¹⁰¹⁸

718. The OAG argued that this information was insufficient, saying that in order to demonstrate that the dues were reasonable and necessary, the Company had to provide (a) a listing of all EEI presentations, trainings, and conferences its employee attended, with an explanation of the customers benefits from each activity, and (b) safety and industry information it receives from EEI, the frequency with which it receives such information, and any other "quantifiable benefit" on how EEI membership benefits customers.¹⁰¹⁹ This request is both impractical and unnecessary.¹⁰²⁰ EEI's activities and the Company's involvement are so varied and extensive that it is not practical to list and quantify each activity which the Company partakes.¹⁰²¹

719. There is ample precedent supporting the Company's position that it has met its burden to demonstrate the utility of membership in the EEI. In the Company's previous electric rate case, as well as in Minnesota Power's 2021 and 2016 rate cases, Witness Lee

¹⁰¹¹ Ex. OAG-7 at 4, 7 (Lee Surrebuttal).

¹⁰¹² Ex. OAG-5 at 3-4 (Lee Direct).

¹⁰¹³ Ex. Xcel-28 at 8 (Robinson Rebuttal).

¹⁰¹⁴ Ex. OAG-5 at 5, 6 (Lee Direct).

¹⁰¹⁵ Ex. Xcel-28 at 3-4 (Robinson Rebuttal).

¹⁰¹⁶ Ex. Xcel-28 at 3-4 (Robinson Rebuttal).

¹⁰¹⁷ Ex. Xcel-28 at 3-4 (Robinson Rebuttal).

¹⁰¹⁸ Ex. Xcel-28 at 9 (Robinson Rebuttal).

¹⁰¹⁹ Ex. OAG-5 at 6 (Lee Direct).

¹⁰²⁰ Ex. Xcel-28 at 9 (Robinson Rebuttal).

¹⁰²¹ Ex. Xcel-28 at 9 (Robinson Rebuttal).

opposed the utility’s recovery of EEI dues.¹⁰²² But in each instance, her arguments were unsuccessful and the utility recovered its EEI dues.¹⁰²³ For example, in Minnesota Power’s 2016 rate case, the ALJ summarized: “The work of three of the organizations Applicant is seeking recovery of dues for—Edison Electric Institute [and two organizations not at issue here]—is reasonable, appropriate, and provides indirect benefit to Minnesota Power’s customers.”¹⁰²⁴ In each of those cases, the utility provided about the same amount of information about EEI that the Company provided in this proceeding.¹⁰²⁵ These past cases demonstrates that the showing made by the Company in this case is sufficient.

720. The OAG’s second argument—its concern that the EEI does include costs that are attributable to lobbying-related activities—is also unpersuasive. In its initial filing, the Company had already removed all lobbying-related activities from its cost recovery request for EEI dues, using a methodology approved in prior rate cases.¹⁰²⁶

721. The OAG also argued that “new developments” should be considered when analyzing the reasonableness of the EEI dues.¹⁰²⁷ The developments referred to are the denial of recovery of EEI dues in a Kentucky rate case, a petition filed with the Federal Energy Regulatory Commission seeking to change how utility association dues are accounted for, and a Congressional investigation of the Utility Air Regulatory Group.¹⁰²⁸ However, none of these developments are “new”—OAG witness Lee admits all of them were presented in the OAG’s arguments in past cases.¹⁰²⁹

722. The OAG’s opposition to recovery of the EEI dues is based on arguments that have previously been rejected or are unrealistic. The Company demonstrated that its membership in the EEI allows it to have access to information, conferences, and trainings that provide value to the Company and its customers. The Company has demonstrated that its requested amount for EEI dues is reasonable.

¹⁰²² Ex. Xcel-28 at 6-7 (Robinson Rebuttal).

¹⁰²³ Ex. Xcel-28 at 6-7 (Robinson Rebuttal).

¹⁰²⁴ *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-015/GR-21-335, FINDINGS OF FACT, CONCLUSION, AND ORDER at 22-23 (Feb. 28, 2023).

¹⁰²⁵ Ex. Xcel-28 at 8-9 (Robinson Rebuttal).

¹⁰²⁶ Ex. Xcel-28 at 6 (Robinson Rebuttal).

¹⁰²⁷ Ex. OAG-7 at 3-4 (Lee Surrebuttal).

¹⁰²⁸ Ex. OAG-7 at 3-4 (Lee Surrebuttal).

¹⁰²⁹ Ex. OAG-7 at 3-4 (Lee Surrebuttal).

(ii) Chambers Of Commerce

723. 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.¹⁰³⁰

724. The OAG recommends that recovery of Chambers of Commerce dues should be limited to 50 percent of the Company's requested recovery, because such dues are akin to economic development costs.¹⁰³¹

725. The Company acknowledges that in its previous electric rate case, the Commission adopted the OAG's position on the recoverability of Chambers of Commerce dues.¹⁰³² However, the Company believes its request is supported in this case because the facts in the record are different.¹⁰³³

726. First, the OAG did not put any evidence into the record to support its position that Chambers of Commerce activities are equivalent to economic development activities.¹⁰³⁴ The OAG's only argument is that somehow participation in Chambers of Commerce "help[s] with retaining and increasing the number of customers on the utility's system, which generally increases revenues for the Company, benefiting shareholders."¹⁰³⁵ The Chamber of Commerce activities are substantially things such as local parades and leadership conferences.¹⁰³⁶ The OAG's suggestion that the Company supports local community activities of this type in order to increase the number of customers is unrealistic.¹⁰³⁷ Rather, by participating in Chamber activities, the Company can interact with and hear from customers in those communities, so that it can better serve community needs.¹⁰³⁸

727. The Company, on the other hand, provided sufficient information to support its request. The Company explained how Chambers of Commerce play roles in their community that go far beyond economic benefit.¹⁰³⁹ By paying dues, the Company is letting the Chambers' communities know that the Company is part of, and is a supporter

¹⁰³⁰ Ex. Xcel-28 at 11 (Robinson Rebuttal).

¹⁰³¹ Ex. OAG-5 at 9 (Lee Direct).

¹⁰³² *n the Matter of the Application of Northern States Power, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-21-630, FINDINGS OF FACT, CONCLUSION, AND ORDER at 75 (July 17, 2023).

¹⁰³³ Xcel Energy Initial Brief at 205.

¹⁰³⁴ Xcel Energy Initial Brief at 205.

¹⁰³⁵ Ex. OAG-5 at 9 (Lee Direct).

¹⁰³⁶ Ex. Xcel-28 at 12 (Robinson Rebuttal).

¹⁰³⁷ Ex. Xcel-28 at 12 (Robinson Rebuttal).

¹⁰³⁸ Ex. Xcel-28 at 12-13 (Robinson Rebuttal).

¹⁰³⁹ Ex. Xcel-28 at 12-13 (Robinson Rebuttal).

of, those communities.¹⁰⁴⁰ Chamber activities provide a vehicle for the Company to stay connected to its customers and better serve community needs.¹⁰⁴¹

728. Based on the record in this case, the Company's request for Chamber of Commerce dues is reasonable.

t. Employee Recognition Awards

729. As it has for many years, the Company recognizes employees' excellent work performance and accomplishments by providing employees with small awards and gifts.¹⁰⁴² These awards are provided through a program called Xcelebrate.¹⁰⁴³

730. 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.¹⁰⁴⁴ The OAG recommended disallowance of the vast majority of the Xcelebrate program expenses, limiting recovery to only safety-related awards.¹⁰⁴⁵ The OAG's recommendation would disallow \$737,144 for 2025 and \$768,252 for 2026.¹⁰⁴⁶

731. The Xcelebrate program recognizes exceptional individual or team performance and accomplishments.¹⁰⁴⁷ In the Xcelebrate program, employees receive points for excellent work, which can be used to obtain merchandise or gift cards through an online catalog.¹⁰⁴⁸ The highest level of award is equivalent to \$100, and this level requires both manager and director approval.¹⁰⁴⁹ In addition, Xcelebrate is used to recognize years of contribution at five-year intervals and at retirement.¹⁰⁵⁰ Spending for 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.¹⁰⁵¹

¹⁰⁴⁰ Ex. Xcel-28 at 12 (Robinson Rebuttal).

¹⁰⁴¹ Ex. Xcel-28 at 12-13 (Robinson Rebuttal).

¹⁰⁴² Ex. Xcel-26 at 104 (Robinson Direct).

¹⁰⁴³ Ex. Xcel-26 at 104 (Robinson Direct).

¹⁰⁴⁴ Ex. Xcel-28 at 15 (Robinson Rebuttal).

¹⁰⁴⁵ Ex. OAG-7 at 10 (Lee Surrebuttal). Witness Lee originally requested denial of recovery of \$1,027,172 (the 2023 actual amount of employee awards and recognition expenses) for both the 2025 plan year and 2026 test year, but then adjusted her recommendation to track with the 2025 and 2026 budgeted amounts and to exclude safety-related awards.

¹⁰⁴⁶ Ex. OAG-7 at 10 (Lee Surrebuttal).

¹⁰⁴⁷ Ex. Xcel-63 at 25 (Ly Rebuttal).

¹⁰⁴⁸ Ex. Xcel-28 at 14 (Robinson Rebuttal).

¹⁰⁴⁹ Ex. Xcel-28 at 14 (Robinson Rebuttal).

¹⁰⁵⁰ Ex. Xcel-28 at 14 (Robinson Rebuttal).

¹⁰⁵¹ Ex. Xcel-28 at 16-17 (Robinson Rebuttal).

732. There are four expense types that are part of the Xcelebrate program: performance, years of contribution, per seat fee, and safety.¹⁰⁵² 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.¹⁰⁵³

733. The OAG argues that the Company did not provide support to demonstrate that the Xcelebrate program expenses are reasonable and necessary for the provision of utility service.¹⁰⁵⁴ The OAG reasons that customers are already paying for employee compensation costs, such as salaries, wages, and employee benefits, and that awards presented through Xcelebrate are unnecessary.¹⁰⁵⁵

734. The Company, however, provided ample support for its request. It explained 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.¹⁰⁵⁶ 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.¹⁰⁵⁷ It is reasonable for the Company to reward excellent performance and years of contribution, and these awards are an essential part of the Company’s overall approach to employee compensation.¹⁰⁵⁸

735. The performance-based awards reinforce “desirable work efforts and contributions in the moment that directly support customer satisfaction and business continuity.”¹⁰⁵⁹ 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.¹⁰⁶⁰ The “per-seat fee” component of the Xcelebrate program is an O&M expense and no amount in that category is received by employees.¹⁰⁶¹

736. The OAG argued that the Company did not provide any “analysis” of how the recognition program helps with employee retention and creates a good corporate culture.¹⁰⁶² But there is no obvious methodology for “analyzing” how recognition programs

¹⁰⁵² Ex. Xcel-28 at 14-15 (Robinson Rebuttal).

¹⁰⁵³ Ex. Xcel-28 at 14-15 (Robinson Rebuttal).

¹⁰⁵⁴ Ex. OAG-7 at 10 (Lee Surrebuttal).

¹⁰⁵⁵ Ex. OAG-7 at 10 (Lee Surrebuttal).

¹⁰⁵⁶ Ex. Xcel-62 at 28 (Ly Direct).

¹⁰⁵⁷ Ex. Xcel-63 at 25-26 (Ly Rebuttal).

¹⁰⁵⁸ Ex. Xcel-28 at 17 (Robinson Rebuttal).

¹⁰⁵⁹ Ex. Xcel-62 at 25 (Ly Rebuttal).

¹⁰⁶⁰ Ex. Xcel-63 at 26 (Ly Rebuttal).

¹⁰⁶¹ Ex. Xcel-28 at 17 (Robinson Rebuttal).

¹⁰⁶² Ex. OAG-7 at 10 (Lee Surrebuttal).

create a good corporate culture or retains employees. One indication, however, that such programs are useful is the State of Minnesota's similar recognition program.¹⁰⁶³ If the State considers such a program to be reasonable for its employees, it is hard to see why it would be unreasonable for Xcel.

737. The OAG also argued that its recommendation is consistent with prior Commission decisions involving employee recognition programs at Minnesota Power and Otter Tail Power.¹⁰⁶⁴ In Minnesota Power's rate case, the Commission denied cost recovery for service-time recognition awards.¹⁰⁶⁵ But the Commission approved Minnesota Power's performance-based awards for cost recovery.¹⁰⁶⁶ At most, the Minnesota Power case would provide support for disallowing the relatively small amount of the Company's Xcelebrate awards that are for years of service. In Otter Tail Power's rate case, the applicant was denied cost recovery because it failed to produce sufficient supporting information and because the expenses included all sort of things, including gifts for life events and holidays.¹⁰⁶⁷ In contrast to the Otter Tail Power case, the Company provided a detailed explanation of how Xcelebrate works and why it is reasonable, and has segregated employee life events and holiday gifts from its recovery request.

738. In addition, even after the Otter Tail Power decision, the Commission has continued to approve the Company's request to recover employee awards through the Xcelebrate program.¹⁰⁶⁸ The Company provided the same, or more, information in this rate case as it did in its prior rate cases where Xcelebrate program costs were approved, and there have been no changes to the Company's recognition program since the Company's last rate case.¹⁰⁶⁹

739. The Company's request to recover costs for recognition awards through the Xcelebrate program is reasonable.

¹⁰⁶³ Ex. Xcel-62 at 26-27 (Ly Rebuttal).

¹⁰⁶⁴ Ex. OAG-5 at 11 (Lee Direct); Ex. OAG-7 at 10 (Lee Surrebuttal).

¹⁰⁶⁵ *In re Application of Minnesota Power for Authority To Increase Rates for Electric Service In Minnesota*, Docket No. E-015/GR-21-335, FINDINGS OF FACT, CONCLUSION, AND ORDER at 30 (Feb. 28, 2023).

¹⁰⁶⁶ *In re Application of Minnesota Power for Authority To Increase Rates for Electric Service In Minnesota*, Docket No. E-015/GR-21-335, FINDINGS OF FACT, CONCLUSION, AND ORDER at 30 (Feb. 28, 2023) ("This type of bonus is distinguishable from bonuses that employees receive for accomplishing goals or achieving benchmarks that specifically increase productivity or safety.").

¹⁰⁶⁷ *In re Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service In Minnesota*, Docket No. E-017/GR-15-1033, FINDINGS OF FACT, CONCLUSION, AND ORDER at 47-48 (May 1, 2017).

¹⁰⁶⁸ Ex. Xcel-63 at 27 (Ly Rebuttal).

¹⁰⁶⁹ Ex. Xcel-63 at 27 (Ly Rebuttal).

u. Investor Relations Expenses

740. The Company included investor relations expenses in 2025 and 2026 cost of service, stating 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 13 its long-term debt securities. Company Vice President and Treasurer Mr. Wehner testified that the 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 maintaining the list of registered shareholders; and (iii) an annual shareholders meeting.¹⁰⁷⁰

741. OAG recommended disallowance of 50 percent of Investor Relations costs, stating that the Company did not identify what portion of these costs benefit customers as opposed to shareholders. OAG also noted that the Commission has generally allowed only 50 percent of these costs in recent rate cases.¹⁰⁷¹

742. On the basis of this record, the ALJ recommends that the OAG adjustment not be adopted. The Company has met its burden to demonstrate that these are reasonable and necessary expenses for a public-traded utility.

v. Distribution Targeted Undergrounding

743. Distribution's targeted undergrounding program is designed to improve reliability by undergrounding overhead lines with the highest historical outage rates.¹⁰⁷² This program improves reliability for those customers who are directly served by these lines. It also improves reliability for customers not served by these lines, since crews are able to focus restoration efforts on other areas of the system, which shortens outage times.¹⁰⁷³ The Company proposed \$2.4 million in 2025 and \$6.7 million 2026 in capital additions for its targeted undergrounding program, and provided testimony supporting these investments.¹⁰⁷⁴

¹⁰⁷⁰ Ex. Xcel-20 at 37-38 (Wehner Direct); Ex. Xcel-94 (Wehner Witness Summary).

¹⁰⁷¹ Ex. OAG-5 at 12-15 (Lee Direct); OAG 7 at 11-13(Lee Surrebuttal).

¹⁰⁷² Ex. Xcel-37 at 3 (Mensen Supplemental Direct).

¹⁰⁷³ Ex. Xcel-37 at 3 (Mensen Supplemental Direct).

¹⁰⁷⁴ Ex. Xcel-37 at 2-4 (Mensen Supplemental Direct); Ex. Xcel-35 at 2-18 (Mensen Rebuttal).

744. Both the OAG and the Joint Intervenors challenged the Company's 2025 and 2026 capital additions for the targeted undergrounding program.¹⁰⁷⁵

745. The OAG challenges the reasonableness of the capital budgets for the program claiming that the budget should be capped at \$1.5 million per mile based on an undergrounding cost estimates provided by the Company in another docket,¹⁰⁷⁶ namely, the Company's 2024 Annual Safety, Reliability, and Service Quality Report (2024 SQR).¹⁰⁷⁷

746. The Company explained 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 undergrounding costs estimates cited by the OAG in the 2024 SQR are for a select group of undergrounding projects¹⁰⁷⁸ that do not account for the different construction requirements of targeted undergrounding program projects.¹⁰⁷⁹ The Company explained further 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.¹⁰⁸⁰

747. The OAG's claim in its Initial Brief that the Company developed its targeted undergrounding budget "without even knowing where it would be implementing the program"¹⁰⁸¹ but the Company provided evidence in Rebuttal about the location of potential targeted undergrounding projects already selected for design and construction.¹⁰⁸² The Company explained that 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.¹⁰⁸³

748. The Company also explained that it has a large number of potential projects in the design phase so that the Company can be ready to proceed with as many projects as possible in 2025 and 2026. 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

¹⁰⁷⁵ Ex. Xcel-35 at 4-5, 12-13 (Mensen Rebuttal).

¹⁰⁷⁶ Ex. OAG-7 at 25 (Lee Surrebuttal).

¹⁰⁷⁷ *In the Matter of Northern States Power Company d/b/a Xcel Energy – Electric's 2024 Annual Safety, Reliability, and Service Quality Report*, Annual Report and Petition at 124-125, Docket No. E002/M-25-27 (Apr. 1, 2025).

¹⁰⁷⁸ Ex. Xcel-35 at 5 (Mensen Rebuttal).

¹⁰⁷⁹ Ex. Xcel-35 at 6 (Mensen Rebuttal).

¹⁰⁸⁰ Ex. Xcel-35 at 6 (Mensen Rebuttal).

¹⁰⁸¹ OAG Initial Brief at 49.

¹⁰⁸² Ex. Xcel-35 at 10-12 (Mensen Rebuttal).

¹⁰⁸³ Ex. Xcel-35 at 10-12 (Mensen Rebuttal).

conditions, and addressing site-specific design constraints.¹⁰⁸⁴ The Company provided information showing that the targeted undergrounding projects expected to be implemented in 2025 and 2026 are in urban areas, validating that the higher costs associated with urban construction are appropriate for inclusion in the targeted undergrounding budget.

749. The Company further explained that the OAG's proposed cost cap is also not necessary given that the targeted undergrounding program is a capital program and subject to the Company's proposed capital true-up mechanism. To the extent the Company spends less than its aggregate capital-related revenue requirement for either 2025 or 2026, the Company will provide a refund to customers.¹⁰⁸⁵ The capital true-up mechanism protects customers from the OAG's "over-budgeting" concerns related to the targeted undergrounding program.

750. The Joint Intervenors support the targeted undergrounding program as a way to address disparities in reliability, but recommended disallowing all costs for the program until the Company provides additional information about the cost-effectiveness, community impact, and process for identification of undergrounding projects in its 2025 IDP.¹⁰⁸⁶

751. In both discovery responses and in Rebuttal, the Company provided the additional information requested by the Joint Intervenors.¹⁰⁸⁷ This additional information included the Company's analysis of alternatives to the targeted undergrounding and support for the Company's conclusion that the targeted undergrounding program offers the most comprehensive and cost-effective solution to the identified reliability issues.¹⁰⁸⁸ Specifically, the Company's analysis showed that the targeted undergrounding program will deliver four times the CELI-12¹⁰⁸⁹ improvement as compared to rebuilding or repairing overhead distribution lines.¹⁰⁹⁰ The Company's analysis also concluded that the targeted undergrounding program would enhance resiliency, eliminate long-duration outages, and increase system capacity to support rooftop solar installations and electric vehicles.¹⁰⁹¹ In addition, the Company provided information about how the Company identified targeted

¹⁰⁸⁴ Ex. Xcel-35 at 10 (Mensen Rebuttal).

¹⁰⁸⁵ Ex. Xcel-15 at 29 (Liberkowski Direct).

¹⁰⁸⁶ Ex. JIN-1 at 8 (Kenworthy Direct).

¹⁰⁸⁷ Ex. Xcel-35 at 12-16 (Mensen Rebuttal); Ex. JIN-1 at Attachment 3 (Kenworthy Direct).

¹⁰⁸⁸ Ex. Xcel-35 at 12-16 (Mensen Rebuttal); Ex. JIN-1 at Attachment 3 (Kenworthy Direct).

¹⁰⁸⁹ CELI-12 refers to any premise that had an outage with a duration of 12 hours or more in a year. Ex. Xcel-35 at 3 (Mensen Rebuttal)

¹⁰⁹⁰ Ex. Xcel-35 at 13-14 (Mensen Rebuttal).

¹⁰⁹¹ Ex. Xcel-35 at 14 (Mensen Rebuttal).

undergrounding projects as well as its community outreach efforts to minimize disruptions from the proposed undergrounding projects.¹⁰⁹²

752. The Joint Intervenors also expressed concern that the Company has not considered the community impacts to traffic, property, and neighborhood disruption, asserting that the Company has not shown how it will “avoid doing more harm than good” in implementing targeted undergrounding projects.¹⁰⁹³

753. The Company explained that while there will be short-term disruption, the Company is always works to minimize the impacts of construction projects on customers and communities, and the Company has extensive experience use of directional boring technology to minimize the extent of construction disturbances. The short-term disruptions associated with construction will result in bigger gains for customers, primarily in greatly improved service reliability.¹⁰⁹⁴

754. The Administrative Law Judge recommends that the Commission approve the Company’s proposed 2025 and 2026 investment in the targeted undergrounding program, which is designed to improve reliability, reduce outages, shorten outage response times, and enhance public safety. The Company has put forth substantial evidence to support both the reasonableness of the budgeted costs and need for this program.

w. Distribution Capacity Investments

755. 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.¹⁰⁹⁵ The Company proposed \$106.6 million in capacity investments in 2025 and \$206.2 million in 2026.¹⁰⁹⁶ The Company provided testimony supporting the need for these capacity investments.¹⁰⁹⁷

756. In Direct Testimony, 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 Integrated Distribution Plan (IDP) processes.¹⁰⁹⁸ Specifically, the Joint Intervenors alleged that the 2025-2026 capacity projects have not

¹⁰⁹² Ex. Xcel-35 at 11-12, 15-16 (Mensen Rebuttal); Ex. JIN-1 at Attachment 3 (Kenworthy Direct).

¹⁰⁹³ Ex. JIN-1 at 8 (Kenworthy Direct); JIN Initial Brief at 44.

¹⁰⁹⁴ Ex. Xcel-35 at 14-16 (Mensen Rebuttal).

¹⁰⁹⁵ Ex. Xcel-34 at 88 (Mensen Direct).

¹⁰⁹⁶ Ex. Xcel-34 at 89 (Mensen Direct).

¹⁰⁹⁷ Ex. Xcel-34 at 88-99 (Mensen Direct); Ex. Xcel-35 at 19-25 (Mensen Rebuttal).

¹⁰⁹⁸ Ex. JIN-1 at 23-24 (Kenworthy Direct).

been subject to alternatives analyses¹⁰⁹⁹ 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.”¹¹⁰⁰

757. 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 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.¹¹⁰¹

758. The Company explained that the Joint Intervenor’s recommendation to condition approval the capacity project in this case on the outcome of an IDP proceeding misunderstands the purpose the IDP. In an IDP, the Commission does not make determinations about the need, timing, and costs of specific projects. Rather, the purpose of the IDP is to provide the Commission and interested stakeholders information about the Company’s distribution strategy and goals, planning processes, and historical and budgeted expenditures, and to present forecasted levels of distributed energy resources and electrification.¹¹⁰²

759. The Company also explained that the Joint Intervenors’ claim that the 2025 and 2026 capacity projects included in this rate case have not been properly analyzed or vetted by the Company is contrary to the facts. 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,¹¹⁰³ and as such, have already gone through the Company’s extensive annual planning processes. The Company’s annual planning process is a rigorous, multi-step process, which considers various alternatives to determine the most appropriate project to mitigate the identified system capacity issue.¹¹⁰⁴ This analysis includes an evaluation of each project’s costs, risks, and effectiveness at addressing the identified need.¹¹⁰⁵ 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.¹¹⁰⁶

¹⁰⁹⁹ Ex. JIN-1 at 24 (Kenworthy Direct).

¹¹⁰⁰ Ex. JIN-1 at 25 (Kenworthy Direct).

¹¹⁰¹ Ex. Xcel-35 at 20 (Mensen Rebuttal); Xcel Energy Initial Brief at 217-218.

¹¹⁰² Ex. Xcel-35 at 21 (Mensen Rebuttal).

¹¹⁰³ Ex. Xcel-35 at 22 (Mensen Rebuttal).

¹¹⁰⁴ Ex. Xcel-35 at 22-25 (Mensen Rebuttal).

¹¹⁰⁵ Ex. Xcel-35 at 22 (Mensen Rebuttal).

¹¹⁰⁶ *In the Matter of Xcel Energy’s 2021 Integrated Distribution System Plan*, 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*, Docket

760. The Company explained that the Joint Intervenors' concern about the increase in capacity expansion investments in 2026 fails to acknowledge the fact that 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.¹¹⁰⁷

761. Based on Xcel Energy's Rebuttal Testimony and further consideration, the Joint Intervenors stated in their Initial Brief that they no longer dispute the Company's 2025-2026 budgets for capacity projects in this case.¹¹⁰⁸

762. The Administrative Law Judge recommends that the Commission approve Xcel Energy's proposed capacity budget for 2025 and 2026. These budgets reflect the planned work necessary to meet the needs of the system and customers. The Company provided testimony supporting the need for these projects, and each project has been thoroughly vetted in both the Company's internal planning process and as part of various IDP proceedings.

x. Distribution Communications Infrastructure

763. The Company's proposed fiber optic buildout program involves construction of Company-owned and controlled communication infrastructure using fiber optic cable to replace communication services previously provided by third-party providers.¹¹⁰⁹ The Company is investing in its own fiber optic network to provide the needed performance and security for its distribution system communications that cannot be met by these existing third-party networks.¹¹¹⁰

764. In Direct Testimony, the Joint Intervenors recommended that the Commission deny recovery of the Company's proposed fiber buildout program at this time and that the Company impose certain conditions on any approval.¹¹¹¹ However, after reviewing the Company's Rebuttal Testimony that explained the limited scope of the project, the Joint Intervenors stated that the Company's approach appears to be a reasonable and appropriately targeted deployment of fiber-based communications,¹¹¹² and the Joint Intervenors no longer consider this a disputed issue in this case.¹¹¹³

No. E002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS (Apr. 15, 2022).

¹¹⁰⁷ Ex. Xcel-35 at 20 (Mensen Rebuttal).

¹¹⁰⁸ JIN Initial Brief at 46.

¹¹⁰⁹ Ex. Xcel-34 at 102 (Mensen Direct).

¹¹¹⁰ Ex. Xcel-34 at 102 (Mensen Direct).

¹¹¹¹ Ex. JIN-1 at 26 (Kenworthy Direct).

¹¹¹² Ex. JIN-4 at 17-18 (Kenworthy Surrebuttal).

¹¹¹³ JIN Initial Brief at 46.

765. The Administrative Law Judge recommends that the Commission approve Xcel Energy's proposed fiber optic program investments that the Company has supported and justified in this rate case.

y. Virtual Power Plants

766. The Joint Intervenors recommended that the Commission make continued approval of Advanced Grid Intelligence and Security (AGIS) contingent on the Company providing a Virtual Power Plant (VPP) business case and implementation plan.¹¹¹⁴ The Joint Intervenors also recommended that the Company's VPP proposal and implementation plan be filed in a separate docket, based a specific VPP model tariff,¹¹¹⁵ asserting that such an would leverage AGIS and Distributed Energy Resource Management System (DERMS) investments to their "full potential."¹¹¹⁶

767. The Company explained that it has not proposed a VPP in this case. The Company further explained that: (1) there is not a uniform definition of what constitutes a VPP; (2) VPPs are a complex ecosystem of technology, new employee skillsets, organizational processes and operations, customer programs, DERs, and equipment, that, among other things, all have to be orchestrated to support a VPP; and (3) while certain capabilities of AGIS could support development of a VPP program, AGIS is not a VPP program.¹¹¹⁷ Further, Joint Intervenors' Direct Testimony discusses DERMS, but DERMS is not a part of AGIS, nor are any costs related to DERMS implementation included in this rate case.¹¹¹⁸

768. The Company also explained 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.¹¹¹⁹ Any future VPP proposal should be assessed on its own merits and the *additional* benefits for customers it would bring (including the extent to which any future proposals may leverage existing technology and/or infrastructure).¹¹²⁰ The Joint Intervenors provided no data or analysis to support its assertion that a VPP would leverage AGIS and DERMS to their "full potential."

¹¹¹⁴ Ex. JIN-1 at 45 (Kenworthy Direct); JIN Initial Brief at 50.

¹¹¹⁵ Ex. JIN-1 at 43-45 (Kenworthy Direct); JIN Initial Brief at 54-55.

¹¹¹⁶ Ex. JIN-4 at 16-17 (Kenworthy Surrebuttal).

¹¹¹⁷ Ex. Xcel-35 at 34, 39 (Mensen Rebuttal).

¹¹¹⁸ Ex. Xcel-35 at 37-38 (Mensen Rebuttal).

¹¹¹⁹ Ex. Xcel-35 at 35 (Mensen Rebuttal).

¹¹²⁰ Ex. Xcel-35 at 35 (Mensen Rebuttal).

769. The Company further explained that it has already recently filed a VPP proposal in a separate docket.¹¹²¹ Specifically, the Company submitted its Distributed Capacity Procurement (DCP) proposal on October 3, 2025,¹¹²² as required by the Commission's April 21, 2025 Order in the Company's most recent Integrated Resource Plan (IRP) in Docket No. E002/RP-24-67. The Company's DCP program would leverage Xcel Energy's planning and procurement capabilities along with a competitive DER supply chain to facilitate timely, economic, and strategically-sited deployment of DERs across the distribution system as a grid asset. The Company explained that the DCP program could be considered a version of a utility-led and funded VPP, with an innovative deployment model allowing for a faster deployment of assets at a higher scale than previous VPP program models. Additionally, while DERMS by itself does not represent a VPP, DERMS and ADERMS (which refers to "Aggregator DERMS") 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).¹¹²³

770. The Administrative Law Judge recommends that the Commission decline to approve the Joint Intervenors' recommendations related to VPPs. There is no evidence to suggest that VPP implementation is necessary to support the benefits of investment in any AGIS components (or future DERMS investments). Further, the Company has recently proposed implementation of a VPP in a separate docket, and DERMS and ADERMS are also being addressed in other proceedings per prior Commission Orders, thus a requirement the Company submit a VPP proposal would be duplicative of efforts already underway. Nor is there any record evidence to support the Joint Intervenors' recommendation for use of a specific VPP model tariff. To the extent the Commission believes there is potential value in further addressing VPPs, that should be explored as part one of the separate proceedings discussed above. A rate case is not the appropriate proceeding to address policy proposals that are not tied to the capital investments proposed for recovery in the case.

¹¹²¹ 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 VPPs (*see* Ex. Xcel-35 at 39-41 (Mensen Rebuttal)).

¹¹²² *In the Matter of the Petition of Northern States Power Company for Approval of Capacity*Connect, a Distributed Capacity Procurement Program*, Docket No. E002/M-25-378, Petition (Oct. 3, 2025).

¹¹²³ Ex. Xcel-35 at 37-38 (Mensen Rebuttal).

z. Equity Considerations In Distribution Operations And Planning

771. In Direct Testimony, the Joint Intervenors recommended that Xcel Energy consider operational changes that could potentially improve equity/reliability outcomes, considering low-income communities in storm response and other activities.¹¹²⁴ The Joint Intervenors also recommended that the Commission direct the Company to integrate equity considerations into its Distribution planning and budgeting processes and recommended that the Commission require the Company to use the newest version of the Lawrence Berkeley National Laboratory Interruption Cost Estimate tool (ICE 2.0) to help quantify equity considerations and inform distribution investments.¹¹²⁵

772. In Surrebuttal Testimony, the Joint Intervenors maintained their initial recommendations but acknowledged “the significant work Xcel Energy has undertaken to elevate the voices of disadvantaged communities,”¹¹²⁶ and clarified that intent was not to prescribe a specific formula for use of ICE 2.0, but to highlight that the ICE calculator now contains tools that can support more equitable planning.¹¹²⁷

773. The Company explained that it is not clear how Joint Intervenors assume these recommendations would apply to this current rate case or to what extent these recommendations would impact the Distribution investments proposed for recovery in this case.

774. The Company explained that it does not oppose potential operational changes or changes to Distribution’s investment planning, but 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.¹¹²⁸ This study will evaluate the topic of disparities identified in the Pradhan/Chan and TRC studies (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.¹¹²⁹ Those study findings will help inform a holistic approach to incorporating equity considerations into capital investment planning and outage restoration practices. The Company further explained that, as required, the Company has already engaged an independent third-party evaluator to conduct the study

¹¹²⁴ Ex. JIN-1 at 10 (Kenworthy Direct).

¹¹²⁵ Ex. JIN-1 at 9-10 (Kenworthy Direct).

¹¹²⁶ Ex. JIN-4 at 2-3 (Kenworthy Surrebuttal).

¹¹²⁷ Ex. JIN-1 at 12 (Kenworthy Direct).

¹¹²⁸ *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).

¹¹²⁹ Ex. Xcel-35 at 17 (Mensen Rebuttal).

and work is underway.¹¹³⁰ As part of this effort, the Company must also engage interested stakeholders to participate and collaborate in this effort.¹¹³¹

775. The Company also explained that the ICE 2.0 application method described in the Joint Intervenors' Direct Testimony to weigh outage costs by "community vulnerability factors" was provided with no quantitative method of implementation or examples where this specific approach has been applied by other utilities.¹¹³² The Company further explained its concerns with the Joint Intervenors' recommendation for application of reliability benefits on a more granular community level. As discussed in Rebuttal,¹¹³³ the Company adopted the ICE 2.0 calculation for evaluation of reliability benefits to be included in its November 2025 IDP filing by calculating and applying benefit based on a single system-level average. However, the Company stated that the Joint Intervenors' proposed more granular application of the ICE 2.0 calculation is problematic for several reasons including: (1) the significant additional layers of analysis that would add to electric system planning costs if required to be applied at the census block group (CBG) level; (2) the difficulty in application of multiple values to the analysis of individual projects that benefit more than one CBG (Distribution system assets serve areas that in no way correspond to CBG boundaries); and (3) because the quantitative factors that the Company is currently able to account for in the ICE 2.0 calculation would apparently overwhelmingly disfavor vulnerable communities, heavily discounting the priority of investment in primarily residential communities and, even more so, in low-income communities.¹¹³⁴

776. The Company also explained that this outcome would conflict with the intent of the Commission's past orders in pursuit of narrowing reliability differences between customer classes, such as Order Point 6 of the Commission's December 5, 2023 order in the 2022 SRSQ.¹¹³⁵

777. The Administrative Law Judge recommends that the Commission decline to approve the Joint Intervenors' recommendations related to equity considerations in Distribution operations and planning. It would be premature for the Commission to adopt specific requirements related to equity considerations for Distribution operations or investment planning as part of this rate case while the required third-party evaluation

¹¹³⁰ Xcel Energy Initial Brief at 226-227.

¹¹³¹ Ex. Xcel-35 at 17 (Mensen Rebuttal).

¹¹³² Ex. Xcel-35, Schedule 1 (Mensen Rebuttal).

¹¹³³ Ex. Xcel-35 at 18-19 (Mensen Rebuttal).

¹¹³⁴ Ex. Xcel-35 at 18 (Mensen Rebuttal).

¹¹³⁵ *In the Matter of Xcel Energy's 2022 Annual Safety, Reliability, and Service Quality Report*, Docket No. E002/M-23-73, ORDER at Order Point No. 6 (Dec. 5, 2023) (Order Point No. 6 required that Xcel Energy "discuss how to lower the differences in SAIDI, SAIFI, and CAIDI between feeders associated with the different customer classes in their 2024 filing.").

efforts are ongoing. Further, due to the significant uncertainties around use of ICE 2.0 and any specific formulas or methodologies, the record evidence does not support a Commission decision at this time. The Commission should wait to review the results from the third-party evaluator prior to setting any new requirements for use of ICE 2.0 in Distribution investment planning.

aa. Good Neighbor Plan (NO_x) Tracker Proposal

778. 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).¹¹³⁶

779. Company witness Jeffrey L. West testified that the GNP seeks to limit ozone-forming emissions of nitrogen oxides (NO_x) from power plants and, in some states, industrial sources. Specifically, the GNP is designed to limit ozone season emissions of NO_x by establishing a NO_x allowance budget for each facility based on the assumed application of certain controls. The subject facilities are included in a NO_x ozone season trading program, which allows for buying and selling NO_x allowances between entities. In addition, the GNP limits NO_x 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.¹¹³⁷

780. 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 NAAQS in downwind states. The rule was effective in August 2023.¹¹³⁸

781. Mr. West testified that the GNP establishes an allowance-based trading program with NO_x emissions budgets for fossil fuel-fired power plants in the subject states. Anticipated allowance allocations are less than the Company’s historic emissions by 20-30 percent. Beginning in 2023, the GNP included electric generating units in Minnesota in a revised ozone season trading program with restricted NO_x allowances. Under the GNP, subject units are allocated NO_x allowances for operation during ozone season. If a subject unit’s NO_x 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

¹¹³⁶ Ex. Xcel-59 at 1-2, 14 (West Direct); Ex. Xcel-17 at 115-116 (Halama Direct).

¹¹³⁷ Ex. Xcel-59 at 2-3 (West Direct).

¹¹³⁸ Ex. Xcel-59 at 4 (West Direct).

will greatly reduce NOx allowance allocations in Minnesota for the ozone season.¹¹³⁹ 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.¹¹⁴⁰

782. Department witness Andrew Golden supported establishment of the tracker, subject to the Company supporting costs included in the tracker in annual compliance filings.¹¹⁴¹ No other party filed testimony related to the Company's requested tracker.

783. While the OAG did not file any testimony opposing the Company's proposed tracker, it indicated in briefing that it opposed establishment of the tracker because the GNP is not in effect and may never go into effect.¹¹⁴²

784. 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.¹¹⁴³

785. The EPA has issued a proposed rule reconsidering the GNP with respect to eight states, including Minnesota.¹¹⁴⁴ That proposed rule has not been finalized.

786. The Administrative Law Judge recommends that the Commission establish the requested tracker because while it is not yet known whether the GNP will be enforced, modified or repealed in its entirety, it remains a final rule and will, if enforced, cause the Company to incur costs that are currently not predictable. As a result, establishment of the requested tracker is the most appropriate way to address this situation.

C. Class Cost of Service Study

787. Once 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 Class Cost of Service Study (CCOSS).

788. The purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for costs incurred by the utility in providing

¹¹³⁹ Ex. Xcel-59 at 6 (West Direct).

¹¹⁴⁰ Ex. Xcel-59 at 9-10 (West Direct).

¹¹⁴¹ Ex. DOC-5 at 18-21 (Golden Direct).

¹¹⁴² OAG Initial Brief at 52-53.

¹¹⁴³ Ex. Xcel-59 at 6-7 (West Direct).

¹¹⁴⁴ *Interstate Transport Plan Review for the 2015 Ozone NAAQS*, 91 Fed. Reg. 4025 (Jan. 30, 2026).

service.¹¹⁴⁵ The CCOSS assists the Commission in determining how a utility's costs should be recovered from a utility's customer classes through revenue apportionment and rate design.

789. A CCOSS involves three primary stages of analysis. The first step in this analysis is functionalization. In this step, costs are separated into four major categories: generation, transmission, distribution, and customer.¹¹⁴⁶

790. The second step in the CCOSS process is classification. In this step, functionalized costs are separated into demand-related, energy-related and customer-related categories. Demand-related costs, sometimes referred to as capacity-related costs, are driven by customers' maximum demand and are usually measured in kW. Energy-related costs are driven by customers' energy consumption and are usually measured in kWh. Customer-related costs are driven by the number of customers.¹¹⁴⁷

791. The third step in the CCOSS process is allocation. This step involves allocating functionalized and classified costs to customer classes and occurs through direct assignment or allocation. Functionalized and classified costs exclusively identified as providing service to a particular customer are directly assigned to the appropriate customer. If it is not possible to directly assign costs, the functionalized and classified costs are allocated using external and internal allocators. External allocators are based on information from outside the CCOSS model, while internal allocates are based on data inside the CCOSS model that has already been allocated using external allocators.¹¹⁴⁸

792. The Company, the Department, the OAG, XLI, and SRA provided recommendations about the design of the CCOSS, which revealed several disputed design issues.

1. Compliance – Capital Structure

793. The Department recommended that the Commission require the Company to provide more robust analysis in future rate cases of “not just the potential costs but also the potential benefits for ratepayers” if the Company lowered its equity ratio.¹¹⁴⁹ However, the Department did not elaborate on the kind of analysis it seeks and noted that the theoretical models available to model the impacts of various capital structures are not easy to implement. The Department also concluded that the Commission can reach a reasonable

¹¹⁴⁵ Ex. Xcel-73 at 5 (Barthol Direct).

¹¹⁴⁶ Ex. Xcel-73 at 5 (Barthol Direct).

¹¹⁴⁷ Ex. Xcel-73, Schedule 2 at 4-6 (Barthol Direct).

¹¹⁴⁸ Ex. Xcel-73, Schedule 2 at 7-8 (Barthol Direct).

¹¹⁴⁹ Ex. DOC-12 at 100 (Addonizio Direct).

conclusion in this case without such analysis and recommended approval of the Company's proposed capital structure.¹¹⁵⁰

794. The Company recommended against adopting this new requirement for future rate cases, noting the practical challenges in any such analysis and that any modeling does not account for the dynamic and often unpredictable nature of the capital markets.¹¹⁵¹

795. The Administrative Law Judge does not recommend adopting a new compliance requirement as recommended by the Department, given the Department's acknowledgement of the practical difficulties of such an analysis and the ability of the Commission to assess the reasonableness of the Company's capital structure on the basis of the current record.

2. Classification Of Fixed Production Plant

796. Fixed production costs refers to costs for generation plant, including non-fuel O&M costs, that do not vary based on output.¹¹⁵²

797. In this proceeding, Xcel Energy used the stratification method to separate fixed production costs into demand- and energy-related subfunctions based on the cost of a comparable peaking plant.¹¹⁵³ Xcel Energy has used the stratification method since the late 1970s.¹¹⁵⁴

798. 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.¹¹⁵⁵

799. XLI argued that stratification is "obsolete" given the development of renewable energy on Xcel Energy's system. XLI disagreed with the stratification method's classification of wind and solar plant as primarily energy-related even though these resources are incapable of generating energy in all 8,760 hours of the year.¹¹⁵⁶ 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

¹¹⁵⁰ Ex. DOC-12 at 14 (Addonizio Direct).

¹¹⁵¹ Ex. Xcel-21 at 2-4 (Wehner Rebuttal).

¹¹⁵² Ex. Xcel-74 at 11 (Barthol Rebuttal).

¹¹⁵³ Ex. Xcel-73 at 15 (Barthol Direct).

¹¹⁵⁴ Ex. Xcel-73 at 15 (Barthol Direct).

¹¹⁵⁵ Ex. Xcel-73 at 15 (Barthol Direct).

¹¹⁵⁶ Ex. XLI-3 at 8 (Ly Direct).

production plant.¹¹⁵⁷ The AED-4CP method compares a class's average demand to excess demand, defined as the difference between the class's coincident peak demand (measured over 4 coincident peaks) and average demand.

800. Both the Company and the Department disagreed with XLI's recommendation to use the AED-4CP method for allocating fixed production costs.

801. Department witness Zajicek concluded that the stratification method continues to be reasonable, based on his observation that wind and solar resources "do not have fuel costs, and thus are clearly invested into in part to reduced fuel costs".¹¹⁵⁸ In Xcel Energy'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.¹¹⁵⁹

802. XLI 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 jurisdiction.¹¹⁶⁰ Company witness Mr. Barthol testified that the fact Minnesota Power makes 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.¹¹⁶¹ Mr. Barthol also testified that the AED-4CP's use of a pure energy allocator, without weighting for marginal energy costs, was unreasonable.¹¹⁶²

803. The Administrative Law Judge finds that the Stratification method is a reasonable method for classification of fixed production plant costs that recognizes that Xcel Energy has procured its specific generation mix to meet its customers' energy usage and peak demand. The Commission has been asked to confirm the reasonableness of the Stratification method many times, and each time has confirmed that it should be used for the Company's CCOSS.

¹¹⁵⁷ XLI Initial Brief at 39-40.

¹¹⁵⁸ Ex. DOC-18 at 4 (Zajicek Surrebuttal).

¹¹⁵⁹ *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*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 97 (July 17, 2023).

¹¹⁶⁰ Ex. XLI-3 at 14-15 (Ly Direct).

¹¹⁶¹ Ex. Xcel-74 at 13-14 (Barthol Rebuttal).

¹¹⁶² Ex. Xcel-74 at 14 (Barthol Rebuttal).

3. Allocation Of Demand-Related Production Costs (D10S Allocator)

804. 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.¹¹⁶³

805. In its Order in the Company's last electric rate case, the Commission ordered the Company to "calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data."¹¹⁶⁴

806. 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.¹¹⁶⁵ In 2023, the MISO system peaked on August 23, 2023 at 4 p.m.¹¹⁶⁶ To apply the D10S allocator for the 2025 Test Year, the Company evaluated the forecasted loads at August 23, 2025 at 4 p.m.

807. The OAG recommended that the D10S allocator be based on many days and hours. The OAG calculated a D10S allocator using hourly load data between 3 and 4 p.m. for every weekday from June 21 to August 26.¹¹⁶⁷

808. The Company, the Department, and XLI opposed the OAG's recommendation that the D10S allocator be based on many days and hours. Department witness Zajicek testified that the OAG's hours "don't correctly reflect the impact of the Company's system peak".¹¹⁶⁸ XLI witness Ly noted that some of the hours included in the OAG's calculation of "peak" were 63 percent of the system peak.¹¹⁶⁹

809. The OAG's recommendation does not comply with the Commission's order in the Company's last rate case. It also does not measure class demand at the time of peak

¹¹⁶³ Ex Xcel-73 at 17 (Barthol Direct).

¹¹⁶⁴ *In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn.*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 99 (July 17, 2023).

¹¹⁶⁵ Ex. Xcel-73 at 18-19 (Barthol Direct).

¹¹⁶⁶ Ex. Xcel-73 at 19-20 (Barthol Direct).

¹¹⁶⁷ Ex. OAG-8 at 12 (Scharber Direct).

¹¹⁶⁸ Ex. DOC-18 at 11 (Zajicek Surrebuttal).

¹¹⁶⁹ Ex. XLI-6 at 5 and Schedule 1 (Ly Rebuttal).

demand, it measures demand at 190 hours over two years.¹¹⁷⁰ Of these 190 hours, only two are hours of peak demand. The other 188 hours are not.¹¹⁷¹

810. Using the MISO system peak, as directed by the Commission in the last rate case, causes some data issues in calculating the D10S allocator. Because MISO does not, and likely will not, forecast the specific hour of peak demand in future years, using the MISO system peak will always require the use of historical data. And in some years, that will mean that taking the MISO historical peak and applying it to the test year will point to a weekend day. The Company provided a reasonable explanation for its methodology and satisfactorily demonstrated that it is consistent with the Commission's prior order. While there may be some issues with the MISO historical data, that does not justify turning the D10S allocator, which measures peak demand, into an average demand calculation as recommended by the OAG. The Administrative Law Judge finds that the Company's calculation of the D10S allocator is reasonable because it recognizes that the system is planned to a single system peak, not to meet average demand.

4. Allocation Of Demand-Related Transmission Costs

811. The Company classifies transmission costs as both demand-related and energy-related.¹¹⁷²

812. In its Order in the Company's last electric rate case, the Commission ordered 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.¹¹⁷³ 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.¹¹⁷⁴

813. Company witness Barthol,¹¹⁷⁵ Department witness Zajicek¹¹⁷⁶ and XLI witness Ly¹¹⁷⁷ each recommended that demand-related transmission costs should be allocated using the D10S allocator.

¹¹⁷⁰ See *In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn.*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 99 (July 17, 2023).

¹¹⁷¹ Tr. Vol. 2 at 362:6-22 (Scharber).

¹¹⁷² Ex. Xcel-73 at 22 (Barthol Direct).

¹¹⁷³ *In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn.*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 159 (July 17, 2023).

¹¹⁷⁴ Ex. Xcel-73 at 22 (Barthol Direct).

¹¹⁷⁵ Ex. Xcel-73 at 23-24 (Barthol Direct).

¹¹⁷⁶ Ex. DOC-16 at 35 (Zajicek Direct).

¹¹⁷⁷ Ex. XLI-3 at 19 (Ly Direct).

814. OAG witness Scharber recommended use of the 12CP allocator instead because transmission capacity is “driven by the need for reliability and resilience across multiple periods and seasons.”¹¹⁷⁸ The OAG suggested that the single hour of peak demand might not reflect the period of greatest transmission system vulnerability.¹¹⁷⁹

815. Company witness Barthol testified 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.¹¹⁸⁰ In effect, the 12CP allocator is a measure of average demand. However, the Company 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.¹¹⁸¹

816. XLI witness Ly explained that using an E8760 allocator for the energy-related portion of transmission costs recognizes the reliability risks throughout the year and assigns costs to customers on that basis.¹¹⁸² 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.¹¹⁸³ The OAG’s arguments regarding the use of the 12CP are addressed because the E8760 allocator is used for assigning energy-related transmission costs to customer class.

817. The Administrative Law Judge finds that it is reasonable to change the CCOSS so that demand-related transmission costs are allocated using the D10S allocator. It is clear from this record that the Company plans the transmission system to meet peak demands, which means that demand-related transmission costs are driven by the single peak day, not monthly peaks, 11 of which are lower than the actual system peak.

5. Classification And Allocation Of Shared Distribution Costs

818. As required by the Commission in the Company’s last rate case,¹¹⁸⁴ 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.

¹¹⁷⁸ Ex. OAG-8 at 18 (Scharber Direct).

¹¹⁷⁹ Ex. OAG-8 at 18 (Scharber Direct).

¹¹⁸⁰ Ex. Xcel-73 at 21 (Barthol Direct).

¹¹⁸¹ Ex. DOC-16 at 35 (Zajicek Direct); Ex. XLI-3 at 19 (Ly Direct).

¹¹⁸² Ex. XLI-3 at 20 (Ly Direct).

¹¹⁸³ Ex. XLI-3 at 20 (Ly Direct).

¹¹⁸⁴ *In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn.*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSION, AND ORDER at 105 (July 17, 2023).

a. Minimum System Method

819. 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, because they vary based on the number of customers, and classifies costs about the threshold as demand-related.¹¹⁸⁵

820. The Company estimated the minimum threshold using two different calculations: the Minimum Size Method and the Zero-Intercept Study.¹¹⁸⁶

821. 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.¹¹⁸⁷

822. 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.¹¹⁸⁸ This calculation results in an estimation of the cost of a distribution system that has zero capacity.¹¹⁸⁹

823. 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.¹¹⁹⁰

824. OAG witness Scharber suggested that the Minimum System Method should be given less weight than other CCOSS models.¹¹⁹¹ The OAG argued that the rate design manual developed by the Regulatory Assistance Project (RAP) gives preference to other methods of classifying distribution system costs.¹¹⁹² However, the National Association of Regulatory Utility Commissions (NAURC Manual) supports the use of the Minimum System Method. Company witness Barthol testified that the NARUC Manual is an

¹¹⁸⁵ Ex. Xcel-73 at 35-36 (Barthol Direct).

¹¹⁸⁶ Ex. Xcel-73 at 35-36 (Barthol Direct).

¹¹⁸⁷ Ex. Xcel-73 at 35-36 (Barthol Direct).

¹¹⁸⁸ Ex. Xcel-73 at 36-37 (Barthol Direct).

¹¹⁸⁹ Ex. Xcel-73 at 37 (Barthol Direct).

¹¹⁹⁰ Ex. Xcel-73 at 37 (Barthol Direct).

¹¹⁹¹ Ex. OAG-8 at 24 (Scharber Direct).

¹¹⁹² Ex. OAG-8 at 24 (Scharber Direct).

objective source because it was written by a number of different Commissioners, whereas the RAP Manual was written by only a few individuals.¹¹⁹³

825. 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.¹¹⁹⁴

826. XLI witness Ly did not challenge the Company's Minimum System Method.¹¹⁹⁵

b. Basic Customer Method

827. The Basic Customer method classifies distribution plant that serves a single customer as 100 percent customer-related and all other costs as demand-related.¹¹⁹⁶ Under this method, equipment such as meters are classified as 100 percent customer-related, and equipment such as power lines and distribution poles are classified as 100 percent demand-related.

828. The Department¹¹⁹⁷ and OAG¹¹⁹⁸ support consideration of the Basic Customer method. The Company opposes the use of the Basic Customer method. Company witness Barthol testified that 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.¹¹⁹⁹

829. While the Department agreed that the Basic Customer method should be considered, Department witness Zajicek raised some concerns about its analytical framework. Specifically, Department witness Zajicek explained that an expansion in the size of the distribution system will always be driven by the number of customers: "[W]hile adding new customers does not always increase the length of the line, increasing the length of the line will always be driven by the addition of new customers."¹²⁰⁰ Similarly, Company witness Barthol explained that, "The 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

¹¹⁹³ Tr. Vol. 1 at 123:15-20.

¹¹⁹⁴ Ex. DOC-16 at 41-42 (Zajicek Direct).

¹¹⁹⁵ Ex. XLI-3 at 25 (Ly Direct).

¹¹⁹⁶ Ex. Xcel-73 at 42 (Barthol Direct).

¹¹⁹⁷ Ex. DOC-16 at 42 (Zajicek Direct).

¹¹⁹⁸ Ex. OAG-8 at 26 (Scharber Direct).

¹¹⁹⁹ Ex. Xcel-73 at 44 (Barthol Direct).

¹²⁰⁰ Ex. DOC-16 at 18 (Zajicek Direct).

for conductors and transformers are driven in part by the number of customers.”¹²⁰¹ Because at least some portion of these costs vary based on the number of customers, the Department and the Company asserted that it was not proper to classify them as 100 percent demand, as in the Basic Customer method.

c. Peak-And-Average Method

830. 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.¹²⁰²

831. The OAG recommends the use of the Peak-and-Average method for the CCOSS.¹²⁰³ However, the OAG has not identified or quantified any significant cost items in the distribution system that vary based on energy use. While OAG witness Scharber suggested that new technologies related to advanced grid initiatives should be classified as energy-related, she does not specifically identify those costs.¹²⁰⁴

832. The Company, the Department, and XLI oppose the use of the Peak-and-Average method for classifying distribution costs. Company witness Barthol testified that the Peak-and-Average method is inappropriate because it ignores the fact that distribution conductors and transformer 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.¹²⁰⁵ Department witness Zajicek recommended that the Commission consider the Minimum-System CCOSS and a Basic Customer CCOSS, but not a Peak-and-Average CCOSS.¹²⁰⁶ 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 to attach customers to the grid and ensure that the grid can meet the expected peak demand of its customers.¹²⁰⁷

d. Demand Adjustment

833. Department witness Zajicek recommended that the Commission require the Company to provide an updated study calculating its demand adjustment applied to the

¹²⁰¹ Ex. Xcel-74 at 25 (Barthol Rebuttal).

¹²⁰² Ex. Xcel-73 at 45 (Barthol Direct).

¹²⁰³ Ex. OAG-8 at 26 (Scharber Direct).

¹²⁰⁴ Xcel Energy Initial Brief at 252.

¹²⁰⁵ Ex. Xcel-74 at 25-26 (Barthol Rebuttal).

¹²⁰⁶ Ex. DOC-16 at 42 (Zajicek Direct).

¹²⁰⁷ Ex. XLI-6 at 14-15 (Ly Rebuttal).

Minimum System Method in its next rate case.¹²⁰⁸ The Company agreed with this recommendation.

e. Findings And Conclusions On Shared Distribution Costs

834. In prior rate cases, the Commission has evaluated multiple methods for classifying and allocating shared distribution system costs. On this record, a different approach is appropriate.

835. The Company, Department, and XLI provided persuasive arguments that the analytical framework of the Peak-and-Average are not reasonable. The OAG has not identified any specific cost items that vary based on customer energy usage. As such, the ALJ concludes that it is not reasonable to rely on the Peak-and-Average method in this case, and recommends that the Company not be required to file one in the next rate case.

836. The analytical framework of the Basic Customer method also contains flaws, as explained by Department witness Zajicek. In particular, it is clear that at least some part of the cost for distribution lines and poles is driven by the number of customers on the system, because the area covered by lines and poles is not expanded unless new customers are added. That means that the core assumption of the Basic Customer method – that distribution lines and poles are 100 percent demand-related – is not correct. For that reason, the ALJ concludes that the Basic Customer method should be given less weight when setting rates in this proceeding.

837. The Company's Hybrid Minimum System CCOSS is the most reasonable method for classifying and allocating shared distribution system costs on this record. It has the broadest support among the parties, and the soundest analytical framework. The ALJ concludes that the Minimum System CCOSS should be given more weight when setting rates in this proceeding.

838. The Administrative Law Judge recommends that the Commission accept the Company's agreement to provide an updated study calculating its demand adjustment applied to the Minimum System Method in its next rate case.

6. Classification And Allocation Of AMI

839. 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.¹²⁰⁹ Classification of meter

¹²⁰⁸ Ex. DOC-16 at 36-37 (Zajicek Direct).

¹²⁰⁹ Ex. Xcel-74 at 26-27 (Barthol Rebuttal).

costs as customer-related costs has continued as the Company has installed Advanced Metering Infrastructure (AMI).¹²¹⁰

840. The OAG recommends that AMI costs should be classified as one-third customer-related, one-third energy-related, and one-third capacity related.¹²¹¹ The Company opposes the OAG's recommendation on the following grounds.

841. First, OAG witness Scharber 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.¹²¹² The Company noted 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.¹²¹³

842. Second, OAG witness Scharber testified that her AMI recommendation was based on the Commission's order regarding AMI classification by Minnesota Power.¹²¹⁴ The Company noted that the classification of AMI meters in the Minnesota Power rate case was not a litigated issue and that the case was fully resolved by settlement. For that reason, the Minnesota Power example does not establish a precedent that must be followed where there is record evidence to support classifying AMI meter costs as customer-related.¹²¹⁵

843. Third, OAG witness Scharber 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.¹²¹⁶ However, this is not a direct comparison of metering costs.¹²¹⁷ OAG witness Scharber had previously testified that the new AMI meters cost approximately \$95.65, compared to \$49.73 for the pre-AMI meters, indicating that the total-investment comparison is off-base.¹²¹⁸ And even 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.¹²¹⁹

¹²¹⁰ Xcel Energy Initial Brief at 253.

¹²¹¹ Ex. OAG-8 at 30 (Scharber Direct).

¹²¹² Ex. OAG-10 at 28-29 (Scharber Surrebuttal).

¹²¹³ Xcel Energy Initial Brief at 255.

¹²¹⁴ Ex. OAG-10 at 26 (Scharber Surrebuttal).

¹²¹⁵ Xcel Energy Initial Brief at 255.

¹²¹⁶ Ex. OAG-10 at 26-27, Table 4 (Scharber Surrebuttal).

¹²¹⁷ Xcel Energy Initial Brief at 256.

¹²¹⁸ Ex. OAG-8 at 27 (Scharber Direct).

¹²¹⁹ Xcel Energy Initial Brief at 256.

844. The Company explained that the system-wide cost of AMI meters is driven by only one thing: the number of meters, which is driven almost entirely by the number of customers. As a result, the costs are customer-related and should continue to be classified as 100 percent customer-related.¹²²⁰

845. The Company recommends 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 Transmission Cost Recovery Rider (TCR Rider). As a result, decisions about.¹²²¹

846. The Administrative Law Judge finds that AMI meters should be classified as customer-related because the cost of AMI meters is directly driven by the number of customers.

7. Classification Of Other Production O&M

847. Other 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. The Company has used this method since it was approved by the Commission in its 2013 rate case.¹²²²

848. 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.¹²²³

849. The Commission rejected XLI's same argument in the last rate case, noting "it is not evident that classifying each O&M category as energy- or capacity-related based on whether the category is predominantly variable or fixed results in an accurate energy/capacity allocation."¹²²⁴

¹²²⁰ Ex. Xcel-74 at 29 (Barthol Rebuttal).

¹²²¹ Xcel Energy Initial Brief at 253-254.

¹²²² *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).

¹²²³ Ex. XLI-3 at 15-17 (Ly Direct).

¹²²⁴ Xcel Energy Initial Brief at 258; *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 (May 8, 2015).

850. The Administrative Law Judge finds that the Company's classification and allocation of Other Production costs is reasonable. Other Production costs are incurred as a result of the specific generation resources that the Company has procured. It is reasonable to align the classification and allocation of these costs with the underlying generation investments that caused them.

8. Allocation Of Economic Development Discounts

851. 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 proposed 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.¹²²⁵

852. The OAG opposes this change. OAG witness Scharber testified that allocation of economic development discounts should include consideration of fuel and riders.¹²²⁶ OAG witness Scharber further stated that the R01 allocator is unreasonable because it assigns more cost responsibility to residential customers, and residential customer do not benefit directly from economic development discounts.¹²²⁷

853. The Company, the Department, and XLI each oppose the OAG's recommendation and agree that it is appropriate to use the R02 allocator. Company witness Barthol 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".¹²²⁸ Department witness Zajicek explained "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."¹²²⁹

854. The Administrative Law Judge finds that the Company's allocation of economic development discounts is reasonable. The Company correctly notes that economic discount rates do not provide a discount on fuel costs, so it would be unreasonable to use an allocator that incorporates fuel as recommended by the OAG.

¹²²⁵ Ex. Xcel-74 at 39 (Barthol Rebuttal).

¹²²⁶ Ex. OAG-8 at 31-32 (Scharber Direct).

¹²²⁷ Ex. OAG-8 at 31-32 (Scharber Direct).

¹²²⁸ Ex. Xcel-74 40:6-8 (Barthol Rebuttal).

¹²²⁹ Ex. DOC-17 at 2-3 (Zajicek Rebuttal).

9. CCOSS Conclusion

855. A comparison of the different CCOSS offered in this proceeding are summarized in the table below:

Table 9. Comparison Of CCOSS

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG	Peak & Avg	3.6%	-8.8%	15.7%	28.7%
OAG	Basic Customer	5.9%	-8.4%	13.9%	31.4%
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%

856. The Administrative Law Judge finds that the Company has shown that its CCOSS provides reasonable results consistent with cost causation and should be used for purposes of determining final rates in this proceeding.

857. As explained in the Findings and Conclusions above, the Company's Hybrid Minimum System CCOSS is the most reasonable on this record. In particular, the recommendations of the OAG all use an unreasonable calculation of the D10S allocator, and use 12CP allocator for demand-related transmission costs instead of the more reasonable D10S allocator. XLI's CCOSS is unreasonable because it departs from the long-accepted Stratification methodology for fixed production plant.

858. For the foregoing reasons, the ALJ finds that the most weight should be given to the Company's Hybrid Minimum System CCOSS when setting rates for this proceeding.

D. Revenue Apportionment And Rate Design

859. Once a revenue apportionment has been established, the following steps in establishing rates are to determine how much revenue should be recovered from each class (revenue apportionment) and how (rate design).

1. Revenue Apportionment

860. Revenue apportionment is the process of determining how much revenue should be collected from each class.

861. The starting point for this analysis is evaluation of how much cost each class is responsible for based on a CCOSS.¹²³⁰ Once a reasonable estimate of cost has been established, the Company weighs non-cost factors to establish a revenue apportionment. On this record, parties disagree about what revenue apportionment to establish, and about whether the revenue apportionment should be changed from the 2025 Test Year to the 2026 Plan Year.

a. Class Revenue Apportionment

862. The Company, the Department, the OAG, XLI, SRA, and Walmart provided revenue apportionment recommendations.

863. The revenue apportionment recommendation with the most support from parties is the Company's revenue apportionment. Company witness Paluck explained that 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. The Company proposed to limit the movement towards cost to 20 percent in consideration of other non-cost factors, including rate continuity and customer understanding.¹²³¹

864. The Company's recommendation for revenue apportionment in 2025, based on the Company's Rebuttal revenue requirement, is displayed in Table 10:

¹²³⁰ Ex. Xcel-74 at 5 (Barthol Direct).

¹²³¹ Ex. Xcel-76 at 11 (Paluck Direct).

**Table 10. Revenue Apportionment and Factors
State of Minnesota Jurisdiction (\$ Thousands)**

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%

865. The Department supported the Company’s 2025 revenue apportionment.¹²³²

866. Walmart and the SRA also supported the Company’s 2025 revenue requirement.¹²³³

867. The OAG recommended a different revenue apportionment that would mitigate the revenue requirement recovered from residential and small commercial customers. The OAG’s recommendation would give one-third weight to each of the OAG’s CCROSS models. From this, the OAG made two adjustments. The first was to mitigate rates for the Lighting Class to limit the increases to those recommended by Xcel Energy. Second, the OAG set the rate increase for Small General customers to zero because all CCROSS models in the record indicate that they are currently above cost.¹²³⁴

¹²³² Ex. DOC-20 at 5 (Bahn Surrebuttal).

¹²³³ WAL Initial Brief at 10-11; SRA Initial Brief at 3-4.

¹²³⁴ Ex. OAG-10 at 39 (Scharber Surrebuttal).

868. As described above, the OAG's CCOSS models are less reasonable because they use the 12CP allocator for demand-related production costs and improperly calculate the D10S allocator. Because it relies in part on these CCOSS models, the OAG's recommendation is less reasonable. Further, it would not be reasonable to assign the small commercial customers zero rate increase. While the cost information from the CCOSS models justifies limiting rate increases to small commercial customers, it would be unreasonable to give one group of customers the benefit of no rate increase, while increasing the rate impact on other customers.

869. XLI also 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 on its understanding of cost, informed by XLI's CCOSS. XLI argues that the Commission must take action to ensure that industrial rates are 5 percent below national averages, based on the goal established in Minn. Stat. § 216C.05. XLI also argues that Xcel Energy's recommendation to move 20 percent toward cost would increase, rather than decrease, inter-class subsidies. XLI recommends moving nearly all the way to cost, with the limitation that no customer class would receive an increase that exceeds 150 percent of the system average. Based on XLI's recommendation, Residential customers would receive a rate increase approximately 150 percent of the average increase.¹²³⁵

870. XLI's recommendation is not reasonable based on this record. First, XLI does not appropriately recognize non-cost factors. Commission and judicial precedent make clear that cost, while an important factor, is one of many factors that should be considered in setting rates.¹²³⁶ By moving nearly the entire way towards its perception of cost, XLI does not incorporate a reasonable consideration of non-cost factors. Second, as noted above XLI's CCOSS contains flaws that indicate it is not a reasonable starting point for the revenue allocation process. XLI's argument about cost subsidies are not well taken because they are based on XLI's perception of cost, which is not reasonable on this record.

871. XLI's argument that industrial rates are not competitive is also unavailing. Minn. Stat. § 216C.05 establishes a goal of having rates that are 5 percent below the national average for each class. Contrary to XLI's argument, this is a goal and not a directive or requirement. While the Legislature has established this important goal, it is best applied in other contexts, and not in the revenue apportionment determination. There is no indication that the Legislature sought to protect industrial customers at the cost of increased rate impacts on other customer groups.

¹²³⁵ Ex. XLI-3 at 33-34 (Ly Direct).

¹²³⁶ *St. Paul Area Chamber of Commerce v. Minn. Pub. Util. Comm'n*, 251 N.W.2d 350, 358 (Minn. 1977); *In re Application of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 14 (May 14, 2012).

872. The three main revenue apportionment recommendations are displayed in Table 11, along with a comparison based on present revenues:

Table 11. Proposed Revenue Apportionment with Company Adjustments

Class	OAG¹²³⁷	Present Revenue	NSP¹²³⁸	XLI¹²³⁹
TY 2025				
Residential	38.87%	39.59%	40.12%	42.04%
Non-Demand	3.16%	3.16%	3.29%	3.09%
C&I Demand	57.06%	56.38%	55.68%	53.95%
Lighting	0.90%	0.87%	0.90%	0.93%
Total Retail	100.00%	100.00%	100.00%	100.00%
PY 2026				
Residential	39.01%	38.88%	40.46%	41.33%
Non-Demand	3.18%	3.07%	3.40%	3.00%
C&I Demand	56.91%	57.19%	55.24%	54.76%
Lighting	0.90%	0.86%	0.90%	0.91%
Total Retail	100.00%	100.00%	100.00%	100.00%

873. Based on all of the facts in this record, the Company’s revenue requirement is the most reasonable for this case. The Company’s recommendation uses the Hybrid Minimum System CCOSS, a method supported by the Department, as a starting point. While there is debate on the record about that CCOSS, the Company appropriately balanced cost and non-cost factors by recommending a movement of only 20 percent towards cost.

874. If the Commission establishes a revenue requirement that is different from the Company’s Rebuttal revenue requirement, the Company should be ordered to make a compliance filing calculating rates that are moved 20 percent toward cost based on the final revenue requirement.

¹²³⁷ Ex. OAG-10 at 40, Table 7 (Scharber Surrebuttal).

¹²³⁸ Ex. Xcel-78 at 3, Table 1 (Paluck Surrebuttal).

¹²³⁹ Ex. XLI-3 at Schedule 5 (Ly Direct).

b. 2025 And 2026 Revenue Apportionment

875. The Company proposed to establish one revenue apportionment for the 2025 Test Year and a different apportionment for the 2026 Plan year. The Company noted that there are different costs and revenues in each of the years, and particularly pointed to an increase in 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.¹²⁴⁰

876. The Department and the OAG disagreed. The Department and OAG primarily relied on previous Commission decisions which established only one revenue requirement for a MYRP.¹²⁴¹ The Department also argued that the Company was not actually reflecting an increase in C&I Demand revenues in the 2026 apportionment.

877. The Company disputed the arguments of the Department and the OAG. The Company explained that the Commission's prior cases are distinguishable. In particular, the Company noted that in the Company's 2015 rate case, the revenue apportionment moved 2/3 of the way towards cost in the first year of the MYRP, which is very different than what is proposed in this case.¹²⁴² The Company also noted that in the 2021 rate case, the Commission found that "maintaining the same revenue apportionment for the duration of the MYRP will gradually move rates closer to cost of service."¹²⁴³ The Company asserted that is not the case for this case, because maintain the 2025 revenue apportionment would end up moving classes farther away from cost during 2026.¹²⁴⁴

878. In addition, the Company noted that if the Commission decides to establish only one revenue apportionment, it would be reasonable to use the 2026 revenue apportionment because final rates are not likely to be in effect until late in 2026.¹²⁴⁵ The Company also argued that it would be unreasonable to use the proposed 2026 apportionment for all of 2025 because it could have impacts on interim rate refunds.¹²⁴⁶

879. The Company's proposal to adjust the revenue apportionment from 2025 to 2026 is reasonable. As explained above, the CCOSS models produce different results in 2025 and 2026 because there are different cost items and revenues. As a result, the

¹²⁴⁰ Ex. Xcel-77 at 6 (Paluck Rebuttal).

¹²⁴¹ Ex. DOC-19 at 24 (Bahn Direct); Ex. OAG-8 at 45 (Scharber Direct).

¹²⁴² *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 56 (June 12, 2017).

¹²⁴³ *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*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 97 (July 17, 2023).

¹²⁴⁴ Xcel Energy Initial Brief at 270.

¹²⁴⁵ Xcel Energy Initial Brief at 270.

¹²⁴⁶ Xcel Energy Initial Brief at 270.

understanding of cost changes from one year to the next. Failing to update the revenue apportionment for 2026 would mean that rates are moved closer to cost during 2025, and then further from cost in 2026.

2. Rate Design

880. Once a revenue apportionment is established, rate design is the process of creating rates to collect that revenue from customers. The parties disagree about several rate design issues, including customer charges for the Residential and Non-Demand classes; rate design for some Street Lighting classes; and the creation of a new rate for low-income customers.

a. Residential And Small Commercial Customer Charges

881. Most customer classes have a multi-part rate that includes a volumetric energy rate 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 \$11.00.¹²⁴⁷

882. The Company explained 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.¹²⁴⁸ According to the Company's Hybrid Minimum System CCOSS, customer-related costs are approximately \$24.00 per month. The Company proposed a moderate increase so that around 45 percent of customer related costs would be recovered through the customer charge.¹²⁴⁹

883. The Company also explained 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 2025.¹²⁵⁰ In addition, the Company noted 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 volumetric charge.¹²⁵¹ 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.¹²⁵² Finally, the Company noted that its current residential and small commercial customer charge is out-of-step with the other investor-owned electric

¹²⁴⁷ Ex. Xcel-76 at 14-16 (Paluck Direct).

¹²⁴⁸ Ex. Xcel-76 at 14-16 (Paluck Direct).

¹²⁴⁹ Ex. Xcel-76 at 16, Table 6 (Paluck Direct).

¹²⁵⁰ Ex. Xcel-76 at 17, Figure 1 (Paluck Direct).

¹²⁵¹ Ex. Xcel-76 at 18, Table 7 (Paluck Direct).

¹²⁵² Ex. Xcel-76 at 20, Figure 2 (Paluck Direct).

utilities in Minnesota. Minnesota Power currently has a residential customer charge of \$9.00, and Otter Tail Power Company has a residential customer charge of \$10.75.¹²⁵³

884. The Company explained that it is important to appropriately balance fixed and volumetric charges in order to produce economically efficient rates. The Company noted that a low fixed charge requires a higher volumetric 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.¹²⁵⁴ The Company noted that artificially high volumetric rates, which is what results when customer charges are kept low, could discourage customers from considering transportation and heating electrification.¹²⁵⁵

885. The Department and the OAG do not agree. They argue that the customer charge should be designed to recover only “customer-specific costs.”¹²⁵⁶

886. The Department and OAG’s analysis is heavily reliant on an estimation of customer-related costs from the Basic Customer method.¹²⁵⁷ But as explained above, it cannot be reasonably disputed that the costs of the Company’s distribution lines, poles, transformers, and substations are driven in some part by the number of customers on the system. As such, the Basic Customer method does not include all customer-related costs. As a result, it is not reasonable to rely entirely on the Basic Customer method.

887. The Department also argues that the costs of service drops should not be included when calculating a customer charge.¹²⁵⁸ The Department bases this conclusion primarily on the fact that the Company has not specifically identified how many residential customers share a service drop, such as residential customers in an apartment served by one service drop.¹²⁵⁹

888. If service drops are included in the customer charge, all residential customers will contribute the same amount towards the costs each month. If they are included in the volumetric rate, high-usage customers will pay for more of the costs of service drops. The facts in this record do not indicate precisely how many residential customers share a service drop, but the record does reflect that the vast majority of service drops have a single customer.¹²⁶⁰ Because the majority of service drops are used to serve a single customer, it is most reasonable to include in the analysis them when establishing a customer charge.

¹²⁵³ Ex. Xcel-77 at 13 (Paluck Rebuttal).

¹²⁵⁴ Ex. Xcel-77 at 13 (Paluck Rebuttal).

¹²⁵⁵ Ex. Xcel-77 at 13 (Paluck Rebuttal).

¹²⁵⁶ DOC Initial Brief at 89; OAG Initial Brief at 95.

¹²⁵⁷ Ex. DOC-19 at 39-40 (Bahn Direct); Ex. OAG-8 at 47-50 (Scharber Direct).

¹²⁵⁸ Ex. DOC-19 at 32 (Bahn Direct).

¹²⁵⁹ Ex. DOC-19 at 32 (Bahn Direct).

¹²⁶⁰ Ex. OAG-9, Schedule 8 (Scharber Direct).

Excluding them entirely, as suggested by the Department, would increase rate impacts on high-usage customers even though the vast majority of service drops serve a single customer.

889. On this record, the Company's recommendation to increase the customer charge to \$11.00 is reasonable. The Department and the OAG have not provided a persuasive argument for why the Company's customer charge should be lower than 90 percent of other utilities nationally. The Company does not propose to increase the customer charge to the full value indicated by the Hybrid Minimum System CCOSS, but recommends a reasonable increase that will increase the efficiency and equity of residential and small commercial rates. After this change, the Company's customer charge will continue to be lower than average nationally, and more consistent with other Minnesota investor-owned electric utilities.

b. Street Lighting

890. 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.¹²⁶¹ 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."¹²⁶² 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."¹²⁶³ As a result, the Company modified the rate design for Street Lighting for this case.

891. SRA asserts that the changes to rate design have resulted in rate shock for the A30 sub-class of Street Lighting customers.¹²⁶⁴

892. The way that Street Lighting rates are designed can result in larger percentage increases for low wattage classes. For example, the Company explained that when the monthly cost to increase street lights increases it could result in a \$2.00 increase to the monthly charge. The percentage increase for a low wattage rate, like A30, would be greater

¹²⁶¹ Ex. SRA-3 at 6, Table 4 (Bride Rebuttal).

¹²⁶² *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*, Docket No. E002/GR-21-630, JOINT STIPULATION OF SUBURBAN RATE AUTHORITY AND XCEL ENERGY at 2 (Mar. 24, 2023).

¹²⁶³ Ex. Xcel-77 at 20-21 (Paluck Rebuttal).

¹²⁶⁴ Ex. SRA-4 at 3-4 (Bride Surrebuttal).

than other wattages even though the actual monthly impact is the same.¹²⁶⁵ The Company explained that in the past, the A30 rate design had unique features to mitigate this impact, but that the Company had removed them because the settlement in the last case required simplification of the A30 rate design.¹²⁶⁶

893. The Company also 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 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.¹²⁶⁷

894. To avoid rate shock, SRA recommended that the Company change the way that it calculates the premium for underground service. The underground premium is a component of Street Lighting rates that recognizes cost differences for underground and overhead conductors. SRA recommended reducing the underground premium, which would increase rates for underground lighting fixtures and reduce rates for overhead lighting fixtures.¹²⁶⁸

895. The Company argued that the 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.¹²⁶⁹

896. Having considered the record, the Administrative Law Judge concludes that an adjustment to Street Lighting rate design is not warranted at this time. The Company has adequately explained the basis for its rate design, which is based on the cost of providing service to Street Lighting customers. The Administrative Law Judge also agrees that SRA's recommendation related to the underground premium should not be considered in this rate case because SRA did not raise it until Surrebuttal. In a future case, SRA can revisit this issue where it can benefit from full record development.

c. Low-Income Discount Rate

897. The Joint Intervenors proposed a study process 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

¹²⁶⁵ Ex. SRA-4 at 22-23(Bride Surrebuttal).

¹²⁶⁶ Ex. Xcel-78 at 4 (Paluck Surrebuttal).

¹²⁶⁷ Ex. Xcel-77 at 23 (Paluck Rebuttal)

¹²⁶⁸ Ex. SRA-5 at 4-8 (Bride Surrebuttal).

¹²⁶⁹ Xcel Energy Initial Brief at 282.

support to low-income customers. Joint Intervenors’ witness Dr. Chan 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 the Federal Poverty Level to lower their electricity bills sufficient to reduce those customers’ energy burden to 6 percent.¹²⁷⁰

898. In support of the proposal, Dr. Chan 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. Dr. Chan 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.” Dr. 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.¹²⁷¹

899. 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.03.¹²⁷²

900. The Company responded that Dr. Chan’s analysis relied on non-specific estimates, provided incomplete affordability program enrollment data, and ignores the distinction between bill credits and discounted base rates. Department of Commerce witness Mr. Schmitz questioned the Joint Intervenors’ estimates as it relates to the cost to implement a universal low-income rate.

901. The Company challenged Dr. Chan’s reliance on the LEAD tool 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 Energy’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

¹²⁷⁰ Ex. JIN-2 at 29-30, 37 (Chan Direct).

¹²⁷¹ Ex. JIN-2 at 31-32 and fn.45 (Chan Direct).

¹²⁷² JIN Initial Brief at 16.

management tool, and it will not provide information on year to year changes because it is based on five year running averages.”¹²⁷³

902. 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 explained that Dr. Chan’s estimates of affordability program enrollment were incomplete and significantly undercounted the number of customer enrolled in those programs. The Company produced data showing that 119,091 customers were enrolled in affordability programs in 2023-2024:¹²⁷⁴

Table 12. Enrollment In Company Affordability Programs

Program	2019-20 Enrollment	2023-24 Enrollment	Percent Increase
Low-Income Discount Program	30,607	32,340	6%
PowerOn	18,561	37,815	104%
Medical Affordability	1,604	1,099	-31%
Low-Usage Affordability Credit (aka LILU)	n/a	14,459	n/a
Automatic Bill Credit Pilot	n/a	17,105	n/a
Gas Affordability Program	7,683	16,273	112%
Totals	58,455	119,091	104%

903. The Company explained that it anticipated customer enrollment in these programs to increase further. Company witness Mr. Martin stated that 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 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, as the Company estimates that 87,000 customer could receive discounts through LUAC in the coming years. The Company is exploring flexibilities created by recent amendments to the

¹²⁷³ 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)).

¹²⁷⁴ Ex. Xcel-71 at 56 and Table 1 (Martin Rebuttal).

statutory definition of “low-income household” to extend self-attestation of income and categorical eligibility to other affordability programs to further drive enrollment.¹²⁷⁵

904. The Company argued that the Joint Intervenors’ proposal also 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 explained 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.¹²⁷⁶

905. The Department also raised concerns with the Joint Intervenors proposed universal low-income rate. Specifically, Department witness Mr. Schmitz noted that the Joint Intervenors’ estimate that \$100 million would be needed to ensure all energy-burdened Xcel Energy customers would have their energy costs reduced to less than 6 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. Mr. Schmitz explained 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.¹²⁷⁷

906. As an initial matter, the Administrative Law Judge finds that there does not appear to be any basis in Minnesota law for the Joint Intervenors’ proposed universal low-income rate. Minn. Stat. § 216B.03 prohibits rates that are unreasonably preferential or inconsistent in application to a class of customers. The proposed rate would violate this mandate.

907. Further, the Administrative Law Judge finds that the Joint Intervenors’ proposal is not sufficiently developed for consideration or demonstrably more effective than the Company’s existing affordability programs. Significant questions remain as costs and implementation. The Department raised reasonable concerns that the costs estimated by the Joint Intervenors are likely understated and the Joint Intervenors introduced no new evidence to support or refine those estimates. The Company presented evidence that its existing affordability programs, including the changes made to those programs in this rate case, are experiencing increased enrollment and are projected to continue to assist more low-income customers in the future.

¹²⁷⁵ Ex. Xcel-71 at 57 (Martin Rebuttal).

¹²⁷⁶ Ex. Xcel-71 at 60-61 (Martin Rebuttal)

¹²⁷⁷ Ex. DOC-22 at 4 (Schmitz Rebuttal).

908. The Administrative Law Judge recommends that the Joint Intervenors' proposal be rejected.

3. Tariff Changes

a. Residential Arrears Management Program (RAMP)

909. In the Company's 2023 Safety, Reliability and Service Quality Annual Report docket, the Commission ordered Xcel Energy 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.¹²⁷⁸

910. The Company proposed the Residential Arrears Management Program (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.¹²⁷⁹

911. RAMP would be available to any residential customer who (1) has an active account with Xcel Energy 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.¹²⁸⁰

912. 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 total by the number of customers with an active account with Xcel Energy in Minnesota, and meeting the

¹²⁷⁸ *In the Matter of Xcel Energy's 2023 Safety, Reliability and Service Quality Annual Report*, Docket No. E002/M-24-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS at Order Point No. 33 (Jan. 13, 2025).

¹²⁷⁹ Xcel-39 at 3-4 (Lindgren Supplemental Direct).

¹²⁸⁰ Xcel-39 at 3 (Lindgren Supplemental Direct).

enrollment criteria above, to derive the one-time benefit amount that each customer could receive. The program would be administered by Xcel Energy to be as cost-effective as possible. The Company estimated a need for up to 5 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.¹²⁸¹

913. As for the revenue requirement impact of RAMP, the Company originally proposed to dedicate the entirety of its projected test year and plan year late payment fee revenue to RAMP, increasing its revenue requirement accordingly.¹²⁸²

914. The Department recommended approval of RAMP with six modifications:

1. Eligible customers must be on a payment plan arrangement with Xcel Energy;
2. Xcel Energy 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.¹²⁸³

915. 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

¹²⁸¹ Xcel-39 at 4-6 (Lindgren Supplemental Direct).

¹²⁸² Ex. Xcel-18 at 7-8 (Halama Supplemental Direct).

¹²⁸³ Ex. DOC-20 at 22-23 (Bahn Surrebuttal).

alternative, CUB recommended that late payment fees be applied to PowerOn instead of used to create RAMP.¹²⁸⁴

916. The Company agreed to five of the six modifications proposed by the Department. Company witness Ms. 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 arrears, the Company agreed to ensure that customer is enrolled in a payment plan or budget billing.¹²⁸⁵

917. 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.¹²⁸⁶

918. The Company disagreed with the Department's proposed modification as to 2026 late payment fees. The Company explained that it proposed to provide lump sum RAMP benefits based on available annual late payment revenues. For this reason, the timing of the Commission's approval of RAMP in 2026 will not impact the amount of funding proposed in 2026. The Company recommended retaining the 2026 late fee revenues of \$5.8 million and not allocating any part of these revenues to the Company's 2026 revenue requirement in order to provide full funding for the first year of RAMP.¹²⁸⁷

919. In response to CUB, the Company noted that the Commission ordered Xcel Energy 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.¹²⁸⁸

¹²⁸⁴ Ex. CUB-3 at 14-15 (Levenson-Falk Direct); Ex. CUB-8 at 21 (Levenson-Falk Surrebuttal).

¹²⁸⁵ Ex. Xcel-81 at 10-11 (Howard Rebuttal).

¹²⁸⁶ Ex. Xcel-81 at 11-12 (Howard Rebuttal).

¹²⁸⁷ Ex. Xcel-81 at 10 (Howard Rebuttal).

¹²⁸⁸ Ex. Xcel-71 at 29-31 (Martini Rebuttal).

920. The Administrative Law Judge finds that RAMP, including the Department modifications that the Company agreed to accept meet the requirements for a proposed program as ordered by the Commission in the Company’s 2023 Safety, Reliability and Service Quality Annual Report docket. The Administrative Law Judge further finds that the Company’s agreement to waive late fees for participating customers resolves CUB’s concerns that those customers must pay late fees in order to eligible for the program.

921. For the reasons discussed previously, the Administrative Law Judge recommends rejecting CUB’s recommendation to eliminate late payment fees. The Administrative Law Judge recommends the Commission approve RAMP using 100 percent of late payment fee revenues for 2026 and including the remaining modifications proposed by the Department and agreed to by the Company.

b. Super Large Customer Tariff

922. In the Company’s most recent Integrated Resource Plan (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.”¹²⁸⁹ Before making this decision, the Commission deliberated whether to combine these issues into this rate proceeding and decided not to do so.¹²⁹⁰

923. That proposal was filed on July 16, 2025 in Docket 25-289. To date, comments have been filed by the Citizens’ Utility Board, the Environmental Law & Policy Center and Vote Solar, Google, LLC, Tract Capital Management, LLC, the Department, the OAG, CloudHQ, LLC, Fresh Energy and Minnesota Center for Environmental Advocacy, Geronimo Power, LLC, Data Center Coalition, LIUNA, Legalectric, Clean Grid Alliance and XLI. The docket is currently pending.

924. In response to XLI’s Surrebuttal Testimony, the Company filed Responsive Testimony which explained that the Company does not currently have any customers that would be eligible for the proposed tariff and that there are no revenues to such customers included in the 2025 Test Year or 2026 Plan Year.¹²⁹¹

925. XLI and Joint Intervenors recommend that several issues related to the super-large tariff be decided in this rate case.

¹²⁸⁹ *In the Matter of Xcel Energy’s 2024-2040 Upper Midwest Integrated Resource Plan*, Docket No. E-002/RP-24-67, ORDER APPROVING SETTLEMENT AGREEMENT WITH MODIFICATIONS at Order Point No. 32 (Apr. 21, 2025).

¹²⁹⁰ *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); Xcel Energy Initial Brief at 295-96.

¹²⁹¹ Ex. Xcel-98 at 4-5 (Paluck Responsive).

926. 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 to increase the allocation of revenues to XLI's members.¹²⁹²

927. XLI and Joint Intervenors each recommend that the Company be ordered to file a new CCOSS to incorporate the tariff.¹²⁹³ The Company explained 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 explained 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.¹²⁹⁴

928. The Administrative Law Judge agrees with the Company that these issues are best resolved in other proceedings. The Commission considered whether to deal with the new tariff in this rate case, and specifically decided it should be reviewed in another proceeding that is currently pending. Further, because there is no approved tariff, it is not currently possible to file a new CCOSS or determine how incremental revenues should be allocated. Those issues can be raised and addressed in a future rate proceeding. XLI and Joint Intervenors will have the opportunity to pursue their recommendations in these other, more appropriate proceedings.

c. Disconnection Moratorium And Randomized Control Trial

929. 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 Energy customers that are eligible for disconnection.¹²⁹⁵

(i) Disconnection Moratorium

930. Joint Intervenors witness Dr. Chan analyzed data from 2022 to 2025 and argued that the increase in disconnections during that time did not cause a corresponding decrease in past-due balances or total residential customer arrearages. The Joint Intervenors

¹²⁹² Ex. XLI-9 at 21-22 (Ly Surrebuttal).

¹²⁹³ Ex. XLI-9 at 21-22 (Ly Surrebuttal); JIN Initial Brief at 48.

¹²⁹⁴ Ex. Xcel-98 at 4-5 (Paluck Responsive).

¹²⁹⁵ Ex. JIN-2 at 4 (Chan Direct); Ex. JIN-3 at 13-16 (Chan Rebuttal).

argued that this demonstrates that disconnections do not have a clear and demonstrated benefit to anyone, and thus do not serve a public purpose.¹²⁹⁶

931. 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.¹²⁹⁷

932. The Company responded that the Joint Intervenors position attempts to shift the burden to the Company to prove that its compliance with Minnesota regulations that allow the Company to disconnect customers for failure to pay meets a heightened burden not established in Minnesota law.¹²⁹⁸

933. Drawing on its experience from the COVID-19 disconnection moratorium, the Company also noted that it provided evidence demonstrating 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.¹²⁹⁹

934. 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.¹³⁰⁰

935. The Administrative Law Judge finds that Minnesota Rule 7820.1000 permits Xcel Energy to disconnect service to customers for failure to pay and does not impose any requirement that a utility demonstrate that disconnections serve a public purpose.

936. The Administrative Law Judge also finds that the Company produced evidence demonstrating that the most recent disconnection moratorium likely caused, or at minimum was a causal factor, in the considerable increase in arrears from March 2020 to July 2021, and is likely one of the factors that arrears remain higher than pre-pandemic years. The Joint Intervenors' proposed, indefinite disconnection moratorium is likely to exacerbate arrears and bad debt by removing incentive for customers to stay current on

¹²⁹⁶ Ex. JIN-2 at 7-8, 10 (Chan Direct).

¹²⁹⁷ JIN Initial Brief at 20-21.

¹²⁹⁸ Xcel Energy Reply Brief at 137.

¹²⁹⁹ Ex. Xcel-71 at 50 (Martin Rebuttal).

¹³⁰⁰ Ex. Xcel-71 at 49 (Martin Rebuttal).

their electricity bills and eliminates outreach opportunities for the Company to connect those customers with energy assistance programs.

937. The Administrative Law Judge recommends the Commission reject the Joint Intervenors' proposed disconnection moratorium.

(ii) Randomized Control Trial

938. As an alternative to the disconnection moratorium, the Joint Intervenors recommended that the Commission order the Company to conduct a randomized control trial (RCT) to evaluate the impact of disconnections on late payments and arrears.¹³⁰¹

939. The Joint Intervenors' proposed RCT is a twelve to twenty-four month experiment in which Xcel Energy customers eligible for disconnection are randomly assigned into three "treatment groups": (1) a disconnection moratorium group that would be shielded from disconnection for the entirety of experiment while all other collection processes would remain unchanged; (2) an extended grace period and enhanced outreach group that would not be fully exempt from disconnection but would be provided an extended grace period (i.e., ninety additional days) and enhanced outreach by third-parties; and (3) a control group that would remain subject to standard disconnection practices.¹³⁰²

940. The Joint Intervenors stated the study is needed because there is no causal evidence for the causal link between disconnections and bad debt showing that a disconnection moratorium will increase bad debt.¹³⁰³

941. The Joint Intervenors' argued that any disparate treatment would not violate Minn. Stat. § 216B.07 because the treatment of customers would not be unreasonable because the RCT "would be for the critical purpose of determining whether Xcel's disconnection practices served their intended purpose and benefit all customers, or whether they require modification."¹³⁰⁴

942. Minn. State. § 216B.07 provides:

Rate Preference Prohibited. No public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage.

¹³⁰¹ JIN-3 at 14 (Chan Rebuttal).

¹³⁰² JIN-3 at 14-15 (Chan Rebuttal).

¹³⁰³ JIN-3 at 7 (Chan Rebuttal).

¹³⁰⁴ JIN Initial Brief at 24.

943. The Company responded that the proposed RCT would violated Minn. Stat. § 216B.07 by granting some Xcel Energy customers an unreasonable preference or advantage.¹³⁰⁵

944. The Company explained that, although no customers would be disadvantaged as compared to existing practices—meaning disconnection for failure to pay after a nine-week outreach program by the Company to offer payment plans, affordability programs, and additional efforts to avoid disconnection—these customers would be disadvantaged as compared to customers in other “treatment groups” that would be exempted from disconnection despite similar failure to pay their utility bills.¹³⁰⁶

945. The Administrative Law Judge agrees that the proposed RCT would result in a violation of Minn. Stat. § 216B.07. The RCT would provide the customers in the two “treatment groups” significantly different treatment in that those customers are either not disconnected or are provided an extended grace period and enhanced outreach. The purpose and intended results of the study has no bearing on this analysis, and the Commission must look to the impact on actual Xcel Energy customers. Because the treatment of the customers in two “treatment groups” would significantly alter the consequences of non-payment to those customers’ advantage to the extent that some retain utility service, this advantage is unreasonable.

946. The Administrative Law Judge recommends denying the Joint Intervenors’ proposed RCT as contrary to Minnesota law.

E. Additional Issues

1. Definition Of Energy Justice

947. The Joint Intervenors proposed that the Commission adopt, in this proceeding, the definition of energy justice from the Initiative for Energy Justice that includes four “tenets”: recognition, procedural, distributional, and restorative justice.¹³⁰⁷

948. In the alternative, the Joint Intervenors support a broader proceeding where all utilities and stakeholders participate.¹³⁰⁸

949. Company witness Mr. Martin explained, energy justice, along with equity and environmental justice, are relevant across many dockets and across all utilities that the Commission regulates. Adoption of a definition of energy justice in this docket would deny those utilities, their customers, and other interested stakeholders the opportunity to

¹³⁰⁵ Xcel Energy Initial Brief at 301-02.

¹³⁰⁶ Xcel Energy Reply Brief at 141.

¹³⁰⁷ JIN Initial Brief at 8, 10.

¹³⁰⁸ JIN Initial Brief at 10.

meaningfully participate in the process of discussing and ultimately choosing a definition. The Company did not recommend adopting a definition of energy justice in this proceeding.¹³⁰⁹

950. The Administrative Law Judge finds that adoption of a definition of energy justice in this proceeding would violated notions of procedural justice by denying interested stakeholders the opportunity to participate. To the extent that the Commission determines it is necessary to investigate and formally adopt a specific definition of energy justice, the Administrative Law Judge recommends the Commission open a broader docket involving other utilities and stakeholders.

2. Recognition Of Energy Affordability And Elimination Of Energy Insecurity As Public Interest

951. The Joint Intervenors recommended that the Commission formally recognize universal energy affordability and the elimination of energy insecurity to be in the public interest. The Joint Intervenors request that the Commission consider the ability to pay and to allocate costs broadly to consumers, including those with a greater ability to pay.¹³¹⁰

952. The Company noted that these factors are already considered by the Commission as non-cost factors in rate design and have consistently been used to allocate rates among customer classes.

953. The Administrative Law Judge finds that the Commission currently recognizes these factors as in the public interest and no action is required on the Joint Intervenors' request.

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. § 14.50 and Chapter 216B.

2. The public and parties received proper and timely notice of the hearing and Xcel Energy 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.

¹³⁰⁹ Ex. Xcel-71 at 45 (Martin Rebuttal).

¹³¹⁰ JIN Initial Brief at 11-12; Ex. JIN-2 at 27 (Chan Direct).

4. The burden of proof is on the public utility to show that a rate change is just and reasonable.¹³¹¹

5. The record supports the resolution of the settled, resolved, and uncontested matters set forth in this Report and Xcel Energy's initial filing. These matters have been resolved in the public interest and are supported by substantial evidence.

6. The rates set in accordance with this Report would be just and reasonable.

7. Any of the foregoing Findings of Fact that are more properly characterized as Conclusions of Law are hereby adopted as Conclusions of Law.

RECOMMENDATION

Based on the foregoing Findings of Fact and Conclusions of Law, the Administrative Law Judge makes the following Recommendations:

1. Determine that Xcel Energy is entitled to increase gross annual revenues in the manner and in the amount consistent with the Findings and Conclusions of this Report.
2. The test of the Findings and Conclusions should govern the mathematical and computational aspects of the Findings and Conclusions. The computations should be adjusted so as to conform to the conclusions of the Report.

Dated: _____

JOSEPH MEYER
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700 and 7829.3100, unless otherwise directed by the Commission. Pursuant to Minn. R. 7829.2700, subp. 3, the parties will be granted an opportunity for oral argument before the Commission prior to its decision. 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.

¹³¹¹ Minn. Stat. § 216.16, subd. 4.

The Commission may, at its own discretion, accept, modify, or reject the ALJ's recommendations. The recommendations of the ALJ have no legal effect unless expressly adopted by the Commission as its final order.

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