BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

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

ISSUE DATE: July 17, 2023

DOCKET NO. E-002/GR-21-630

FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Contents

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PROCEDURAL HISTORY

I. Initial Filings

On October 25, 2021, Northern States Power Company d/b/a Xcel Energy (Xcel or the Company) filed a general rate case seeking three consecutive annual rate increases under the Multiyear Rate Plan statute phased as follows:

2022: $395.97 million increase (12.2%)
2023: $150.51 million increase (4.8%)
2024: $131.24 million increase (4.2%).

On December 23, 2021, the Commission issued three separate orders in this case: one finding the rate case filing substantially complete and suspending the proposed final rates; one referring the case to the Office of Administrative Hearings for contested case proceedings; and one setting interim rates for the period during which the rate case was being resolved.

II. The Parties and Their Representatives

The following parties appeared in this case:

- Xcel Energy, represented by Shubha M. Harris, Matthew B. Harris, and Ian M. Dobson of Xcel; Eric F. Swanson, Elizabeth H. Schmiesing, and Joseph M. Windler of Winthrop and Weinstein; and Elizabeth M. Brama and Valerie T. Herring of Taft Stettinius & Hollister LLP.

- The Department of Commerce, Division of Energy Resources (the Department), represented by Katherine Hinderlie, Richard E.B. Dornfeld, and Greg Merz, Assistant Attorneys General.

- The Office of the Attorney General Residential Utilities Division (the OAG), represented by Kristin K. Berkland, Joseph C. Meyer, and Peter G. Scholtz, Assistant Attorneys General.

- Citizens Utility Board of Minnesota (CUB), represented by Brian Edstrom, Senior Regulatory Advocate, and Annie Levenson-Falk.

- The Commercial Group, represented by Alan R. Jenkins, Jenkins at Law, LLC.[1]

- The Suburban Rate Authority (SRA), represented by James M. Strommen and Joseph L. Sathe, of Kennedy & Graven.

- Xcel Large Industrials (XLI), represented by Andrew P. Moratzka and Riley A. Conlin, Stoel Rives, LLP.

- Energy CENTS Coalition (ECC), represented by Catherine Fair and Pam Marshall.

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

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

III. Proceedings Before the Administrative Law Judge

The Office of Administrative Hearings assigned Administrative Law Judge (ALJ) Christa L. Moseng to hear the case.

The parties filed direct, rebuttal, and surrebuttal testimony prior to the opening of evidentiary hearings and initial and reply briefs after the close of evidentiary hearings.

The ALJ held evidentiary hearings on December 13 and 14, 2022. The ALJ also held public hearings in the case, as set forth below:

- October 4, 2022 in Golden Valley and Woodbury
- October 5, 2022 in Red Wing
- October 6, 2022 in St. Cloud
- October 20, 2022 in St. Paul
- October 21, 2022 in Minneapolis
- November 3, 2022 in Mankato

Virtual public hearings were held on October 31, November 2, and December 9, 2022. Written public comments were received until January 6, 2023.

[1] The Commercial Group is an ad hoc association of Xcel's large commercial customers; for purposes of this proceeding, the Group includes Penney OpCo LLC d/b/a JCPenney and Walmart Inc.

More than 500 members of the public attended the public hearings or filed written comments. Many comments opposed the proposed rate increase, citing adverse financial impacts and hardships that the increase would impose.

IV. Proceedings Before the Commission

On March 31, 2023, the Administrative Law Judge filed her Findings of Fact, Conclusions of Law, and Recommendations (the ALJ's Report).

By April 17, 2023, the following parties had filed exceptions to the report of the Administrative Law Judge under Minn. Stat. § 14.61 and Minn. R. 7829.2700: the Company, the Department, the OAG, XLI, SRA, the Commercial Group, Just Solar, Clean Energy Organizations, and CUB.

On May 23 and 24, and on June 1, 2023, the Commission heard oral argument from and asked questions of the parties.

On June 1, 2023, the record closed under Minn. Stat. § 14.61, subd. 2.

FINDINGS AND CONCLUSIONS

I. The Ratemaking Process

A. The Substantive Legal Standard

The legal standard for utility rate changes is that the new rates must be just and reasonable.[2] The Minnesota Supreme Court has described the Commission's statutory mandate for determining whether proposed rates are just and reasonable as "broadly defined in terms of balancing the interests of the utility companies, their shareholders, and their customers . . .", citing Minn. Stat. § 216B.16, subd. 6.[3] That statute is set forth in pertinent part below:

> 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. . . .

B. The Commission's Role

While the Public Utilities Act provides baseline guidance on the ratemaking treatment of different kinds of utility costs, it generally makes only threshold determinations on rate

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[2] Minn. Stat. § 216B.16, subds. 4, 5, and 6.

[3] *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, 410 (Minn. 1998).

recoverability, leaving to the Commission the tasks of determining (a) the accuracy and validity of claimed costs; (b) the prudence and reasonableness of claimed costs; and (c) the compatibility of claimed costs with the public interest.

In ratemaking, therefore, 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.

These diverse issues require different analytical approaches, involve different burdens of proof, and require the Commission to exercise different functions and powers. In ratemaking, the Commission acts in both its quasi-judicial and quasi-legislative capacities: As a quasi-judicial body it engages in traditional fact-finding, and as a quasi-legislative body it applies its institutional expertise and judgment to resolve issues that turn on both factual findings and policy judgments. As the Supreme Court has explained:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[4]

C. The Burden of Proof

Under the Public Utilities Act, utilities seeking a rate increase have the burden of proof to show that the proposed rate change is just and reasonable.[5] Any doubt as to reasonableness is to be resolved in favor of the consumer.[6]

On purely factual issues, the Commission acts in its quasi-judicial capacity and weighs evidence in the same manner as a district court in a civil case, requiring that facts be proved by a preponderance of the evidence. On issues involving policy judgments, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.

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[4] *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).

[5] Minn. Stat. § 216B.16, subd. 4.

[6] Minn. Stat. § 216B.03.

Utilities seeking rate changes must therefore prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the "just and reasonable" standard set by statute. As the Supreme Court has explained:

> A utility seeking to change its rates has the burden of proving by a preponderance of the evidence that its proposed rate change is just and reasonable. "Preponderance of the evidence" is defined for ratemaking proceedings as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[7] (Citation omitted.)

II. Summary of the Issues

Many initially contested issues were resolved among several of the parties in the course of evidentiary proceedings. The Administrative Law Judge found that the resolutions reached by the parties were reasonable and supported by record evidence; she recommended accepting them.

Other issues remained contested, and some issues resolved among the settling parties were disputed by one or more non-settling parties. The following issues either were contested or otherwise require discussion.

Financial Issues

- ***Allen S. King Generating Station (King) and Sherburne County Generating Station Unit 3 (Sherco 3)***–Should Xcel be allowed to shorten the remaining depreciable lives of Sherco 3 and King to reflect their early retirements?

- ***Long-term Incentive Compensation***–Should the Company be allowed to recover from its Minnesota ratepayers Minnesota's jurisdictional share of long-term incentive compensation expense?

- ***Annual Incentive Plan***–At what level should the Commission cap the Company's recovery of annual incentive plan compensation expense?

- ***Executive Compensation***–Should Xcel be allowed to fully recover executive compensation expenditures for its 10-highest paid executives?

- ***Prepaid Pension Asset***–Should the Company be allowed to earn a return on prepaid pension amounts?

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[7] *In the Matter of the Petition of Minnesota Power & Light Company, d.b.a. Minnesota Power, for Authority to Change its Schedule of Rates for Electric Utility Service Within the State of Minnesota*, 435 N.W.2d 550, 554 (Minn.App. 1989).

- ***Qualified Pension Expense***–Should Xcel be allowed to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates?

- ***Medical and Post-Employment Benefits***–Should the Company be allowed to earn a return on its accrued liabilities for retiree medical and post-employment benefits?

- ***Energy Supply Operations and Maintenance (O&M) Expense***–Should the Company be allowed to recover 2022–2024 Energy Supply O&M expenses?

- ***Business System O&M Budget***–Should the Company be permitted to recover the cost of its 2022-2024 business systems O&M expenses?

- ***Income Tax Tracker Costs***–Should the Commission allow Xcel to recover its income tax tracker amount, which results in a 2022-2024 revenue requirement reduction?

- ***Aurora Solar Project Costs***–Should the Company be allowed to recover the Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and South Dakota Public Utilities Commission proxy price?

- ***Wind2Battery System Dismantling Costs***–Should the Commission approve costs for dismantling of the Wind2Battery System?

- ***Construction Work in Progress***–Should the Commission approve Xcel's proposal to include Construction Work in Progress (CWIP) in rate base as an average of projected CWIP beginning and ending balances?

- ***Fault Location Isolation and Service Restoration (FLISR)***–Should the Commission approve Xcel's proposed Fault Location Isolation and Service Restoration (FLISR) 2022-2024 cost recovery, cost allocation, and deployment strategy? Should Xcel be required to track and report on reliability performance for circuits equipped with FLISR and base future FLISR cost recovery on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR?

- ***Asset Health and Reliability***–Should the Commission approve Xcel's 2022-2024 Minnesota jurisdictional distribution capital addition costs for asset health and reliability?

- ***Integrated Distribution Plan (IDP)***–In its next IDP, should Xcel be required to propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases?

- ***Proactive Cable Replacements***–Should Xcel be required to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate case filing? Should Xcel be required to track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing?

- ***Distribution Capital Addition***–Should the Commission approve Xcel's distribution capital addition costs for the grid reinforcement program for the 2022–2024 test years?

- ***Distributed Intelligence***–Should the Commission approve Xcel's proposal for the Distributed Intelligence program without prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement?

- ***Production Tax Credits***–Should the Commission approve the Department's recommended baseline Production Tax Credits update?

- ***Load Flexibility Program***–Should the Commission approve Xcel's proposal to recover costs for the load flexibility program that were not deferred?

- ***IDP Filings***–Should Xcel be required to file an assessment and explanation in its next IDP of whether Integrated Volt-Var Optimization (IVVO) is in the public interest?

- ***Insurance Premium Costs***–Should Xcel be required to base 2022 insurance premium costs on historical averages as proposed by the Department?

- ***Membership Dues***–Should the Commission approve Xcel's request to recover Edison Electric Institute dues, American Gas Association dues, and Chambers of Commerce dues? Should Xcel be required to continue providing information mandated by Minn. Stat. § 216B.16, subd. 17, for all dues costs it seeks to recover regardless of the type of membership (individual, corporate, or chamber)?

- ***Carbon-Free Future MN Coalition Costs***–Should Xcel be allowed to recover Carbon-Free Future Minnesota Coalition costs?

- ***Advertising Expenses***–Should the Commission approve recovery of Xcel's advertising expenses?

Cost of Capital Issues

- ***Return on Equity***–What is a fair and reasonable return on equity for the Company, on this record, at this time?

Class Cost of Service Study (CCOSS) Issues

- ***CCOSS***–What action should the Commission take, if any, with respect to the class cost-of-service studies proposed in this case? What requirements, if any, should be established for future rate cases?

- ***General Allocator***–Should Xcel be required to calculate is General Allocator (for allocating costs among operations) based in part on the number of employees assigned to each operation, or on the full-time equivalent hours assigned to each operation? Should Xcel also be required to use its updated 2022 allocators in 2023 and 2024?

- ***Interchange Agreement Allocators***–Should Xcel be required to calculate its 2022 Interexchange Agreement Allocator (for distinguishing the cost of facilities used in its Minnesota operations from costs used in its Wisconsin operations) based on forecasted data, or based on updated data approved by the Federal Energy Regulatory Commission (FERC)? If the latter, should Xcel also have to make an equal adjustment to its forecasted Interexchange Agreement Allocators for 2023 and 2024?

Rate Design Issues

- ***Class Revenue Apportionment***–What percentage of the revenue requirement should be allocated to each customer class?

- ***Monthly Customer Charges–***At what amounts should monthly customer charges be set?

- ***Commercial & Industrial Demand Class***–Should Xcel be required to, in its next rate case, further segment the Commercial & Industrial Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I Time of Use (TOU) rate?

- ***Real Time Pricing Service Tariff***–Should the Commission allow Xcel to discontinue its Real Time Pricing Service Tariff?

- ***Business Incentive and Sustainability (BIS) Rider***–Should the Commission approve the Company's proposed discretionary discount for the BIS rider?

- ***Low-Income, Low-Usage Discount Program***–Should Xcel be required to implement the Low-Income, Low-Usage Discount Program as proposed by Energy Cents Coalition?

- ***Electric Vehicle (EV) Charging Rates and Upgrade Costs***–Should Xcel be allowed to waive the cost sharing requirement for EV-rate customers and exclude EV-rate customers from the general cost-sharing tariff? Should Xcel be required to include its proposal to waive cost sharing requirements for EV-rate customers to Xcel's Transportation Electrification Plan?

- ***Commercial & Industrial Demand Class–***Should Xcel be required to, in its next rate case, further segment the Commercial & Industrial Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I Time of Use (TOU) rate?

- ***Residential Space Heating Tariff–***Should the Commission approve Xcel's proposed changes to its Residential Space Heating Tariff?

- ***Residential Time-of-Use Rates–***Should the Commission require the Company to develop a residential time-of-use rate?

- ***Street Lighting Rate Design–***Should the Commission approve the Joint Stipulation between the Company and SRA?

- ***Advanced Rate Design*–**Should the Commission open an Advanced Rate Design docket for Xcel?

- ***Sales True-Up*–**Should the Commission approve Xcel's sales true-up for the term of the Multiyear Rate Plan?

- ***Rider Restrictions*–**Should the Commission approve CUB's proposed restrictions on riders?

Energy Justice Tenets and Remaining Issues

- ***Energy Justice Tenets*–**Should the Commission adopt Just Solar Coalition's recommendation to apply the principles of Energy Justice to this rate case?

- ***Term of the Multiyear Rate Plan*–**Should the Company be required to file a five-year multiyear rate plan?

- ***Corporate Government-Dividend Policy*–**Should the Commission initiate an investigation or the creation of a stakeholder group to examine the Company's corporate governance and dividend policy?

- ***Distributed Energy Resources – Circuit Breakers, Reclosers, and Regulator Replacement Prioritization***–Should the Commission direct the Company to modify its ELR programs to include the prioritization of replacements that would increase hosting capacity?

- ***Distributed Energy Resources – EV Charging Studies***–Should the Commission direct the Company to conduct additional studies to assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods?

- ***Grid Modernization*–**Should the Company be required to comply with future grid modernization filing requirements?

- ***Energy Assistance***–Should the Company be required to take steps to address energy assistance budgets and qualifying customers to address barriers to assistance?

- ***Locational Reliability and Service Quality***–Should the Company be required to conduct analyses related to locational differences in reliability, disconnections, and service quality, specifically related to low-income and energy justice communities?

- ***Company Audit of Third-Party Sales Forecast Data***–Should the Company's request to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit be approved?

- ***Regulatory Sandbox***–Should Xcel be required to work with interested parties and other utilities to discuss methods for improving the effectiveness and efficiency of pilot programs?

- ***Quantifying Incremental Hosting Capacity Beneficial Electrification***–Should Xcel be required to determine the incremental hosting capacity and beneficial electrification accommodation resulting from planned Asset Health and Reliability (AH&R) capital Expenditures?

- ***Unintentional Islanding***–Should the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) investigate unintentional islanding and research less costly alternatives to VSR to address the risk of unintentional islanding?

III. The Administrative Law Judge's Report

The Administrative Law Judge's Report is well reasoned, comprehensive, and thorough. The ALJ held two days of formal evidentiary hearings and six public hearings. She reviewed the testimony of expert witnesses offered by 10 parties, and related hearing exhibits. She reviewed written comments submitted by over 500 members of the public.

The ALJ received and reviewed initial and reply post-hearing briefs from the parties, as well as their proposed findings of fact and conclusions of law. Based on this record, the ALJ made some 1,263 findings of fact and conclusions of law and made recommendations on stipulated, settled, and contested issues based on those findings and conclusions.

The Commission has itself examined the record, considered the report of the Administrative Law Judge, considered the exceptions to that report, and heard oral argument from the parties. Based on the entire record, the Commission concurs in most of the Administrative Law Judge's findings and conclusions. On some issues, however, the Commission reaches different conclusions, as delineated and explained below.

On all other issues, the Commission accepts, adopts, and incorporates the ALJ's findings, conclusions, and recommendations to the extent they are consistent with the decisions made herein.

FINANCIAL ISSUES

IV. Sherco 3 and King Plant Depreciation

A. Introduction

In Xcel's 2020–2034 resource-planning docket, the Commission approved Xcel's proposal to retire two coal-fired electric generating plants—Allen S. King Generating Station (King) and Sherburne County Generating Station Unit 3 (Sherco 3)—earlier than previously anticipated by nine and ten years, respectively.[8] Consistent with the Resource Plan Order, Xcel now plans to

[8] *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Resource Plan Order), at 7, 31, Ordering Para. 2.A.4. (April 15, 2022).

retire King in 2028 and Sherco 3 in 2030 and has requested that the remaining depreciable lives of Sherco 3 and King be shortened to reflect their early retirements.

Utilities recover capital costs for assets that are used and useful in providing service by depreciating those costs over a number of years.[9] Commission rules generally require that an asset's costs be amortized over its probable service life, defined as the period of time "from the date of its installation to the forecasted date when it will probably be retired from service."[10] The depreciation rules reflect a regulatory preference to avoid intergenerational inequity (i.e., unfair distribution of costs among current and future customers), and to recover costs from ratepayers who receive the benefit of an asset while it is used and useful.

If a utility terminates operations of a facility before the end of the probable service life that was assumed when setting its depreciation schedule, there will be unrecovered net book value outstanding after the facility is retired. Ordinarily, remaining net book value is no longer recoverable once the facility stops being used and useful in the provision of utility service. However, under Minn. Stat. § 216B.16, subd. 6, the Commission may—but is not required to—allow a utility to recover a facility's positive net book value after retirement if the Commission ordered the facility to terminate operations before the end of its physical life "in order to comply with a specific state or federal energy statute or policy."

B. Positions of the Parties

1. Xcel, the Department, and the OAG

Xcel and the Department initially took different positions on the appropriate rate treatment for Sherco 3 and King in light of their early retirement.[11] However, by the time the Commission met to consider the matter, both Xcel and the Department had agreed that it would be reasonable to reserve this issue for further record development and consideration of alternative rate-treatment proposals in a new docket, particularly to explore whether the Inflation Reduction Act[12] could offer rate-mitigation opportunities.

The OAG did not oppose deferring the decision, but it maintained the position that there is no reasonable basis on which to authorize Xcel to earn a return on these investments once they are no longer used and useful, and its preferred recommendation was that the Commission make that determination in the current proceeding.

[9] *See* Minn. Stat. § 216B.16, subd. 6.

[10] Minn. R. 7825.0500, subps. 2, 10.

[11] Xcel initially proposed two alternative methods for reflecting the early retirement of the coal units: (1) allow the Company to implement the shortened accounting lives beginning in 2024, which would result in a $35.1 million increase in base rates for 2024; or (2) authorize the Company to defer the incremental depreciation expense until its next rate case and introduce a recovery proposal that could include establishing a regulatory asset. The Department initially recommended implementing the shortened accounting lives beginning in 2023 to reduce the magnitude of the rate impact in 2024.

[12] Inflation Reduction Act of 2022, Pub. L. No. 117–169, 136 Stat. 1818 (Aug. 16, 2022).

Xcel, the Department, and the OAG agreed that any financial adjustments resulting from decisions made in the new docket related to Sherco 3 and King rate treatment should be implemented in the Company's next rate case or other appropriate proceeding.

2. XLI

XLI opposed deferring this issue to a separate proceeding and instead continued to recommend that the Commission maintain the current depreciation schedules for King and Sherco 3 and require Xcel to remove each plant from rate base when it is no longer used and useful. However, XLI also recommended allowing the Xcel to recover any remaining balances for depreciation, operations and maintenance (O&M), property tax, and property insurance until those expenses are fully recovered, even after the plants are retired.

Because similar issues are likely to reoccur as utilities work to transition away from carbon-emitting generation resources, XLI recommended that the Commission open an investigation to establish a uniform cost-recovery policy for generation assets that are retired early by any utility in the state.

C. Recommendation of the Administrative Law Judge

Before Xcel and the Department agreed to explore this issue further in a new docket, the ALJ recommended that the Commission adopt a modified version of XLI's proposal that, in the ALJ's view, would maintain the status quo while preserving the Commission's ability to adopt a different approach in a future proceeding with a more fully developed record on the various options for post-retirement recovery. The ALJ found that this approach would be reasonable because the timing of the Resource Plan Order relative to this proceeding limited the parties' ability to develop a full record on the range of alternatives.

D. Commission Action

Although parties differed on the merits of rate treatment of costs related to early retirement of these assets, there was broad agreement that issues of depreciation accounting for early-retiring generation facilities will have significant ratepayer impacts and involve important policy considerations that have not been fully developed in this record. Accordingly, rather than adopt the ALJ's findings and recommendations on this issue at this time, the Commission will instead open a new docket to investigate depreciation accounting or other ratemaking issues related to the early retirement of generating facilities.

As the Department noted, the Inflation Reduction Act could provide opportunities to mitigate costs for ratepayers without leaving the Company uncompensated. Because this issue was introduced relatively late in the proceeding, a new docket will provide opportunities to develop a full record, including an exploration of these potential mitigations and any other potentially reasonable solutions.

Rather than limiting the discussion to Sherco 3 and King specifically, the new docket will address depreciation accounting and other ratemaking issues for retiring generating facilities for all Minnesota utilities. As multiple parties noted, similar issues are likely to reoccur as utilities continue to decarbonize their generation fleets in light of climate goals and changing economics.

Investigating these questions in a single docket with an eye toward broader policy considerations should encourage more robust stakeholder participation and record development and allow for more efficient and effective use of resources as compared to potentially having to revisit the same questions multiple times in individual facility-specific dockets.

For any depreciation adjustments that may be required for Sherco 3 or King as a result of the new docket, the Commission finds reasonable Xcel's proposal, agreed to by the Department and the OAG, to implement these changes in the Company's next rate case or other appropriate proceeding. This will help to avoid the possibility that Xcel may be left with a significant expense between rate cases that could prompt the Company to initiate a new general rate case before it otherwise would have, which may not be an effective use of regulatory, utility, and stakeholder resources.

V. Long-Term Incentive Compensation

A. Introduction

Parties disagreed about whether Xcel should recover the costs of two components of its long-term incentive (LTI) employee compensation—environmental LTI and time-based LTI. Environmental LTI is available only to executives. Xcel provided testimony that environmental LTI compensation is tied to the Company's goals to reduce the carbon-dioxide emissions associated with its electric service by 80% below 2005 levels by 2030 and to have 100% carbon-free electricity by 2050. If Xcel does not meet its environmental goals, then environmental LTI is not paid out, which means the employees do not receive their full market-based compensation amount. According to Xcel, activities that affect carbon emission levels and therefore may affect environmental LTI include implementing renewable energy resources, promoting energy efficiency programs, and improving plant operations to reduce carbon output.

Time-based LTI compensation is designed to incentivize both executive and non-executive employees to remain at the Company long term. It becomes available to eligible employees after a three-year vesting period. Time-based LTI is one of three LTI programs available to Xcel's executive-level employees and is the sole form of LTI offered to non-executive employees. For non-executive employees, time-based LTI payout is increased or decreased from the target amount based on a performance goal, which is the total shareholder return relative to a peer group for each individual vesting year. Time-based LTI paid to executives does not include this performance element.

The following table summarizes Xcel's LTI-expense requests:

Table 1
Xcel Requested LTI Expense ($Million)

	2022	**2023**	**2024**	**Total**
Environmental LTI	$2.210	$2.218	$2.329	$6.757
Time-Based LTI	$5.668	$5.960	$6.202	$17.830
Total LTI Expense	**$7.877**	**$8.178**	**$8.531**	**$24.586**

B. Positions of the Parties

1. Xcel

Xcel argued that customers benefit from tying a portion of an employee's total compensation to these incentive structures because it promotes superior employee performance by aligning compensation with results. Xcel contended that its environmental LTI compensation incentivizes environmental achievements aligned with environmental and climate goals. Xcel argued that its time-based LTI compensation helps the Company to provide efficient and reliable service by promoting the retention of experienced employees who have the knowledge and skills necessary to guide, manage, and operate the utility.

Additionally, Xcel asserted that its incentive-based compensation structure reduces fixed labor costs by reducing the level of base pay on which some benefit-related expenses are based.

2. The Department and XLI

The Department opposed Xcel's request to recover any LTI expense, arguing that these programs are designed chiefly to serve the interests of shareholders, not customers, so it would be unreasonable for customers to bear their costs.

The Department asserted that Xcel provided no detailed analysis of what environmental benchmarks would be achieved or the impact of any benchmarks on the environment beyond its general carbon-reduction goals as a result of environmental LTI spending. Additionally, Xcel earns returns on capital additions, including renewable-energy facilities, and the record does not show how environmental LTI compensation separately incentivizes Xcel's executives to achieve renewable-energy and environmental goals.

Similarly, the Department argued that Xcel has not shown that its time-based LTI compensation incentivizes employee performance related to the provision of safe and reliable service or otherwise benefits customers.

XLI joined the Department's arguments opposing Xcel's request to recover LTI expenses.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel has not met its burden to show that including its environmental LTI compensation in its rate base would be just and reasonable. Noting that the environmental goals underlying Xcel's environmental LTI program are not more ambitious than Minnesota's carbon-free standard,[13] the ALJ found that it would not be reasonable for ratepayers to pay for executive incentive compensation designed to incentivize utility actions that are currently required by law and for which the Company receives rate recovery.

[13] The "carbon-free standard" refers to 2023 Minn. Laws ch. 7, which amended Minn. Stat. § 216B.1691 to add the requirement that, by 2040, each electric utility generate or procure electricity from "carbon-free" technologies—those that generate electricity without emitting carbon dioxide—in an amount equivalent to 100% of the utility's total electric sales to retail customers in Minnesota.

Additionally, the ALJ agreed with the Department that Xcel's time-based LTI program is fundamentally tied to achieving shareholder goals, and that it is therefore unreasonable to require ratepayers to pay for those incentives.

Accordingly, the ALJ recommended that the Commission deny Xcel's request to recover costs for environmental and time-based LTI compensation and make the following corresponding reductions to Xcel's revenue requirements: $7,877,000 in 2022, $8,178,000 in 2023, and $8,531,000 in 2024.

D. Commission Action

The Commission concurs with the ALJ that Xcel did not meet its burden to establish that it would be just and reasonable for customers to pay for Xcel's time-based or environmental LTI compensation.

Xcel did not justify its environmental LTI costs with an adequate showing that the program offers unique benefits that justify separate rate recovery. The Commission is not persuaded that it would be reasonable to require customers to pay the requested $6.757 million in environmental long-term incentive compensation.

Nor did Xcel provide persuasive evidence that its time-based LTI will lead to additional customer benefits to justify imposing the additional $17.830 million cost on customers. To the contrary, the shareholder-return-based performance element of the time-based LTI program for non-executives may incentivize employees to prioritize shareholder interests over customer interests in order to increase their potential time-based LTI payout amount.

Therefore, the Commission will deny Xcel's requests to recover environmental and time-based LTI compensation expenses and will require the Company to make the corresponding revenue-requirement adjustments recommended by the ALJ.

VI. Annual Incentive Program

A. Introduction

Annual incentive program (AIP) is a short-term compensation program offered only to non-union employees. AIP is paid out only if the Company's earnings-per-share rate meets a target level. If the target is reached, then AIP is awarded to eligible employees based on a combination of the employee's achievement of individual performance goals and the Company's achievement of key performance indicators that Xcel develops annually. Xcel asserted that these performance indicators are aligned with customer-oriented goals related to the provision of safe and reliable electric service at reasonable cost.

According to Xcel, an employee's total compensation would be below market levels without AIP and the LTI programs discussed above.

Xcel currently recovers a portion of its AIP expense through rates. Recovery of each employee's AIP is capped at 15% of that employee's base salary. Xcel requested to recover Minnesota jurisdictional AIP expense totaling $24.005 million for 2022, $24.750 million for 2023, and

$25.524 million for 2024. Its request includes three changes from current AIP cost recovery: (1) increasing the cap on AIP compensation from 15% of base pay to 20%; (2) applying the cap on an aggregate basis rather than an individual-employee basis; and (3) removing the requirement that Xcel refund to ratepayers any portion of the total AIP balance collected through rates that is not paid out to employees for a given year.

Xcel also requested to eliminate its annual AIP compliance filing requirement and associated reports. Alternatively, Xcel proposed to change the reporting requirements to (1) compare the amounts of AIP paid to the amount authorized in rates in the aggregate rather than individual level; (2) eliminate the requirement to calculate whether AIP is under 105% of median overall compensation; and (3) eliminate calculations and breakdowns across business units, employee groups and varying AIP cap levels, and the respective allocations across business units.

B. Positions of the Parties

1. Opposition to Xcel's Proposed Changes

a. AIP Cost-Recovery Cap

XLI opposed increasing the cap on AIP recovery to 20% of base salary, arguing that doing so would increase the cost burden on ratepayers without producing ratepayer benefits sufficient to justify the cost. XLI asserted that the earnings-per-share target fundamentally aligns AIP with shareholder interests and that the performance indicators Xcel considers when making AIP payouts are not designed to keep customers' bills low.

The Department also opposed Xcel's proposal to increase the cap on AIP recovery. Although some AIP recovery may be reasonable to balance ratepayer interests with the Company's needs for furnishing utility service, the Department contended that such recovery should be limited because AIP primarily incentivizes employees to act in the interest of shareholders, and because requiring customers to pay for AIP transfers some portion of risk to customers while largely accruing benefits to shareholders. Additionally, the Department argued that AIP prioritizes short-term earnings and rewards short-term thinking, which could adversely affect customers if it factors too heavily into an employee's compensation.

Additionally, the Department opposed Xcel's request to apply the AIP cap to the aggregate of employees' salaries rather than applying it on an individual basis. The Department argued that aggregation of the cap would allow Xcel to concentrate its total AIP balance on a few employees, potentially tying their compensation too closely to shareholder interests and compromising their duties to exercise independent judgment on behalf of the Company to provide safe and reliable service. An aggregate cap could allow Xcel to fully recover 15 or 20% of all eligible employees' aggregate base pay for AIP even if most employees fail to meet their performance goals, which could further compromise incentives.

Recalculating Xcel's AIP expense to reflect a 15% individual cap, the Department recommended reducing Xcel's AIP revenue requirements by $1.127 million for 2022, $1.161 million for 2023, and $1.197 million for 2024.

b. Refunds of Unpaid AIP Amounts

The Department argued that allowing Xcel to retain unpaid incentive compensation would unjustly and unreasonably allow shareholders to offset losses with funds provided by ratepayers.

Additionally, allowing the Company to retain these amounts would functionally eliminate the purported justification for requiring ratepayers to fund this type of compensation: If AIP is not paid out, it can be inferred that the desired ratepayer benefits were not achieved; therefore, it would be unjust and unreasonable to allow Xcel to enrich itself by retaining ratepayer-funded AIP amounts that are not paid out to employees.

c. AIP Reporting Requirements

The Department contended that Xcel did not substantiate its proposal to change its AIP reporting requirements, failing to identify a burden that outweighs the benefit of such reporting. Accordingly, the Department recommended that the Commission maintain the existing reporting requirements but allow Xcel to file its proposed changes in its next AIP refund filing, with support showing why such reporting changes are appropriate and showing that the information needed to review AIP compliance would still be provided if the changes were adopted.

2. Xcel

Xcel argued that its AIP request is reasonable because its total employee-compensation request, including AIP, does not exceed market-based levels. Xcel claimed that it needs to offer employees AIP equal to more than 20% of their base pay to remain competitive in the labor market, so increasing the recoverable cap will simply reduce the amount under-recovered. Xcel rejected concerns about the earnings-per-share threshold aligning employee compensation with shareholder interests, contending that the threshold is reasonably designed to ensure that the Company has the funds to pay out AIP and that the Company's financial strength and ability to attract capital in varying economic conditions are integral to its ability to provide safe, reliable, and affordable service to customers. Additionally, Xcel argued that the key performance indicators it uses to determine AIP payouts for individual employees are aligned with customer-oriented goals.

Xcel argued that a 15% cap is no longer appropriate because the Company has changed its compensation structure consistent with industry trends. Xcel contended that past decisions upholding the 15% cap were based on a concern that AIP would result in total compensation exceeding market levels, and that this concern is no longer present because the company now treats AIP as a component of the total compensation needed to reach the targeted market median level, rather than an additional payment above market median.

Xcel noted that Minnesota Power was authorized to apply a 20% cap to its short-term incentive program in a past rate case and argued that the reasons for that decision apply equally to Xcel.[14] In defense of its proposals to aggregate the calculation of the AIP cap and to allow the Company

[14] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 33 (March 12, 2018).

to retain unpaid AIP amounts, Xcel argued that requiring the Company to calculate a refund at the individual level and refund amounts not paid out according to the cap hinders the Company's ability to differentiate pay among its incentive-eligible employees in a way that effectively manages performance expectations. Xcel argued that calculating the cap in the aggregate and not requiring refunds of unpaid amounts would allow the Company the flexibility necessary to allocate the total AIP budget in a way that effectively incentivizes and rewards top performance.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with the Department that it is just, reasonable, and in the public interest to limit rate-recoverable AIP because that type of compensation is contingent upon first satisfying shareholder interests. However, the ALJ was persuaded that it would be reasonable to increase the cap to 20% of base pay because market-rate compensation practices have evolved to include more incentive-based compensation in recent years. In support of this recommendation, the ALJ cited the 2018 order authorizing a 20% cap on short-term incentive compensation for Minnesota Power.[15]

The ALJ recommended maintaining the requirement to apply the cap on an individual-employee basis rather than switching to an aggregate cap. The ALJ agreed with the Department that aggregating the AIP would permit the Company to align employee incentives too closely with shareholder interests over customer interests, which would not be in the public interest. Additionally, the ALJ recommended that the Commission require Xcel to refund to ratepayers any AIP amounts not paid out as AIP compensation. The ALJ found that the reasonableness of recovering incentive compensation through rates is contingent on the incentives advancing ratepayer interests, and if incentive compensation is not paid out to employees, it is reasonable to infer that the desired ratepayer advantages were not achieved.

The ALJ also recommended that the Commission deny Xcel's proposal to modify its AIP compliance filing requirements because the proposal was not sufficiently supported in the record, but adopt the Department's suggestion to allow Xcel to propose changes to filing requirements in its next AIP refund filing.

D. Commission Action

1. AIP Cost-Recovery Cap

The Commission respectfully disagrees with the ALJ's recommendation to increase the AIP cap to 20% of base salary; instead, the Commission will maintain the cap at 15% of base salary. Although Xcel presented evidence that it uses AIP to meet, not exceed, market-based total compensation levels, and that it pays some employees AIP equal to more than 15% of their base pay to remain competitive, the Company has not met its burden to demonstrate that it would be just and reasonable for ratepayers to pay more for incentive compensation tied to an earnings-per-share threshold that primarily benefits shareholders.

AIP is not like most O&M expenses that are necessary for the provision of safe and reliable service, for which the goal in ratemaking is to identify a representative test-year figure to fully

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[15] *Id.*

compensate the Company for its reasonable costs. Rather, because AIP is driven in part by shareholder interests, the Commission has consistently held that it is reasonable to limit rate recovery of AIP even if that leaves the utility's actual AIP expense partially unrecovered. In asserting that it under-recovers its actual and necessary compensation expenses with a 15% cap, the Company did not persuasively show that it is unable to adequately compensate and incentivize its employees by supplementing the rate-recoverable portion of AIP with other options available outside of rates.

The Commission finds that capping AIP recovery at 15% of the employee's base salary strikes a reasonable balance between ratepayer interests and the Company's needs for furnishing service. The Commission is not persuaded that Xcel's evidence of shifting market compensation structures is sufficient to outweigh the concerns discussed above regarding incentives and risks associated with earnings-per-share-based AIP so as to justify imposing a greater share of AIP expense on ratepayers.

The Commission also respectfully disagrees that the Commission's 2018 decision to authorize a 20% recovery cap on Minnesota Power's short-term incentive compensation supports increasing the cap to the same level for Xcel's AIP. The Commission based its decision in Minnesota Power's case in part on a finding that Minnesota Power's short-term incentive program was not shown to create skewed incentives or other public-policy concerns. Notably, unlike Minnesota Power's program, Xcel's AIP program is subject to a dispositive earnings-per-share threshold such that *no* AIP is paid out if earnings per share do not reach the target level, regardless of any other performance metrics. The Commission is therefore not convinced that Xcel's proposal is sufficiently broadly beneficial to justify a higher percentage of recovery from ratepayers.

With respect to the ALJ's recommendation to continue applying the AIP cap on an individual-employee basis rather than applying an aggregate cap, the Commission concurs and will maintain this approach. The Department persuasively argued that aggregating the cap could allow the Company to concentrate the total AIP budget on a small number of employees, a result that might inadvertently misalign employee incentives, potentially incentivizing those who earn AIP to prioritize shareholder interests and compromising their duty to exercise independent judgment on behalf of the Company to provide safe and reliable service at reasonable cost to customers. The Commission is also not persuaded that the individual application of the cap unreasonably impedes Xcel's ability to compensate and incentivize its employees.

2. Refunds of Unpaid AIP Amounts

The Commission will also adopt the ALJ's recommendation to continue requiring Xcel to refund ratepayers for any recovered AIP amounts not paid out to employees.

The reasonableness of recovering any AIP expense through rates is contingent on the incentives advancing ratepayer interests. To the extent that Xcel is not able to pay out the full authorized AIP amount based on its employees' achievement of performance goals, it can reasonably be inferred that the offering of AIP did not fully accomplish its intended benefits for customers; in such a case, it would not be reasonable to allow Xcel to retain the portion not paid out to employees at customers' expense. The requirement that the Company refund any unused AIP amounts to ratepayers provides an important protection against some of the risk-transferring concerns raised by the Department.

3. AIP Reporting Requirements

Finally, because Xcel did not adequately support its request to alter its AIP reporting requirements, the Commission will adopt the ALJ's recommendations to maintain Xcel's existing compliance filing requirements relating to incentive compensation and the associated refund and direct Xcel to provide support for any requested reporting changes in its next annual incentive compensation compliance filing.

VII. Compensation for Top 10 Highest-Paid Officers and Employees

A. Introduction

Xcel requested rate recovery of executive compensation for its top 10 highest-paid officers and employees through a combination of base salary, pension and other benefits, annual incentive pay, and two out of three long-term incentive programs.

The rate-recoverable components of compensation for Xcel Energy Inc.'s top executives are allocated among its various operating subsidiaries and to customers located in different states within those subsidiaries based on jurisdictional percentage allocators. The NSP–Minnesota electric jurisdiction (which also includes North Dakota and South Dakota) is allocated approximately 37% of recoverable compensation expenses for shared Xcel Energy executives, and Minnesota customers are allocated about 87% of the NSP–Minnesota electric share.

Xcel proposed that Minnesota electric customers pay approximately \$7.05 million for compensation of Xcel Energy's 10 highest-paid executives for the 2022 test year, \$7.57 million for 2023, and \$7.88 million for 2024. These amounts are in addition to the compensation those 10 individuals receive from customers in other jurisdictions and from non-rate-recoverable components such as long-term incentive programs and AIP above applicable percentage-of-base-salary caps.

Xcel stated that it generally aims to set non-bargaining employee compensation at a level consistent with the median for comparable positions to remain competitive in the labor market.

While the ALJ did not directly address the issue of top-10 executive compensation and no formal party commented on it, the Commission received comments from members of the public stating that it would be unreasonable for ratepayers to pay such levels of compensation for Xcel's executives, particularly as many Minnesotans face continuing economic challenges including widespread inflation in the costs of necessities such as food, fuel, and medical expenses; ongoing surcharges and high market prices for natural gas related to extreme weather and market events; and lasting effects of the COVID-19 pandemic on individual incomes and on the broader economy.

For example, two members of the public, commenting jointly, stated:

> CEO compensation is also a sore spot during these days when most of us are watching our dollars closely. In 2021 alone Xcel paid compensation of about \$20.5 million (combined for current and previous CEO). It takes a lot of homeowners paying their monthly

> bills to cover this cost. During these times of oppressive cost increases on just about all the basics in our lives, we need the Public Utilities Commission to acknowledge that these increases are an excessive burden on customers.[16]

Characterizing Xcel's executive compensation as "exorbitant" and stating that its CEO was one of the highest-paid CEOs in Minnesota and the highest paid among the state's utilities, another commenter recommended that the Commission reduce the amount of executive compensation included in rates rather than increase the financial burden on customers.[17]

Multiple members of the public further questioned the reasonableness of Xcel's executive compensation structure and increasing rates to fund it, asserting that Xcel had the eighth highest-paid CEO in Minnesota and the second highest CEO-to-median-worker pay ratio among U.S. utilities (139:1) in 2020.[18]

B. Commission Action

The Commission is not persuaded that Xcel has met its burden to show that requiring ratepayers to pay for top-10 executive compensation at the full proposed levels is reasonable.

Minnesota law requires the Commission to review costs related to a utility's highest-paid executives closely,[19] and several factors warrant a closer examination in this case. In particular, in this proceeding, Xcel initially requested rate increases of $677.72 million. While Xcel has moderated its request over the course of the proceeding, its final request is still one of the largest rate-increase proposals the Commission has ever considered. Further, through multiple rate cases and multiyear rate plans, the Company has increased its rates nearly every year for the past decade, such that ratepayers are paying hundreds of millions in increased rates compared to 10 years ago.[20]

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[16] Comment of James and Katherine Anderson (October 27, 2022).

[17] Comment of Nanette Echols (November 14, 2022).

[18] Comment of Joan Pasiuk (November 28, 2022); comment of Janet Pope (January 5, 2023).

[19] *See* Minn. Stat. § 216B.16, subd. 17(5) (requiring utility to file a schedule separately identifying costs for its 10 highest-paid executives).

[20] *See 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, and Order (June 12, 2017) (approving settlement agreement to increase rates by $244.721 million over 2016–2019); *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-13-868, Findings of Fact, Conclusions, and Order (May 8, 2015) (authorizing rate increases of approximately $58.908 million in 2014 and $105.854 million in 2015); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, Findings of Fact, Conclusions, and Order (September 3, 2013) (approving rate increase of $102.797 million for 2013). *See also In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Up Adjustments (August 5, 2022) (approving Xcel's 2021 sales true-up surcharge of $59.427 million as part of stay-out proposal); *In the Matter of Northern States Power Company d/b/a Xcel Energy for Approval of True-Up Mechanisms*, Docket No. E-002/M-19-688, Order

Further, as discussed above, the Commission received more than 20 public comments expressing dissatisfaction with the high level of compensation paid to Xcel's executives and many more comments discussing financial impacts the proposed rate increase would have on ratepayers.[21] These comments illustrate the difficulties consumers are facing and raise concerns about the reasonableness of the Company's executive compensation request. In light of these considerations, a closer review of Xcel's proposal for recovery of top-10 executive compensation expense is warranted.

Based on this record, the Commission concludes that Xcel has not demonstrated that full recovery of its proposed top-10 executive compensation would result in just and reasonable rates.

Xcel's primary justification for its executive compensation costs was that its employee compensation levels are based on a market comparison to other firms that compete with Xcel for employees. In this case, the Commission finds that argument unpersuasive.

First, the market comparison that Xcel conducted is based on other corporate officers, all of whom have a fiduciary duty of care to shareholders—but no comparable duty to ratepayers. While it may benefit shareholders to compensate Xcel's executives at the same level as profit-maximizing executives at other firms, the Commission is not persuaded that comparison is reasonable for setting rates in this case. Xcel has not provided a persuasive argument for why ratepayers should bear the full requested cost of market-based corporate compensation.

Second, the shareholder focus of Xcel's executive compensation package is further demonstrated by Xcel's AIP and LTI programs, discussed above, which closely tie overall executive compensation to shareholder earnings. That compensation structure focuses the executive team on shareholder benefits, which are not necessarily aligned with the interests of ratepayers.

Third, it does not appear that the Company meaningfully considered the impact of this high cost on ratepayers or explored the possibility of reducing any component of the executive compensation packages it offers as a means of shouldering the burdens of inflation alongside its customers.

Approving Implementation of Sales True-Up Adjustments (June 28, 2021) (authorizing Xcel to implement 2020 sales true-up surcharge of $119.4 million as part of stay-out proposal).

[21] *See, e.g.,* Comment of Araceli Morales (October 16, 2022); comment of Pangea Carpio-Evans (October 21, 2022); comment of Lydia McAnerney (October 26, 2022); comment of James and Katherine Anderson (October 27, 2022); comment of Angelina McDowell (November 2, 2022); comment of Claudia Furlong (November 4, 2022); comment of Nanette Echols (November 14, 2022); comment of Joan Pasiuk (November 27, 2022); comment of Robert Frank (November 28, 2022); comment of Josiah Gregg (November 29, 2022); comment of Tracy Kugler (December 4, 2022); comment of Catherine Day (December 6, 2022); comment of Joy Anderson (December 8, 2022); comment of Maia Homstad (December 9, 2022); comment of Mike Skucius (December 9, 2022); comment of Tim Ballman (December 13, 2022); comment of Sue VanZanden (December 15, 2022); comment of Joshua Lewis (December 16, 2022); comment of Lori Belz (December 27, 2022); comment of Catherine Early (January 4, 2023); comment of Janet Pope (January 4, 2023).

As with all rate-increase requests, the Commission has an obligation to both verify that the amount of costs is accurate and evaluate whether, based on the facts in the record and the application of its judgment, it is just and reasonable to include the cost in rates. In the Commission's judgment, Xcel has not made that showing in this case.[22]

Having concluded that Xcel's full request for recovery is not reasonable, the Commission must determine what level of recovery is appropriate. On this record, the Commission concludes that it would be reasonable for Xcel's ratepayers to pay an amount for Xcel's top 10 executives that is comparable to the amount they pay for their own executives in state government. Beginning in 2024, Minnesota's highest executive officer—its Governor—will be paid approximately $150,000 per year. The Commission finds that allowing recovery of compensation at a level similar to that of Minnesota's top executive on average for each of Xcel's 10 highest-paid executives reasonably reflects the level of expense that should be borne by ratepayers.

The Commission will therefore limit the level of executive compensation for the top 10 highest-paid employees and officers recoverable through Minnesota electric rates to $1.5 million per year in total. This decision also precludes Xcel from recovering any AIP expense for its 10 highest-paid officers and employees.

The Commission will require Xcel to calculate the Minnesota jurisdictional revenue-requirement adjustments resulting from these limitations on top 10 executive compensation and to file the calculations both in this docket and in the annual incentive compensation plan docket.

On this issue as with other compensation-related issues, the Commission's decision is limited to the amount of compensation costs that Xcel may include in its rates charged to Minnesota customers. The Company has been and continues to be free to compensate its employees at levels in excess of its authorized rate recovery if it chooses to do so.

VIII. Prepaid Pension Asset

A. Introduction

Xcel makes contributions to its pension plan to ensure adequate funding for future employee-benefit obligations. Since the pension plan's inception, the Company has contributed more to the plan than it has recognized in its actuarially calculated pension expense recovered from ratepayers. Xcel refers to the positive net balance resulting from the cumulative difference between its annual pension expense amount and the annual contributions made by shareholders to the qualified pension trust since it began offering the benefit as its "prepaid pension asset."

Xcel seeks to include a prepaid pension asset of approximately $167.3 million, less $46.8 million in accrued liabilities for retiree medical and post-employment benefits (discussed below), in rate base so it can earn a return on the net amount. The net total of the prepaid pension asset and

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[22] The Commission's conclusion is further supported by the fact that Xcel failed to file its top-10 executive expenses with its initial case, as required by Minn. Stat. § 216B.16, subd. 17. While Xcel stated that it provided courtesy copies of the expenses to the Commission, the Department, and the OAG, it is undisputed that the required information was not filed until the final days of the proceeding, and that other parties and the public did not have required opportunity to review Xcel's top-10 executive expenses.

accrued liabilities, which Xcel proposes to add to rate base, is approximately $95.4 million for 2022, $102.2 million for 2023, and $117.0 million for 2024.

B. Positions of the Parties

1. Xcel

Xcel requested that its net prepaid pension asset be included in rate base because it arose due to factors beyond the Company's control, including heightened funding requirements due to the federal Pension Protection Act and increasing pension liability due to the Federal Reserve's actions to reduce interest rates to stimulate the economy.

According to Xcel, this is an asset fully funded by shareholders that benefits customers by solidifying the status of the Company's pension plan, thereby helping Xcel to attract and retain the employees necessary to provide safe and reliable service. Xcel asserted that customers receive financial benefits in the form of significantly lower rates because shareholders have funded this prepaid pension asset and that any investment income from the shareholder-funded prepaid pension asset is passed on to ratepayers.

Xcel contended that rejecting the request for a return on prepaid pension asset would disincentivize the Company from contributing more than the minimum required amounts to its pension plan each year, which would negate the financial benefits to customers noted above.

Alternatively, Xcel argued that, if it is not authorized to earn a return on prepaid pension asset, it should be permitted to recalculate its pension expense without including the expected return on prepaid pension asset. Xcel argued that such a recalculation would avoid the inequity of customers effectively earning a benefit in the form of reduced pension expense reflected in rates without customers paying corresponding compensation to shareholders for their prepayment.

2. The Department

The Department opposed Xcel's request to earn a return on its prepaid pension asset, stating that Xcel's request is not consistent with Generally Accepted Accounting Principles or any current accounting standards.

Asserting that rate base is intended to provide a return on the total investment in, or fair value of, the facilities a utility employs in providing service, the Department argued that the prepaid pension asset does not fit within that principle. As opposed to a true asset used in providing service, the Department characterized the prepaid pension asset as essentially a temporary accounting difference resulting from quirks of applying differing accounting schemes to pension contributions and expenses, which does not warrant inclusion in rate base.

The Department cited the following additional reasons for denying a return on the prepaid pension asset:

- Utilities already recover allowable pension expense from ratepayers through O&M costs.

- Unlike the kinds of assets on which utilities are traditionally entitled to earn a return, the prepaid pension asset is nontangible and temporary in a way that cannot be accounted for like the depreciation and capital additions of tangible assets.

- Unlike other prepaid assets, the prepaid pension asset fluctuates depending on funding, market conditions, and amendments to the plan.

- The asset already earns a return in the form of investment returns.

- Including the prepaid pension asset in rate base would earn a return on out-of-test-year expenses for which the Commission has not authorized deferred accounting.

- Characterizing this amount as an asset is misleading because it does not account for the funding status of the entire pension plan; in fact, as of the end of 2021, Xcel's NSPM pension plan was underfunded by approximately $240 million.
- It would be impracticable to separate the prepaid amount attributable solely to the utility's contributions from that attributable to ratepayer contributions and market returns, so it cannot be shown that the asset is fully funded by shareholders.

Further, the Department opposed Xcel's alternative request to recalculate its pension expense without including the return on prepaid pension asset if the Commission excludes this item from rate base. The Department asserted that Xcel did not provide sufficient explanation or support for its recalculations, which show substantial revenue-requirement increases between $7.9 million and $9.1 million in each year of the rate plan. Further, the Department argued that allowing Xcel to recalculate its pension expense would advantage Xcel over other Minnesota utilities that have not been afforded the same opportunity.

3. XLI

XLI opposed Xcel's request to earn a return on its prepaid pension asset for substantially the same reasons raised by the Department. XLI emphasized that it is impossible to determine the funding sources of the prepaid pension asset reliably from the record and noted the statutory standard that any doubt as to reasonableness is to be resolved in favor of the consumer.

Additionally, XLI recommended against allowing Xcel to recalculate its qualified pension expense without applying the expected return on the prepayment portion of the trust because Xcel raised this alternative proposal late in the proceedings, limiting other parties' opportunity to review and respond to the proposal,[23] and because Xcel did not adequately support its request with persuasive evidence and argument.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's proposal to include a prepaid pension asset in rate base, finding that Xcel had not met its burden to show that it would be reasonable to

[23] Xcel briefly raised this argument in rebuttal testimony, but the issue was not addressed again by any party until a statement in Xcel's post-hearing reply brief that did not include a citation to the record. (Schrubbe Rebuttal at 32; Xcel Reply Brief at 46.)

do so. The ALJ agreed with the Department that Xcel's prepaid pension asset request is not consistent with Generally Accepted Accounting Principles and other guidance and that there is doubt with respect to the source of the asset's value because it is determined in part by market gains and losses. Additionally, the ALJ found that Xcel has not adequately justified deferred accounting for any surplus shareholder contributions exceeding the pension expense amounts approved for rate recovery.

However, the ALJ recommended that the Commission allow Xcel to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates.

D. Commission Action

The Commission concurs with the ALJ, the Department, and XLI that Xcel has not justified rate-base treatment of its prepaid pension asset. Accordingly, the Commission will require the Company to remove the prepaid pension asset from rate base.

In previous rate cases, the Commission has rejected the inclusion of prepaid pension asset in rate base because it is distinct from assets typically included in rate base. It already earns a return in the form of investment returns, it fluctuates in value, and it is misleading in that it does not account for the funding status of the entire pension plan. Pension-plan assets and benefit obligations fluctuate up and down depending on funding, market conditions, and amendments to the plan. The balances in the prepaid pension asset are temporary and fundamentally different from typical rate-base assets on which the Company earns a return. The Commission concludes that this reasoning is still sound.

Xcel has not pointed to any accounting requirements, rules, or laws that require prepaid pension assets to be included in rate base and earn a return; instead, the Company appears to argue simply that it would be reasonable for the Commission to allow such treatment. To the extent any party has pointed to specific requirements rather than policy preferences, the Department has raised valid concerns about whether Xcel's accounting proposal would be consistent with Generally Accepted Accounting Principles.

Minnesota law requires that Xcel be allowed to earn a return on its rate base and provides the following description of how rate base should be calculated:

> In determining the rate base upon which the utility is to be allowed a fair rate of return, the commission shall give due consideration to evidence of the *cost of the property* when first devoted to public use, to *product acquisition cost* to the public utility less appropriate depreciation on each, to c*onstruction work in progress*, to offsets in the nature of capital provided *by sources other than the investors*, and to other expenses of a capital nature.[24]

When evaluating what type of costs should be allowed to earn a return, this statutory language directs the Commission's attention to capital property that is acquired by the utility, which

[24] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

depreciates over time, and which is constructed. "Other expenses of a capital nature" likewise reflects a focus on longer-term investments as distinct from operating expenses. While the requirement to give "due consideration" does not prohibit the Commission from including other types of expenditures in rate base, as it has done for some other non-capital assets, the Commission is not persuaded that it would be reasonable to do so for the prepaid pension asset. Based on the record, the Commission finds that Xcel's prepaid pension asset is fundamentally different from capital expenditures and other allowed rate-base categories and that Xcel has not demonstrated it would be just and reasonable to allow a return on the prepaid pension asset.

Further, the Commission finds persuasive testimony of the Department's expert witness that the two components of the prepaid pension amount—actuarially determined pension expense and pension contributions—can vary significantly from year to year depending on actuarial assumptions and the Company's decisions in any given year about whether to contribute more than the legally required minimum amount. Not only can a prepaid pension asset fluctuate over time, but the asset is temporary in that a change in market returns, legally required minimum contributions, or actual contributions can turn the asset into a liability. At a minimum, the testimony and arguments raise doubts about the amount and permanence of the prepaid pension asset. The Commission is to resolve those doubts in favor of ratepayers.

The Commission finds that Xcel's arguments are unpersuasive, and that the Company has failed to carry its burden to prove that its proposed ratemaking treatment of its prepaid pension asset would result in just and reasonable rates.

The Commission respectfully disagrees with the ALJ's recommendation to allow Xcel to recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust. Although Xcel noted the results of its recalculations in a spreadsheet comparing the impacts of the ALJ's and parties' recommendations on the revenue requirement, the Company did not provide sufficient details to explain how it arrived at these adjusted totals or support the reasonableness of the proposed adjustments. Further, Xcel did not introduce this proposal until late in the proceedings, and parties therefore had a limited opportunity to respond. Based on the limited record on this issue, the Commission is not persuaded that Xcel met its burden to support its request. Therefore, the Commission will not allow Xcel to reflect its recalculated qualified pension expense in rates.

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

A. Introduction

Over the life of its retiree medical and post-retirement benefits plans, Xcel has recovered from customers more than it has contributed to those plans, resulting in unfunded liabilities. Xcel sought to include these accrued liabilities in rate base along with its request to include prepaid pension asset in rate base, discussed above.

B. Positions of the Parties

Xcel acknowledged that its accrued liabilities for retiree medical and post-retirement benefits should be treated consistently with the prepaid pension asset. The Company's reasoning for including these liabilities in rate base echoed its reasons for its prepaid-pension-asset request, discussed above.

The Department and XLI opposed Xcel's request to include these accrued liabilities in rate base for the same reasons they opposed including the prepaid pension asset in rate base—largely because these balances are distinct from traditional rate-base assets in multiple ways, as discussed above.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's request to include in rate base accrued liabilities for retiree medical and post-employment benefits, for the same reasons discussed above related to excluding prepaid pension asset from rate base.

D. Commission Action

The Commission agrees with the ALJ and the parties that accrued liabilities for retiree medical and post-employment benefits should be treated the same as prepaid pension asset for purposes of this rate case. Like the prepaid pension asset, these accrued balances are fundamentally different from typical rate-base assets in that they represent the cumulative difference between expenses and contributions, they fluctuate in value, and they are difficult to estimate accurately. Accordingly, having decided to exclude prepaid pension asset for the reasons discussed above, the Commission will also adopt the ALJ's recommendation to exclude from rate base accrued liabilities for retiree medical and post-employment benefits for the same reasons.

X. Energy Supply Operations and Maintenance Expenses

A. Introduction

Xcel's energy supply business area is responsible for operating and maintaining the Company's non-nuclear generation portfolio, managing capital construction projects, overseeing environmental compliance, and supporting the coordination of generating-unit dispatch with Midcontinent Independent System Operator, Inc. (MISO). Xcel's energy supply O&M budget reflects the costs to operate and maintain the Company's non-nuclear generating facilities on a day-to-day basis, including labor, chemicals, materials, outside services, rents, land easements, and employee expenses. In developing its energy supply O&M budgets, Xcel reviews historical costs and factors in anticipated changes such as changes to plant operating profiles, new and retiring generation, overhaul schedules, and plant improvements.

Xcel proposed the following budgets for energy supply O&M expense: $154.6 million for 2022, $160.8 million for 2023, and $157.7 million for 2024.

Xcel's proposed average energy supply O&M budget for the years 2022–2024 is 13.8% higher than its average yearly budget over 2018–2020, and between 8.8% and 12.8% over its 2021 actual expense. Xcel asserted that the primary drivers of this increase are new wind farm O&M contracts and land easement payments.

B. Positions of the Parties

1. The Department

The Department argued that Xcel did not meet its burden to prove its requested energy supply O&M expense is just and reasonable. Raising a concern that utilities have an incentive to overestimate expenses in test years to secure higher rates and then cut corners on actual spending between rate cases to increase profits, the Department argued that Xcel has not met its burden to prove that its test-year budgets are representative of actual needs and not overestimated for profit-inflating purposes.

As possible evidence of this incentive having led Xcel to overestimate costs to inflate rates, the Department asserted that Xcel has over-forecasted its energy supply O&M expense by between $6.0 million and $28.2 million each year between 2016 to 2021 and, since 2016, has collected $97.6 million more from ratepayers than it actually spent on this expense category. The Department also questioned the reasons for year-to-year volatility in the Company's 2016–2021 energy supply O&M expenses.

The Department disputed some of Xcel's claimed drivers of the increase in forecasted energy supply O&M expense. For example, the Department challenged Xcel's assumption of a 3% increase in internal labor costs because the employee headcount is forecasted to decrease after 2022. Additionally, the Department contended that Xcel's retirement of Unit 2 of the Sherburne County Generation Facility (Sherco 2) in 2023 did not appear to be sufficiently accounted for. Based on its analysis that Xcel did not meet its burden, the Department recommended reducing the energy supply O&M expense by $5.3 million in each year, which is equal to the amount Xcel over-collected in the Minnesota jurisdiction in 2021. The Department argued that reducing Xcel's budget by $5.3 million each year would reasonably approximate a representative amount of energy supply O&M expense to sustain Xcel's normal operations.

2. Xcel

Xcel criticized the Department's analysis as simplistically looking backward at past costs rather than evaluating the Company's current generation portfolio. In response to assertions that Xcel has historically over-forecasted this expense category, the Company argued that its generation fleet underwent significant unanticipated changes after budgets were created for its 2016 rate case, including transitioning two of the Company's coal-fired generating plants from year-round to seasonal operation in 2020.

Of the $6.5 million difference between Xcel's forecasted and actual energy supply O&M expense for 2021, the Company attributed $5.5 million to liquidated damage payments received from wind turbine manufacturers that ultimately flowed back to customers through the renewable energy standard (RES) rider. Xcel argued that these payments could not have been forecast in advance because they are dependent on each wind facility's actual performance in a given year. Therefore, Xcel argued that these historical variations in forecasted and actual expense do not call into question the reasonableness of the Company's accounting practices.

Xcel argued that year-to-year fluctuations in its energy supply O&M expenses are primarily due to planned major overhauls at the Company's coal and natural gas facilities, which are essential to keeping the facilities running efficiently, safely, and in compliance with regulations. Xcel stated that in years with planned major overhauls, O&M expenses increase for internal labor, contract labor, and materials needed to complete these overhauls. Further, Xcel stated that the addition of new renewable generation also contributes to year-to-year O&M cost fluctuations. Xcel asserted that its forecast assumed reductions of 51 full-time-equivalent employees between 2022 and 2024 and accounted for the retirement of Sherco 2, so these changes do not support further reducing energy supply O&M recovery as the Department suggested. Xcel noted that the retirement of Sherco 2 may not lead to a net reduction in O&M costs because the Company will need to replace Sherco 2's generation through increased dispatch of other units or adding new generation facilities.

Further, Xcel argued that the Department's recommended reduction of $5.3 million per year is unreasonable because Xcel's energy supply O&M expenses have increased since it created its budgets in this rate case for the following reasons: (1) inflation, (2) wage increases for collective bargaining employees due to new agreements with unions, (3) the proposed life extension of wind facilities, and (4) year-round rather than seasonal operation of the King and Sherco 2 coal facilities in 2022–2023.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to establish that its forecasted energy supply O&M budget is just and reasonable. The ALJ did not concur with the Department's rationale that the Company's over-recovery in past years justifies denying recovery of the forecasted amounts in this case. The ALJ found that Xcel's prior over-recoveries were largely attributable to events the Company could not reasonably have anticipated, while its 2022–2024 forecast appears to be reasonably calculated based on realistic projections of anticipated costs of furnishing service, which the Department did not persuasively dispute. The ALJ therefore recommended that the Commission allow Xcel to recover its proposed energy supply O&M expenses without the Department's adjustment.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve recovery of Xcel's energy supply O&M expenses totaling $154.6 million, $160.8 million, and $157.7 million for 2022, 2023, and 2024, respectively. Xcel described in detail how it developed each component of the budgets and why the budgeted amounts were reasonable and necessary to support the operation and maintenance of the Company's generation facilities. Xcel also offered reasonable explanations for the increases in these costs over previous years and variations between forecasted and actual energy supply O&M expense in past years.

XI. Business Systems Operations and Maintenance Expenses

A. Introduction

Xcel's business systems O&M budget includes costs related to the operation and maintenance of information technology (IT) services across Xcel Energy, including software systems, computers, printers, phones, radio systems, servers, annual software contract and license fees, and maintenance agreements for existing software and hardware. This expense category also includes non-capitalized costs associated with developing, enhancing, and maintaining new or existing IT systems.

Xcel's proposed business systems O&M budget for the Minnesota electric jurisdiction is $89.9 million in 2022, $96.2 million in 2023, and $103.8 million in 2024, exclusive of the Advanced Grid Intelligence and Security (AGIS) costs being recovered separately through the Transmission Cost Recovery rider.

B. Positions of the Parties

1. The Department

Noting that Xcel's requested business systems O&M budget for 2022–2024 reflects a 32.2% growth rate over 2021 actual spending in this category, the Department argued that the Company has not met its burden to justify the substantial increase. The Department argued that Xcel's requested increase is inconsistent with the Company's own historical expense, which averaged $77.2 million in this category each year from 2018–2021.

The Department also stated that Xcel has a history of over-forecasting its business systems O&M expense and raised concerns about utility incentives to overestimate test-year O&M budgets to inflate rates, only to cut spending in an attempt to increase profits between rate cases. For example, Xcel's actual 2021 expense in this category was 16% lower than projected.

Further, the Department claimed that Xcel's proposal significantly deviates from IT spending trends in the industry. The Department cited a 2021 report stating that IT budgets were expected to increase by an average of 3.1% in North America or 3.6% worldwide, which is much lower than Xcel's requested 14.5% increase for 2022.

The Department analyzed some of the individual programs and expenses Xcel claimed were driving costs in this category but determined that the data did not adequately explain the requested overall increase.

Based on its analysis that Xcel did not meet its burden to justify its requested costs, the Department recommended that the Commission reduce the Company's recovery in this category to an annual amount based on Xcel's actual business systems O&M expense for 2021, adjusted to reflect continued inflation at a high rate of 7.5% over 2021 actuals in 2022, 7.5% in 2023, and 7.0% in 2024. The Department's proposed adjustments would reduce Xcel's revenue requirement by $5.5 million in 2022, $5.5 million in 2023, and $6.9 million in 2024.

2. Xcel

Xcel contended that its proposed business systems O&M budget reflects the reasonable costs of the Company's growing needs for IT services and is representative of the level of business systems O&M necessary to support an appropriate level of service to the Company's customers year over year. Xcel stated that its customers have benefited from lower IT costs in past years but that technology investments are now necessary to ensure safe and reliable service. It stated that investments in technology help the Company's other business areas to maintain and enhance the quality of service to customers.

Xcel attributed much of the overall budget increase to rising software license and maintenance costs, company labor costs, shared assets costs, and network services costs, in addition to necessary updates to address cyber security concerns and other vulnerabilities.

Xcel described the need for some specific components adding costs to this category, including the need to maintain the new General Ledger and Work and Asset Management system, which was a significant undertaking as part of the Company's Productivity Through Technology initiative. Xcel also explained new capital projects such as the Digital Operations Factory, Customer Enhancements including the Customer Experience program, and the Core Human Resources Application project, which also added costs to the business systems O&M budget. Xcel asserted that no party challenged the reasonableness of undertaking any of these IT projects.

Opposing the Department's proposed adjustments, Xcel argued that the Department's analysis unreasonably focused on historical trends and did not adequately consider, or effectively dispute, Xcel's explanations for the factors driving these costs and the reasons why the costs are higher and increasing at a faster rate than in past years. Xcel contended that the Department failed to identify any unreasonable cost associated with any particular business systems capital investment or O&M expense to support its criticism of the overall budget, and that it would be unreasonable to disallow any of these costs even though they are associated with reasonable investments solely on the ground that overall spending in this category is higher than it has been in past years.

To the extent that the Department analyzed some individual projects and budget items, Xcel argued that the Department's analysis is of limited value because it did not account for all of the new capital projects and other factors driving business systems O&M costs.

Xcel challenged the applicability of the report the Department cited regarding IT spending growth rates, noting that they pertained to worldwide IT spending forecasts and were not specific to similarly situated U.S. utilities or O&M spending forecasts.

Xcel argued that the Department's recommendation to set the budget at the level of the Company's 2021 actual business systems O&M spending, adjusted for inflation, is not sufficiently tied to any analysis of the reasonableness of the Company's costs and is not supported by the record. Further, Xcel argued that the Department's proposed inflation rates of 7.5% and 7.0% are not supported by evidence. Xcel countered that the Department's suggested inflation rate for 2022 is below the level reflected in the record and, therefore, would result in rates insufficient to recover rising costs for new purchases even without the addition of new projects and other drivers of cost increases.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Xcel met its burden to demonstrate that its proposed business systems O&M costs are reasonable. The ALJ found that Xcel persuasively explained the drivers for its claimed costs and showed how these investments are necessary to maintain and enhance service to customers. The ALJ found that the Department's analysis, which focused on historical and industry trends in IT spending growth generally, did not adequately consider or rebut the reasonableness of the specific cost-driving factors or the accuracy of the associated costs Xcel established in the record. Nor did the Department persuasively demonstrate the reasonableness of its proposed alternative budget based on 2021 actual costs and inflationary adjustments, in the ALJ's view. The ALJ therefore recommended that the Commission allow Xcel to recover its proposed business systems O&M expenses without modification.

D. Commission Action

The Commission concurs with the ALJ that Xcel has met its burden to show that its proposed business system O&M costs are reasonable. The record contains substantial evidence supporting both Xcel's cost estimates and the need for and reasonableness of the underlying investments to enable the Company to maintain and enhance its provision of service to customers. The Commission will therefore approve Xcel's Minnesota jurisdictional business systems O&M expenses of $89.9 million for 2022, $96.2 million for 2023, and $103.8 million for 2024.

XII. Income-Tax Tracker Amortization

A. Introduction

Xcel requests to collect approximately $6.9 million in income tax and interest that the Company paid for the tax years ending in 2010–2016 following IRS audits that concluded in 2017, 2018, and 2020. Amortized over the three-year rate plan, Xcel proposes to recover $2.492 million in 2022, $2.300 million in 2023, and $2.110 in 2024 for these post-audit tax liabilities.

Generally, when determining a utility's revenue requirement in a rate case, the Commission evaluates the utility's investment in capital assets, operating revenues, and operating expenses based on a representative test year (or in the case of an MYRP like this one, a specific set of recent or forecasted test and plan years). Generally, the operating expenses are limited to those expenses forecasted to be incurred in the designated test and plan years.

To recover out-of-test-year expenses, a utility generally must petition for approval to use deferred accounting. Deferred accounting is a regulatory tool that allows a utility to postpone the standard accounting treatment otherwise required for a particular item by tracking out-of-test-year expenses and seeking recovery in a future proceeding. Deferred-accounting requests are subject to Commission discretion and are granted only upon a showing of good cause.[25]

Historically, the Commission has permitted deferred accounting in unusual cases where utilities incur out-of-test-year expenses that, because they are unforeseen, unusual, and large enough to have a significant impact on the utility's financial condition, should be eligible for possible recovery in the next rate case. Deferred accounting has also been permitted when utilities have incurred sizeable expenses to meet important public-policy mandates.

B. Positions of the Parties

1. The Department

The Department recommended that the Commission deny Xcel's request because the Company has not received authorization to defer these out-of-test-year tax expenses. In the 1992 Rate Case

[25] Minn. R. 7825.0300, subp. 4.

Order, the Commission explicitly required Xcel to petition for deferred-accounting status of tax credits and debits at the time when final decisions are received on disputed items.[26]
The Department argued that Xcel's current request is untimely because the Company received the audit decisions in 2017, 2018, and 2020, but did not promptly petition for deferred accounting upon any of those final decisions. The Department argued that requiring utilities to petition for deferred accounting as soon as they know of additional costs provides important protections for ratepayers, as rate cases are already large and complex undertakings and the petition process allows the Commission to maintain a greater degree of control over the items deferred to a given rate case.

The Department argued that, if advance petitions for deferred accounting were not required, it would be easier for utilities to exploit rate cases as opportunities to reach back into past years and attempt to collect costs of furnishing past service from current ratepayers who may not have benefited from those past expenditures, on top of the rates that were approved and in effect during the past years. This would raise concerns both about (1) the intergenerational inequities of requiring current customers to pay for the costs of providing past service that did not benefit the current customers and (2) the reasonableness of allowing utilities to recover unanticipated out-of-test-year expenses when they presumably would not be required to refund any unanticipated surpluses.

Further, asserting that customers paid Xcel significantly more for income tax than the Company remitted to taxing authorities from 2010–2021, the Department argued that Xcel has not shown that the requested amounts have not already been collected through rates.

2. Xcel

Xcel claimed that it was not required to petition for deferred accounting immediately at the conclusion of each audit because there has been a historical practice of including income tax in rate cases. The Company contended that its filing initiating this rate case was its first opportunity to request recovery of these costs since its last rate case was filed in 2015.

Xcel argued that deferred accounting is appropriate in this case because no party disputes the amount of tax-audit credits and debits the Company seeks to recover and because income-tax audits are beyond the Company's control and their timing and outcomes are unpredictable. Additionally, Xcel argued that public policy supports deferred recovery of these costs because the post-audit tax and interest expenses arose out of Xcel's prudent efforts to keep income tax low during the relevant tax years. Xcel argued that denying its request would deter the Company from aggressively pursuing its options to minimize tax liability under the tax code. Xcel implied that, if it knew it could not defer these expenses, its incentive would be to not pursue arguable tax-reduction options and instead to pay the highest possible tax amount and pass that cost on to customers, rather than risk unrecoverable out-of-test-year tax liability after a future audit.

Finally, the Company disputed the claim that Xcel already recovers more income-tax expense from customers than it pays to taxing authorities, asserting that any difference between taxes recovered from customers before they are paid to the government reduces rate base, so customers are not ultimately charged more for taxes than the Company incurs.

[26] 1992 Rate Case Order at 58.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's arguments unpersuasive. She found that, before the Company initiated this rate case in September 2021, it had more than a year in which it could have petitioned the Commission to approve deferred accounting for the last-resolved of the audits, which had a final decision in second quarter 2020, and several years for the other audits which were resolved in 2017 and 2018. Finding that Xcel offered no satisfactory explanation for failing to request deferred-accounting authorization at the time the audit decisions were issued, the ALJ declined to consider the merits of Xcel's untimely deferred-accounting request based on her determination that to do so would be inconsistent with the 1992 Rate Case Order.

The ALJ therefore recommended that the Commission deny Xcel's request to recover costs arising from the income-tax audits for the tax years ended 2010–2016 and adopt the Department's corresponding reductions to the revenue requirement.

D. Commission Action

The Commission concurs with the ALJ and will therefore deny recovery of the costs arising from income-tax audits for the tax years ending in 2010–2016, thus requiring Xcel to remove the corresponding $2.492 million, $2.300 million, and $2.110 million from its revenue requirements for 2022, 2023, and 2024, respectively.

These are out-of-test-year expenses for which Xcel failed to timely petition for deferred-accounting authorization. Requiring utilities to petition for deferred accounting in advance helps the Commission to maintain control over the items deferred to a given rate case to ensure that all issues receive due attention—including consideration of customer impacts and the public interest—in large and complex rate-case proceedings.

Moreover, considering the potential for intergenerational inequities and concerns about the equity of utilities generally using deferred accounting to track increases but not decreases in costs outside of a rate case (thus likely benefiting the utility over ratepayers), the Commission is not persuaded that there is good cause to grant an exception to accounting standards for these expenses on this record.

XIII. South Dakota Aurora Cost Amortization

A. Introduction

In proceedings stemming from Xcel's 2010 resource plan, the Commission required Xcel to negotiate a power-purchase agreement for the Aurora Solar Project, finding it appropriate for Xcel's system.[27] The Commission approved a power-purchase agreement (PPA) between Xcel and Aurora Distributed Solar, LLC (Aurora), relating to the Aurora Solar Project.[28]

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[27] In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need, Docket No. E-002/CN-12-1240, *Order Directing Xcel to Negotiate Draft Agreements with Selected Parties* (May 23, 2014).

[28] *In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket No. E-002/CN-12-1240,

In a settlement stipulation negotiated between Xcel and the South Dakota Public Utilities Commission (SDPUC) staff, Xcel agreed not to recover the actual costs of the Aurora Solar PPA from South Dakota ratepayers. Instead, Xcel agreed in the settlement to limit its recovery from South Dakota customers to an energy proxy price derived from the system average cost of fuel and purchased power with no capacity component.

In this rate case, Xcel requests to recover from Minnesota customers the portion of the Aurora Solar PPA cost that it agreed not to recover from South Dakota customers under the SDPUC settlement. As proposed, the Company would recover the difference between the PPA price and the SDPUC-approved proxy price from January 1, 2017, to January 1, 2024, to be amortized over a two-year period. Then, beginning January 1, 2024, Xcel requests to include this portion of Aurora Solar PPA costs in its Fuel Clause Adjustment Rider so it may continue collecting the unrecovered South Dakota costs from Minnesota customers.

The Commission previously denied a similar request relating to the North Dakota share of Aurora Solar PPA costs. In 2015, after the North Dakota Public Service Commission (NDPSC) denied Xcel's request to recover the North Dakota jurisdictional share of Aurora Solar PPA costs from North Dakota ratepayers, Xcel requested approval to recover these North Dakota costs from Minnesota ratepayers. The Commission denied that request in 2016, reasoning that the Aurora Solar project was approved as a cost-effective resource addition in the context of Xcel's integrated system as a whole and that Xcel had not shown that it would be just and reasonable for Minnesota ratepayers to subsidize North Dakota customers' solar energy consumption.[29]

B. Positions of the Parties

1. The Department

Echoing the reasons articulated in the Commission's 2016 order denying recovery of North Dakota PPA costs from Minnesota customers, the Department argued that it would be unjust and unreasonable to require Minnesotans to pay for Aurora Solar PPA costs that are rightfully attributable to South Dakota customers.

The Department asserted that the PPA was approved as a cost-effective addition to meet capacity needs in Xcel's system as a whole and, accordingly, fundamental cost-causation and allocation principles require that its costs be allocated across the entire system like any other shared system cost. The Department contended that Xcel provided no data to support a finding that the project is a reasonable way to meet the needs of only Minnesota ratepayers or that it would be just and reasonable for Minnesotans to subsidize this benefit for South Dakotans.

The Department disputed Xcel's argument that Minnesota customers should cover these costs because Minnesota policies favoring renewable and solar energy also factored into the Commission's selection of the Aurora Solar PPA; in the Department's view, any additional

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Order Approving Power Purchase Agreement with Calpine, Approving Power Purchase Agreement with Geronimo, and Approving Price Terms with Xcel (February 5, 2015).

[29] *In the Matter of the Petition of Northern States Power Co. d/b/a Xcel Energy for Approval of Cost Recovery of the Aurora Power Purchase Agreement*, Docket No. E-002/M-15-330, Order Denying Recovery of North Dakota Related Purchased-Power Costs at 4 (April 13, 2016).

benefit toward Minnesota renewable-energy goals does not negate the capacity benefits South Dakota customers receive from the project or the requirement that South Dakota customers pay for such benefits under fundamental cost-allocation principles.

Additionally, the Department argued that Xcel's request to recover PPA costs incurred from 2017–2021 should be denied because these are out-of-test-year costs for which the Company did not timely petition for deferred-accounting authorization and for which good cause has not been shown to authorize deferred accounting.

2. Xcel

Xcel argued that it is reasonable to recover these costs from Minnesota ratepayers because the Commission directed the Company to enter into the Aurora Solar PPA despite Xcel's concerns about the cost of the project. Xcel stated that, in approving the Aurora Solar PPA, the Commission referred to Minnesota policies favoring renewable energy and greenhouse-gas reduction which have no analog in South Dakota. Because South Dakota law does not recognize renewable-energy generation and the reduction of greenhouse-gas emissions from electricity generation as policy goals, Xcel characterized these features of the PPA as Minnesota-specific benefits for which Minnesota customers alone should pay.

Xcel sought to distinguish this case from the 2016 North Dakota decision, arguing that the 2016 Commission decision was predicated in part on an agreement in which Xcel agreed to waive its termination right and Aurora agreed to reimburse Xcel if neither the North Dakota nor the Minnesota commissions allowed recovery of the North Dakota costs. In contrast, the record contains no evidence that Xcel has an alternative means to recover the South Dakota costs if recovery is denied in this proceeding.

C. Recommendation of the Administrative Law Judge

Noting that the Commission's 2016 denial rested on a determination that the Aurora Solar PPA was cost effective for Xcel's system as a whole and that it would be unreasonable to require Minnesota customers to subsidize this benefit for customers in another state, the ALJ concluded that the same reasoning applies equally in this case.

The ALJ found that Xcel did not meet its burden to show that it would be just and reasonable for Minnesota ratepayers to pay for South Dakota customers' solar energy usage. Additionally, the ALJ found that Xcel did not establish that the SDPUC settlement—in which Xcel voluntarily agreed to absolve South Dakota ratepayers of these costs—is consistent with Minnesota ratepayers' interests or reflects a just and reasonable cross-jurisdictional allocation of system costs. The ALJ determined that Xcel's voluntary settlement of the issue of recovery in South Dakota provides an additional independent basis to conclude that Xcel has not met its burden to establish the reasonableness of recovering South Dakota costs from Minnesota ratepayers. Therefore, the ALJ recommended that the Commission deny Xcel's request to recover South Dakota Aurora Solar PPA costs both through base rates in 2022–2023 and through the Fuel-Clause Adjustment Rider starting in 2024, and adopt the corresponding revenue-requirement reductions of $2.857 million in 2022 and $2.689 million in 2023.

D. Commission Action

The Commission agrees with the ALJ that Xcel has not shown that it would be just and reasonable to require Minnesota customers to pay the requested portion of South Dakota Aurora Solar PPA costs. Therefore, the Commission will deny Xcel's request to recover South Dakota Aurora PPA costs through base rates in 2022–2023 and through the Fuel-Clause Adjustment Rider starting in 2024 and will adopt the corresponding revenue-requirement reductions of $2.857 million in 2022 and $2.689 million in 2023.

Xcel's request stands at odds with fundamental cost-causation and allocation principles. In its order approving the Aurora Solar PPA, the Commission found that the PPA was a reasonable and cost-effective investment for Xcel's distribution system as a whole, not limited to Minnesota. Although the order addressed beneficial environmental outcomes, the approval was also based on findings that the PPA would provide a cost-effective source of energy to support the reliability and adequacy of Xcel's power supply while alleviating transmission-line congestion and providing other benefits unrelated to Minnesota's renewable-energy and climate policies which benefit customers throughout the Company's multistate service area. The existence of environmental benefits recognized under Minnesota policy does not negate the other unrefuted benefits the PPA delivers to customers in other states within Xcel's integrated system.

Despite implying that Minnesota renewable-energy policies prompted the Commission to select the Aurora Solar PPA at a higher cost than the Company would have incurred in the absence of any renewable-energy preferences, Xcel has not demonstrated that the portion of South Dakota's costs it seeks to impose on Minnesotans is a reasonable approximation of any incremental cost attributable to Minnesota policies or of any incremental value that Minnesota customers purportedly receive from this PPA over an alternative as a result of Minnesota-specific policies.

Rather, the South Dakota cost that Xcel would impose on Minnesotans derives from the proxy price set in the Company's settlement agreement with SDPUC staff. The proxy price was not imposed against the Company's objection through an SDPUC decision or court order. To the contrary, in settling, Xcel voluntarily agreed to waive its right to recover from South Dakota customers their full jurisdictional share of Aurora Solar PPA costs. The record contains no persuasive evidence that the settlement, the settled proxy price, or the resulting balance that Xcel seeks to impose on Minnesota customers are consistent with Minnesota ratepayers' interests or reflect a just and reasonable cross-jurisdictional allocation of these system costs.

Because it would be neither just nor reasonable for Minnesota customers to pay the portion of South Dakota Aurora Solar PPA costs Xcel agreed not to recover from South Dakota customers under its settlement with SDPUC staff, the Commission will deny Xcel's request and require the Company to remove the corresponding amounts from its revenue requirement.

XIV. Luverne Wind2Battery Removal Costs

A. Introduction

The Luverne Wind2Battery System is a one-megawatt (MW) wind energy battery storage system that was installed in December 2009 and connected to a nearby 11-MW wind farm as one of the first utility-scale batteries installed in the United States. Xcel took on this project as an experimental pilot to assess the utilization of battery storage in conjunction with wind production. The project was decommissioned in 2019, years after the pilot study had been completed, when the battery was approaching the end of its useful life and its manufacturer informed Xcel that it would no longer manufacture replacement parts for the battery. Xcel explored options for future use of this asset but ultimately determined that the removal of the battery was the best course of action and now requests to recover its costs for removing the battery through a reserve reallocation.

When the battery was placed in service in 2009, Xcel proposed a net salvage value of 0% because it assumed the net cost of disposal would be approximately equal to the salvage value of materials recovered from the battery. Since then, Xcel has performed three comprehensive dismantling studies: in 2010, 2015, and 2020. Xcel did not update the battery's salvage value or provide supporting documentation for its removal costs following either its 2010 or its 2015 dismantling studies. As late as the 2015 study, Xcel maintained the same assumption that the disposal cost and the value from recycling the battery would offset each other. At that time, Xcel considered the cost of further investigating the net salvage value to be too large relative to the battery's value to be worth pursuing.

Xcel did not provide any updated estimates for Wind2Battery dismantling costs during the battery's service life. According to the Company, it first began investigating the removal cost once it learned that the battery was entering legacy status in 2018.

In its 2020 remaining lives and depreciation study, Xcel updated the net salvage value for the battery to –135.6%. Xcel sought to recover $5.6 million in decommissioning costs through a reserve allocation in its 2020 remaining lives docket, but at that time the Company cited only a manufacturer's representation and not a dismantling study in support of its estimation, and the Commission determined that the issue should be revisited in this rate case following additional record development.[30]

In this docket, Xcel filed a 2022 dismantling cost study which the Company maintains does not modify its previous $5.6 million reserve allocation request. The study estimated that the expected total for decommissioning the Wind2Battery asset is $2.14 million, with a worst-case upper estimate of $5.26 million. The higher estimate reflects the cost if damage or leakage occurs requiring special handling and an increase in recycling and other costs.

Xcel proposed to perform a reserve reallocation to recover the estimated costs of removal of the Luverne Wind2Battery project. The Company initially requested to shift $5.6 million of reserves from Other Production plants and apply it toward battery removal. However, after oral argument, Xcel agreed to reduce its reallocation request to no more than $2.14 million and agreed that it would not seek any additional reserve reallocations from assets in the Other Production account or seek recovery of any additional costs associated with Wind2Battery if this request is granted.

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[30] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of its 2020 Annual Review of Remaining Lives and Five-Year Depreciation Study*, Docket No. E,G-002/M-19-723, Order Approving Petition in Part (September 2, 2021).

If the actual cost to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system turns out lower than the reallocated amount, Xcel agreed to perform an inverse reallocation to return the unused reserves back to the groups they came from in a future proceeding.

B. Positions of the Parties

1. Opponents of Xcel's Proposal

The Department and the OAG opposed Xcel's proposed reserve reallocation or any recovery of costs for removal of the Wind2Battery asset, arguing that it would contravene standard depreciation practices and create intergenerational inequities.

Depreciation expense, including removal cost, is normally collected while the asset is in service so that any removal costs are collected from the same ratepayers that benefit from the asset. The Department and the OAG argued that Xcel's proposal would violate this standard practice and unjustly impose removal costs on customers that have not benefited from the battery.

The OAG and the Department argued that Xcel had the opportunity to recover estimated removal costs during the battery's useful life and failed to avail itself of that opportunity, and that it would be unjust to grant its untimely request now.

For these reasons, the Department and the OAG recommended that the Commission deny Xcel's reserve-reallocation request, disallow recovery of any Wind2Battery removal costs, and remove any depreciation expense for the Wind2Battery asset for 2022–2024.

Further, because the Wind2Battery depreciation expense for each year was not clearly identified in the record, the Department and the OAG recommended that the Commission require Xcel to make a compliance filing explaining the calculation of those depreciation-expense amounts and demonstrating that they have been removed from rates.

2. Xcel

In defense of its failure to recover removal costs during the battery's useful life, Xcel argued that its initial dismantling estimate of $0 was reasonable based on the information that was available at the time, including prevailing assumptions about the salvage value of components of the battery and discussions with its initial vendor. Further, Xcel contended that the experimental nature of the battery used in the project created challenges in estimating the disposal cost, excusing Xcel's delay in investigating the cost and requesting associated cost recovery.

Additionally, Xcel argued that its proposed reserve reallocation would not result in intergenerational inequities because the Wind2Battery pilot program generated significant research value, leading to the development of valuable information about the use of sodium sulfur batteries for renewable energy storage, which benefits current customers.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny Xcel's request to recover any Luverne Wind2Battery removal costs from ratepayers. The Company is obligated to provide five-year updates on salvage rates under Minn. R. 7825.0700 but failed to do so with respect to this project. The ALJ was not persuaded by Xcel's arguments that the novelty of the project made it infeasible to estimate removal and salvage costs earlier; to the contrary, the project's novelty and status as a pilot should have prompted Xcel to be more diligent about evaluating this aspect of the project and revisiting early assumptions during the project's useful life rather than forgoing a 2015 reassessment and relying on assumptions made when first placing the new, experimental technology into service until the battery entered legacy status. The ALJ found that Xcel had not provided an adequate justification for failing to act sooner to estimate and recover the costs.

The ALJ also found unpersuasive Xcel's argument that the pilot's research benefits justify recovering the removal costs from current ratepayers. The ALJ stated that this rationale is unsupported by typical ratemaking principles and generally accepted utility accounting practice, which strive to provide for recovery for depreciation of utility property while the property is used and useful in rendering service to the public. The ALJ added that the insights gained from the pilot project are distinct from the asset, have not been quantified, and do not justify ongoing recovery for the asset from ratepayers.

For these reasons, the ALJ recommended that the Commission disallow Xcel's requested reserve reallocation for the Luverne Wind2Battery removal project and adopt the Department's proposed adjustment to Xcel's revenue requirement corresponding with that decision.

Additionally, the ALJ recommended that the Commission adopt the OAG's recommendation to disallow the associated depreciation expense of $300,000 for the Minnesota jurisdiction in the 2022 test year and amounts to be identified by Xcel in 2023 and 2024.

Alternatively, if the Commission finds it reasonable to allow a reserve reallocation for these costs, the ALJ would recommend limiting the amount to $2.14 million and requiring Xcel to return any unused reallocated amounts to the groups they originated from if actual costs are lower than the amount reallocated. The ALJ found that $2.14 million—the expected total from Xcel's dismantling study—is a reasonable cost to dismantle the Wind2Battery system, but that the prudence of any cost above that total has not been demonstrated.

D. Commission Action

Respectfully, the Commission disagrees with the ALJ's recommendation to deny Xcel's proposed reserve reallocation for Wind2Battery removal costs.

Although the OAG and the Department raised important questions about whether Xcel should have taken further actions to estimate dismantling costs earlier and recover those costs during the battery's useful life, the Commission is persuaded by Xcel's argument that the novelty and experimental nature of the project presented barriers to obtaining that information earlier in the course of the battery's development and operation such that the Company's actions of relying on the limited information it knew at the time, including representations from the initial vendor, fell within the broad range of reasonable utility conduct under the circumstances.

Furthermore, although the Commission recognizes the concerns that this reserve reallocation is a departure from traditional practices, the Commission is persuaded that current customers will benefit from the valuable information about the use of sodium sulfur batteries for renewable energy storage developed through the Wind2Battery pilot and, therefore, granting a limited reserve allocation will not result in unreasonable intergenerational inequities. Based on the unique circumstances demonstrated in the record, the Commission finds that enforcement of depreciation rules in the way the Department and the OAG request in this case would impose an excessive burden on Xcel, and that approving a limited reserve reallocation for Wind2Battery dismantling would not adversely affect the public interest or conflict with legal standards.

The Commission concurs with the ALJ that $2.14 million is a reasonable estimate for the costs to dismantle the Wind2Battery system based on the record. Therefore, the Commission will approve a reserve reallocation of no more than $2.14 million for recovery of reasonable costs to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system. If actual costs are lower than $2.14 million, Xcel will be required to perform an inverse reallocation to return the unused amounts back to the groups they came from in a future proceeding. As Xcel agreed during the Commission meeting, the Company shall not seek additional reserve allocations from assets in the Other Production plants account and shall not seek recovery of any additional costs associated with Wind2Battery in the future.

XV. Construction Work in Progress

A. Introduction

"Construction work in progress" (CWIP) and "allowance for funds used during construction" (AFUDC) are accounting devices used to allow utilities to recover the financing costs of capital projects while they are under construction, before the plant is placed into service. Capital costs incurred during construction are placed into rate base as CWIP; the associated financing costs are added to net operating income as AFUDC, normally offsetting any return on CWIP until the plant goes into service. Once the plant is in service, CWIP and AFUDC are recovered over the life of the asset through the recording of book depreciation expense.

The Commission is authorized to consider CWIP and AFUDC when determining a utility's rate base under Minn. Stat. § 216B.16, subds. 6 and 6a.

Xcel's rate-increase request includes a substantial amount of CWIP in rate base to reflect forecasted construction expenditures related to putting fixed assets into use, with a corresponding offset of AFUDC added to operating income.

B. Positions of the Parties

1. The Commercial Group

The Commercial Group recommended excluding CWIP from Xcel's rate base, arguing that including CWIP shifts onto ratepayers risks that should be assumed by utility investors.
The Commercial Group asserted that, if issues arise during construction that lead to substantial delay or non-completion of a project, ratepayers who have funded the construction through the inclusion of CWIP in rate base are forced to bear the loss; they do not receive the expected benefit in the form of completed plant, and they have no recourse to recover the value they contributed through rates. The Commercial Group argued that placing this risk of stranded costs

on ratepayers is unjust and unreasonable because ratepayers receive no compensation for the use of their funds.

Instead, the Commercial Group contended that a more just and reasonable approach would be to treat this risk of stranded costs as a cost of doing business to be borne by shareholders, who are compensated for such business risks through the return they receive on plant once it is in service. Alternatively, if Xcel is permitted to include CWIP in rate base, the Commercial Group would recommend that the Commission reduce Xcel's return on equity to reflect the corresponding transfer of risk from Xcel's shareholders to ratepayers.

2. Xcel

Xcel opposed the Commercial Group's recommendation, contending that the Commission has authorized the inclusion of CWIP in rate base for many years and that the Commercial Group has not offered a persuasive reason to depart from past practice in this case.

Further, Xcel argued that it is inappropriate to reduce its return on equity to reflect CWIP because the Company's proposed return already includes an offset for AFUDC. Xcel contended that the AFUDC offset ensures that no return is earned on the construction of assets before they have been placed in service, effectively negating the Commercial Group's concern that the return does not accurately reflect the risk impacts of CWIP.

Xcel also noted that the cost of short-term debt is included in the calculation of the allowed overall return on rate base, which further ensures that the inclusion of CWIP in rate base does not inappropriately place costs on customers or shift risks onto them. Xcel argued that removing CWIP from rate base without offsetting adjustments to AFUDC and the inclusion of short-term debt in calculating the Company's overall return would unreasonably upset this balance.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve Xcel's proposed inclusion of CWIP in rate base and not adopt the Commercial Group's proposal to adjust the Company's return on equity based on CWIP. Asserting that Minn. Stat. § 216B.16 requires the Commission to consider CWIP when determining rate base, the ALJ found that Xcel's inclusion of AFUDC and the cost of short-term debt in the calculation of the return on rate base avoids inappropriately placing costs on, or shifting risks to, ratepayers in connection with the inclusion of CWIP in rate base.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve Xcel's proposed inclusion of CWIP in rate base. Xcel supported its request with persuasive evidence and argument and demonstrated that its consideration of AFUDC and the cost of short-term debt in calculating the return on rate base avoids inappropriately placing costs on ratepayers in connection with CWIP.

XVI. Fault Location, Isolation, and Service Restoration

A. Introduction

Fault Location, Isolation, and Service Restoration (FLISR) is a form of distribution automation that involves deployment of automated switching devices that work to detect faults in feeder mainlines, isolate the faults, and restore power to unfaulted sections, thus decreasing the duration and number of customers affected by any individual outage.

Xcel proposed to add about $19 million in capital costs to its rate base and incur about $1 million in related O&M costs to install FLISR on 208 feeders in Minnesota between 2022 and 2024. Xcel asserted that this investment would improve reliability and lead to a two-thirds reduction in the number of customers who experience a sustained outage because of a fault.

B. FLISR Cost-Benefit Analysis

Xcel performed a cost-benefit analysis that sought to quantify the reliability benefits of deploying FLISR on 208 feeders compared to the cost of doing so. To calculate benefits, Xcel estimated the improvement in customer restoration times from the FLISR proposal in the form of reduced "customer minutes out." Xcel multiplied this estimate by the value of these outage minutes according to the Lawrence Berkeley National Lab Interruption Cost Estimate calculator, which involved a meta-analysis of customer value-of-service studies and a two-part regression model to estimate customer interruption costs per event by season, time of day, day of week, and geographical region for industrial, commercial, and residential customers.

Xcel also estimated the total net present value of FLISR costs through 2041, including asset costs, distribution communication, Advanced Distribution Management System integration and testing, and O&M costs corresponding to deployment and ongoing support and communications. Based on its cost-benefit analysis, Xcel estimated that the benefits of its proposed FLISR deployment will likely exceed the costs.

C. Positions of the Parties

1. FLISR Expense and Cost-Benefit Analysis

The Department argued that Xcel's cost-benefit analysis was reasonable because it relied on sound assumptions and methodologies. The Department agreed with Xcel's analysis that the proposed FLISR program is likely to produce net benefits and therefore recommended that the Commission approve recovery of the requested FLISR expense.

2. Allocation of FLISR Costs

Xcel proposed to recover FLISR costs based on the investments' functionalization as distribution assets, using general cost-causation principles through a class cost-of-service study.

The Department initially recommended reallocating FLISR costs so that residential customers pay only 3% and demand-class customers pay 97% to reflect the disparate class benefits. Using Berkeley Lab's Interruption Cost Estimate Calculator with inputs adjusted to match Xcel's Minnesota recorded system average interruption duration and frequency indices in 2020, the

Department estimated that about 97% of the financial benefits from the proposed FLISR deployment would flow to commercial and industrial customers while only 3% would flow to residential customers.

Before the Commission meeting, however, the Department withdrew its recommendation to adjust FLISR cost allocation in the current rate case due to the practical challenges of adjusting a class cost-of-service study at this late stage of the proceedings. However, beginning in the Company's next rate case, the Department recommended that Xcel be required to directly allocate FLISR costs to demand-class customers in its class cost-of-service study for the reasons discussed above.

The Clean Energy Organizations supported the Department's initial recommendation to allocate 97% of FLISR costs to demand customers as well as its alternative recommendation to require allocation of these costs to demand-class customers in Xcel's next rate case.

Xcel disputed the argument that FLISR costs should be allocated differently than other distribution assets, contending that FLISR aims to improve system reliability for all customer classes and to deliver those benefits as widely as possible. Further, Xcel argued that there are no established ratemaking methods to allocate these types of costs based on class benefits the way the Department proposes and that it would be impractical to attempt to do so because these costs involve many different types of distribution equipment.

The Commercial Group also opposed the proposal to reallocate FLISR costs and supported Xcel's preference to allocate these costs like other distribution-system costs.

3. Performance Metrics and Reporting

d. a. The Department

The Department recommended that Xcel's future recovery of FLISR expense be contingent on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR. The Department recommended that, prior to seeking future cost recovery for any incremental FLISR investments, Xcel should be required to propose a mechanism to base cost recovery for FLISR investments on reliability improvements.

The Department recommended that the Commission require Xcel to immediately begin tracking and reporting on the reliability performance of circuits equipped with FLISR improvements approved in this rate case, indicating in the Company's safety, reliability, and service-quality filings—beginning with the next such report, due April 2024—which circuits have been equipped with FLISR. The Department recommended that Xcel be allowed to modify the requirements on circuit-level performance reporting in its annual safety, reliability, and service quality reports to align with this recommendation.

Further, the Department recommended requiring Xcel to immediately begin reporting on the FLISR budget approved in this rate case along with a summary of FLISR's reliability results in its integrated distribution system plan (IDP), beginning with its next IDP due November 1, 2023. In its next rate case, or in any future proceeding where it seeks cost recovery for incremental FLISR investments, the Department recommended requiring Xcel to propose performance targets for System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), and, if applicable, any additional aspect of FLISR, based on the reliability performance data collected for circuits equipped with FLISR approved in the present rate case.

In the Company's next rate case or in any future proceeding seeking cost recovery for FLISR investments, the Department recommended requiring Xcel to propose a Performance Incentive Mechanism (PIM) for demonstrated benefits of circuits equipped with FLISR, using the PIM Design Process outlined in Docket No. E-002/CI-17-401. The Department recommended that Xcel's PIM proposal include, at minimum, the following elements:

(1) PIM structure.

(2) The dates when the PIM will take effect and terminate.

(3) Determination of the quantifiable and verifiable incentive values associated with performance in terms of SAIDI, SAIFI, and CAIDI above and below future associated targets, which may include a neutral zone around any particular target for acceptable performance.

(4) Specific mechanisms for effectuating a penalty or incentive on the Company; and

(5) An explanation of how stakeholders were engaged in the creation of PIMs.

The Clean Energy Organizations also supported adopting performance metrics and reporting requirements related to FLISR.

b. Xcel

Xcel largely agreed with proposals to require tracking and reporting on reliability performance for circuits equipped with FLISR, but it did not support conditioning cost recovery on performance metrics.

D. Recommendation of the Administrative Law Judge

The ALJ found Xcel's FLISR cost-benefit analysis reasonable and recommended that the Commission approve Xcel's proposed recovery of FLISR costs.

Further, finding that FLISR would provide reliability benefits for all customers, the ALJ recommended approving Xcel's proposal to allocate FLISR cost recovery based on the investments' functionalization as distribution assets. The ALJ was not persuaded by the Department's arguments for allocating 97% of FLISR costs to demand-class customers.

The ALJ found that it would be reasonable to modify Xcel's reporting requirements as recommended by the Department,[31] and that the additional reporting would not be unduly

[31] At the time the ALJ Report was prepared, the Department was recommending an initial, less-developed version of the reporting requirements described above. The initial recommendation was to require Xcel to track and report on reliability performance for circuits equipped with FLISR and compare these results with the average of reliability data from the previous eight-year period before FLISR was installed, including annual reporting on SAIDI, SAIFI, and CAIDI.

burdensome because it is largely an extension of Xcel's existing obligations. Moreover, the ALJ found that the additional information may help inform the Commission, stakeholders, and the Company of the efficacy of grid modernization spending going forward.

E. Commission Action

The Commission concurs with the ALJ that Xcel's FLISR cost-benefit analysis is reasonable and shows that the benefits of the proposed FLISR deployment will likely outweigh its costs. The Commission will therefore approve Xcel's request to recover 2022–2024 FLISR program costs. Xcel persuasively demonstrated that its proposed investments in FLISR are reasonable and will likely produce substantial benefits for customers sufficient to justify their costs.

The Commission will also approve Xcel's proposed allocation of FLISR costs, as recommended by the ALJ. Xcel persuasively demonstrated that FLISR will provide system benefits for all customers and that it is therefore reasonable to allocate its costs based on the investment's functionalization as distribution assets. On this record, the Commission is not persuaded by the Department's proposal to require Xcel to allocate FLISR costs to demand customers only in its class cost-of-service study in its next rate case.

The Commission finds reasonable and will adopt a modified version of the Department's proposal regarding performance metrics and reporting, as set forth in the ordering paragraphs below.

The principal substantive difference between the reporting requirements adopted by the Commission and those recommended by the Department is that the Commission will not require future FLISR cost recovery to be contingent on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR. Instead, the Commission finds that future FLISR cost recovery *may* be based on such showings. The Commission agrees with the Department that it is important to consider reliability benefits and other benefits when making decisions on future FLISR cost recovery; however, it is also important to preserve flexibility and avoid restricting the Commission's future decisions prematurely.

XVII. Asset Health and Reliability

A. Introduction

Asset health and reliability is a capital budget category within Xcel's distribution area that covers programs and projects that address the age and condition of distribution facilities. Projects in this category include replacement of underground cable, wood poles, overhead lines, and substation equipment that have reached the end of their lives as well as replacements due to damage. Xcel's proposed capital investments for asset health and reliability total $168.9 million in 2022, $180.8 million in 2023, and $205.0 million in 2024 on a Minnesota jurisdictional level.

B. Positions of the Parties

1. The Clean Energy Organizations

Noting that the proposed asset health and reliability budget has significantly increased from previous years, the Clean Energy Organizations recommended that Xcel be required to develop a cost-benefit analysis for investments in this category and cap any "discretionary" investments—i.e. those not specifically required by an order—at their expected level of benefits. The Clean Energy Organizations argued that much of Xcel's asset health and reliability spending is discretionary because the Company has discretion to decide when, where, and how much to spend in this category.

Alternatively, the Clean Energy Organizations recommended that the Commission require Xcel, in its next IDP, to propose and discuss ways for the IDP process to inform financial and cost-recovery issues in rate cases, including but not limited to (a) the feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget and (b) the decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.

Just Solar supported the Clean Energy Organizations' alternative recommendation to require Xcel to explore these issues in its next IDP.

2. Xcel

Xcel opposed the Clean Energy Organizations' recommendations. Xcel argued that increased investment in this category compared to previous years is necessary due to the age and condition of key assets, including transformers that are already past their anticipated service lives. The Company challenged the characterization of asset health and reliability investments as discretionary, asserting that this category of spending focuses on addressing assets that are aging or in poor condition which would place the system at greater risk of equipment failures and outages if not addressed. Although there is some flexibility with respect to the timing of these investments, such as determining when to replace end-of-life assets that have not yet failed, Xcel argued that it is inaccurate to characterize these investments as discretionary because they are necessary to fulfilling the Company's obligation to provide reliable service.

Moreover, Xcel contended that it would be unreasonable to make asset health and reliability investments contingent on a cost-benefit analysis because the reliability benefits of these types of investments are difficult to quantify but necessary to the provision of service. Further, Xcel provided testimony that requiring cost-benefit analyses for these kinds of investments would be impractical and costly, as this category is the distribution area's largest budget category and includes more than 100 subprograms and projects.

Within its asset health and reliability budget category, Xcel asserted that it uses a thorough budgeting process for each program that ensures the proper level of investments. This budgeting process accounts for the need to proactively replace end-of-life assets before they fail as well as forecasted replacements due to unanticipated failure or damage.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to demonstrate that its asset health and reliability budgeting process and proposed budget are reasonable. The ALJ rejected the Clean Energy Organizations' recommendation to make many of these investments contingent on a cost-benefit analysis and cap spending at the expected level of quantifiable benefits, finding persuasive

Xcel's argument that these investments provide reliability benefits that are necessary to the provision of adequate service even though they are difficult to quantify.

The ALJ therefore recommended that the Commission approve Xcel's proposed asset health and reliability costs and not adopt the recommendation to require cost-benefit analyses for discretionary spending in this category.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve Xcel's proposed Minnesota jurisdictional distribution capital addition costs for asset health and reliability of $168.9 million for 2022, $180.8 million for 2023, and $205.0 million for 2024. The record contains substantial evidence supporting Xcel's asset health and reliability budgeting process and the reasonableness of the Company's proposed budget in this category for 2022–2024.

The Commission will not adopt the Clean Energy Organizations' recommendations to require a cost-benefit analysis and to cap recovery of discretionary spending in this category at the investment's expected level of benefits. Xcel persuasively argued that some asset health and reliability investments are necessary to maintain the distribution system at the level of reliability needed for the provision of adequate service to customers, and that the true value of these functions may not feasibly be quantified or captured in a traditional cost-benefit analysis.

However, the Commission acknowledges the Clean Energy Organizations' concerns about the size of this budget category and the degree to which it has increased since Xcel's last rate case. In light of these concerns, it is in the public interest to explore possible ways to achieve greater transparency and closer scrutiny of future distribution spending to ensure due consideration of ratepayer interests and other policy goals. Further, it is reasonable to direct this conversation to Xcel's next IDP docket, where it may be considered in the broader context of Xcel's integrated distribution system planning.

Accordingly, the Commission will adopt the Clean Energy Organizations' alternative recommendation to require Xcel, in its next IDP, to propose and discuss ways for the IDP process to inform financial and cost-recovery issues in rate cases, including the feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget and the decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases aligns with policy goals established through the IDP.

XVIII. Cable Replacement Program

A. Introduction

Xcel requested to recover capital additions of $32.7 million in 2022, $34.3 million in 2023, and $35.4 million in 2024 for its cable replacement program, which is within the asset health and reliability program discussed above.

The largest portion of the cable replacement program budget is for "reactive" cable replacement, i.e., replacing cable that either is damaged beyond repair or has failed more than once in a two-year period. If reactive replacements are lower than forecasted in a given year, Xcel uses the remainder of the program budget to perform "proactive" replacements of cable that has a history of poor reliability but does not meet the criteria for reactive replacement.

B. Positions of the Parties

1. Xcel

Xcel cited four reasons for the increase in its 2022–2024 cable-replacement budgets over previous years: (1) a rise in cable failures in 2019 and 2020, (2) inflationary increases in labor and material costs, (3) Xcel's decision to transition to conduit construction for mainline cable replacements beginning in 2022, and (4) Xcel's new proposals to sometimes replace mainline cables after their first rather than their second failure and replace entire half-loop segments of underground residential distribution cable after the first failure of a segment. While the first two factors driving the budget increase may be considered beyond Xcel's control, the latter factors relate to changes in Xcel's practices.

Xcel contended that, although it is more costly, using conduit construction as opposed to direct-burying mainline cable improves reliability by protecting cable from wildlife and the elements. With respect to its proposal to replace the entire half-loop of underground residential distribution cable after the first failure of a segment, Xcel argued that this proactive approach will prevent additional failures and outages. The Company provided testimony that additional failures on the same half-loop tend to occur in rapid succession after the first failure of a segment, as all cables in the half-loop are exposed to the same environmental and loading conditions.

Additionally, Xcel contended that replacing cable that has failed just once would allow the Company to avoid emergency replacements. Emergency replacements leave the system with less redundancy and switching options and can lead to lengthy outages if additional failures occur. Xcel maintained that it would only perform these proactive types of cable replacements if sufficient funding were available in a given year, which will depend on the number of other types of cable replacements performed each year.

Xcel argued that the requested funding is necessary for reliable service because cable failures are a main contributor to outages for customers who are served by underground facilities and account for approximately 65% of the "customer minutes out" on the Company's underground system from 2016–2020.

2. Just Solar Coalition

Just Solar recommended that the Commission deny Xcel's proposed cable-replacement budget until Xcel distinguishes the portion of the budget dedicated to reactive replacement from the proactive portion and justifies any proactive spending with a reliability-driven cost-benefit analysis that demonstrates that such proactive replacements are reasonable and cost effective. Just Solar recommended that the Commission require Xcel to identify the criteria used in its analysis—which should include equity and energy justice considerations—and demonstrate why such criteria result in just and reasonable investments.

Just Solar argued that Xcel has not met its burden to justify its proposal to engage in more proactive cable replacements or the associated funding increase. It asserted that, by combining the budget for proactive and reactive replacements, Xcel obscured the different analysis required to assess the benefits and reasonableness of these different types of replacements. Just Solar contended that it is important to evaluate the reasonableness and cost effectiveness of the cable replacement program specifically because it represents a large portion or Xcel's requested capital additions and, thus, is a significant contributor to the requested rate increase.

Additionally, Just Solar recommended that the Commission require Xcel to track and report its planned and actual spending on each category of replacements.

3. Xcel's Reply

Xcel opposed Just Solar's recommendation to condition cable-replacement funding on a cost-benefit analysis, arguing that it is difficult to quantify the reliability benefits of the proposals because multiple factors influence overall reliability performance. Further, given the increase in cable failures in recent years, Xcel argued that although proactive cable replacement may not produce immediate quantifiable reliability benefits, it could allow the Company to maintain its current reliability performance, which is necessary to fulfilling the Company's obligations to customers even though this value may not be adequately reflected in a cost-benefit analysis.

Xcel also opposed Just Solar's recommendation to designate rigid "reactive" and "proactive" components of the program budget, arguing that such a distinction would eliminate the flexibility the Company needs to address reactive replacement needs, which vary from year to year, while making efficient proactive use of any remaining funds.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's proposed cable-replacement budgets reasonable and prudent and recommended that the Commission approve them. The ALJ also specifically found that Xcel's plans to replace mainline cable after one failure and to replace the entire half-loop of an underground residential distribution cable after the first failure of a segment as funding is available are reasonable and prudent plans based on substantial evidence in the record. The ALJ found that Xcel's proposals for the cable-replacement program are reasonable because they will provide reliability benefits and avoid emergency cable replacements that can lead to lengthy outages when additional failures occur.

The ALJ was not persuaded by Just Solar's arguments for denying any budget increase driven by proactive cable replacements unless they are shown to be cost effective. The ALJ found that it would be unreasonable to condition funding on a cost-benefit analysis for several reasons. The reliability benefits of Xcel's proposal are difficult to quantify and, moreover, are essential to fulfilling the Company's obligation to provide reliable service and therefore may be necessary and prudent even if their benefits that are quantifiable through a traditional cost-benefit analysis do not exceed their costs. Additionally, the ALJ found that it would be impractical or impossible to designate specific components of the budget for proactive and reactive cable replacements in advance because the amount of funding available for proactive replacements will fluctuate from year to year depending on the need for reactive replacements, which is affected by multiple factors that cannot be predicted with a high degree of accuracy.

However, the ALJ recommended adopting Just Solar's recommendation to require Xcel to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate-case filing. The ALJ found this requirement reasonable because the increased budget reflects a shift in the Company's approach, which regulators and the public should have an opportunity to review following implementation. The ALJ found that this tracking and reporting requirement would provide transparency and would not be unduly burdensome to the Company.

D. Commission Action

The Commission concurs with and will adopt the ALJ's recommendations on this issue. Xcel persuasively argued that allowing the Company flexibility to perform proactive replacements as funding allows after satisfying reactive-replacement needs in a given year is more reasonable than strictly committing specific portions of the budget to either reactive or proactive replacements in advance, before all relevant circumstances are known. Further, the Commission agrees with the ALJ that conditioning proactive cable-replacement spending on a cost-benefit analysis would not be effective in quantifying improvements that, whether proactive or reactive, substantially benefit customers by helping Xcel to maintain a reasonable level of reliability performance.

However, the Commission will adopt Just Solar's recommendation to require Xcel to track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate-case filing as well as in its IDP budget filing. Because Xcel's proposal includes certain shifts in the way the Company intends to approach cable replacements, it is reasonable to collect and report on this data so that the Commission and stakeholders can review the effects of the shift following implementation.

XIX. Grid Reinforcement Program

A. Introduction

Xcel proposed $12.08 million in capital additions from 2022–2024 for a grid reinforcement program, which the Company stated would help prepare its distribution system to handle increased load from rising adoption of electric vehicles (EVs) and electrification of other sectors of the economy. The program would replace distribution-system infrastructure in areas where Xcel expects new load could eventually overload distribution equipment and cause outages.

Currently, Xcel handles distribution-equipment upgrades to accommodate increases in customer loads through two budget categories: (1) routine capacity reinforcements, which includes projects to support reliability by addressing known capacity constraints such as undersized transformers or conductors; and (2) new business, which includes projects to extend electric service to new customers or to support increased loads in response to customer requests.

The types of upgrades Xcel would make under the proposed grid reinforcement program are similar to routine capacity reinforcements and new business projects, including upgrades to service transformers, poles, primary conductors, and secondary conductors. The main difference between the existing programs and the proposed program is that, instead of targeting equipment or customers with an existing capacity need, the grid reinforcement program would focus on locations that Xcel determines are likely to experience an overload in the future because of anticipated EV load or other new electrification.

The Company stated that it would replace transformers and conductors under the program based on forecasted load growth, forecasted EV-adoption rates, and transformers that are at high risk of failure, targeting replacement of overhead residential service transformers rated 25 kVA or less that have the highest risk of failure according to Xcel's forecast.

B. Positions of the Parties

1. Parties Opposing the Grid Reinforcement Program

The OAG and Just Solar recommended that the Commission reject the grid reinforcement program, arguing that Xcel has not justified the substantial cost. They characterized the proposal to prospectively replace equipment that is not yet overloaded as being inherently speculative and based on unreasonable and unfounded assumptions about EV adoption and electrification. For example, the purported need for the project assumes that new EV-charging load will peak at the same time as the distribution-system peak; but the OAG and Just Solar argued that capacity constraints (and thus the need for costly infrastructure investments) related to EV load may be avoided entirely if the Company employs rate design, active managed charging, or other load-shifting techniques to shift EV charging away from times of peak demand.

Additionally, the OAG and Just Solar questioned why Xcel did not propose any reductions to its routine capacity reinforcements or new business budgets given that the need for those types of projects—which materially overlap with grid reinforcement projects—should decrease if the grid reinforcement program is approved. The OAG argued that adding the requested grid reinforcement program budget on top of Xcel's other distribution budgets would create a significant risk of unreasonable double recovery.

Just Solar contended that Xcel should be able to proactively plan for increased EV adoption and electrification using its existing new business and routine capacity reinforcement programs, without needing customers to pay for a new, overlapping $12.08 million program.

2. Xcel

Disputing arguments that the proposed grid reinforcement program is duplicative of other existing programs, Xcel contended that the grid reinforcement program is narrowly designed to proactively replace undersized overhead residential service-level transformers for a specific purpose; its routine capacity reinforcement program, in contrast, is a broad program to reactively address all smaller capacity issues for all customers throughout the system.

While acknowledging that the grid reinforcement program may lead to a reduction in reactive routine capacity reinforcement projects in the future, Xcel argued that the program will not result in an immediate reduction in routine capacity projects because this program would cover only 2% of the total residential service transformers in Minnesota.

Xcel emphasized that proactive replacement of residential service-level transformers that are near their capacity limits will benefit customers by avoiding both customer outages and costlier reactive replacements.

Xcel disputed the argument that the issues the program aims to solve can be entirely avoided through rate design and load-shifting programs, noting that customers participating in the Company's EV programs are not the only cause of increased load and that customers switching from gas to electric appliances or heat sources could also lead to a transformer overload. Additionally, Xcel argued that, although EVs can be programmed to charge during off-peak periods, scheduled off-peak EV charging could lead to new EV-related peaks, thus merely shifting rather than avoiding the overloading concerns. Xcel added that some customers cannot or will not modify their EV-charging behaviors in response to price signals.

Xcel argued that the benefits of the grid reinforcement program justify the reasonableness and prudence of the proposed investment.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission exclude the grid reinforcement program costs from Xcel's revenue requirement. The ALJ found persuasive the arguments of Just Solar and the OAG that Xcel has several existing means of avoiding transformer-related problems associated with EV and other electric load growth, including the Company's existing programs for new business and routine capacity reinforcement as well as EV programs that could facilitate strategic load shifting.

The ALJ found that the concern Xcel intends to address is speculative and depends on the confluence of multiple contingencies—a sufficient concentration or breadth of EV adoption during the MYRP, unavoidable synchronization of EV-charging loads, and inelastic EV-charging demand. The ALJ found that the record does not show that this alignment of events is more likely than not to justify the proposed revenue requirement increase and does not establish the reliability of the forecasts and analysis underlying Xcel's request for this purpose.

D. Commission Action

The Commission will adopt the ALJ's recommendation to reject Xcel's distribution capital addition costs for the grid reinforcement program for 2022–2024. Although it is important to ensure that the distribution system is prepared to handle increased load from increased EV adoption and other electrification, the Company has not established that its proposed $12.08 million grid reinforcement program is reasonable.

As the OAG noted, Xcel has not shown that it duly considered whether managed EV charging or other load-shifting programs could be used to avoid or reduce the need for costly grid upgrades associated with transportation electrification. Nor does Xcel's proposal provide sufficient transparency or detail regarding where the grid reinforcement projects would be done or whether any costs of this program are duplicative of costs accounted for in the Company's routine capacity reinforcements and new business expense categories, which appear to materially overlap with grid reinforcement projects. Based on this record, the Commission will reject Xcel's grid reinforcement program as proposed and require its removal from the Company's revenue requirement for ratemaking purposes.

XX. Distributed Intelligence Capital Additions and Operations and Maintenance Costs

A. Introduction

Distributed intelligence (DI) generally refers to the computer processing and analytics capabilities of localized distribution grid devices and platforms. DI involves relatively new technology that enables the Company to extract precise, instantaneous insights that it can use for grid operations or to communicate real-time usage data directly to customers to help them make decisions about energy usage.

Xcel proposed to procure DI software and computer hardware that would allow the Company to leverage advanced meter data to offer new services to customers and help the utility to manage its distribution system more efficiently. Xcel identified the following initial uses for its proposed DI program: energy analysis, home area network connectivity, EV detection, outage and voltage fluctuation detection, and a connectivity pilot.

During 2022 and 2023, Xcel plans to develop and deploy three customer-facing DI uses: (1) home area network connectivity, which would allow customers to connect to the meter on their premises using Wi-Fi and provide customers real-time access to energy usage data; (2) energy analysis, which would provide customers information on the energy usage of specific appliances; and (3) EV detection, which would detect a customer's EV charging, quantify the EV-specific energy-consumption profile, and provide a channel for Xcel to introduce customers to EV programs and rates that best suit their needs.

The Company plans for additional deployment of grid-facing DI in 2024, including broader deployment of the grid-facing pilots introduced in 2022 and 2023 and potentially including development of other applications that are not currently available.

Xcel's proposed DI budget includes $33 million in capital additions beginning in 2024 and $3.6 million in O&M expenses from 2022–2024. This budget includes costs to implement the foundational software architecture necessary to enable DI capabilities and to develop and deploy initial customer- and grid-facing DI use cases. In rebuttal testimony, Xcel proposed a revised budget that includes electric-only allocators for DI costs and a new shared-asset accounting structure.

B. Distributed Intelligence Cost-Benefit Analysis

Xcel provided a cost-benefit analysis for the energy analysis use which, according to the Company, was conservative in that it included all costs during the rate-plan years but only captured the portion of the benefits that could be quantified at this time with sufficient certainty, rather than all of the project's likely benefits. Xcel's updated cost-benefit analysis showed an expected benefit-to-cost ratio of approximately 1.44 under the Company's base scenario. Xcel asserted that there is 95% certainty that the benefit-to-cost ratio would be greater than 0.98, with a maximum ratio of 2.33.

Xcel asserted that the primary benefit of DI is the potential to provide information to customers that allows them to change their behavior in ways that promote energy efficiency and demand response, save on energy bills, and reduce carbon emissions. Additionally, Xcel stated that DI analytics will extend the Company's advanced capabilities for the distribution grid to allow more precise monitoring and control at the edge of the grid, leading to greater reliability and lower costs for managing the system.

C. Positions of the Parties

1. The Clean Energy Organizations

The Clean Energy Organizations requested that Xcel agree to implement its DI program consistent with the terms of a settlement agreement that the Company's affiliate in Colorado entered into for implementation of a similar program. The settlement terms of interest to the Clean Energy Organizations addressed Home Area Network deployment and issues of customer and third-party access to data. In its reply brief, Xcel stated that it planned to implement its DI program in Minnesota in a way that is generally consistent with the Colorado terms.

With this clarification, the Clean Energy Organizations supported Xcel's requested DI recovery, asserting that it could help customers better understand and reduce their energy usage and noting that the Company had significantly reduced the cost of the program from its initial proposal in its IDP docket.

2. The Department

The Department argued that Xcel's DI cost-benefit analysis was not reliable, citing concerns with the benefits measure used and with several assumptions underlying the model.

First, Xcel used estimated customer bill savings for participating customers to quantify DI benefits. The Department argued that, because a bill-savings-based analysis relies on prices derived from historical costs that cannot be avoided by the utility investment, quantifying benefits based on customer bill savings violated the principle that cost-benefit analyses should be forward-looking, long-term, and incremental to what would have occurred absent the investment.

Second, the Department argued that because customer bill savings would accrue only to actively participating customers, Xcel's analysis likely presents a high-end limit on potential benefits and does not adequately account for the risk that participating customers who save money may do so at the expense of non-participating customers. To produce methodologically reliable results rather than a best-case scenario, and to reflect the program's effects on all customers, the Department argued that Xcel should have evaluated program benefits by estimating the avoided utility costs of its DI proposal. The Department asserted that avoided utility costs are the standard measure of benefits for these types of analyses.

Further, the Department argued that Xcel's model was skewed by unreasonable assumptions about participation levels. Xcel based its participation-rate assumptions on its website's "My Account" login data, but the primary reasons customers log into those accounts are to view and pay bills; accordingly, the Department contended that this data is not a reasonable proxy to estimate how many customers would actively participate in DI programs to engage in energy-efficiency and demand-management best practices.

The Department challenged Xcel's use of general market research for digital products to estimate the percentage of enrolled customers leaving the program annually (referred to as "churn rate") and further contended that Xcel's selection of the highest churn rate was self-serving because the benefit-to-cost ratio improves as annual churn increases under Xcel's model.

The Department also argued that there was insufficient support for Xcel's 80% customer-interest value, which the Company derived from a single survey question asking how "interested" respondents would be in downloading "an app to allow you to understand your energy usage." The Department argued that the generalized interest gauged by the survey question is not a reasonable proxy for active participation that would yield benefits.

Further, the Department questioned Xcel's assumptions about advanced meter deployment. Acknowledging that inflation and supply-chain issues have affected meter availability, Xcel reduced its 2022 estimate from 250,000 to 90,000 meters; however, the Company maintained its estimate of 670,000 meters in 2023. The Department argued that Xcel has not explained the significant increase in expected advanced meter deployment from 2022 to 2023 and contended that the high 2023 estimate inflates expected benefits relative to cost under Xcel's model.

The Department also expressed concern with the fact that Xcel's analysis produced a range of potential benefit-to-cost ratios from 0.98 to 2.33, arguing that this broad range of results reflects the limitations of Xcel's benefit-estimation methods and the significant risk associated with the proposal. The Department recommended that the Commission deny Xcel's request to impose the substantial cost of the proposed DI program on ratepayers at a significant risk that its benefits will fall below, or only barely exceed, its costs.

Finally, the Department opposed Xcel's proposal to change its accounting structure from treating DI as a shared asset owned on an enterprise-wide basis to an asset owned by Northern States Power–Minnesota (NSPM), which would add $37.8 million in capital to its 2024 plan-year rate base, approximately $14.3 million above the Company's original recommendation. The Department argued that this revised accounting structure would unreasonably shift business risk from shareholders to NSPM customers because Xcel's claim that other jurisdictions will contribute to the cost in the form of licensing fees in the near future relies on assumptions that Xcel's other jurisdictions will timely adopt DI programs.

3. The OAG

The OAG shared the Department's concerns and recommended that the Commission reject Xcel's proposed DI costs. However, the OAG recommended that the Company be allowed to seek approval of the program in a future proceeding with a more robust record.

Alternatively, if the Commission grants recovery of DI expenses, the OAG would recommend requiring Xcel to account for the DI program as an enterprise-wide asset as initially proposed by the Company. On a Minnesota-jurisdictional basis, this accounting structure would result in the removal of $3.1 million from rate base and $303,000 in O&M expenses in the 2022 test year; $12.1 million from rate base and $1,528,000 in O&M expense in 2023; and $24.6 million from rate base and $1.7 million in O&M expense in 2024.

The OAG argued that Xcel failed to support the revised DI accounting structure with adequate explanation and enough detail to allow parties to evaluate it. Further, the OAG argued that the costs for the DI asset do not reflect any credits from other operating companies for their use of the asset and that approving this structure would result in Minnesota ratepayers paying more than their fair share of DI costs in 2025 and beyond. Additionally, the OAG asserted that Xcel did not explain why the accounting changes should be reflected in the current rate case because (1) the DI asset would not be in service until the final month of 2024 and (2) Xcel claimed that the allocator update would not have a material impact on the overall DI budget allocated to NSPM through 2028.

The OAG argued that Xcel's late introduction of its revised accounting structure in rebuttal testimony heightened the need for the Company to provide detailed cost information to support the changes, which Xcel did not fulfill, and hindered other parties' ability to vet the proposal.

4. Xcel

Xcel argued that avoided cost is not the only potential measure of benefits and that it selected customer bill savings as the most indicative measure of the magnitude of expected DI impact based on the information currently available. In response to arguments that the cost-benefit analysis is not supported by enough data, Xcel contended that it is impossible to develop additional data about the benefits of DI without first deploying DI, particularly at this nascent stage in the technology's development.

Although its cost-benefit analysis is limited to the development of foundational DI capabilities and deployment of the initial customer- and grid-facing use cases proposed to be in service in late 2024, Xcel characterized its DI proposal as a necessary investment in the formative infrastructure for DI development that will unlock additional benefits in the future.
In defense of its participation-rate assumptions, Xcel asserted that it used additional data beyond the My Account login statistics and incorporated a sensitivity analysis including a range of assumptions and probabilities of different outcomes.

Xcel contended that the record contains sufficient evidence of DI benefits to support approving the requested cost recovery at this time even though some benefits cannot yet be quantified. Xcel stated that its cost-benefit analysis provides one point of reference to show that DI benefits will outweigh the costs of the foundational DI investments proposed.

To support its revised accounting structure, Xcel asserted that the asset should be owned by NSPM because DI applications will be available only in Minnesota initially, but that NSPM will receive offsetting O&M credits from other operating companies beginning in 2025 as regulatory approval is received and as customers begin benefitting from the asset in other jurisdictions. Xcel contended that this accounting structure will facilitate balanced allocation of costs to Xcel Energy's operating companies and better aligns with current information about when customers will benefit from DI in each jurisdiction.

Xcel opposed the OAG's suggestion to seek recovery of DI costs in a future proceeding, arguing that it is reasonable to approve the Company's request in the current rate case because customers will begin to receive benefits from DI in 2023 as advanced meters are deployed.

D. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission deny cost recovery for Xcel's DI proposal, but without prejudice to any request in a future proceeding. The ALJ found that the Department identified significant shortcomings with Xcel's cost-benefit analysis and that, because the Company's analysis only narrowly found a net benefit, there are genuine doubts about the methodology of the analysis and the reliability of its conclusions sufficient to conclude that Xcel did not meet its burden to show that the costs are reasonable.

Alternatively, if the Commission allows Xcel to recover distributed intelligence costs, then the ALJ would recommend adopting the OAG's alternative proposal to apply the accounting structure Xcel proposed in its supplemental direct testimony in lieu of the Company's revised accounting structure. The ALJ agreed with the OAG and the Department that Xcel's revised proposed accounting structure for these costs raises concerns about increased risk and uncertain benefits to Minnesota ratepayers, and that the introduction of this revised accounting proposal late in the proceedings deprived intervenors of the opportunity to develop a full record and analysis of that proposal.

E. Commission Action

The Commission will reject Xcel's proposal to include DI costs in rates. The Commission concurs with the ALJ's finding that Xcel has not met its burden to show that its proposed DI costs are just and reasonable. The Department raised important concerns about the assumptions and methodology underlying Xcel's cost-benefit analysis, and Xcel has not satisfactorily resolved those concerns. Although Xcel has identified potential uses of DI to help customers understand and control their energy usage and help the Company manage its distribution system more efficiently, the Commission is not persuaded that approval of Xcel's proposed DI program is justified based on the current record.

However, in recognition of the potential benefits suggested in the record, the Commission will direct Xcel to re-file its DI proposal in its next IDP. The Commission agrees with the OAG and the ALJ that there may be merit in allowing Xcel another opportunity to support its proposal with a more fully developed record that addresses the concerns discussed herein. Additionally, as Xcel agreed, the proposal to be filed in the next IDP shall be consistent with the settlement entered into by the Company's Colorado affiliate relating to a similar program.

XXI. Production Tax Credits

A. Introduction

Production tax credits (PTCs) are federal tax credits earned from the generation of electricity using qualified renewable energy resources. PTCs affect Xcel's revenue requirement by reducing income-tax expense and increasing operating income.

Because PTCs vary from year to year, Xcel proposed to create a PTC tracker account in its Renewable Energy Resources (RES) rider to annually refund or surcharge customers for the difference between actual PTCs received and the baseline set in the rate case.

Xcel initially forecasted that it would generate PTCs totaling $190.169 million for 2022, $192.916 million for 2023, and $193.385 million for 2024, and the Company requested to use those values as the baselines for PTC recovery during the MYRP.

In August 2022, the Inflation Reduction Act expanded the renewable generation facilities eligible for PTCs, increased the eligible percentage of PTCs for existing renewable facilities, and increased the megawatt-hour (MWh) rate for new and repowered renewable facilities. These changes significantly affected the amount of PTCs Xcel could expect to receive during the term of the MYRP.

Xcel provided an updated PTC forecast incorporating the Inflation Reduction Act changes as well as an updated wind generation forecast reflecting the most recent information about expected wind energy production. The updated PTC forecast is $217.753 million for 2022, $192.204 million for 2023, and $194.738 million for 2024.

No party opposed using the RES rider to true-up PTCs. However, parties disagreed on the appropriate baseline level for PTC recovery.

B. Positions of the Parties

1. The Department

The Department recommended using Xcel's updated PTC forecast as the baseline, arguing that using the most current estimate available will promote rate stability by protecting ratepayers from substantial surcharges or refunds when the amount is trued up.

The Department asserted the availability of a true-up mechanism does not eliminate the potential harm to ratepayers from overestimating the baseline because significant time will pass between any baseline overpayment and its corresponding true-up refund, during which time customers will be deprived of the use of the overpaid sums. Contrary to Xcel's claim that the differences of $1.288 million in 2023 and $1.353 million in 2024 are too small to warrant a baseline adjustment, the Department asserted that this amount of ratepayers' money is not negligible from each ratepayer's perspective and that Xcel has not shown that it is reasonable to collect those excess amounts in rates, even if they will be returned through future true-ups.

In response to Xcel's argument that the baseline should not be updated until the IRS provides further guidance on the implementation of the Inflation Reduction Act, the Department argued that any details that might change from the current understanding of PTC calculation under the Act based on future IRS guidance will not be so significant as to render the original forecast—which assumes the Inflation Reduction Act does not exist—a more accurate alternative than the updated forecast which reflects the most current information available.

2. Xcel

Xcel maintained its request to continue using its original PTC forecast, which does not reflect the Inflation Reduction Act or the Company's updated wind generation forecast. Xcel argued that it should not update the PTC forecast because the Company is awaiting further guidance from the IRS on Inflation Reduction Act implementation. Although the updated forecast reflects Xcel's current understanding of the impact of the Inflation Reduction Act on PTC calculation, the Company contended that the baseline should not be updated until final guidance is available because such guidance could cause PTC-calculation details to change.

Additionally, Xcel stated that its 2022 RES rider true-up has already been approved and its implementation has begun, so if the amounts included in base rates do not align with the assumptions made in the RES rider filing, then the amount in the RES rider would require an additional offsetting adjustment to avoid over- or under-recovery. Xcel argued that this approach would be needlessly complex, require additional administrative burden, and create risks of confusion and error. Given this procedural posture, Xcel argued that it could update PTC values more quickly directly through the RES rider, and thus refund customers sooner, if PTC adjustments are handled directly through the RES rider rather than through base rates.

While acknowledging that setting a reasonably accurate baseline is important to send appropriate price signals and to provide rate stability by minimizing the extent of future surcharges or refunds, Xcel disputed the contention that maintaining the initial forecast as the baseline would result in dramatic rate changes when the true-up occurs. Xcel asserted that the difference between the initial and updated PTC forecast for each year is under $1.4 million, which is relatively small in the overall context of the rate case.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Department's recommendation to update the PTC baselines reflects the best information available and is more reasonable than Xcel's proposal to rely on its initial forecast. The ALJ found that Xcel did not provide sufficient arguments to outweigh the ratepayer benefits of setting the baseline using the most up-to-date forecast available in the record. The ALJ therefore recommended that the Commission adopt the Department's recommended PTC baseline update, with corresponding reductions to the revenue requirement in the following amounts: $27,584,000 in 2022, $1,288,000 in 2023, $1,353,000 in 2024.

D. Commission Action

The Commission will adopt the ALJ's recommendation to update the PTC baseline amounts to reflect Xcel's updated PTC forecast, reducing the Company's 2022–2024 revenue requirements by $27,584,000, $1,288,000, and $1,353,000, respectively.

No party disputed the importance of setting a reasonably accurate baseline to reduce the likelihood of substantial surcharges or refunds when the baseline amount is trued up and to send appropriate price signals. Using the most current forecast information available can often be expected to yield the most accurate baseline cost estimates. In this case, the updated PTC forecast reflects significant changes resulting from the Inflation Reduction Act and Xcel's updated wind-generation forecast, neither of which was available when Xcel produced its initial forecast. The Commission finds it is reasonable to base the PTC baseline values on the updated PTC forecast because this approach is likely to produce more accurate results than the initial forecast developed based on out-of-date information.

Xcel did not provide persuasive reasons why it would be better to set the baseline based on outdated information. Although forthcoming IRS guidance could potentially vary some PTC-calculation details, the Commission agrees with the Department that it is exceedingly unlikely that any such changes would be so great as to render Xcel's original PTC forecast—which does not account for the Inflation Reduction Act at all—more accurate than the updated forecast. Additionally, the Commission is not persuaded that Xcel's concerns about administrative burden or potential confusion due to straying from the assumptions underlying the 2022 RES rider true-up filing outweigh the interests in aligning the base-rate baseline with current forecast information.

Finally, Xcel's claim that the likely over-recovery of up to $1.4 million per year based on the initial PTC forecast is so small as to be negligible, and therefore does not warrant a baseline update, is not persuasive.

XXII. Load Flexibility Program Costs

A. Introduction

In Docket No. E-002/M-21-101 (the Load-Flexibility Docket),[32] Xcel requested approval of deferred accounting for costs related to load-flexibility pilot programs. In the Load-Flexibility Docket, which was underway when Xcel filed this rate case, Xcel requested authorization to track all 2021–2023 costs of its load-flexibility pilots for possible future recovery. Xcel divided its estimated load-flexibility-pilot expenses into the following categories: bill credits, customer services (equipment cost), program administration (including labor), advertising and promotions, measurement and verification (evaluations), and product development and research.

In the Load-Flexibility Docket, the Department recommended that the Commission deny deferred accounting for all of the pilot expense categories except two—bill credits and customer services—arguing that the remaining categories appeared to be labor costs already included in base rates. In a March 2022 order, the Commission approved some of the proposed load-flexibility pilots and authorized deferred accounting for bill credits and customer services costs.[33] Although the deferral authorization was specific to the cost categories recommended by the Department, the Commission did not make a determination as to the veracity of the Department's claim that the other cost categories were labor costs already included in base rates.

Xcel subsequently updated its cost of service to include the categories of load-flexibility-pilot costs that were not approved for deferred accounting in the Load-Flexibility Docket, totaling $870,000 in 2023 and $1.1 million in 2024 for the Minnesota jurisdiction.

B. Positions of the Parties

1. The OAG

The OAG opposed Xcel's request to recover load-flexibility program costs. It argued that the Commission's denial of deferred accounting for these expense categories in the Load-Flexibility

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[32] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, Docket No. E-002/M-21-101.

[33] Load-Flexibility Docket, Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action at 25, 30 (March 15, 2022).

Docket was based on an implicit finding that they are labor costs already included in base rates, as the Department had argued.

The OAG contended that Xcel offered only a conclusory assertion that these costs are incremental to the labor costs already included in the Company's initial filing and did not provide sufficiently detailed evidence to verify the costs or the claim that they are incremental.

2. Xcel

An Xcel witness testified that the load-flexibility costs requested were not included in the initially filed cost of service; the Company had specifically removed these costs from the initial rate case filing to avoid double recovery because, at the time, it was seeking authority in the Load Flexibility Docket to track them separately and request deferred recovery.

In response to the timeliness argument, Xcel stated that it transferred the costs from the Load-Flexibility Docket to the rate case as soon as practicable following the partial denial of deferred accounting in the former docket, which is the earliest time the Company knew it would need to include the costs in this rate case because it would not be allowed to request deferred recovery in a future proceeding.

Xcel contended that denying recovery in this proceeding would leave the Company with no avenue to recover these costs, which would be unreasonable because the Commission approved the associated programs as reasonable and in the public interest in the Load-Flexibility Docket.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve rate recovery of Xcel's load-flexibility pilot costs as identified in the Company's rebuttal testimony, finding that Xcel established by a preponderance of the evidence that the requested recovery is reasonable.

The ALJ found that no party had identified any load-flexibility program cost shown to duplicate an expense already included in the Company's initial request. Because the Commission approved deferred accounting for portions of the costs of the load-flexibility programs upon a finding that the programs would serve important ratepayer and policy interests, and because Xcel's testimony that the additional costs are incremental has not been substantively rebutted, the ALJ found it reasonable to include the costs in rate base.

D. Commission Action

The Commission will adopt the ALJ's recommendation to approve rate recovery of the load-flexibility costs identified in Xcel's rebuttal testimony.

Contrary to the OAG's assertion, the Commission's March 2022 order in the Load-Flexibility Docket did not entail a finding that these expense categories are labor costs already included in base rates. Rather, after noting that deferred accounting is an exception to the uniform system of accounting under Minn. R. 7825.0300, subp. 4, and discussing concerns about deferred accounting generally being used to track only increases and not decreases in costs outside of a rate case—which could lead to inequities for ratepayers if used inappropriately—the

Commission did not find good cause for an exception to allow *deferral* of these costs. But the order did not preclude traditional recovery within a rate case corresponding to the test years in which the costs are incurred, as Xcel requests now, nor did it determine that these expenses are duplicative of costs already in base rates. Nothing in the Load-Flexibility Docket forecloses Xcel's request to recover load-flexibility-program costs not approved for deferred accounting.

The record persuasively demonstrates that Xcel specifically excluded the claimed costs from the Company's initial cost-of-service estimate in this rate case because, until the Commission denied its request in the March 2022 order, the Company was intending to seek deferred recovery of these costs instead of traditional rate recovery. No party effectively rebutted Xcel's evidence to show that these costs are duplicative of costs included elsewhere in the cost-of-service estimate or otherwise should not be added to rates. The Commission therefore finds that the load-flexibility costs Xcel requested in rebuttal testimony are incremental and can reasonably be added to Xcel's cost of service for recovery through base rates.

For these reasons, in addition to reasons articulated in the March 2022 order to approve the load-flexibility programs based on findings that they will serve important ratepayer and policy interests, the Commission finds that Xcel has met its burden to demonstrate the reasonableness of its requested recovery of load-flexibility-program costs.

Accordingly, the Commission will approve Xcel's request to recover load-flexibility-program costs totaling $870,000 in 2023 and $1.1 million in 2024 for the Minnesota electric jurisdiction.

XXIII. Integrated Volt-Var Optimization

A. Introduction

Xcel's initial revenue request included capital additions for integrated volt-var optimization (IVVO), an application that optimizes voltage as power travels from substations to customers. However, after it prepared the budget included in its rate-case filing, Xcel changed its plans and decided not to pursue IVVO during the term of the MYRP.

The parties agreed that Xcel should remove $0.2 million from 2023 and $1.8 million from the 2024 to reflect IVVO-related assets that were not used and useful during those years due to Xcel's termination of its IVVO plans. The ALJ recommended that the Commission adopt these adjustment amounts.

Following oral arguments, Xcel clarified that it has no plan to resume implementing IVVO at any time, including after the rate-plan years. When asked to explain its reason for abandoning its IVVO plans, Xcel stated that the Commission's decision not to certify the Company's proposed IVVO project in the 2020 IDP order led the Company to conclude that the Commission was not comfortable with the project moving forward.[34]

[34] *See In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects, at 15 (July 23, 2020) (2020 IDP order).

B. Commission Action

With respect to the $0.2 million and $1.8 million IVVO-related adjustments agreed upon by the parties and recommended by the ALJ, the Commission finds the adjustments reasonable and supported by the record and will therefore adopt them.

However, the Commission is concerned with Xcel's stated reasoning for terminating its IVVO efforts. In the 2020 IDP order, the Commission expressed general support for the goals of IVVO but was not persuaded that there had been enough record development or analysis to certify the specific proposal for purposes of rider recovery at that time. The Commission expressly noted that its decision not to certify at that time would not prevent Xcel from continuing its work on IVVO or seeking cost recovery through traditional means.

The record suggests that, rather than pursuing further development of its IVVO proposal and analysis of the project's potential to serve the important goals identified in the IDP docket, as the 2020 IDP order anticipated, Xcel simply scrapped the pursuit based on its incorrect assumption that the Commission's decision implied a negative judgment about the merits of the project. To ensure that the Company does not unduly abandon IVVO and all of its potential benefits based solely on a misunderstanding of the 2020 IDP order, the Commission will require Xcel, in its next IDP, to include an assessment and explanation of whether IVVO is in the public interest.

XXIV. Insurance Premium Expenses

A. Introduction

Xcel estimated its insurance-premium expense for the Minnesota electric jurisdiction as $20.7 million in 2022, $22.4 million in 2023, and $25.2 million in 2024, net of budgeted distributions from mutual insurance and captive insurance providers.

When estimating insurance costs, Xcel consults with insurance brokers on general trends in insurance markets to try to predict if prices will be trending up, down, or flat. Xcel then estimates its likely exposure using metrics the Company evaluates annually, including the number of employees, miles of pipes and wires, and changes to the value of insurable assets. To set test-year insurance budgets, Xcel starts with the premiums it paid in the two preceding years and adjusts those amounts to account for the identified insurance-market trends and company exposure metrics. Xcel's insurance budgeting process also accounts for expected distributions from mutual insurance pools and captive insurers as credits against its estimated premiums.

B. Positions of the Parties

1. The Department

Noting that the insurance expenses Xcel estimated for 2022–2024 are significantly higher than the actual insurance expenses the Company incurred in 2021, and that proposed year-over-year percentage increases are significant compared to actual increases in Xcel's insurance expenses each year from 2017–2021, the Department argued that Xcel failed to show that its proposed insurance expenses are reasonable. In particular, the Department objected to the exceptionally large percentage increase between the 2021 actual insurance expense and the 2022 forecasted amount.

Although Xcel stated that the Company sought input from insurance brokers, the Department criticized the Company's decision not to offer any evidence from insurance brokers themselves directly into the record. The Department questioned persuasive value of Xcel's secondhand summaries of information purportedly obtained from insurance brokers in the absence of direct evidence of market information to substantiate claims about market trends.

The Department argued that Xcel did not provide sufficiently detailed or persuasive explanations for the substantial variances in its cost forecasts from year to year. Responding to Xcel's statement that insurance budgets vary "for numerous reasons, including overall market conditions, inflation, and actual experience," the Department characterized this explanation as overly general and unconvincing.

In response to Xcel's contention that the increases are driven by a general upward trend in claim experience for primary casualty insurance due to increasing catastrophic events, the Department stated that primary casualty is just one of multiple insurance programs and can account for only a small portion of the overall increase. Moreover, noting that Xcel testified that it does not carry insurance for certain utility plant in part because of market volatility and because other utilities that are more prone to natural disasters have driven up premiums, the Department argued that insurance Xcel does not carry cannot be the driver of its increased insurance costs.

Citing Xcel's testimony that insurers develop premiums based on each utility's unique risk profile and that Xcel does not face the same risk as other utilities for hurricanes and wildfires given its geographic location, the Department argued that this testimony contradicted the notion that a rising risk of hurricanes and wildfires contributed to increased premiums for Xcel.
In response to Xcel's testimony that its actual 2022 insurance expense was on track to be within 0.4% of the forecasted value as of late 2022, the Department asserted that the Company did not verify whether that late-2022 projection was accurate or remained true for the full year's costs when 2022 was complete.

Further, the Department challenged Xcel's adherence to the same forecasting process it has used in the past to budget for insurance expense, arguing that this process has yielded inaccurate, overstated forecasts since 2017, which a particularly large gap between forecasted and actual insurance expense in 2021.

In light of its positions that Xcel's forecasting process (1) has not been substantiated with sufficient evidence in the record and (2) has significantly overestimated insurance expense in past years, the Department argued that a more reliable and reasonable approach would be to ground insurance-premium forecasting in historical trends from Xcel's actual average insurance-expense growth over a range of recent years.

The Department analyzed Xcel's past insurance spending data to determine the average annual percentage increase Xcel incurred for insurance premiums from 2017–2021. The Department then applied that average percentage increase to Xcel's actual 2021 insurance expense to calculate a proposed insurance budget for 2022. For 2023 and 2024, the Department applied the same year-over-year percentage increases Xcel proposed for those years, starting from the Department's reduced 2022 insurance budget amount.

The Department's proposed adjustments of reducing the 2022 percentage increase to align with the historical average but maintaining Xcel's requested percentage increases for 2023 and 2024 would reduce the revenue-requirement insurance expenses by approximately $9 million to $11 million in each year of the rate plan.

2. Xcel

Xcel opposed the Department's recommended adjustment, arguing that historical insurance costs are not reliable predictors of future insurance costs and that an insurance-premium forecast must be based on a thorough investigation with input from insurance brokers on general trends in insurance markets. Xcel asserted that the Department did not refute the Company's evidence of insurance market trends or identify any flaws in the Company's process for forecasting insurance expense. It characterized the Department's arguments as unreasonably retrospective and argued that the size of the forecasted costs compared to past actual costs is not a good reason to reject the forecasts Xcel developed based on prospective market trends.

Xcel attributed the substantial increases in its forecasted insurance expense to a "hardening" market, meaning that insurance companies are generally increasing premiums pursuant to supply-and-demand principles as a result of large claims industrywide or reduced insurance capacity. Xcel stated that hardening in the market is causing increased premiums in its master property insurance and excess liability insurance programs. In the area of primary casualty insurance, Xcel contended that insurance premiums are increasing due to a general upward trend in claim experience driven by an increase in catastrophic events such as gas explosions, hurricanes, and wildfires.

Xcel asserted that its insurance-premium forecasting methodology was an accurate predictor of its 2022 insurance costs. Xcel stated that the Company's actual 2022 insurance expenditures as of late 2022 were on track to be within about 0.4% of the Company's forecasted insurance expense for 2022.

Additionally, Xcel contended that its actual insurance expense for 2021 would have been close to its forecasted amount if not for the receipt of certain unforecastable surplus distributions from mutual insurance pools that were much larger than expected. In particular, Xcel in 2021 received a large distribution from its nuclear mutual insurance pool (Nuclear Electric Insurance Limited, or NEIL) because NEIL experienced either lower claims or higher investment returns than it had anticipated and reflected in its premiums. Xcel credits any expected NEIL distributions against forecasted premiums in its insurance budgets; however, distributions from NEIL fluctuate significantly from year to year because of NEIL's varying investment results and loss experience and, therefore, Xcel cannot forecast these distribution amounts with high accuracy or certainty.

C. Recommendation of the Administrative Law Judge

The ALJ found that Xcel met its burden to support its proposed insurance-premium expenses for 2022–2024 and recommended that the Commission approve the Company's proposed amounts without the Department's recommended adjustment.

The ALJ found persuasive the Company's testimony that an increase in catastrophic events such as hurricanes and wildfires is generally driving up primary casualty insurance premiums across the industry.

Additionally, in finding that Xcel demonstrated the accuracy and thoroughness of its insurance-expense forecasting method, the ALJ was persuaded by the small size of the variance between the forecast and actual expenses in 2022.

D. Commission Action

Respectfully, the Commission disagrees with and will not adopt the ALJ's findings and recommendation regarding Xcel's proposed insurance-premium expense. Instead, the Commission will require Xcel to apply the Department's recommended adjustments to the 2022–2024 test-year and plan-year insurance-expense amounts.

Xcel's request relied heavily on overly generalized and indirect testimony about insurance-market trends. For example, Xcel filed a general summary of information purportedly received from insurance brokers rather than providing evidence directly from the brokers or other industry experts so that parties could cross-examine the sources of the market-trend claims and assess their credibility. Given the magnitude of the insurance costs Xcel seeks to recover from ratepayers and the substantial departure from historical trends in this cost category, the burden of persuasion required more robust record development to support Xcel's request on this issue.

Although the ALJ credited Xcel's slightly more specific explanation for expecting higher premiums for primary casualty insurance, Xcel did not detail a link between the increasing catastrophic events and claim experience and the specific premium amounts estimated for each insurance program. Moreover, the few explanations Xcel offered for changes in the markets relative to specific insurance programs relate to only a small subset of the Company's insurance programs and cannot explain the claimed cost increases in all the insurance programs the Company maintains. Moreover, Xcel did not persuasively show that the factors it cited as affecting the insurance markets are so substantial and consequential in Xcel's insured locations that they fully account for the expansive differences between Xcel's proposed insurance expenses for 2022–2024 and its actual insurance expenses incurred from 2017–2021.

The Commission also is not persuaded that Xcel's adherence to the same forecasting methods it has used in past years lends credence to the resulting 2022–2024 estimates. The record shows that Xcel's process significantly over-forecasted insurance expenses from 2017–2021, and these past performances call into question the accuracy of the forecasts produced through the same process in this case.

Xcel's argument that its 2021 actual insurance expense would have been close to the forecasted value if not for a larger-than-expected NEIL distribution is not a persuasive reason to accept the Company's forecasting process amid the other concerns raised in the record. Xcel routinely budgets for estimated NEIL distributions to be credited against its insurance premiums each year, and these distribution amounts fluctuate significantly and unpredictably. The record does not suggest that the 2021 NEIL distribution was an anomaly that can reasonably be excluded from consideration when evaluating the accuracy of Xcel's 2021 forecast; rather, varying distributions from mutual insurance pools appear to be a continuing issue equally likely to affect future years in unanticipated ways as they have in past years.

Xcel's claim that its forecast was closer to the actual expense in the singular year of 2022—the accuracy of which Xcel did not substantiate—is not enough to outweigh the substantial over-collection in this expense category demonstrated throughout the preceding years so as to persuade the Commission of this method's merits.

Having found that Xcel has not met its burden to support the requested amount of insurance-premium expense, the Commission will exercise its discretion to identify substitute values that reasonably approximate representative insurance costs based on the record and will result in just and reasonable rates.

Where costs fluctuate from year to year based on multiple factors beyond the Company's control and are difficult to predict, it is often reasonable to consider historical averages over a range of years in setting test-year costs.

Based on the record of variability in net insurance expense each year, the Commission finds that the Department's proposal to project 2022–2024 insurance costs based on historical trends in Xcel's actual insurance expenditures over a recent multiyear period is reasonable and is the approach most strongly supported by the record. The Commission will therefore require Xcel to calculate its 2022 test-year insurance-expense amount by applying the annual average percentage change in the Company's actual insurance expense from 2017–2021 to its actual 2021 insurance expense amount, and then calculate 2023 and 2024 plan-year values by applying the increase percentages Xcel proposed to use for those years.

Accordingly, the Commission will require Xcel to adjust its insurance-premium expenses as proposed by the Department, reducing the revenue requirement by $9.274 million in 2022, $10.017 million in 2023, and $11.311 million in 2024 for the Minnesota electric jurisdiction.

XXV. Organizational Dues

A. Introduction

Xcel's rate request included dues the Company pays for membership in certain utility associations and chambers of commerce. Parties disagreed about whether the Company should recover dues for the following organizations: (1) Edison Electric Institute (EEI) (2) the American Gas Association (AGA), and (3) 68 chambers of commerce.

Additionally, as a threshold matter, parties disagreed about which legal standard applies to the disputed organizational dues and whether certain filing requirements apply.

B. Legal Standard

Under Minn. Stat. § 216B.16, subd. 17, a utility may not recover as operating expenses "a public utility's travel, entertainment, and related employee expenses" if the Commission finds those expenses to be unreasonable and unnecessary for the provision of utility service.[35] To assist the Commission in evaluating which of these expenses are recoverable, a utility filing a general rate case petition must include "a schedule separately itemizing all travel, entertainment, and related employee expenses" including "dues and expenses for memberships in organizations or clubs" and other categories identified by statute or by the Commission.[36]

1. Positions of the Parties

Parties disagreed about whether Minn. Stat. § 216B.16, subd. 17, applies to the organizational dues at issue in this case. Expenses falling under subdivision 17 must be itemized separately and are not recoverable if they are "unreasonable and unnecessary for the provision of utility service."

The OAG argued that organizational dues fall under subdivision 17 regardless of whether the dues relate to individual employee memberships or corporate memberships and regardless of whether the utility pays the dues directly to the organization or reimburses an individual employee who first pays the dues to the organization. The OAG contended that the itemized information required by subdivision 17 is necessary to allow ratepayer advocates and the Commission to evaluate the recoverability of these expenses.

Xcel disagreed, contending that subdivision 17 applies only to expenses that are incurred by an individual employee, tracked through the Company's expense-reporting system, and then reimbursed to the individual employee consistent with the Company's employee expense policy. The EEI, AGA, and chamber dues at issue in this case are paid directly to the organizations by Xcel, not incurred by individual employees and then reimbursed through the expense-reporting system, so Xcel argued that these expenses are not within the scope of subdivision 17.

Instead of applying the employee-expense standard from subdivision 17, Xcel contended that these EEI, AGA, and chamber dues should be analyzed under the ordinary legal standard that governs all expenses in rate cases: Rates must be just and reasonable, balancing the interests of the utility, its shareholders, and its customers.

2. Recommendation of the Administrative Law Judge

The ALJ concluded that the dispute about the applicability of subdivision 17 does not materially affect the rate-recovery analysis in this case. Although subdivision-17 employee expenses are subject to specific itemization and filing requirements, the ALJ found that the "[not] unreasonable and unnecessary" standard in subdivision 17 is consistent with the general ratemaking standard that all rates be just and reasonable giving due consideration to the utility's need to meet the cost of furnishing service.[37] The ALJ noted that Minn. Stat. § 216B.16, subd. 19 (the multiyear rate-plan statute) requires that rates "be based only upon the utility's reasonable and prudent costs of service," and that the Commission routinely examines the need for and reasonableness of utility expenses outside the context of employee expenses under subdivision 17.

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[35] Minn. Stat. § 216B.16, subd. 17.

[36] *Id.*

[37] *See* Minn. Stat. § 216B.16, subds. 4, 6.

Having determined that the distinction is not material to the rate-recovery analysis, the ALJ declined to decide whether the organizational dues at issue constitute employee expenses subject to subdivision 17. However, because the utility has the burden to establish the recoverability of all claimed expenses by a preponderance of the evidence, the ALJ noted that Xcel bears the risk that the Commission may find that an expense is not adequately supported and therefore deny recovery if the Company provides less detail. In other words, even if an expense does not strictly fall under the requirements of subdivision 17, providing detailed, itemized information is likely to help Xcel meet its burden under either standard.

The ALJ recommended that the Commission evaluate rate-recoverability of corporate organizational dues on a case-by-case basis in light of the facts of the case. Additionally, for the Company's next rate case filing, the ALJ stated that the Commission may impose any specific filing requirements that the Commission deems necessary to evaluate the recoverability of any organizational dues.

3. Commission Action

The Commission concurs with the ALJ that, as applied to the specific questions of recoverability of the organizational dues at issue herein, the legal standard expressed in Minn. Stat. § 216B.16, subd. 17(a) is functionally equivalent to the general legal standard that governs all utility expenses, such that applying either standard does not alter the outcome of the recoverability analyses in this case.

Although the ALJ did not make a recommendation as to the legal applicability of subdivision 17, the Commission will require Xcel in future rate cases to provide the information identified in Minn. Stat. § 216B.16, subd. 17, for all costs it seeks to recover for organizational dues, including chamber-of-commerce dues, regardless of membership type and regardless of whether the Company paid the organization directly or reimbursed an employee for the expense.
The Commission is not persuaded by Xcel's argument that subdivision 17 applies only to expenses first incurred by individual employees and subsequently reimbursed by the Company.

Nothing in the statutory language implies any limitation based on whether the expenses were incurred by an employee and reimbursed or paid by the utility directly to the organization. To the contrary, subpart (b) of subdivision 17 requires separate itemization for certain subpart (a) expenses "incurred by *or on behalf of*" certain employees or board members, indicating that expenses incurred by the Company directly and not reimbursed to an employee may also fall within the scope of subdivision 17.[38]

Moreover, as the ALJ noted, the Commission has authority to impose specific filing requirements that are necessary to evaluate the recoverability of utility expenses. The Commission agrees with the OAG that the itemized expense data identified in subdivision 17 is necessary to facilitate thorough examination of Xcel's organizational dues expenses for both institutional and individual-employee memberships, whether paid directly by the utility to the organization or reimbursed to an individual employee, so that the Commission may determine whether the expenses are recoverable.

[38] Minn. Stat. § 216B.16, subd. 17(b) (emphasis added)

C. Edison Electric Institute

EEI is a trade organization that represents investor-owned electric companies in the United States. Xcel's estimated EEI dues for the Minnesota jurisdiction are $1.021 million in 2022, $1.011 million in 2023, and $1.012 million in 2024.

1. Positions of the Parties

The OAG opposed Xcel's request to recover EEI dues, arguing that Xcel has not met its burden to prove that membership in this organization is reasonable and necessary for the provision of electric service or benefits ratepayers. The OAG principally argued that because EEI engages in lobbying and related advocacy on behalf of its members, the Commission should closely scrutinize these dues to ensure that ratepayers are not made to pay for advocacy activities that are not sufficiently tied to the provision of utility service and beneficial to customers.

Although Xcel removed from its request the percentage of dues that EEI reports as being for lobbying activities as defined by the IRS, the OAG argued that excluding this percentage from the total dues is not sufficient to prove that the remaining expenses are reasonable and necessary for the provision of utility service. Rather, the OAG argued, it is Xcel's burden to make an affirmative showing as to the value of and need for EEI's services—a burden that has not been met in this record.

Just Solar echoed the OAG's arguments opposing Xcel's EEI request. Additionally, Just Solar argued that requiring Xcel's customers to pay for these dues would effectively compel customers to subsidize EEI's speech activities in violation of First Amendment free-speech protections. Xcel asserted that membership in EEI provides important benefits to customers including public policy leadership, strategic business intelligence, and essential conferences and forums, and provides services that Xcel cannot duplicate on its own such as critical industry data and training. In response to the OAG's assertion that it is unreasonable to rely on the lobbying-activities percentage identified by EEI, Xcel stated that there is no practical way for Xcel to independently review EEI's activities and determine which ones constitute lobbying under some standard other than the widely used IRS definition.

2. Recommendation of the Administrative Law Judge

The ALJ found that EEI dues provide some ratepayer benefits but that Xcel failed to meet its burden to show that EEI's method of distinguishing lobbying and non-lobbying expenses is sufficient to rely upon as a basis to conclude that the non-lobbying portion is fully recoverable. Therefore, the ALJ recommended that the Commission adopt the OAG's recommendation to remove Minnesota jurisdictional amounts of $1,021,000 from the 2022 test year, $1,011,000 from 2023, and $1,012,000 from 2024.

3. Commission Action

The Commission respectfully disagrees with the ALJ's findings and will approve Xcel's request to recover EEI dues. Xcel met its burden to explain how membership in EEI benefits customers by providing critical industry data and training, public policy leadership, strategic business intelligence, and essential conferences and forums to enhance Xcel's ability to serve customers.

Additionally, Xcel demonstrated that it excluded from its request the portion of dues EEI designated for lobbying to protect customers from paying for activities that do not benefit them.

The Commission recognizes the OAG's concerns that EEI may use dues to engage in policy advocacy that promotes utilities' interests over customers' but falls short of the IRS definition of lobbying and, thus, is not excluded from rates through the provided percentage. However, Xcel persuasively argued that it would not be reasonably practical to require the Company to conduct an independent audit of all of EEI's activities to confirm whether there is any policy advocacy against utility customers' interests under a standard broader than the IRS definition. Under the circumstances, the Commission is not persuaded that the OAG's concerns warrant denying recovery of these dues which have been shown to be beneficial in the provision of utility service.

Based on the demonstrated customer benefits and Xcel's exclusion of the EEI-identified lobbying-related portion from the recovery request, the Commission will approve Xcel's request to recover, on a Minnesota jurisdictional basis, $1,021,000 for 2022, $1,011,000 for 2023, and $1,012,000 for 2024 for EEI dues.

D. American Gas Association

The AGA is an industry association for companies that engage in activities associated or affiliated with the natural gas industry. Xcel's estimated AGA dues for the Minnesota jurisdiction are $365,000 in 2022, $361,000 in 2023, and $362,000 in 2024.

1. Positions of the Parties

The OAG opposed Xcel's request to recover AGA dues. Noting that AGA activities focus on the natural gas industry, the OAG argued that Xcel has not established that membership in the AGA is reasonable and necessary for the provision of electric service and has not established a clear connection between AGA membership and the improvement of electric utility service to benefit electric customers.

Just Solar joined the OAG's arguments against recovery of AGA dues and added that requiring Xcel's customers to pay for AGA dues would violate First Amendment free-speech protections by compelling customers to subsidize the AGA's speech activities.

Xcel contended that its AGA membership provides significant benefits to the Company's electric operations and electric customers by helping the Company to manage procurement of natural gas for its gas-fired electric generation facilities and to handle the location of gas lines safely. Additionally, Xcel stated that the AGA is a leader in the development of clean hydrogen technology, which is an element of the Company's decarbonization vision.

2. Recommendation of the Administrative Law Judge

The ALJ found Xcel's arguments persuasive and recommended that the Commission approve the Company's requested recovery of AGA dues.

3. Commission Action

The Commission respectfully disagrees with the ALJ's findings and will preclude Xcel from recovering AGA dues in electric rates.

The AGA represents energy companies that deliver natural gas, and its activities focus on the gas industry. Although Xcel uses gas at some of its electric-generation facilities, the rates at issue in this case are for Xcel's electric service, not gas service. Xcel has not provided substantial, persuasive evidence demonstrating that its membership in the AGA is reasonable and necessary for the provision of electric service, that its electric utility service would be diminished or its quality reduced without AGA membership, or that AGA membership materially benefits its electric customers. The record does not establish a sufficient connection between AGA activities and benefits to Xcel's electric customers to justify requiring Xcel's electric customers to pay these costs.

The Commission will therefore require Xcel to remove from its revenue requirement Minnesota jurisdictional amounts of $365,000 for 2022, $361,000 for 2023, and $362,000 for 2024 for AGA dues.

E. Chambers of Commerce

1. Introduction

Xcel requests to recover $156,286 in each year of the rate plan for dues paid to 68 different chambers of commerce. The requested amount represents the full Minnesota jurisdictional share of Xcel's chamber dues, excluding portions the chambers attributed to lobbying.

Under Minn. Stat. § 216B.16, subd. 13, the Commission may (but is not required to) allow rate recovery of expenses incurred for economic and community development. The Commission's traditional practice has been to allow utilities to recover only half of their economic-development costs through rates, leaving shareholders to bear the other half. The primary reason for limiting ratepayers' share of these costs is because economic development in a utility's service area often leads to increased electric usage, which typically increases the utility's revenue and profits, thus benefiting shareholders.

The parties in this case did not dispute that only 50% of economic development expenses should be recovered from ratepayers because economic development within a utility's service territory tends to benefit the utility's shareholders as much as it benefits customers. However, they disagreed about whether the dues Xcel pays to chambers of commerce should be characterized as economic-development expenses subject to this recovery limit.

2. Position of the Parties

The OAG recommended that Xcel's recovery be limited to 50% of the non-lobbying dues it pays to be a member of any state, regional, or local chamber of commerce because these organizations engage in economic-development activities that benefit Xcel's shareholders. The OAG stated that over 85% of the chambers identified the objective of furthering business and economic activity in their mission statements. The OAG's requested 50% adjustment would reduce Xcel's revenue requirement by $78,143 in each year of the rate plan.

Xcel argued that chambers of commerce play roles in their communities beyond economic development, such as fostering relationships and strengthening community ties. Xcel contended that, by paying dues and participating in chambers of commerce, the Company demonstrates its support for and commitment to those communities and improves its ability to respond to the needs of customers in those communities. Xcel also stated that chamber activities provide a vehicle to interact with customers so it can better serve them. Because chamber-of-commerce membership provides the Company and local customers these other benefits, Xcel argued that chamber dues should not be considered economic-development investments.

3. Recommendation of the Administrative Law Judge

The ALJ found that membership in the various chambers of commerce provides a ratepayer benefit beyond economic development. Therefore, the ALJ recommended that the Commission allow Xcel to recover the full amount requested for chamber-of-commerce dues and not adopt the OAG's recommended adjustment.

4. Commission Action

The Commission respectfully disagrees with the ALJ's recommendation and will require Xcel to reduce its recovery of chamber-of-commerce expenses by 50%.

As the OAG noted, the vast majority of the chambers of commerce identified in the record highlight furthering business and economic activity in their mission statements. Thus, it is reasonable to conclude that at least some of the dues Xcel contributes to these organizations will be used for economic development in the Company's service territory and should therefore be limited to 50% recovery under the parties' agreed upon practice for economic-development expenses.

Although Xcel provided evidence suggesting that chamber-of-commerce membership yields some benefits beyond economic development, Xcel has not proposed any way to quantify the relative proportions of economic-development and non-economic-development benefits. The record offers no guidance for designating a specific percentage of the total chamber-of-commerce expense category as being associated with economic development so that the 50% limitation may be applied only to that portion while the Company recovers 100% of the chamber dues associated with other benefits.

The Commission has discretion to disallow economic-development costs under Minn. Stat. § 216B.16, subd. 13. The utility bears the burden to show that any requested rate increase is just and reasonable, and any doubt as to reasonableness is to be resolved in favor of the consumer.[39]

In this case, the record shows that at least some portion of Xcel's chamber-of-commerce expense is incurred for economic development, and Xcel has not met its burden to show that any particular portion of this expense category (or its requested 100%) is *not* associated with

[39] Minn. Stat. § 216B.16, subd. 4; Minn. Stat. § 216B.03.

economic development. Therefore, resolving doubts in the consumer's favor, the Commission finds it reasonable to limit recovery of Xcel's chamber-of-commerce expense to 50%. This adjustment will reduce Xcel's revenue requirement by $78,143 in each year of the rate plan.

XXVI. Carbon-Free Future MN Coalition

A. Introduction

Xcel's revenue request includes $935,946 for 2022, $93,595 for 2023, and $93,595 for 2024 associated with the Carbon-Free Future MN Coalition.

Xcel described the Carbon-Free Future MN Coalition as an initiative to educate non-traditional stakeholders about the Company's carbon-free energy vision, its plans for transitioning to clean energy, and how stakeholders can engage in discussions of the transition process. Xcel stated that some of these funds were used to make presentations to customers, communities, membership organizations, chambers of commerce, environmental advocacy groups, individuals, and other stakeholders regarding various elements of the Company's resource plan related to the clean-energy transition. Xcel argued that helping stakeholders to understand the Company's transition plans would better position stakeholders to be able to support an ambitious clean-energy future if they so choose.

B. Positions of the Parties

The OAG recommended that the Commission disallow recovery of Xcel's claimed 2022–2024 Carbon-Free Future MN Coalition costs. The OAG questioned whether these expenses should have been disclosed as lobbying expenses and argued that Xcel had not provided sufficient evidence to support its requested amounts or to show that it is just and reasonable to recover these costs through rates.

Xcel asserted that it did not view the Carbon-Free Future MN Coalition as a lobbying program and maintained its request to recover the full amount claimed.

C. Recommendation of the Administrative Law Judge

The ALJ did not make a recommendation on this issue.

D. Commission Action

The Commission will require Xcel to remove all 2022–2024 Carbon-Free Future MN Coalition costs from the revenue requirement, totaling $935,946 for 2022, $93,595 for 2023, and $93,595 for 2024. The activities underlying these costs appear similar to lobbying activities directed at the Commission and the Legislature, which are not recoverable, and Xcel has not demonstrated that the costs are related to recoverable activities or necessary to provide service to customers.

XXVII. Advertising Costs

A. Introduction

Xcel's revenue request includes $317,439 in each year of the MYRP for expenses identified as FERC Account 912 "Customer Program – Advertising" and "Customer Program – Promotion" costs. FERC Account 912 is a type of federally regulated account that utilities maintain for certain costs incurred in "promotional, demonstrating, and selling activities."[40]
In Xcel's initial filing, FERC Account 912 items were marked as "economic development." As noted above, the parties agreed that only 50% of economic-development costs should be recovered from ratepayers.

B. Positions of the Parties

Because Xcel's initial filing identified FERC Account 912 costs as economic development, the OAG argued that only 50% of these costs should be recovered through rates.

Xcel maintained that its FERC Account 912 costs should be fully recovered, asserting that they are not economic-development costs and were only mislabeled as such through inadvertence. Xcel stated that these costs are actually "demonstrating and selling expenses" consistent with the federal regulations governing this type of account. Further, Xcel argued that the costs shown reflect a reasonable level of advertising costs to include in rates and that the advertising samples included in the Company's initial filing further demonstrate their reasonableness.

Disputing Xcel's assertion that the costs were inadvertently mislabeled, the OAG argued that Xcel failed to provide examples of these advertisements sufficient to prove their recoverability. Accordingly, the OAG argued that Xcel failed to meet its burden and recommended that the Commission resolve doubt in favor of consumers by limiting recovery to 50% for these costs.

C. Recommendation of the Administrative Law Judge

The ALJ found Xcel's explanation of inadvertent mislabeling persuasive and found that the costs attributed to FERC Account 912 are fully recoverable advertising expenses, not related to economic development. The ALJ further found that the costs requested by the Company reflect a reasonable level of advertising costs to include in rates for 2022–2024. The ALJ noted that the OAG had the opportunity to review Xcel's provided advertising samples and did not identify any samples that appeared to be related to economic development.

The ALJ therefore recommended that the Commission approve Xcel's proposed FERC Account 912 expenses and not adopt the OAG's recommended adjustment.

D. Commission Action

The Commission concurs with the ALJ that Xcel adequately supported its FERC Account 912 costs and persuasively explained that the mislabeling as economic development does not warrant

[40] *See* 18 C.F.R. § 367.9120.

a 50% adjustment. The Commission will therefore approve recovery of these expenses as proposed by Xcel.

RATE OF RETURN

XXVIII. Capital Structure

To determine an overall rate of return for Xcel Energy, it is necessary to determine the amount of long-term debt, short-term debt, and common equity needed by the Company to finance its operations (the capital structure) and the cost of each of these components.

The Company proposed the following capital structure.

Table 2 Proposed Capital Structure			
Type of Capital	**2022**	**2023**	**2024**
Long-Term Debt	46.89%	46.50%	47.08%
Short-Term Debt	0.61%	1.00%	0.42%
Common Equity	52.50%	52.50%	52.50%
Total	100%	100%	100%

No party opposed the Company's proposal, and the Commission concurs on its reasonableness.

XXIX. Cost of Debt

Xcel proposed the following costs of long-and short-term debt, which reflects the weighted average cost of each individual debt issuance anticipated in each of the years listed below. Typically, short-term debt is any financial obligation that is due in less than one year whereas long-term debt is any financial obligation due later than one year.

Table 3 Xcel's Proposal			
Type of Debt	**2022**	**2023**	**2024**
Long-Term Debt	4.13%	4.12%	4.06%
Short-Term Debt	0.94%	0.80%	1.47%

In response to the Company's proposal, the Department recommended that the costs be adjusted upward to reflect the impact of increased interest rates, as shown in the table below.

Table 4 The Department's Proposal			
Type of Capital	**2022**	**2023**	**2024**
Long-Term Debt	4.19%	4.33%	4.40%
Short-Term Debt	3.73%	3.50%	4.17%

Ultimately, the Company agreed on the reasonableness of the Department's calculations. The Commission also concurs on the reasonableness of these calculations and will approve them. While the Commission has not approved a revised cost of debt in a rate case proceeding in over a decade, in this instance, the Commission concurs on the reasonableness of these calculations, which reflect increases in interest rates due to inflationary factors. The approximate revenue requirement impact of this upward revision is equivalent to an additional 30 return-on-equity basis points.

XXX. Rate of Return on Equity

A. Introduction

In determining just and reasonable rates, the Commission is required to

> 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 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*.[41]

One of the critical components of that fair and reasonable return upon investment is the return on common equity, which—together with debt—finances utility infrastructure. The Commission must set rates at a level that permits stockholders an opportunity to earn a fair and reasonable return on their investment and permits the utility to continue to attract investment.

All parties in this proceeding point to two decisions of the United States Supreme Court to provide further explanation as to how a fair and reasonable return should be calculated—the *Hope* and *Bluefield* decisions.[42] In particular, the *Bluefield* Court held:

> A public utility is entitled to such rates as will permit it to a return . . . equal to that generally being made at the same time . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.[43]

The *Hope* Court further explained:

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure

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[41] Minn. Stat. § 216B.16, subd. 6 (emphasis added).

[42] *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 43 S. Ct. 675 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281 (1944).

[43] *Bluefield*, 262 U.S. at 692–93.

> confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[44]

B. The Analytical Tools

Xcel, the Department, XLI, and CUB conducted cost-of-equity studies and based their analyses on comparison groups of utilities they considered similar enough to Xcel to serve as proxies in determining the Company's cost of equity.

The Discounted Cash Flow (DCF) analytical model, on which this Commission has historically placed its heaviest reliance, uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is high enough to induce investment. The model is derived from a formula used by investors to assess the attractiveness of investment opportunities using three inputs—dividends, market equity prices, and growth rates.

The three DCF models in this record include: constant growth, two-growth (or two-stage), and multi-stage. Constant growth DCF is used where dividends are expected to grow at a constant rate over time. Two-growth DCF uses growth forecasts to model dividend growth in years one through five and then applies a different growth rate for years six and beyond. Multi-stage adds a transition period between short- and long-term growth. The basic approach is, for both the two-stage and multi-stage DCF, to recognize that unusually low or high growth rates are unlikely to continue in the long term, and to adjust them in later years of the model.

The Company and the Department also used the Capital Asset Pricing Model (CAPM) as a secondary, corroborating resource, consistent with the Commission's historical treatment of this model. This model estimates the required return on an investment by determining the rate of return on a risk-free, interest-bearing investment; adding a historical risk premium determined by subtracting that risk-free rate of return from the total return on all market equities; and multiplying the remainder by beta, a measure of the investment's volatility compared with the volatility of the market as a whole.

Xcel also conducted an Empirical CAPM study, which addresses the tendency of the CAPM to underestimate the cost of equity for companies with lower beta coefficients (in effect, lower return potential) such as regulated utilities. It recognizes the results of academic research showing that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM underestimates the "alpha," or the constant return term.

The Predictive Risk Premium model, also used by Xcel, is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. According to RPM theory, an estimate of a common equity risk premium over bonds (either historically or prospectively) is used to derive a cost rate of common equity. The Total Market Approach Risk Premium model develops three different equity risk premiums, using different measures for those premiums.

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[44] *Hope*, 320 U.S. at 603.

CUB used the Residual Income model, a method of determining a cost of equity using the current stock price, the book value of equity (per share), return on equity, and long-run sustainable growth.

C. Proxy Groups

As noted above, the standard method for estimating the cost of equity would normally begin by examining the price of the utility's stock, but Xcel is a subsidiary of Xcel Energy, Inc. and has no publicly traded common stock. Its cost of common equity—essential to determining overall rate of return and the final revenue requirement—must therefore be inferred from market data for companies that present similar investment risks.

A standard method for estimating the cost of equity of a private company like Xcel is to develop a proxy group of publicly–traded companies that pose similar risks to equity investors as the non-public company and then apply cost models to the members of the proxy group to infer the non-public company's cost of equity.

The Company, the Department, XLI, and CUB each developed criteria used to screen companies to identify those most analogous to Xcel. These criteria included such factors as whether the company is a vertically integrated utility, what percentage of its operating income is derived from regulated electric distribution operations, dividend growth rate projections, and whether it was involved in a recent merger, among others.

Xcel and the Department updated their proxy groups throughout the proceeding to account for changes in circumstances affecting companies that no longer met their screening criteria. Xcel began with 13 companies, then removed two and added one. The Department started with a very similar list of companies, then removed one and added one, for a total of 16 companies. XLI included 12 companies, nearly identical to the Company's with the exception of excluding Xcel Energy, Inc., (Xcel's parent company) from the list. CUB developed a proxy group of 38 companies that included a broader range of companies with a central similarity being a shared industry.

In addition to these proxy groups, Xcel developed a list of 39 companies that comprised the Company's non-price regulated proxy group. These included entities identified based on different criteria other than those used by the Company's utility proxy group. Primarily, they are domestic, non-price regulated companies, not utilities, who are similar in total risk to the utility proxy group. They have beta coefficients that are within plus or minus two standard deviations of the average unadjusted beta coefficients of the utility proxy group; beta coefficients measure market, or systematic, risk, which is not diversifiable. This proxy group includes diverse companies such as Alphabet, Inc., Lockheed Martin, and Pfizer.

D. Positions of the Parties

1. The Company

a. Proposed Return-on-Equity

Xcel proposed a return on equity of 10.20% based on the results of multiple models and proposed adjustments, including an adjustment for flotation costs.[45]

Xcel's initial set of data, representative of market conditions as of August 2021, shows the following results of its models.

Table 5 Xcel's Initial Filing	
Model/Analysis	**Result, Adjustment Amount, or Range**
Discounted Cash Flow Model	8.78%
Risk Premium Model	10.95%
Capital Asset Pricing Model	12.53%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.24%
Indicated Range of Common Equity Cost Rates Before Adjustments	9.65% - 11.65%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.13%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	9.65% - 11.65%
Recommended Cost of Common Equity	10.20%

Xcel's DCF results of 8.78% above is calculated based on the results of *both* DCF models, the constant growth and two-stage growth models. The Company took the average of the mean and median of both models to calculate its DCF-indicated common equity cost rate for the utility proxy group. The average, as calculated by the Company, of the constant growth model is

[45] Flotation costs are associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs. Due to issuance costs, the price an investor pays for a new share is higher than the price the company issuing the new share receives. As a result, utilities frequently request an adjustment to their return.

8.83%, while the average of the two-growth model is 8.72%; the Company then averaged these results to arrive at 8.78%.

The Company also considered the results of its non-price regulated proxy group results, as well as adjustments and other models. According to the Company, its recommended return fairly balances the interests of customers and shareholders, is consistent with applicable law, and would maintain the Company's financial integrity and ability to attract capital at reasonable rates.

The Company subsequently updated its analysis based on market conditions in September 2022 but continued to recommend that the Commission authorize a return on equity of 10.20%.

The Company explained that inflationary and other market factors led to an increase in its analytical results, as shown in the table below.

Table 6
Xcel's Updated Results

Model/Analysis	Result, Adjustment Amount, or Range
Discounted Cash Flow Model	9.30%
Risk Premium Model	11.65%
Capital Asset Pricing Model	12.06%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.91%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.10% - 12.10%
Business Risk Adjustment	0.05%
Credit Risk Adjustment	-0.18%
Flotation Cost Adjustment	0.08%
Indicated Range of Common Equity Cost Rates after Adjustment	10.05% - 12.05%
Recommended Cost of Common Equity	10.20%

Xcel again took the average of the mean and median results of both DCF models to calculate its DCF-indicated common equity cost rate for the utility proxy group. The average, as calculated by the Company, of the constant growth model is 8.80%, while the average of the two-growth model is 9.79%; the Company then averaged these results to arrive at 9.30%.

In addition to requesting an adjustment for flotation costs, the Company also recommended that the Commission authorize an adjustment mechanism that would alter the return on equity each year of the rate case depending on changes in interest rates on long term utility bonds.

Finally, the Company discounted the returns recommended by other parties, stating that their approaches were flawed, their results therefore skewed, and their adjustments unreasonable, as discussed in further detail below.

2. The Department

The Department offered the results of several DCF models, as well as the results of the CAPM model, in its filings. In recommending a return of 9.25%, the Department stated that the results of its multi-stage DCF analysis are the most reliable and a reasonable starting point for setting a return.

The multi-stage DCF has three stages. In years one through five (the first stage), the model assumes that dividends grow at the forecasted growth rates predicted by equity analysts for the proxy group companies. In the second stage, a proxy company's dividend growth rate moves linearly from the equity analyst growth rate to projected growth of GDP (i.e., the value of the total output of goods and services in the national economy). In the third stage, the model assumes that dividends for the proxy group companies grow at the same rate as GDP.

The Department used two different intervals for the second stage transition period: 10 years and 20 years. The Department filed initial and updated data, including stock prices, dividends, and forecasted growth used as modeling inputs to reflect changes in market conditions. The table below shows the updated results of each of the Department's models, adjusted to include flotation costs.

Table 7
Department Summary of Updated Model Results

	Mean Low ROE	Mean Average ROE	Mean High ROE
Multi-Stage DCF with 10-year second stage	7.83%	8.50%	9.66%
Multi-Stage DCF with 20-year second stage	8.03%	8.74%	9.82%
Constant Growth DCF	9.04%	9.94%	10.68%
Two-Growth DCF	9.09%	9.88%	10.52%
CAPM w/10 Year Growth Transition Period	6.39%	6.75%	7.63%
CAPM w/20 Year Growth Transition Period	7.13%	7.43%	8.16%

The Department explained its rationale for relying on the results of its multi-stage DCF analysis, stating that financial literature demonstrates that equity analysts' long-term earnings growth forecasts are generally biased upwards, thus overestimating future growth. Such growth rates exceed GDP, which acts as a practical ceiling on perpetual growth rates. While the two-growth DCF includes an adjustment to eliminate outlier growth rates, the Department maintained that the model relies on growth rates that exceed expected GDP growth. A multi-stage DCF model solves this problem by assuming growth equal to GDP after either 10 or 20 years.

In assessing the results of the CAPM, the Department recommended against squarely relying on its results, stating that it has drawbacks that make it a poor tool for ratemaking. In particular, it relies on expert judgment at nearly every turn—for determining the term of the risk-free, interest-bearing investments used as a benchmark, determining the time frame for calculating growth rates, determining the beta that represents market volatility, and determining the historical periods over which to measure returns. This reliance on judgment is unlike the DCF as none of the CAPM's inputs are basic matters of fact and public record. According to the Department, the subjectivity of these judgments creates significant variation in their estimating inputs, which is compounded when the inputs are combined. The Department stated that it instead uses the CAPM as a check on the reasonableness of the results of the DCF analyses.

Finally, the Department opposed the Company's proposed adjustment mechanism that would be triggered in each year of the rate case depending on market conditions, stating that the Company had not quantified its proposed metric or otherwise filed its proposed calculations for determining the adjustment.

In response to the Department's recommended return of 9.25%, the Company stated that the Department's approach is not grounded in sound economic theory or a scholarly approach to the field of regulatory finance, stating that reliance on GDP to determine a return on equity unfairly discounts the return's correlation to the Company's need to attract capital.

The Company also rebuked the Department's upward adjustment from the results of its multi-stage analysis (a three-growth stage with a return of either 8.50% or 8.74% based on the average returns of the model using a second-stage growth rate of both 10 and 20 years). The Company stated that the Department's proposed upward adjustment to 9.25% from its results bears no principled relationship to the model's results.

3. XLI

XLI initially recommended a return of 9.17%, though it did not update its data after its initial filing as was done by both the Company and Department. XLI subsequently revised its recommended return to 9.16% based on a correction to its CAPM calculations.

XLI's range of results from all models is shown in the table below. The average results of its DCF constant-growth analysis is 8.60% and the average of its two-growth analysis is 8.55%. In developing its range of results for purposes of recommending a return on equity, XLI excluded the constant growth DCF low result due to its use of unreasonably low growth assumptions; XLI instead relied on the two-growth DCF to set the lower end of the range and used the constant-growth DCF high result for the upper end.

In arriving at a 9.16% recommended return, XLI took the median of the results of its analyses, shown below.

Table 8 XLI Return on Equity Results	
Model	**Return on Equity**
Low Single Stage DCF	7.23%
Mean Single Stage DCF	8.60%
High Single Stage DCF	10.28%
Two Stage DCF	8.55%
Historical CAPM	9.91%
Proj. S&P MRP CAPM	11.66%
Proj. Value Line MRP CAPM	14.46%
Risk Premium	9.42%
Median Return on Equity	**9.66%**

In recommending its return, XLI began with the median of returns from its results and then applied a downward adjustment of 50 basis points to account for the Company's lower-risk profile compared to the utilities in the proxy group. XLI based the adjustment on the fact that the Company has both a multi-year rate plan and sales true-up, as well as a mechanism for recovery of other investments between rate cases, which significantly offset the Company's risk.

XLI also recommended against adjusting the return to account for flotation costs, stating that such costs are incurred by the parent company (Xcel Energy, Inc.), not by the utility in this case, Xcel Energy. XLI also opposed the Company's proposed rate adjustment mechanism for the reasons described by the Department.

In response to XLI's recommended return of 9.16%, the Company stated that XLI mistakenly relied on long-term historical averages, rather than interest rates, to calculate the equity risk premium in its Risk Premium analyses; the Company also faulted XLI for not subsequently updating its DCF and CAPM analyses to reflect changes in market conditions, failings that the Company claimed produce unreasonably low average returns. The Company also stated that XLI's 50-basis point downward adjustment from the results of its analyses to account for the Company's low-risk profile was unfounded; XLI had not fairly considered that other comparable companies have similar rate mechanisms in place to Xcel's, such as a sales true-ups, that affect their risk profiles.

4. CUB

CUB applied a residual income model, which it explained as an algebraic re-expression of the DCF model, to all 38 electric utility stocks in the Value Line Investment Survey, resulting in a 7.00% cost of equity estimate. CUB applied a CAPM to the same list of 38 stocks, resulting in a cost of equity of 7.40%. Similar to the Department's approach, the Residual Income model assumes that growth does not exceed the GDP growth rate.

Based on its analysis, CUB recommended a return of between 8.80% and 9.00%, a range that CUB acknowledges is higher than the actual cost of equity. A fair return, CUB stated, is typically higher than the cost of equity. CUB stated that a reasonable return is justifiably lower than cost but that gradualism supports a result between 8.80% to 9.00% in this case. CUB explained that determining the degree to which a return should be higher than the cost of equity is unrelated to utility risk or financial models that are theoretical in nature but is rather a subjective determination based on public policy analysis, not corporate finance. CUB echoed the Department's position that identifying the cost of equity and then determining a fair return are essentially separate exercises. Identifying a reasonable return is rooted in judgment, which is the best approach to balancing finance variables and policy fairness.

In applying its approach to this case, CUB took into consideration the impacts of inflation on both the utility and its customers, stating that high short-run inflation rates hurt customers more than shareholders, pointing to data that showed Xcel's parent company's stock trading higher at the end of 2022 than it had the year prior. CUB stated that applying short-term high inflation rates to cost-of-equity analyses can skew the estimates of long-term growth rates in favor of the utility to the disadvantage of the ratepayer at a time when inflation is harming consumers.

Finally, CUB opposed the Company's proposed multi-year rate adjustment mechanism for the reasons explained by the Department.

In response to CUB's recommended return of between 8.80% and 9.00%, the Company stated that this recommendation echoes the flaws in the Department's analyses by relying on a presumption that utility returns have been set at unreasonably high levels for years. The Company again discounted this approach, stating that it is premised on public policy considerations instead of the reality of corporate finance.

5. The OAG

The OAG recommended against setting the return at Xcel's recommended level of 10.20%, stating that an increase of that magnitude—114 basis points above the Company's existing return of 9.06%—was not supported by the record. Noting that Xcel's recommended return was substantially higher than any return recommended by any other party, the OAG urged the Commission to rely on the analytical results and the recommendations of other parties in setting the return.

6. The Commercial Group

The Commercial Group supported the recommendations of the Department and XLI, stating that their analyses and recommendations better reflect investor expectations than the Company's. The Commercial Group also echoed opposition to the Company's proposed adjustment mechanism, aligning its reasoning with that of the Department, XLI, and CUB.

7. Just Solar Coalition

Just Solar Coalition recommended that the Commission reject Xcel's proposed return and instead set a return that more equitably considers the analyses and recommendations of CUB and the Department.

E. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission authorize a return on equity of 9.87%, based on the average results of the Company's DCF two-growth analysis as shown in its updated analysis.

In assessing the parties' proxy groups, she found that the utility proxy groups developed by the Company and the Department were not materially different and were both reasonably reliable. She found that one shortcoming of XLI's proxy group is that it was not subsequently updated to reflect market changes. She found CUB's 38-member proxy group to be too broad, and she was not persuaded by CUB's assertions that all firms in the same industry have nearly the same cost of capital, making a larger proxy group superior.

She also found that the Company's non-price regulated companies have dramatically different businesses from Xcel as well as from one another and that, as the Company acknowledged, as individual businesses, their risks have not been shown to be comparable to Xcel's. For this reason, she concluded that the Company's application of its models to the non-price regulated proxy group was unpersuasive in informing a return-on-equity determination.

In analyzing the parties' models and their results, she discounted the Department's reliance on GDP to estimate long-term growth in its multi-stage DCF analyses, finding that over the course of more than 50 years at least seven industries, including utilities, had grown faster than overall GDP. She also found that the CAPM has flaws that render it an unreliable single source for setting a return due its heavy reliance on an analyst's subjective judgment.

Based on extensive analysis of the record and the multitude of models, she found the two-growth DCF analysis in the record most reliable due to the model's accuracy in calculating growth rates and its use of relevant market data. In concluding that 9.87% is well-supported by the record, she stated that in the year between the filing of the rate case and the filing of rebuttal testimony, changes in the market environment had occurred, notably a significant increase in inflation as measured by the Consumer Price Index. She therefore weighed more heavily the results of the Company's updated two-growth DCF analysis in making her return-on-equity recommendation.

Finally, she recommended that the Commission accept an adjustment for flotation costs but otherwise recommended against the Company's other adjustment request. She found that the Company had not explained whether or how its proposed adjustment, triggered by the proposed true-up mechanism, would allow for meaningful, timely consideration of customers' ability to pay for a corresponding rate increase resulting from that adjustment. The ALJ also found that the Company had failed to adequately demonstrate that the mechanism is reasonable, necessary, or effective in balancing the interests of ratepayers and investors.

F. Commission Action

1. Introduction

As explained by the *Hope* and *Bluefield* decisions, the Commission must analyze the facts in the record, exercising its quasi-judicial authority, and apply its judgment, exercising its quasi-legislative authority, to determine a rate of return that appropriately balances the competing interests of ratepayers and shareholders, and which produces just and reasonable rates. Applying these principles, the Commission will set the return on equity at 9.25% for the following reasons.

2. Proxy Groups

In assessing the parties' proxy groups, the Commission recognizes that when developing a proxy group, varying sets of criteria may be reasonably applied for the purpose of identifying which other companies are acceptable proxies for Xcel. In this case, the proxy groups generally reflect reasonable criteria and consistent application of those criteria, albeit the larger and more varied the proxy group the more difficult it likely becomes to compare risk.

In particular, the Commission is not persuaded that the Company's non-price regulated proxy group includes companies with enough similarity to each other as well as to Xcel to justify its use in setting a return on equity. As the ALJ found, the risk of these companies, as individual businesses, has not been shown to be comparable to Xcel's risk

3. Analysis

a. Results of the Models

The Commission concurs with the ALJ that there is no convincing basis on this record for departing from reliance on the two-growth DCF model.

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. And while the two-growth DCF model is not the only useful model, its strengths underscore the limitations of other models such as CAPM, which is more subjective, and Risk Premium, which does not provide information about the returns investors require.

The Commission therefore finds that the two-growth DCF analysis provided by the Company provides a reasonable basis for setting a return in this case. No party showed that the utility proxy group criteria used by Xcel were unreasonable, that the Company's DCF analyses inaccurately reflect the results of the inputs of the model, or that the data the Company used in its DCF models misrepresented market conditions at the time the Company's studies were conducted.

The Commission also recognizes, however, that relying too heavily on a single set of results from one model could inadvertently narrow the range of reasonable returns considered, needlessly eliminating relevant data from close examination. For example, the Company's *two-growth* DCF analysis results from its *initial* filing show that the average return among the proxy group is 8.66%. After updating its data, the average return within the proxy group rose to 9.83%. Put into context, the Company's recommended return of 10.20% is still 37 basis points higher than the *updated* average of returns (and 154 basis points above the initial average of returns). Xcel's updated results incorporate data from September 2022.

By comparison, the Department's updated results corroborate this upward trend in returns. The *initial* results of the Department's four DCF analyses (constant growth, two-growth, and 10 and 20-year multi-stage) show average returns ranging between 7.77% and 9.06%. The Department's *updated* DCF analyses show average returns ranging between 8.50% and 9.94%. The Department explained sharp increases as a result of a notable decrease in utility stock prices in September and October, 2022, which increased dividend yields, coupled with a notable increase in five-year earnings growth estimates.

This trend contrasts the results of the Company's constant-growth model, which appears to underestimate the impact of market conditions, rendering it less reliable than the two-growth model for purposes of setting the return in this case. The results of the Company's initial *constant-growth* DCF analysis show an average return of 8.77%, but after updating its analysis, the average of returns *decreased* to 8.56%.

b. Changes in Market Conditions

As the data shows, the results of Xcel's two-stage DCF analysis increased by 117 basis points in approximately one year. In spite of such changes, no party modified its recommended return based on those changes, a factor that weighs in favor of applying initial and updated data to the return-on-equity analysis.[46] And while the Company declined to modify its recommended 10.20% return, it continued to emphasize the relevance of financial market conditions, both existing *and expected*, when setting the return-on-equity, noting that near the time the updated data was filed, the Federal Reserve cautioned that the longer inflation continued, the more likely that expectations of higher inflation could become entrenched. At that time, there was significant uncertainty about the direction, duration, and impact of inflation. But this sharp, upward trend in inflation has not continued into 2023; rather, inflation has declined since the highest point of inflation in June 2022, with more substantial declines in 2023.[47] The economic outlook is now considerably better than it was in 2022.

Further supporting the proposition that the proportionate impacts of inflation should be taken into account, CUB filed end-of-year 2022 stock price data showing that although stocks in general had decreased during the year by 15%, utility stocks had risen by 4%, suggesting that utility investors have not been substantially adversely affected by inflationary impacts.

Under these circumstances, it is reasonable to rely on multiple data sets from the two time periods covered by the parties' models to better estimate earnings growth. Utilizing both data

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[46] XLI initially recommended a return of 9.17%, with an updated recommendation of 9.16%, but the change was not due to updated market data; XLI did not file an updated analysis.

[47] These facts are generally known and based on publicly available information; see, for example: U.S. Bureau of Labor Statistics, *CPI for All Urban Consumers, 12-Month Percent Change, All Items in U.S. City Average*, DATABASES, TABLES & CALCULATORS BY SUBJECT (last visited July 13, 2023), https://data.bls.gov/timeseries/CUUR0000SA0?output_view=pct_12mths

sets provides a more informed and comprehensive understanding of market conditions and their impacts. Notably, averaging the results of the Company's initial and updated two-growth DCF analyses produces a return of 9.25% (8.66% is the average return based on the results of the Company's initial filing, and 9.83% is the average based on the results from rebuttal testimony).

This approach also takes into consideration the Department's recommended return of 9.25%, premised largely on the theory that market analysts' use of current market earnings over-estimate long-term growth. In this case, the impact of high inflation rates in 2022, when Xcel updated its data, merits consideration of that position. Considering both Xcel's initial and updated data fairly accounts for the Department's emphasis on estimating growth as reasonably and accurately as possible. As stated above, no party changed its recommendation as the case progressed, despite discussing the underlying economic conditions, which suggests that the parties—including Xcel—continued to find their initial analyses reasonably reliable.

Taking into account the results of multiple data sets reasonably balances the risk to both ratepayers and the Company by avoiding over-compensating for high inflation while simultaneously protecting the Company's financial integrity.

Further, setting rates in an MYRP means that rates will continue for at least three years—under Minn. Stat. § 21B.16, subd. 19, rates for the third year will be in effect until the Company files another rate case. The Commission is not persuaded that it would be reasonable to rely exclusively on data that, based on this record, appears to be significantly impacted by a period of peak inflation, for a duration of at least three years and possibly longer.

c. Check on Reasonableness

While the results of other models or analyses are less persuasive, they do provide a check on reasonableness. The Department's recommended return-on-equity of 9.25%, while derived from a different DCF model than the Company's, is consistent with the average results of the Company's DCF models. The average of XLI's two-growth DCF analysis (8.55%), based on initial data not subsequently updated, corroborates the reasonableness of the average of the Company's initial two-growth DCF analysis results (8.66%). The Company itself represented 9.30% as a reasonably updated average of its DCF analyses (both constant growth and two-growth).

Although CUB's approach to financial modeling is rooted in a philosophically different approach to setting utility returns, the Commission appreciates CUB's recommendation to meaningfully consider the impacts of high inflation on both the utility *and consumers* when setting the return.

The Commission is also unpersuaded by Xcel's claims that a 9.25% return is insufficient to enable the Company to attract capital at reasonable rates, maintain its credit rating and financial integrity, and provide returns commensurate with those earned on other investments with equivalent risks. The Commission also finds value in XLI's arguments that Xcel's investors face lower levels of risk because of the regulatory tools used by the Company, which include multiyear rate plans and riders; the Department noted that Xcel's financial performance has been successful with a return on equity of 9.06%. While Xcel correctly notes that the stock price and dividends are those of its parent company, and not its regulated Minnesota utility, it is clear that the Minnesota utility contributes to the success of the parent company. The fact that its enterprise has been financially strong while earning a return of 9.06% is an indication, in light of the facts on this record, that increasing its rate of return by nearly 20 basis points, to 9.25%, will not jeopardize Xcel's financial integrity.

Finally, no party recommended a return higher than 9.25% other than the Company.

For all these reasons, the Commission will set the Company's return on equity at 9.25%, including flotation costs.

4. Adjustments

The Commission concurs with the ALJ that no further adjustments are warranted. As she explained, the Company did not substantiate how its proposed adjustment mechanism in each year of the rate case would be calculated or implemented and did not adequately quantify how it might affect ratepayers.

Furthermore, the Company agreed to the Department's recommended adjustments to the Company's cost of short-term and long-term debt to reflect increases in interest rates, which thereby increases the Company's overall rate of return.

The Company has not established that other adjustments are necessary to align the Company's return with its ability to attract capital to finance investments at reasonable rates.

XXXI. Financial Capital Structure and Overall Rate of Return

The final capital structure and overall rate of return resulting from the decisions made herein are set forth below.

Table 9
2022 Capital Structure and Overall Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.89%	4.19%	1.96%
Short-Term Debt	0.61%	3.73%	0.02%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.84%

Table 10
2023 Capital Structure and Overall Rate of Return

Type of Capital	Capital Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.50%	4.33%	2.01%
Short-Term Debt	1.00%	3.50%	0.04%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.90%

Table 11 2024 Capital Structure and Overall Rate of Return			
Type of Capital	**Capital Ratio (%)**	**Cost (%)**	**Weighted Cost (%)**
Long-Term Debt	47.08%	4.40%	2.07%
Short-Term Debt	0.42%	4.17%	0.02%
Common Equity	52.50%	9.25%	4.86%
Total	100.00%		6.95%

CLASS COST-OF-SERVICE STUDY

XXXII. Cost of Service and Rate Design

A. Introduction

The preceding sections have sought to quantify the costs that a prudently managed utility serving Xcel's service area would bear throughout the 2022 test year and 2023 and 2024 plan years--in other words, Xcel's *revenue requirement*. The following sections will address how Xcel may recover those costs, and especially how it may recover costs from its ratepayers in Minnesota--in other words, Xcel's *rate design*. As discussed further below, one consideration when designing rates is how the cost of providing service differs from one ratepayer to another.

Estimating the cost to serve any given customer is challenging because a utility will incur different costs to serve different types of customers, and will incur many costs that benefit multiple types of customers. Because similar types of customers tend to impose similar types of costs on the system, utilities simplify their analyses by first dividing customers into classes—for example, distinguishing residential customers from commercial or industrial customers. Utilities then attempt to determine the amount of revenues they should recover from each customer class.

To aid this analysis, the Commission directs utilities to conduct a class cost-of-service study (CCOSS). Minn. R. 7825.4300(C) directs a utility to file a cost-of-service study by customer class of service, geographic area, or other categorization as deemed appropriate for the change in rates requested, showing revenues, costs, and profitability for each class, area, or category, identifying the procedures and underlying rationale for cost and revenue allocations.

For purposes of its class cost-of-service study, Xcel identified seven retail customer classes: Residential, Outdoor Lighting, and five categories of commercial/industrial customers.

B. Steps for Conducting a Class Cost-of-Service Study

A class cost-of-service study seeks to identify, as accurately as possible, each customer class's causal responsibility for each cost the utility incurred in providing service. *The Electric Utility Cost Allocation Manual* of the National Association of Regulatory Utility Commissioners (NARUC Manual) recommends conducting a CCOSS in three steps. First, the manual recommends grouping costs according to their function. Second, the manual recommends classifying costs based on how they are incurred. Third, the manual recommends allocating costs to the various customer classes.[48]

Functionalization: For purposes of an electric utility CCOSS, the typical functions are generation/production of electricity, transmission, and distribution.

Generation refers to the cost of plant used to generate electricity.

Transmission refers to assets that permit electricity to move efficiently at high voltage from where the electricity is generated to the distribution network.

The distribution system carries electricity from the transmission system to a customer's location. Utilities distinguish between the primary distribution system and the secondary distribution system. In the primary distribution system, electricity travels from the high-voltage transmission system to substations, which reduce the voltage and distribute it via lines and poles to the neighborhoods of retail customers. Some large industrial customers purchase power at primary distribution voltages, but otherwise this electricity flows to the secondary distribution system, where distribution transformers again reduce the voltage, allowing it to be distributed via lines and poles to customer premises.

Classification: The cost of a function may be classified as related to customers, energy, demand (or capacity), or a combination of the three.

Customer-related costs increase as the number of customers increases. Energy-related costs increase as a customer's consumption of energy increases. Demand-related costs increase as the rate at which the customer consumes energy increases, especially during periods of peak demand. Demand-related costs become relevant because a utility must design its system to, at a minimum, meet the forecasted simultaneous demand of all its customers plus maintain a specified amount of additional generating capacity (known as a reserve margin) to address unanticipated levels of demand or equipment failures. MISO establishes criteria for determining the amount of capacity each generator contributes to the regional power grid, and the amount of reserve margin required for each load-serving entity—that is, each retail utility—within its grid.

For commercial and industrial customers with a demand meter, Xcel calculates a charge for the cost of the facilities required to serve that customer's peak usage (a "demand charge"), as well as a separate charge for the amount of energy consumed. For customers in the other customer classes, the costs of energy and demand are recovered through a charge solely on energy.

Allocation: The various costs are then allocated to each customer class using a formal called an allocator.

Choices about classification and allocation strongly influence the results of a CCOSS. The choice of allocator can have important rate consequences. For example, residential customers tend to have a lower load-factor than industrial customers—that is, energy consumption by residential customers tends to fluctuate more than energy consumption by industrial customers.

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[48] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, at 18-23 (January 1992), attached to Collins Direct.

As a result, classifying a given cost based on energy will tend shift more responsibility toward industrial customers, whereas classifying that cost based on demand will tend to shift cost responsibility toward residential customers.

C. Multiyear Rate Plan

Because Xcel filed an MYRP, its CCOSS calculated a new estimate of costs attributable to each customer class for 2022, 2023, and 2024.

XXXIII. CCOSS-Model Selection

In addition to Xcel, the OAG and XLI filed CCOSS models. As a general proposition, the ALJ concluded that each party's CCOSS modelling provided useful information. Noting that the Commission has in recent years "taken a holistic approach and indicated a preference for reviewing multiple methods," the ALJ concluded that each of the CCOSS models had useful attributes, and that all should be considered.[49]

The Commission has previously found that "[n]o single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data."[50] The Commission retains the view that each CCOSS model provides useful information and will therefore decline to adopt any one model for all purposes.

XXXIV. CCOSS—Classifying and Allocating Fixed Production Plant

A. Issue

Fixed production plant refers to the capital cost of generators and related equipment.

No party disputes that the cost Xcel bears for production plant is driven by the level of demand for electricity as well as energy. The cost reflects demand because, as previously noted, Xcel must design its system to be able to meet the anticipated peak level of demand. The parties also agree that the cost reflects Xcel's energy costs—although the parties disagree about why.

B. Positions of the Parties

1. The Department, the OAG, and Xcel

The Department, the OAG, and Xcel favor classifying and allocating fixed production costs using the Stratification Method—a variant of the Equivalent Peaker Method set forth in the NARUC Manual—which Xcel has employed since the 1970s. These parties argued that Xcel selected its portfolio of generators to meet its anticipated peak demand and reserve margins. But

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49 ALJ Report ¶ 829 (discussing distribution plant).

50 *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. E-017/GR-20-719, Findings of Fact, Conclusions, and Order (February 1, 2022) at 44.

Xcel observed that if it were to design a system solely to serve that function, it might have built its entire system out of natural gas “peaking” generators, which have the lowest capital cost per unit of generation (for example, per kilowatt or kW). But these generators also have high operating costs per unit of energy generated (for example, per kilowatt-hour or kWh). According to Xcel, the fact that electric utilities chose to rely on a variety of generators—including generators with higher capital and lower operating costs—demonstrates that utilities design their systems not only to meet peak demand, but also to reduce energy costs.

Xcel proposed allocating the energy-related costs among customer classes using its E8760 allocator. Throughout the year, each customer class’s consumption of energy varies, and the cost of generating a unit of energy varies. To fairly allocate these costs among customer classes, Xcel considers both the cost of acquiring a unit of energy for each of the 8,760 hours of the year, and the amount of energy being consumed by each customer class for each hour. The Department and OAG supported this proposal.

In addition, Xcel proposed allocating capacity-related costs using the D10S allocator, which allocates costs among customer classes in proportion to each class’s energy usage during the period of peak demand. The Department and the OAG supported this concept, but the OAG raised concerns about how Xcel calculated this allocator; these concerns will be addressed further below.

XLI opposed Xcel’s use of the Stratification method. XLI argued that, while the Stratification method may have appropriately classified and allocated the cost of traditional generators, it fails to appropriately allocate the cost of intermittent generators—especially solar- and wind-powered generators. According to XLI, utilities primarily value these generators for their low energy cost rather than the capacity they contribute to the system. XLI argued that allocating the cost of these intermittent generators using the Stratification method, with its reliance of Xcel’s D10S capacity allocator and E8760 energy allocator, causes customers with relatively high, stable energy consumption to bear a disproportionate share of capacity costs while depriving these customers of the corresponding benefit of the lower energy costs.

2. XLI

Instead, XLI favored classifying production costs using the Average and Excess – Four Coincident Peak (AED-4CP) method. Under this method, XLI estimates the cost of generating capacity Xcel requires under average circumstances and assigns those costs to customer classes in proportion to each class’s average energy usage. XLI regarded the rest of Xcel’s generating capacity as reflecting the cost of capacity created to meet peak demand. XLI allocated these costs among customer classes in proportion to each class’s peak demand costs measured four times per year—that is, the amount of energy each class uses during four periods of peak demand, but only to the extent that this amount exceeds the class’s average energy consumption.

XLI also noted that the Administrative Law Judge in Minnesota Power’s then-pending rate case recommended the use of the AED-4CP method.

The OAG and Xcel opposed use of the AED-4CP method. The OAG disputed the model’s relevance, arguing that a utility must design its system to meet total demand regardless of whether anyone would characterize the demand as “average” or “excess.” Because this method focuses on the variability of each class's energy consumption, the OAG argued, it has the effect of minimizing the share of costs borne by the customer class with the highest energy consumption.

Xcel challenged the way XLI applied its method. Xcel noted that XLI's method allocates cost on the basis of four *coincident peaks*—that is, the extent to which each customer class consumes energy during four specific periods of peak demand on the relevant system. The NARUC Manual states that the Average & Excess method should allocate costs on the basis of *non-coincident peaks*—that is, each class's highest periods of consumption throughout the relevant test period, even if those periods do not coincide with the relevant system peaks.[51]

C. Recommendation of the Administrative Law Judge

Citing a prior Xcel rate case order, the ALJ concluded that the Stratification method is more reflective of cost-causation than the AED 4CP method because this method "appropriately reflects the fact that Xcel builds baseload plants to meet both demand and energy needs."[52]

D. Commission Action

Both proposed methods for classifying and allocating fixed production cost acknowledge the role that energy and capacity play in influencing Xcel's portfolio of generators. However, the Stratification method uses the economics of a peaker plant as the basis for distinguishing between investment motivated to procure capacity and investment motivated to procure energy. This provides a sounder rationale for distinguishing between energy-related and capacity-related costs than the distinction between average and excess energy consumption.

XLI correctly observes that Xcel is increasingly acquiring energy from solar- and wind-powered generators, which are notable for their low energy costs and low contributions to system capacity requirements. But the Commission is not persuaded that this fact alters the applicability of the Stratification method—focused on peaker generators that contribute capacity with *low* capital costs and *high* energy costs—for purposes of a CCOSS.

Finding insufficient reason to alter its prior practice, the Commission concurs with the ALJ and will retain the use of the Stratification method for classifying and allocating fixed production cost.

XXXV. CCOSS – Peak Demand (D10S) Allocator

A. Issue

As previously discussed, a CCOSS classifies certain investments as related to capacity or demand. No party disputed that these investments would be allocated among the customer

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[51] *See*, for example, Jeffry Pollock Direct at 21 ("[T]he customer non-coincident peak … measures the maximum demand of each customer, irrespective of when it occurs.")

[52] *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-13-868, Findings of Fact, Conclusions, and Order at 64 (May 8, 2015).

classes in proportion to each class's energy consumption during periods of peak demand. But there are various methods for calculating this allocator.

Non-coincident peak demand refers to the maximum amount of energy a given customer class consumes over a specified period. *Coincident peak demand* refers the amount of energy a customer class consumes during the period of peak demand on the system. The coincident peak identifies the period when the electrical system has the least spare resources to manage additional load or a loss of capacity, so the coincident peak has often provided the basis for allocating demand-related costs.

Historically electric utilities operated independently, building their own plant to generate, transmit, and distribute electricity to their own customers. These utilities designed their system to be able to meet their customers' needs during periods of peak demand plus a reserve margin to manage unanticipated circumstances (extra demand, or an unplanned outage from a generator or transmission line).

But today many electric utilities join to create independent system operators such as MISO. MISO's wholesale energy markets permit utilities to make use of each other's facilities—provided there are sufficient resources available at that time. To ensure resource adequacy, MISO establishes the required amount of reserve capacity and allocates the responsibility for meeting this obligation among load-serving entities such as electric utilities. Finally, MISO calculates this reserve margin based on its peak demand—which may not coincide with the peak demand on any individual utility's network.[53]

As a result, MISO's coincident peak now identifies the period when the electrical system has the least spare resources to manage additional load or a loss of capacity. For this reason, the Commission ordered the utility to "base the D10S capacity allocator on Xcel's system peak coincident with MISO's system peak."[54]

In the current case, Xcel acknowledged that it did not base its D10S allocator on this basis, explaining that MISO had not published the data that would enable Xcel to comply. Xcel proposed a proxy allocator instead. The Department found this proxy satisfactory under the circumstances; the OAG did not.

B. Positions of the Parties

1. Xcel, the Department, and XLI

When Xcel filed this rate case in October 2021, Xcel could not know what the MISO peak hour would be in the 2022, 2023, or 2024 test years. Instead, Xcel analyzed data from MISO's system

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[53] MISO collects data in different zones for different purposes. MISO's Local Resource Zone 1 encompasses most of Minnesota, all of North Dakota, and portions of Montana, South Dakota, and Wisconsin.

[54] *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, and Order at 46 (June 12, 2017).

peak in the relevant planning zone for the past 12 years to forecast the amount of energy each customer class would consume for the six highest peak hours on Xcel's system. According to Xcel, this calculation would likely encompass the MISO peak hour.

The Department and XLI concluded that Xcel's D10S allocator reflects a reasonable effort to implement the Commission's requirement. The Department cautioned against pursuing a pseudoscientific precision in calculating peak demand, noting that the rate case relies on forecasted test years, forecasted planning years, and weather-normalized data.

2. The OAG

The OAG emphasized that the Commission directed Xcel to develop its demand allocator using the peak for MISO's entire system, not for one zone within the system. According to the OAG, this is appropriate because MISO establishes Xcel's resource adequacy requirements based on MISO's system peak, not the zone peak. Accordingly, the OAG calculated a revised D10S allocator based on MISO's system peak for 2016, 2020, and 2021, which it said were the most recent years for which Xcel provided hourly usage data by class.

Xcel raised concerns about the OAG's proposal, noting that it relied on data that had not been weather-normalized—that is, data that had not been adjusted to offset how each year's idiosyncratic weather would predictably alter patterns of energy consumption. But the OAG noted that its proposed allocator is scaled to the weather-normalized sales forecast for each test year.

While Xcel continued to support its own proposed allocator, the utility stated that it would not oppose a Commission order directing the utility to employ the OAG's formula prospectively—a proposal that the OAG supported as well.

C. Recommendation of the Administrative Law Judge

Because MISO did not provide the necessary data that would permit Xcel to comply with the Commission's direction for calculating its D10S allocator, the ALJ concluded that Xcel was justified in using some proxy method for creating the allocator, and that Xcel's proposed method represented a reasonable proxy. Accordingly, the ALJ supported Xcel's recommendation.

D. Commission Action

The Commission concurs that MISO has not provided the data necessary to permit Xcel to forecast the periods of peak demand on MISO's system in future years, and that Xcel was justified in developing a proxy method. That said, the Commission finds that the OAG's proxy—based on MISO's past system peaks rather than on the peaks in a single MISO zone—better reflects the Commission's instruction.

The Commission will not seek any revisions for purposes of the current case. But for Xcel's next general rate case, consistent with the suggestions of the utility and the OAG, the Commission will direct Xcel to calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data.

XXXVI. CCOSS – Classification of Joint Transmission Costs

A. Issue

Transmission assets permit electricity to move efficiently—which entails moving at high voltage—from where the electricity is generated to where it is needed. While some high-voltage lines serve a single industrial customer, most serve the electrical system in aggregate—and no party disputes that all customer classes should bear a share of these joint transmission costs. But parties disagree about how to classify these costs for purposes of allocation. Given the nature of the parties' disputes, the Commission will first discuss the classification of joint transmission costs, followed by a discussion of the allocation of these costs.

B. Positions of the Parties

1. Xcel and XLI

Citing the NARUC Manual, Xcel argued that it designs and builds its joint transmission capacity in order to be able to meet the needs of all customers during the period of maximum customer demand. Accordingly, Xcel classified these costs as demand-related. XLI supported this analysis.

2. The OAG

The OAG acknowledged that meeting peak demand is the central goal when designing transmission assets. But the OAG also argued that Xcel's transmission system, like its portfolio of generators, is also designed to provide access to lower-cost energy; accordingly, the OAG recommended classifying transmission assets as 70% demand-related and 30% energy-related.

According to the OAG, MISO characterizes 32% of Xcel's transmission lines as Multi-Value Projects. These lines are designed and justified in part for their value in providing regional reliability and access to cheaper sources of energy, forecasted to save $20 billion to $71 billion over time. The OAG also noted that other load-serving entities (that is, utilities) pay Xcel for the use of Xcel's transmission assets, and roughly 24% of those revenues are based on the energy transmitted rather than on demand factors.

While Xcel cited the NARUC Manual for the proposition that transmission assets should be classified as demand-related, the OAG also cited the manual for the proposition that the cost of transmission assets should be classified in the same manner as generation assets—which all parties agreed should be analyzed as both demand- and energy-related. The NARUC Manual states —

> After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated.[55]

[55] NARUC Manual, at 75.

In addition, the OAG cited the cost allocation manual published by the Regulatory Assistance Project (RAP Allocation Manual)[56] supporting its position.

XLI also opposed the OAG's position. XLI acknowledged that transmission assets generate some benefit by permitting greater access to generators with lower-cost energy but argued that this benefit is subordinate to the goal of meeting peak demand, and thus the Commission should classify these assets as demand-related.

That said, Xcel acknowledged that it is currently developing transmission lines for the purposes of connecting solar- and wind-powered generation to the grid to replace energy from retiring coal-powered generators. As a compromise, therefore, Xcel proposed developing a new classification method that would distinguish among the goals of maintaining resource adequacy, maintaining system reliability, and cost causation—the objectives justifying Multi-Value Projects.

C. Recommendation of the Administrative Law Judge

The ALJ adopted the OAG's analysis. While meeting peak demand remains the primary purpose for transmission assets, the ALJ concluded that the value of these assets in securing other goals—especially the goal of securing lower-cost electric energy—justifies classifying them as both demand- and energy-related.

D. Commission Action

The Commission concurs with both the OAG and the ALJ. Without minimizing the importance of designing transmission systems to meet forecasted demand, the Commission acknowledges—and no party disputes—that these assets provide additional benefits to the electric system. In particular, transmission assets permit Xcel to gain access to low-cost energy to serve its retail customers, and to deliver surplus energy to sell into the wholesale market.

Accordingly, the Commission will adopt the ALJ's proposal to classify Xcel's transmission assets as 70% demand-related and 30% energy-related.

XXXVII. CCOSS – Allocation of Transmission Costs

A. Issue

All parties concurred with classifying Xcel's transmission assets as at least partially demand-related. But the parties disagree about how to allocate the resulting demand-related costs among customer classes.

[56] Regulatory Assistance Project, *Electric Cost Allocation for a New Era*.

B. Positions of the Parties

1. Xcel, the Department, and XLI

Xcel proposed allocating demand-related transmission costs among the classes using its D10S allocator, which analyzes each class's forecasted energy consumption during the hour of MISO's peak demand during each test year. The Department and XLI concurred.

The OAG also supported allocating demand-related transmission costs among customer classes based on each class's consumption of energy during MISO's peak—but supported incorporating other demand data as well.

2. The OAG

Specifically, the OAG would consider not merely data from MISO's annual peak, but data from one peak hour during each month of the year, resulting in an allocator incorporating data from twelve peak hours (the 12 Coincident Peak allocator, or 12CP allocator). The OAG noted that, when other load-serving entities use Xcel's transmission assets, Xcel collects revenues from them based in part on demand charges that are calculated based on the entity's peak load during each month; the OAG's proposal emulates this formula.

Both Xcel and XLI opposed this proposal. They argued that a utility must design its system to meet peak annual demand (typically during the most extreme weather of summer or winter), and that it makes no sense to give equal weight to the peak annual demand and to the peak demand during months of more moderate demand (such as in the spring and fall).

C. Recommendation of the Administrative Law Judge

The ALJ concluded that Xcel, XLI, and the OAG had articulated sound arguments for their proposals, and that the Commission would be justified in adopting either proposal.

D. Commission Action

While utilities have traditionally given exclusive focus to the annual peak demand, the growing acceptance of relying on a broader concept of peak demand is reflected in the manner in which Xcel is compensated for the use of its transmission assets, as argued by the OAG. Precisely because annual peak demand tends to occur during the summer and winter, utilities tend to take generators out of service for maintenance during the spring and fall. But this strategy results in greater system vulnerabilities during these off-peak seasons when an unplanned outage occurs due to some equipment failure. Managing these failures requires ensuring adequate transmission capacity as the grid's supply and demand change at all points of the calendar.

Accordingly, the Commission will approve allocation of demand-related transmission costs using the OAG's 12CP allocator incorporating demand from the forecasted peak hour of every month of the year.

XXXVIII. CCOSS – Classification and Allocation of Distribution Costs

A. Issue

Transmission facilities take high voltage electricity from where it is generated to a substation near where it is needed; in contrast, distribution facilities—including poles, wires, and other equipment—deliver the electricity at lower voltage from the substation to the premises of retail customers.

Distribution costs relate to the number of customers served because adding a new customer requires some incremental cost, even if that customer then never actually uses any electricity. Distribution costs also relate to demand because the utility designs the plant not merely to provide minimum connection, but to have sufficient capacity to reliably meet customers' peak needs.

B. Positions of the Parties

1. Xcel and the Department

Xcel used the Minimum System Methodology to determine the portion of distribution costs that are customer-related and the portion that are demand-related. The NARUC Manual identifies at least two ways to implement the Minimum System Methodology: the Minimum Size Method and the Zero-Intercept Method. Xcel used both.

In implementing the Minimum Size Method, Xcel estimated the minimum cost to connect all customers to a minimum distribution system covering Xcel's service area, and classified these costs as customer-related. Xcel then classified all remaining distribution costs—that is, costs related to increasing the system's capacities above the minimum level—as demand-related.

In implementing the Zero Intercept Method, Xcel conducted a statistical analysis to find out how much the cost of its distribution system increases as its capacity increases. Based on that relationship, Xcel then estimated the costs the utility would have had to incur to create a hypothetical distribution system with zero capacity. Xcel classified these costs as customer-related and classified all remaining distribution costs—costs related to increasing the system's capacities above zero—as demand-related.

Thereafter Xcel incorporated the two methods into a third method, its Hybrid Method. Xcel divided its distribution plant into functional categories, and then used the previous two classification methods to estimate the share of customer-related costs in each category. Where these two methods disagreed, Xcel would pick the smaller of the two estimates of customer-related cost. The remaining share of costs in each category would be assumed to be demand-related costs.

In support of this choice, Xcel argued that both the Minimum System Method and the Zero Intercept Method were designed to identify the cost of some minimally sized distribution plant necessary to reach all customers, and to characterize only that cost as customer-related. Xcel found both models reasonable, and reasoned that by picking the lowest allocation attributed to customer costs, Xcel could best fulfill the models' objectives.

The Department generally found this classification method to be reasonable.

2. The Suburban Rate Authority

The Suburban Rate Authority also generally supported Xcel's proposal—but acknowledged that other classification and allocation methods were reasonable, and the Commission would be justified in considering a range of methods for classifying and allocating distribution costs.

3. XLI

XLI supported use of either the Minimum System or Zero Intercept Methods, but opposed Xcel's Hybrid Method. XLI argued that the Hybrid Method—picking data from the other two methods based solely on the criterion of minimizing customer costs—was structurally biased to inflate demand costs, which would ultimately have the effect of increasing the share of costs to be recovered from commercial and industrial customers.

In addition, XLI objected to an adjustment for the minimum system load that Xcel made as part of its Zero Intercept Method.

4. The OAG

The OAG opposed using the Minimum System Methodology, citing arguments set forth in the RAP Allocation Manual. In addition, the OAG argued that Xcel had inappropriately excluded relevant data from its Zero Intercept analysis, skewing the results.

Instead, the OAG supported the Basic Customer Method and the Peak-and-Average Method. The Basic Customer Method classifies distribution plant that serves a single customer or meter as customer-related—for example, the cost of customer meters and service drop lines—because those costs obviously vary based on the number of customers. All other distribution costs are classified as demand-related.

The Peak-and-Average Method also identifies a narrow range of customer-related costs, but then identifies as energy-related the cost of building a distribution plant to meet average energy consumption, and classifies only the remaining costs—costs needed to serve customer needs that exceed the average level—as demand-related.

Citing the RAP Allocation Manual, the OAG ultimately advocated identifying the customer-related costs using the Basic Customer Method, identifying the energy-related costs using the Peak-and-Average Method, and classifying all remaining costs as demand-related. But the OAG acknowledged that the Commission would be justified in considering other methods as well.

In contrast, Xcel and XLI opposed use of the Basic Customer and Peak-and-Average Methods. They argued that the Basic Customer Method understated the customer-related share of distribution plant, and therefore failed to reflect principles of cost-causation imbedded in the methods supported by the NARUC Manual. Also, XLI argued that the OAG provided insufficient support for classifying distribution plant as energy-related, as assumed in the Peak-and-Average Method, and XLI raised technical challenges to the manner in which the OAG had applied this method. Xcel and XLI acknowledged that the OAG cited instances where these classification methods were endorsed by the staff of other states' regulatory commissions, but argued that this support was atypical.

Finally, as a procedural matter, the OAG recommended that the Commission direct Xcel to include in its next rate-case filing CCOSSs analyzing distribution costs from multiple perspectives. In the current case, the OAG asked Xcel to prepare various studies once the rate case had been filed, but this resulted in practical challenges compounded by the time constraints of the case. The OAG stated that it would be more practical for all concerned to have these analyses prepared at the beginning of the case. Xcel opposed the idea that it should have to file studies as part of its initial filing that would, in practice, contradict its own case. According to Xcel, the appropriate time for the OAG to pursue such filings is during the discovery phase of a case, and Xcel agreed to work with the OAG to produce studies at that time.

5. Just Solar Coalition

Just Solar Coalition supported classifying distribution costs using the Basic Customer Method. But like the Suburban Rate Authority and the OAG, Just Solar Coalition acknowledged that the Commission would be justified in considering a range of methods.

C. Recommendation of the Administrative Law Judge

The ALJ concluded that each proposal had merit and recommended that the Commission consider them all. But the ALJ found insufficient reason to ask Xcel to file specific distribution studies as part of its next rate case filing, as requested by the OAG.

D. Commission Action

The classification of distribution costs produces the widest range of arguments in a CCOSS, and the Commission appreciates the critical analyses contributed by the parties. Having evaluated each of the proposals, the Commission concurs with the ALJ that considering multiple perspectives on the classification and allocation of distribution costs provides an appropriately broad perspective for creating a CCOSS. Each analysis provides the Commission with a standpoint from which to evaluate the other analyses. Therefore, consistent with the recommendation of the OAG as supported by the Suburban Rate Authority and the Just Solar Coalition, the Commission will direct Xcel to classify and allocate distribution costs using multiple methods—including at a minimum the Minimum System Method, the Basic Customer Method, and the Peak-and-Average Method.

Moreover, given the range of complexity of parties' positions regarding distribution plant, and the time constraints once a rate case has been filed, the Commission sees the wisdom of the OAG's recommendation to have Xcel prepare studies from various perspectives when it files its next rate case. Accordingly the Commission will direct Xcel to file multiple CCOSSs classifying and allocating distribution system costs, including the following:

- A study using the Minimum System Method.

- A study using the Basic Customer Method to identify customer-related costs and classifying the remainder as demand-related costs.

- A study using the Basic Customer Method to identify customer-related costs and using the Peak-and-Average Method to identify both demand- and energy-related costs.

While Xcel will have to prepare these studies at the Commission's direction, the Company will be free to explain why it believes one method or the other should receive more weight in a future rate proceeding

XXXIX. General Allocator

A. Issue

A utility will incur some costs for the benefit of its entire operation. To determine the share of these costs to be recovered from each of its operations, Xcel has developed its General Allocator.

Xcel typically calculates this allocator by giving equal weight to total assets, revenues, and number of employees associated with each of its operations. But in a previous case, this Commission directed Xcel to use a different allocator based in equal measure on total assets, revenues, and employment hours based on full-time equivalent (FTE) employment.[57] For this component of the allocator, Xcel identifies all the FTEs expended directly on Minnesota regulated operations or allocated to those operations, and divides by all the FTE hours expended on operations covered by the allocator.

The Commission's order notwithstanding, Xcel prepared its current case using its standard General Allocator calculated in part based on each operation's number of employees rather than FTEs.

B. Positions of the Parties

1. The Department

The Department opposed use of Xcel's General Allocator and disputed the claim that Xcel's allocator generated the appropriate jurisdictional allocation. To the contrary, the Department noted that the Commission ordered Xcel to use a revised allocator to remedy the problem of Xcel allocating excessive costs to Xcel's Minnesota operations and allocating insufficient costs to affiliates with no assigned staff.

The Department acknowledged that the Minnesota jurisdiction has a higher staffing level than Xcel's other jurisdictions but argued that the Commission's General Allocator appropriately accounts for those costs.

In sum, the Department recommended that the Commission retain the use of its General Allocator based in part on full-time equivalent hours, and therefore reduce Xcel's reported revenue requirement by $5.900 million for 2022, $6.241 million for 2023, and $6.613 million for 2024.

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[57] *In the Matter of Northern States Power Company's Cost Allocation Procedures and General Allocator*, Docket No. E,G-002/AI-10-690, Order Requiring Change in General Allocator and Requiring Filings (March 15, 2011) (2011 Order); Erratum Notice (March 25, 2011).

2. Xcel

Xcel offered various arguments in support of its General Allocator.

First and foremost, Xcel asserted that using its General Allocator results in the Minnesota jurisdiction bearing its fair share of Xcel's costs, while using the Minnesota-specific allocator has resulted in Minnesota's operations failing to bear its fair share of costs. Second, while Xcel acknowledged that using its allocator increased the costs recovered from the Minnesota jurisdiction, the allocator reduced Minnesota's share of the cost of certain corporate officers.

Third, Xcel argued that calculating an allocator based on each operation's number of employees results in a more stable allocator than relying on the number of FTEs—a number that fluctuates as projects come and go. Fourth, Xcel argued that reliance on FTE hours overstates the labor costs of subsidiaries for whom an employee provides occasional services and understates the labor costs of the subsidiary with the employee on its payroll. Finally, Xcel argued that calculating and applying a different allocator for its Minnesota operations than for the rest of its operations was administratively cumbersome and could result in Xcel failing to recover some of its prudently incurred costs.

C. Recommendation of the Administrative Law Judge

Noting that the Commission had previously addressed the issue of how to calculate an appropriate general allocator, the ALJ concluded that Xcel had failed to demonstrate that the Commission's concerns were no longer relevant, that Xcel's preferred allocator remedied the problems the Commission had identified, or that Xcel's preferred allocator would promote just and reasonable rates in Minnesota. The ALJ confirmed that using a general allocator calculated on the basis of FTEs would allocate less cost to the Minnesota jurisdiction than using Xcel's preferred allocator, but the ALJ did not find this fact relevant to the question of identifying the more appropriate allocator.

In conclusion, the ALJ supported the Department's recommendation to continue using a general allocator calculated on the basis of FTEs in lieu of employee headcount, and to reduce Xcel's revenue requirement accordingly.

D. Commission Action

In ordering Xcel to calculate its general service allocator based on FTEs in lieu of labor headcount, the Commission held as follows:

> First, the labor component of the general allocator is designed in a way that results in no labor-related costs being allocated to unregulated subsidiaries that do not have their own payrolls. This is unreasonable on its face since no business can have labor costs of zero. Similarly, allocating the full costs of each employee to the subsidiary on whose payroll he or she appears overstates the labor costs of that subsidiary and understates the labor costs of any other

> subsidiary for whose benefit the employee occasionally performs services.[58]

Xcel has provided no evidence that persuades the Commission that these rationales no longer apply. As a result, the Commission will continue to direct Xcel to use a general allocator based in part on full-time equivalent employment. For this reason, the Commission will adopt the Department's position and direct Xcel to make the appropriate adjustments to Xcel's revenue requirement for test years 2022, 2023, and 2024.

XL. Interchange Agreement Allocators

A. Issue

Among the wholly owned subsidiaries of Xcel Energy Inc. are Northern States Power Company, a Minnesota corporation organized under the laws of the State of Minnesota (NSPM), and Northern States Power Company, the Wisconsin corporation (NSPW). These two entities are legally distinct and own distinct assets separated at the state Minnesota/Wisconsin boundary. Yet Xcel stated that the two entities operate as a single integrated electric generation and transmission system and a single electrical "local balancing authority area" serving customers in both states.

An interchange agreement sets forth principles for allocating costs and revenues between these entities—for example, revenues from transmission services or off-system wholesale sales. Xcel stated that it prepared its current rate case in accordance with this agreement and budgeted information for the 2022-2024 test years, just as it had in prior rate cases.

Each operating company bills the other for its share of the joint costs, using energy requirements as the basis for sharing variable costs and peak demand as the basis for sharing capital and other fixed costs.

B. Positions of the Parties

1. The Department

Based on Xcel's responses to the Department's discovery requests, the Department learned that Xcel had filed—and FERC approved—a new interchange agreement with revised demand allocators for 2022.[59] This change resulted in a $149,983 increase in Minnesota's revenue and a $1,332,358 decrease to Minnesota's generation and transmission expense in 2022. The Department argued for making these changes in Xcel's 2022 financial data for the current rate case. Moreover, the Department argued for carrying this same adjustment into the future as a known and measurable change to Xcel's forecasted allocators.

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[58] *Id*., 2011 Order, at 1-2 (citing Findings of Fact, Conclusions of Law, and Order, at 20).

[59] See FERC Docket No. ER22-1234 (May 3, 2022).

2. Xcel

In response to the Department's recommendations, Xcel agreed to using the revised demand allocations for 2022 that the utility had filed with FERC. But otherwise Xcel opposed the Department's proposed revisions and continued to recommend using the original demand allocator for later years, and recommended using the original forecast energy allocators for 2022 through 2024. Xcel argued that a change of a few variables in a multi-faceted interchange agreement did not justify altering all the forecasted allocations for years into the future. Xcel filed revised allocators annually and, according to the utility, these revisions provide no basis to expect identical revisions in the future.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with Xcel's initial recommendations. According to the ALJ, the best available evidence revealed that Xcel made good-faith estimates of its interexchange allocators when it filed its rate case, and had made good-faith revisions by the time it filed with FERC. The fact that the subsequent filing differed from an earlier one provided an insufficient basis to justify modifying the interchange agreement's forecasted cost and revenue allocations for purposes of the rate case.

D. Commission Action

The Commission concurs with the Department. No party faults Xcel for the fact that it revised its forecasted demand allocator over time. Nevertheless, the utility bears the burden of proof to demonstrate the reasonableness of its rate proposals. Clearly utilities rely on forecasts when actual data is unknowable. Still, the Department's argument is reasonable and based on the most contemporary evidence in the record.

Xcel makes a plausible argument that the Department's proposed revisions fail to reflect the many changes that occur when revising allocators. The Department states that it recommended revising the demand allocator because, in response to a discovery request, Xcel provided data justifying that revision. Perhaps Xcel could have provided other data justifying an offsetting adjustment—but that did not occur. The Department cannot be faulted for acting on the basis of the record before it.

Xcel bears the burden of proof to demonstrate the reasonableness of its proposals. The record before the Commission does not demonstrate that Xcel's proposal is superior to the Department's. Therefore the Commission will adopt the Department's filed position and direct Xcel to do the following:

- Use the actual 2022 demand allocator for the interchange agreement as approved by FERC, rather than the 2022 demand allocator as filed in this rate case, thereby increasing Minnesota jurisdictional revenue for generation and transmission by $149,983 and reducing Minnesota jurisdictional costs by $1,332,358.

- Use the updated 2022 allocators in 2023 and 2024 as well.

XLI. Allocation of the Cost of Community Solar Gardens

A. Issue

Under Minn. Stat. § 216B.1641, a community solar garden refers to an array of photovoltaic cells (solar panels) that generate electricity to sell to the local utility, where the facility is partially financed by ratepayers who elect to subscribe to the garden in return for receiving bill credits in proportion to the amount of electricity generated and the size of their subscriptions. Because solar gardens limit their subscriptions, any given ratepayer may no longer be able to find a garden still accepting subscriptions. During the Commission hearings on this case, the issue arose regarding how Xcel recovers the program's costs.

While the credits can reduce bills for solar garden subscribers, some of the program's costs are recovered from non-subscribing customers. Xcel recovers the cost of its community solar garden program in the same manner that it recovers fuel costs—that is, through a "fuel clause," a special rate that can adjust outside the context of a rate case as costs change. In 2019 utilities revised how they implement their fuel clauses and began filing "lessons learned" reports on their experience with the new policies.

Xcel estimated that an average bill for a Minnesota ratepayer includes about $10 per month to finance Xcel's community solar garden program.[60] Commercial and industrial customers have subscribed for most of the program's output, and thus received most of the bill credits. When considering how to allocate a program's costs among customer classes, the Commission may consider whether the program bestows benefits disproportionately to some classes rather than others.

Moreover, the Legislature recently adopted a new statute stating —

> The cost of a subscriber's community solar garden subscription must not exceed the value of the subscriber's community solar garden bill credit. For a LMI [low- to moderate-income] subscriber, the cost of the community solar garden subscription must not exceed 90 percent of the LMI subscriber's community solar garden bill credit and must not include any fees at the time the subscription is executed.[61]

This statutory change may require changes in how Xcel finances its community solar gardens.

B. Commission Action

To explore opportunities to better align program costs with program participants, and potentially to address new statutory requirements, the Commission will direct Xcel to file a proposal for an alternative class allocation methodology for recovering the cost of community solar gardens.

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[60] This docket, transcript of oral argument (May 23, 2023) at 63.

[61] See Laws 2023, Chapter 60, Article 12, Section 13, adopting Minn. Stat. § 216B.1641, subd. 10(b).

Xcel shall file this proposal in the Commission's docket established to evaluate the fuel clause adjustment,[62] as part of its "lessons learned" report. The Commission intends to take up the issue again by February 1, 2024.

RATE DESIGN

XLII. Revenue Apportionment

A. Introduction

After establishing a utility's revenue requirement, the Commission designs rates that will provide the utility with a reasonable opportunity to recover those costs. The first step is to determine the share of Xcel's revenue requirement to be recovered from each class of customers, a process referred to as revenue apportionment.

In apportioning the utility's revenue requirement, the Commission considers the utility's cost of serving each customer class based on the results of the CCOSS methods discussed above. The Commission also considers a number of non-cost concerns such as: equity, justice, and reasonableness; the avoidance of discrimination, unreasonable preference, and unreasonable prejudice; continuity with prior rates to avoid rate shock; revenue stability; economic efficiency; encouragement of energy conservation; customers' ability to pay; and ease of understanding and administration.[63]

B. Positions of the Parties

Xcel, the Department, OAG and XLI proposed revenue apportionments based on the results of the parties' preferred CCOSS method or combination of methods. Xcel was the only party who recommended adjusting the apportionment each year of the multiyear rate plan (MYRP), while the other parties recommended maintaining the same apportionment throughout the MYRP.

The four proposed revenue apportionments for 2022, along with the Company's current revenue apportionment, are displayed in the table below:

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[62] *In the Matter of an Investigation into the Appropriateness of Electric Energy Cost Adjustments*, Docket No. E-999/CI-03-802.

[63] Minn. Stat. §§ 216B.01, .03, .2401; 216C.05; 216B.16, subd. 15.

Table 12 Proposed Revenue Apportionment for 2022					
	Current	**Proposed**			
		Xcel	**Department**	**OAG**	**XLI**
Residential	39.01%	39.29%	39.29%	37.51%	40.97%
C&I Non-Demand	3.37%	3.31%	3.31%	3.29%	3.14%
C&I Demand	56.82%	56.55%	56.55%	58.32%	54.93%
Lighting	0.79%	0.86%	0.86%	0.87%	0.96%
Total	**100%**	**100%**	**100%**	**100%**	**100%**

1. Xcel

Xcel proposed a revenue apportionment that would move all classes 50% closer to cost each year of the MYRP, based on the results of its Hybrid CCOSS. Xcel argued that movement towards cost is important because cost-based rates are equitable, stabilize utility earnings, and provide economically efficient and appropriate usage incentives.

Xcel argued that the other parties' proposed revenue apportionments did not strike a reasonable balance between setting rates at cost and moderating rate increases. Xcel disagreed with the Department that adjusting the apportionment to move 50% closer to cost each year of the MYRP was inconsistent with Commission precedent. Rather, Xcel urged the Commission to take advantage of the opportunity presented by the MYRP to move rates closer to cost modestly and gradually throughout the duration of the MYRP.

2. The Department

The Department agreed with Xcel that moving classes 50% closer to cost was a reasonable approach for the Company's revenue apportionment. But the Department recommended maintaining Xcel's proposed 2022 revenue apportionment until Xcel's next rate case, rather than adjusting the apportionment in 2023 and 2024 as recommended by Xcel.

The Department argued that its proposed apportionment better balances the tension between the economic efficiency of cost-based rates and the potential for rate shock if rates increase too quickly. The Department explained that Xcel's Hybrid method CCOSS overestimates the cost impact of the Residential class while the Basic Customer method underestimates the impact, so the Department's Residential class apportionment represents a measured approach that falls in between the results of these methods.

3. OAG

OAG noted that all CCOSS models are subjective and require simplifying assumptions, and the Commission has historically relied on multiple CCOSS to inform its revenue-apportionment decisions. OAG argued that its CCOSSs reflect reasonable assumptions regarding the causation of production, transmission, and distribution costs.

OAG calculated rate increases based on the magnitude of the difference between the amount a class is currently paying and the cost-share patterns identified in the CCOSS, while moderating increases to avoid rate shock. OAG's analysis showed that the Small C&I class is consistently contributing significantly more than its share of costs and so should receive the smallest rate increases, while the Lighting class is consistently contributing significantly less than its share of costs and so should receive the largest rate increase but moderated to avoid rate shock. Furthermore, OAG determined the Residential class should receive a smaller-than-average increase and the Large C&I class should receive a larger-than-average increase because those classes are currently each contributing more and less than their cost of service, respectively.

4. XLI

XLI argued that C&I customers on Xcel's system have consistently subsidized other classes, which has serious implications for the competitiveness of C&I customers and their ability to remain viable in Minnesota, nationally, and internationally. XLI argued that these issues can be addressed by moving C&I customers to cost, and that eliminating existing interclass subsidies on the Company's system will benefit the Company, C&I customers, and other customers by promoting efficiency, stability, and conservation while also providing just and reasonable rates to all customer classes.

XLI maintained that Xcel's proposed revenue allocation will not meaningfully eliminate the interclass subsidies and does not account for past increases and market conditions facing C&I customers. XLI maintained that the Company's proposal reduces interclass subsidies by less than 20%, with Residential customers moving only 14% closer to cost and C&I Demand customers moving only 17% closer to cost. XLI instead urged the Commission to adopt its proposed revenue allocation that sets the revenue allocation at the cost of service as determined by XLI's CCOSS.

5. ECC

ECC noted that at the beginning of Xcel's rate case, the Commission found that exigent circumstances caused by the COVID-19 pandemic justified lowering the interim-rate increase for Residential customers from 9.7% to 6.4%. ECC argued that the economic hardships endured by Xcel's ratepayers persist, particularly due to rising inflation and the end of the moratorium on utility disconnections. Due to these circumstances, ECC argued that the Commission should limit the Residential rate increase to at or below the level of the current interim-rate increase.

6. Commercial Group

The Commercial Group argued that the revenue requirement should be apportioned as closely to cost as possible. The Commercial Group noted that the C&I Demand class currently pays rates that exceed the Company's cost to serve this class, and the Commission should adopt Xcel's revenue apportionment that moves rates 50% towards costs each year.

C. Recommendation of the Administrative Law Judge

The ALJ found the Department's proposed class revenue apportionment to be the most reasonable of the parties' proposals and recommended that the Commission adopt the Department's recommendation. The ALJ noted that the Department's recommendation reasonably moves customers to cost more gradually than Xcel's proposal and reasonably balances the goals of economic efficiency, competitive rates, and avoiding rate shock. The ALJ also noted that the Department's approach is consistent with prior Commission decisions to use fixed revenue apportionment.

D. Commission Action

In apportioning the revenue requirement among customer classes, the Commission strives to set rates to recover the cost of service for each class while also moderating the rate increase to avoid rate shock for customers and considering other non-cost factors. As explained in the previous section, the Commission supports the use of multiple CCOSS methods to estimate the cost of service for each class. Xcel, OAG, and the Department based their revenue-apportionment recommendations on multiple CCOSS methods, while XLI used one CCOSS.

The Commission agrees with the ALJ that the Department's recommended revenue apportionment represents the most reasonable and appropriate approach to move rates closer to cost while avoiding rate shock. Although XLI urges the Commission to more aggressively shift revenue apportionment to reflect XLI's CCOSS, the Commission finds that a measured approach reflects the range of CCOSS methods without unreasonably burdening a single class of customers. Furthermore, maintaining the same revenue apportionment for the duration of the MYRP will gradually move rates closer to cost of service. The Commission will therefore adopt the Department's proposed 2022 test year revenue apportionment for the entire MYRP.

XLIII. Residential and Small General Service Customer Charge

A. Introduction

While revenue apportionment focuses on how revenue responsibility should be divided among customer classes, the remaining rate-design analysis addresses how revenues are collected within each customer class. One key component of rate design is the customer charge, which is a fixed monthly charge billed to each customer in the class. This charge is intended to cover the utility's fixed costs caused by each class that do not vary with the amount of energy used.

B. Positions of the Parties

1. Xcel

Xcel recommended a customer charge of $9.00 for all Residential customers, which would increase the charge by $1.00 and eliminate the incremental $2.00 fixed monthly charges for space-heating customers, customers with underground service, and customers on Residential Time-of-Day service. Xcel argued that its proposed customer charge was well below the customer-related cost-per-bill of $19.28 shown by its Hybrid CCOSS. Xcel noted that ECC agreed to support a $1.00 customer-charge increase if Xcel agreed to its low-income discount program, which Xcel did support. Xcel argued that its recommended customer charge preserved a substantial and appropriate conservation incentive balanced with accurate cost-based pricing to improve customer equity.

In response to the Department's and ALJ's recommended $6.00 customer charge, Xcel argued that lowering the customer charge was unreasonable and inconsistent with past Commission decisions that have modestly increased or maintained the customer charge. Xcel maintained that the Department's analysis relied heavily on the Basic Customer method compared with other CCOSS models, and that decreasing the customer charge would shift costs from fixed to variable energy charges and force higher usage customers to pay for more customer-related costs. Xcel also opposed the Department's and ALJ's recommended $5.00 customer charge for Residential customers in multi-family dwellings, arguing that the Company did not have a reliable way to identify these types of customers and the lower charge would severely impair the Company's ability to recover its fixed costs.

2. The Department

The Department recommended a $6.00 customer charge for all single-unit Residential customers and Small General Service customers and a $5.00 customer charge for Residential customers in multi-unit dwellings. The Department argued that a lower customer charge will incentivize energy conservation because customers can more meaningfully reduce their bills through conservation when their total bill is largely the product of usage as opposed to fixed charges. The Department explained the importance of maintaining a clear link between consumption and cost in order to encourage energy conservation, while fixed charges weaken that link. The Department further argued that Xcel's proposed sales true-up addresses the Company's concern about its ability to recover its revenue requirement, and decoupling can be paired with lower customer charges to send price signals to customers that encourage energy conservation to the maximum reasonable extent.

In support of its proposed $5.00 multi-unit dwelling customer charge, the Department argued that multi-unit dwellings impose fewer fixed costs on Xcel's system because customers in multi-unit dwellings often share secondary distribution system facilities. The Department noted that Xcel's marginal cost study showed multi-unit dwellings have 60% lower system costs than single-family dwellings. The Department urged the Commission to require Xcel to implement a multi-unit dwelling charge for the approximately 270,000 customers the Company can currently identify and develop an outreach plan to identify remaining eligible customers.

3. OAG

OAG recommended that Xcel reduce its Residential and Small General Service customer charges by $3.00 to move them closer to cost. OAG argued that the current customer charges for these classes collect more than the customer-specific cost to serve these customers because Xcel's CCOSS overclassifies costs as customer-related. OAG cited Minn. Stat. § 216B.03, which requires the Commission to set rates to encourage energy conservation and renewable energy and argued that reducing customer charges would increase the incentive for customers to conserve energy and pursue renewable generation. OAG further argued that increasing the customer charge reduces the incentive to conserve energy by lowering the value of each kilowatt-hour (kWh) saved and increasing the payback period for energy-efficient investments.

OAG noted that people with lower incomes tend to use less energy and pay a disproportionate amount of their household income toward energy costs, and fixed costs exacerbate this energy burden for low-usage customers. OAG argued that Xcel should empower low-income customers by reducing their fixed fees, thereby giving them a greater ability to control their bills by conserving energy. OAG also supported the Department's proposed multi-family dwelling customer charge as a way to help many Minnesotans, and asserted that Xcel should not wait until it can identify every possible eligible customer.

4. Just Solar Coalition

Just Solar argued that Xcel's proposed customer charge would unreasonably charge customers for costs that are not customer costs, which is contrary to Minnesota's energy policy goals encouraging adoption of energy efficiency and distributed energy resources. Just Solar recommended the Department's initial proposal of reducing by $3.00 per month the customer charge for single-family Residential and Small General Service customers and reducing the charge by $4.00 per month for customers in multi-family homes. Just Solar did not oppose the Department's updated recommendation to set the customer charge for all single-unit Residential customers and Small General Service customers at $6.00 and for Residential customers in multi-unit dwellings at $5.00.

Just Solar reiterated that Xcel's Hybrid CCOSS method overestimates customer costs by including costs related to meeting customer demand. Just Solar argued that fixed charges are regressive because they impact low-income and lower usage customers to a greater extent. Just Solar explained that lower-usage customers have flatter demand curves, which is why peak-driven costs should not be incorporated into fixed charges as they are in Xcel's Hybrid method. For the multi-family dwelling customer charge, Just Solar suggested that Xcel could rely on self-certification with verification and other methods while it obtains more robust customer data. Lastly, Just Solar recommended Xcel be required to rely on the Basic Customer method for customers charges in future rate cases.

5. ECC

ECC indicated it could agree to a $1.00 increase in the Residential customer charge if the Company agreed to ECC's proposed low-income low-usage discount program.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's recommended customer charge of $6.00 for all single unit-dwelling Residential customers and Small General Service customers and $5.00 for Residential customers in multi-unit dwellings.

The ALJ reasoned that the Department's proposed customer charges are supported by the Company's Basic Customer CCOSS, and multi-unit-dwelling customers can be served at a lower fixed cost than single-unit Residential or Small General Service customers. The ALJ also noted that reducing the customer charge will reasonably incentivize energy conservation and advance other state energy policy goals, and the Company can reasonably identify a significant number of qualifying ratepayers.

D. Commission Action

Monthly customer charges are an important component of the Company's Residential and Small General Service rates by facilitating recovery of the costs caused by each customer that do not vary with the amount of energy used. However, higher fixed customer charges discourage customers from conserving energy and investing in renewable energy by reducing the impact of these efforts on the customers' bills. Customer charges also tend to confuse and alienate customers by impairing customer understanding of their energy bills. The Commission notes that Minn. Stat. § 216B.03 requires the Commission to design rates to encourage energy conservation and renewable-energy use to "the maximum reasonable extent." Considering this statutory mandate and the evidence submitted by the parties, the Commission agrees with the ALJ that it is reasonable and appropriate to lower the monthly customer charge for the Residential and Small General Service classes to $6.00.

While Xcel opposes a downward shift in its customer charge, the Commission is not persuaded that higher-usage customers will likely pay for a higher portion of fixed costs as a result. The Company's Basic Customer method shows the fixed costs of this class to be in line with the Department's recommended $6.00 monthly customer charge. As the Department explained, that method classifies customer-specific distribution equipment, such as meters and services, as customer costs, because these investments are not shared among customers within a class.

In setting the customer charge in this case, alignment with the Basic Customer method is particularly important in light of the wide variety of residential customers within Xcel's service territory. Many Residential customers are in single family dwellings, but according to the Department, more than 200,000 customers live in multi-unit dwellings of various sizes. Thus, a lower Residential charge is more likely to have a greater impact on energy conservation when applied to all of Xcel's Residential customers, and this charge will continue to reflect a reasonably representative portion of the fixed costs attributable to the many different types of customers within this class. For these reasons, the Commission is persuaded that the most equitable course of action is to reduce the monthly customer charge to $6.00.

However, the Commission disagrees with the ALJ that Xcel should implement a separate monthly customer charge for Residential customers who reside in multi-family dwellings. At this time, the Company does not have a sufficiently precise and reliable way to identify which customers would be eligible for a reduced customer charge, nor has there been robust analysis of the potential cost impacts. The Commission declines to impose this change to Residential rate design without a more accurate method for implementation or understanding of the ramifications.

XLIV. Commercial & Industrial Demand Class Rate Design

A. Introduction

C&I Demand classes encompass non-residential customers besides Small General Service customers. C&I Demand customers take service under a three-part rate that includes a fixed customer charge, volumetric energy usage charge, and demand charge. The demand charge is calculated based on the maximum amount of electricity demanded at any moment during the billing period.

B. Positions of the Parties

1. Xcel

Xcel proposed the following actions related to C&I Demand rate design:

- Maintain a similar ratio between demand and energy rates to limit rate design changes

- Moderately increase interruptible service discount that generally reinstates the discount levels prior to the Federal Tax Cut and Jobs Act

- Modify certain rules for application of the Peak Controlled Services tariff by requiring customers to provide reliable contact information and changing testing requirements to provide more certainty about available load relief during MISO emergency events

- Eliminate the Annual Minimum Demand Charge to simplify and streamline the interruptible tariff for customers

- Revise the demand charge voltage discounts under the C&I Demand tariff based on current cost levels and revise the energy charge voltage discounts for the proposed level of base energy and fuel charges

- Eliminate the Real-Time Pricing tariff and add a discretionary discount to the Business Incentive and Sustainability Rider, discussed further in subsequent sections.

2. The Department

The Department argued that Xcel should develop rates for its C&I Demand classes using the same rate design principles and CCOSS results that are applicable to other classes, but the Company failed to submit evidence-based rate proposals for the C&I Demand classes. The Department recommended that Xcel be required to produce analysis of its C&I Demand rate design proposals in Docket No. E-002/M-20-86. The Department explained that that proceeding is already focused on advanced rate design and would allow stakeholders to more substantively engage with Xcel on evidence-based commercial and industrial rates.

C. Recommendation of the Administrative Law Judge

The ALJ agreed with the Department that Xcel's C&I Demand rates should be evidence-based and therefore recommended that the Commission adopt the Department's recommendation to require Xcel to work with stakeholders and address C&I fixed customer charges, demand rates and demand-related costs, seasonal costs and rates, other demand response and distributed-energy resource initiatives in Docket No. E-002/M-20-86.

D. Commission Action

The Commission agrees with the Department and the ALJ that the Company's C&I Demand rates should be evidence-based and developed using the same rate-design principles and CCOSS results that apply to other customer classes. The Commission will therefore direct Xcel to work with stakeholders in Docket No. E-002/M-20-86 to address C&I fixed customer charges, demand rates, demand-related costs, seasonal costs and rates, and other demand response and distributed-energy resource initiatives.

XLV. Real-Time Pricing Service Tariff Elimination

A. Introduction

Xcel has described its Real-Time Pricing tariff as a complicated time-of-use rate design with pre-established pricing as opposed to a pure real-time pricing design based on market conditions. Xcel proposed to eliminate this rate due to lack of customer interest.

B. Positions of the Parties

1. Xcel

Xcel proposed to eliminate the Real-Time Pricing rate because it had never attracted more than two customers at the same time over the nearly 20 years the rate has been in effect. Xcel posited that the lack of customer interest could be due to the complexity of the rate. Xcel noted that there is currently only one customer with three accounts taking service on this rate, and this customer was informed prior to taking service in 2018 that the Company planned to propose eliminating the rate in its next rate case. Xcel suggested that other rates such as the new three-period TOU rate would likely be more attractive and beneficial to customers.

2. The Department

The Department opposed elimination of the Real-Time Pricing Service tariff, arguing that the Company currently lacks other similar, permanent offerings and that Xcel is currently deploying advanced meters and engaged in advanced rate discussions with stakeholders in other proceedings. The Department maintained that Xcel's experience with the real-time pricing rates may inform these other rate designs.[64]

C. Recommendation of the Administrative Law Judge

The ALJ agreed with Xcel that the Department's concerns should not stop the Company from eliminating the rate offering. The ALJ reasoned that other rate offerings could be more attractive to more customers, and the potential informational value of the Real-Time Pricing Service tariff rate is not significant enough to justify requiring Xcel to continue offering the rate.

D. Commission Action

The Commission agrees with the ALJ that Xcel's proposal to eliminate the underutilized Real-Time Pricing Service tariff is reasonable and should be approved. However, the Commission recognizes that, when properly designed, real-time pricing has the potential to meaningfully incentivize demand response for sophisticated customers who can manage the risk of wholesale

[64] In its Exceptions to the ALJ Report, the Department indicated that it did not contest the ALJ's recommendation in an effort to limit the number of issues before the Commission.

electricity prices. The Commission will therefore require Xcel to work with stakeholders to develop a new real-time pricing offering.

XLVI. Business Incentive and Sustainability Rider Discretionary Discount

A. Introduction

The Business Incentive and Sustainability (BIS) Rider tariff provides an economic-development incentive to existing demand-metered C&I customers with new or additional load of 350 kW or greater.

Xcel proposed to add a five-year discretionary 50% discount to the off-peak base energy rate, applicable only to incremental loads of more than 5 MW with a minimum load factor of 70%. Xcel indicated that this was designed to attract primarily data-center customers. Xcel would file with the Commission any agreements with prospective customers, and those agreements would take effect after 30 days unless an objection was raised, a process referred to as a negative check-off.

B. Positions of the Parties

1. Xcel

Xcel argued that its proposed discretionary discount is reasonable because it would appeal to higher-load customers like data centers but would benefit all customers by spreading system fixed costs more broadly. Xcel dismissed the Department's concerns by reiterating that any party could oppose a proposed customer agreement during the 30-day negative check-off period. The Company confirmed that revenues exceed cost of service even with the discounts under the BIS Rider tariff, demonstrating the incremental financial benefits all customers enjoy due to the tariff.

2. The Department

The Department did not oppose Xcel's proposed discretionary discount but argued that Xcel should have to obtain express Commission approval before any contracts with prospective data-center customers take effect. The Department argued that this approach would allow stakeholders and the Commission a greater opportunity for review and analysis to decide if the agreement is in the public interest.[65]

3. Just Solar

Just Solar argued that Xcel should demonstrate that the net present benefits of the BIS rider outweigh the net present costs and it does not have a regressive impact in order to continue offering the rider. Just Solar argued that the BIS rider raises significant distributional justice concerns because current commercial demand and all future customers will have to bear the costs of the subsidies and incremental infrastructure costs associated with the BIS rider. Just Solar also expressed concern that stakeholders would not have sufficient ability to review agreements during the negative check-off period.

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[65] In its Exceptions to the ALJ Report, the Department indicated that it did not contest the ALJ's recommendation in an effort to limit the number of issues before the Commission.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve the Company's proposed BIS Rider discretionary discount. The ALJ reasoned that the 30-day negative check-off provided parties with a reasonable opportunity to review and object to a proposed agreement if the public benefit is uncertain. The ALJ also noted that even with the discounts, revenues under the BIS tariff exceed cost of service.

D. Commission Action

The Commission agrees with the ALJ that Xcel's proposed discretionary discount though the BIS rider is reasonable, and the Commission will therefore approve the BIS rider as filed by Xcel. The proposed discounts have the potential to attract large customers to Xcel's system and provide real system benefits. If there is a question as to whether an agreement is in the public interest, stakeholders can initiate Commission review by objecting within the 30-day window. The Commission believes that this approach properly balances the Company's interest in expeditiously implementing customer agreements with stakeholders' ability to protect the public interest.

XLVII. Low-Income, Low-Usage Discount

A. Introduction

ECC proposed a discount rate for low-income, low-usage customers. Under the proposal, the Company would provide a 35% discount on 300 kWh of monthly electric usage to all low-income Residential customers whose average monthly electricity consumption is 300 kWh or less. ECC recommended establishing the income-eligibility threshold at 50% of state median income, the same threshold used in Minnesota to qualify for the Low-Income Home Energy Assistance Program (LIHEAP).

ECC recommended that eligibility be established through receipt of LIHEAP, through categorical or income-based program participation, or through an income-based self-declaration. ECC estimated that out of 305,000 residential customers that consume 300 kWh or less per month, approximately 30% of those customers (roughly 92,000) would be income-eligible for the discount. ECC explained that any usage-qualified customer that receives LIHEAP would be automatically enrolled in the discount, which applies to around 20% of eligible customers. The remaining 80% of usage qualified low-income customers (nearly 74,000) would be enrolled in the discount through the self-declaration process.

Assuming 100% eligible participation, ECC estimated the annual cost of the program at $8.3 million, which would be paid for through a $0.57 monthly surcharge to non-eligible residential customers.

B. Positions of the Parties

1. ECC

ECC urged approval of its proposed low-income, low-usage discount program as a way to provide direct financial benefits to low-income customers who are least likely to benefit from other affordability or energy-efficiency programs. ECC explained that low-income customers tend to use less electricity than higher income customers, and energy efficiency measures or other usage reduction strategies may have a negligible impact on the utility bills of low-usage customers. ECC noted that Minnesota Power has been successfully implementing a similar program by conducting robust outreach to customers who have not benefited from other programs.

ECC opposed Just Solar's recommendation to remove the usage threshold to qualify for the discount. ECC argued that doing so would increase Xcel's current low-income program funding by 200%, and a flat monthly discount regardless of energy usage does not address the disparities in energy burden, disconnection rates, target arrears, nor encourage conservation.

2. Just Solar Coalition

Just Solar Coalition supported ECC's proposed program and argued that it should be expanded to provide relief to more low-income customers. Just Solar analyzed three modifications to ECC's proposal and ultimately recommended that the 35% discount be available to all low-income customers for the first 300 kWh of monthly consumption, regardless of their total monthly consumption. Just Solar argued that this would reach an additional 230,000 customers and cost non–participating customers $1.47–$2.48 per month, depending on program enrollment. Just Solar argued that its recommended modification would go further to address energy insecurity in Xcel's service territory, noting that LIHEAP can be difficult for low-income customers to access.

3. OAG

OAG supported ECC's proposed low-income, low usage discount because it would meaningfully help low-income Minnesotans at a modest cost to nonparticipating customers. OAG acknowledged that the program would not address the systemic causes of poverty and racial inequality in the state, but it would help mitigate the impact on some of Xcel's most vulnerable customers.

4. Xcel

Xcel supported implementation of the low-income, low-usage discount rate proposed by ECC. Xcel argued that the discount helps to address the housing challenges and energy burdens faced by the Company's low-income customers during a time of high inflation and ongoing instability from the COVID-19 pandemic. Xcel also noted that the program offers a practical way to address the barriers to participation that exist in energy assistance programs by leveraging enrollment in other assistance programs or through self-declaration of income. Xcel suggested that the discount provides a way to counteract the potentially regressive impacts of a uniform customer service charge, which imposes a larger percentage bill increase on low-usage customers.

Xcel opposed Just Solar's proposed expansion of the program, arguing that it would dramatically increase the cost of the program, and that Just Solar did not provide a cost estimate of the expansion.

C. Recommendation of the Administrative Law Judge

The ALJ recommended adoption of the low-income, low-usage discount as proposed by ECC, concluding that the discount provides relief to the Company's most financially at-risk customers and appropriately limits the impact of the electric rate increase. The ALJ reasoned that although addressing the undesirable effects of the 300 kWh-per-month cap is a worthwhile goal, Just Solar's proposal would add significant cost to the program. The ALJ noted that the OAG, which is statutorily responsible for representing the interests of residential and small business ratepayers, supports ECC's recommendation.

D. Commission Action

Under Minn. Stat. § 216B.16, subd.15(a), the Commission "must consider ability to pay as a factor in setting utility rates and may establish affordability programs for low-income residential ratepayers in order to ensure affordable, reliable, and continuous service to low-income utility customers." ECC's proposed low-income, low-usage discount would provide relief to Xcel's low-income customers who are less likely to benefit from existing energy-efficiency programs and has the potential to reach more customers through the self-declaration eligibility process.

Just Solar's proposed expansion of the program would not encourage conservation, and without a reliable cost estimate in the record, the Commission lacks sufficient evidence to approve that proposal.

The Commission will therefore require Xcel to implement the low-income, low-usage discount program as proposed by ECC. The program shall be available to customers the later of the effective date of final rates or October 1, 2023. The Company will be required to submit a program status update on December 1, 2023, and annually thereafter with its electric low-income annual report.

XLVIII. EV Charging Upgrade Costs

A. Introduction

When a customer adds new load that necessitates distribution system upgrades, the Company covers the cost of the upgrades up to 3.5 times the anticipated annual revenue from the sale of additional service, excluding the portion that represents recovery of fuel costs. The customer adding the load that requires upgrades is generally responsible for the remaining cost. However, Xcel has exempted Residential customers on EV rates from upgrade costs directly related to their EV load.

B. Positions of the Parties

1. Xcel

Xcel explained that it implemented the exception for EV upgrade costs in 2021 after this issue was raised as part of the Company's Annual Residential EV Report. In that docket, clean energy groups recommended that the Company waive any potential distribution-upgrade charges for customers taking service under one of the Company's Residential EV-related time-varying rates. The Company agreed to this change, and the Commission did not object. As a result, the

Company implemented this change and continues to support this policy as consistent with its current tariff and beneficial to all customers by encouraging EV adoption and off-peak charging for this new load.

Xcel opposed Just Solar's recommendation to expand this policy to all residential customers who drive EVs regardless of whether a customer takes service under one of the Company's EV rates. Xcel explained that its exemption for customers on EV rates encourages participation in off-peak charging to reduce the impact of this new load on the distribution system.

2. Just Solar Coalition

Just Solar recommended that Xcel be required to implement an alternative approach to EV-related upgrades to improve the likelihood of customers notifying the Company of their planned EV load. Just Solar suggested a study to estimate the total cost of serving typical residential customer configurations which may result in a need for a transformer or service upgrade. Just Solar argued that EV customers' upgrade costs should be waived to avoid inequality because newer, larger homes tend to be able to accommodate this new load.

3. OAG

OAG recommended that Xcel stop exempting EV owners from the cost-sharing provisions of its tariff unless and until the tariff is revised to specifically allow it, because Xcel implemented its policy without obtaining authority from the Commission. OAG argued that this exception creates a regressive subsidy in favor of EV owners who tend to be wealthier. OAG further argued that the exception undercuts the purpose of the cost-sharing tariff by unduly burdening other customers with costs they did not cause and would tend to make electricity more expensive for those who can least afford it.

OAG countered Just Solar's arguments by noting that EV owners in older homes will still tend to have higher incomes than Xcel's customers as a whole, and therefore a ratepayer-funded subsidy in favor of EV owners is likely to be regressive.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission approve Xcel's practice to waive the cost sharing requirement for EV-rate customers and require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff. The ALJ found that it would be reasonable to waive distribution-transformer-upgrade charges for EV-rate customers, because doing so incentivizes participation in the Company's EV-rate offerings, helps the Company shift EV charging load through EV-specific rate design, and can reduce the cost barrier for customers who wish to undertake beneficial electrification. The ALJ found that Xcel's tariff does not presently allow it to exclude EV-rate customers from the cost-sharing provision, so a tariff amendment was necessary to continue the practice.

The ALJ was unpersuaded by Just Solar's alternative upgrade-cost proposal, because Just Solar's proposal would result in inaccurate price signals to customers. The ALJ noted that Just Solar's proposal would also eliminate an incentive to enroll in an EV-specific rate. Customers with electric vehicles should be encouraged to participate in the Company's EV programs as these programs help the Company manage EV loads and allow customers to take advantage of lower off-peak rates.

D. Commission Action

As the ALJ explained, EV rates incentivize EV charging at off-peak times, which helps the Company manage EV load and provides system benefits. By waiving the cost-sharing requirement for EV-rate customers, Xcel can encourage customers with EVs to join the EV rate. On the contrary, Just Solar's proposal would not encourage adoption of EV rates and would send inaccurate price signals by imposing the same rate regardless of when EV charging occurs rather than incentivizing consumption during off-peak hours, as the EV tariff is designed to do.

The Commission agrees with the ALJ that Xcel's practice of waiving the cost-sharing requirement for EV-rate customers is reasonable, consistent with the Commission's directives on EVs, and should be approved. The Commission will therefore require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff. The Commission will also require Xcel to discuss its policy of waiving cost-sharing requirements for EV-rate customers in its Transportation Electrification Plan in order to better understand how the policy is being implemented.

XLIX. Residential Space Heating Rates

A. Introduction

In its March 2022 order approving Xcel's load-flexibility pilots, the Commission ordered Xcel to:

> review its existing electric heating rate options, including the Back-up Relief Rate Plan, to ensure that they accurately reflect the value of the additional load and additional load flexibility for customers installing an air source heat pump and maintaining an existing gas heating backup source. If existing rates do not reflect the added value of these electrified loads, the rates should be adjusted, or new rate offerings should be developed.[66]

In response to the March 2022 order, Xcel proposed that customers with heat pumps receive service on the Company's Residential space-heating rate. Xcel proposed to eliminate the incremental $2 customer charge for residential space-heating customers and increase the differential from the standard Residential winter rate from 2.815 cents per kWh to 5.42 cents per kWh. Xcel also proposed a new space heating category for Residential TOU customers.

[66] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, Docket No. E-002/M-21-101, Order Approving Modified Load-Flexibility Pilots and Demonstration Projects, Authorizing Deferred Accounting, and Taking Other Action at 29 (March 15, 2022).

B. Positions of the Parties

1. Xcel

Xcel argued that it had complied with the Commission's directive in the March 2022 order and reasonably shown how the new Residential space-heating rate would impact annual base-rate revenues for the average Residential space-heating customer. Xcel estimated that its proposed changes would result in annual savings of approximately $159 for a typical overhead-service space-heating customer and $242 for a typical underground-service space-heating customer, with the savings for a customer with a heat pump to be approximately $133 annually on the heat pump usage alone. Xcel maintained that its proposed changes would promote equity among all customers who have electric space-heating needs so that customers on standard residential rates and customers on the space-heating rate, with average usage, pay the same annual base-rate revenue.

Xcel disagreed with the Department that its proposal should be raised in another proceeding and argued that Clean Energy Organizations call for a more granular proposal does not mean the Company did not comply with the Commission's directive.

2. Department

The Department stated that due to the complexity of the Company's proposal, further record development of the proposal is warranted. The Department also noted that other interested stakeholders who are not parties in this proceeding may have useful input that would aid record development. The Department therefore recommended that the Commission reject Xcel's proposal and direct the Company to refile it in Docket No. E-002/M-21-101.

3. Clean Energy Organizations

The Clean Energy Organizations acknowledged that Xcel's proposed space-heating rate could benefit customers by aligning on-peak pricing with the on-peak net load forecasts for the different seasons. They explained that maintaining a three-period TOU structure year-round helps avoid customer confusion and maintain price signals to shift usage away from the on-peak period throughout the year.

But the Clean Energy Organizations argued that Xcel's proposal was insufficient because it should not be limited to electric space-heating customers. They maintained that a technology-specific TOU rate is not necessary when the pricing changes it includes reasonably reflect system costs for the whole Residential class.

The Clean Energy Organizations further argued that Xcel had not shown why 5.4 cents per kWh is the appropriate reduction to on-peak and mid-peak rates in the non-summer months. They noted that the reduction is likely excessive for the mid-peak period and would result in a price signal that insufficiently encourages off-peak usage, which may cause a higher revenue shortfall that would have to be collected through other rate adjustments. They also questioned how Xcel would implement the proposed space-heating TOU rate.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission adopt the Department's recommendation to deny Xcel's residential space-heating rate without prejudice and direct Xcel to re-file its proposal in Docket No. E-002/M-21-101, to ensure there is sufficient opportunity for interested stakeholders to participate and provide adequate time for review.

D. Commission Action

The Commission agrees with the ALJ that stakeholders who may not be parties to this proceeding should have the opportunity to weigh in on Xcel's proposed space-heating rate. Accordingly, the Commission will deny Xcel's proposed changes to its Residential Space heating Tariff without prejudice and require Xcel to refile its proposal in a new docket within 90 days of the final order in this docket.

L. Residential Time-of-Use Rates

A. Introduction

Xcel Residential customers are currently able to enroll in a two-period TOU rate with an on-peak period from 9:00 a.m. to 9:00 p.m. Xcel developed and piloted an updated TOU rate from 2017–2022, but that rate is closed to new enrollment. Xcel has started a stakeholder process to develop a full Residential TOU rate.

B. Positions of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that Xcel's TOU offerings for Residential customers are currently insufficient and should be updated to reflect changing policy and energy system conditions. They emphasized the importance of meaningful price signals that encourage conservation during periods of system constraint and argued that the piloted TOU rate may disincentivize electrification of appliances.

The Clean Energy Organizations argued that Residential customers should be able to enroll in the pilot TOU rate and suggested several modifications to the pilot TOU rate structure to better reflect cost causation and achieve residential heating electrification through seasonal differentiation: 1) eliminate the on-peak period in non-summer months, 2) reduce the on-peak rate in non-summer months, or 3) use a four-season structure where spring and fall rates are symmetrical.

They proposed that the Commission require Xcel to develop a modified, optional TOU rate, to be made available on an opt-in basis for customers with advanced meters who are not already on the TOU pilot, while the Company develops a default Residential TOU tariff.

2. Xcel

Xcel argued that the Clean Energy Organizations' proposal is not reasonable, because adjusting the TOU rate downward without another adjustment to offset lost revenue could deprive Xcel of a reasonable opportunity to recover its revenue requirement. Xcel also argued that Clean Energy Organizations' proposal would not provide customers on TOU rates with appropriate price signals and could confuse customers.

At the Commission meeting, Xcel stated that it planned to submit a Residential TOU rate proposal by the end of 2023.

C. Recommendation of the Administrative Law Judge

The ALJ found that Clean Energy Organizations' proposal was not reasonable, because it would not provide appropriate price signals accounting for increased EV load and could confuse customers. The ALJ also noted that requiring Xcel to implement a proposal outside of the current TOU development process would deprive interested stakeholders of sufficient opportunity to participate or adequate time for review. The ALJ therefore recommended that the Commission reject the CEO Residential TOU proposal in this proceeding.

D. Commission Action

The Commission agrees with the ALJ that changes to Residential TOU rates should be considered in the current TOU stakeholder process to allow all interested stakeholders to participate. The Commission appreciates that Xcel has committed to filing a Residential TOU rate proposal by the end of this year, and that the Clean Energy Organizations have indicated support for this timeline. The Commission will therefore require Xcel to file a proposed permanent Residential TOU rate by December 31, 2023.

LI. Street Lighting Rate Design

A. Joint Stipulation

Following briefing and prior to the ALJ Report, Xcel and SRA filed a Joint Stipulation that resolved all rate-design issues pertaining to the Street Lighting class in this proceeding. According to the Joint Stipulation, the agreed-to rate design changes are designed to be revenue neutral within the Street Lighting class while balancing LED lighting customer rate relief attributable to LED cost savings to both overhead and underground distribution line fed LED lighting. The Joint Stipulation contains specific rate adjustments that reduce LED rates and increase non-LED rates and underground fed street lighting rates, along with informational requirements for Xcel in its next rate case.

B. Administrative Law Judge Recommendation

The ALJ found that the Joint Stipulation could be reasonable and consistent with the interests of ratepayers and the public but concluded that there had not been a reasonable opportunity for parties to review and respond to the Joint Stipulation before the issuance of the ALJ Report. The ALJ recommended that the Commission adopt the terms of the Joint Stipulation if no party objects.[67]

[67] The ALJ Report also fully analyzed the formerly-contested street-lighting issues.

C. Commission Action

The Commission appreciates the efforts of Xcel and SRA to resolve the rate-design issues related to the Street Lighting class through the Joint Stipulation. No party has objected to the Joint Stipulation, and the Commission agrees with the ALJ that approval of the Joint Stipulation is reasonable and consistent with the interests of ratepayers and the public.

The Commission will therefore approve the Joint Stipulation between Xcel and SRA, approve the structure of the rate design for street lighting as proposed by Xcel and amended by the stipulated agreement between the SRA and Xcel and recommended by the ALJ, and approve the new LED option for Directional Lighting in the Automatic Protective Lighting Service Tariff.

LII. Advanced Rate Design

A. Introduction

The Clean Energy Organizations recommended that the Commission open a docket for a single, overarching proceeding to discuss advanced rate design (ARD) for Xcel. ARD and load-management programs are currently addressed in multiple different dockets.

B. Positions of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that Xcel should maximize customer load flexibility by developing a comprehensive suite of load-management offerings and ensuring these keep up with market and policy changes. Clean Energy Organizations explained that load flexibility enables customers to match electricity usage with periods of low-cost renewable-energy generation, which reduces the cost of energy generation and supports further clean-energy deployment. Load flexibility also decreases long-term system costs by reducing demand peaks and improving system utilization, allowing utilities to avoid or defer capacity-related investments.

Clean Energy Organizations further argued load flexibility is becoming increasingly important and complex due to customer-sited energy technologies and rapidly evolving load-management technologies. Clean Energy Organizations maintained that addressing ARD and load-management initiatives across multiple dockets has hindered a clear and transparent load-flexibility strategy resulting in an inefficient use of resources, limiting stakeholders' ability to effectively participate in the development of these initiatives. Clean Energy Organizations further contended that the Company's current rate-design processes are insufficiently nimble to keep pace with a rapidly evolving power system, citing specific examples such as the Residential TOU pilot which already relies on outdated energy-price assumptions only five years after development.

Clean Energy Organizations recommended that the Commission establish an ARD proceeding to provide the following: 1) a framework for assessing load management priorities and objectives across all customer segments; 2) a process for building on existing rate designs as policy, technology, and grid economics change; and 3) opportunities for collaboration between the utility and stakeholders, including around stakeholder-driven proposals. Clean Energy Organizations suggested a number of goals and issues to be addressed in an ARD proceeding.

2. Xcel

Xcel argued that a separate ARD proceeding is not necessary and supported handling its TOU rates for residential and commercial customers in their respective dockets. Xcel recommended that if the Commission requires an ARD proceeding, any revenue impacts associated with new rates or rate structures should be addressed in the Company's next rate case.

C. Recommendation of the Administrative Law Judge

The ALJ recommended that the Commission take no action on the Clean Energy Organization's proposal for an ARD docket, finding that Clean Energy Organizations had not shown why a separate proceeding is necessary when ongoing dockets or an alternative process could provide a forum for discussing and improving rate designs. The ALJ acknowledged that the Clean Energy Organizations had identified appealing objectives for such a proceeding, but the ALJ agreed with Xcel that the potential scope of such a proceeding was too broad and may duplicate the work of a general rate case.

D. Commission Action

The electricity system is undergoing rapid, fundamental changes due to numerous factors including increasing renewable-energy generation and customer load-management capabilities. Designing rates to take advantage of these emerging opportunities is a complex process that would benefit from a formal proceeding to develop, evaluate, and prioritize the Company's load-management offerings. A comprehensive ARD docket would also enable analysis of the extent to which these new initiatives are consistent with Minnesota's statutory goal for rates to be 5% lower than the national average, a crucial public-interest consideration that can be overlooked when programs are developed across multiple proceedings.[68]

For these reasons, the Commission will open an Advanced Rate Design docket for Xcel and direct Xcel to work with stakeholders to develop a proposed scope and process for this docket. In this docket, Xcel shall include analysis on its compliance with Minnesota's goal for rates to be 5% lower than the national average, Minn. Stat. § 216C.05, subd. 2(4), including at minimum the following issues:

- The impact of its proposed rate increase on compliance with the statutory goal;
- The impact of conservation on bills and its relevance to the statutory goal;
- Strategies that could be employed to improve compliance with the statutory goal; and
- An alternate rate increase proposal that would be in compliance with the statutory goal, and Xcel's justifications for proposing any rate increases in excess of the alternate plan.

[68] Minn. Stat. § 216C.05, subd. 2(4).

LIII. Sales True-Up

A. Introduction

As explained in Minn. Stat. § 216B.2412, decoupling is “a regulatory tool designed to separate a utility’s revenue from changes in energy sales. The purpose of decoupling is to reduce a utility’s disincentive to promote energy efficiency.” A sales true-up similarly allows a utility to surcharge or refund customers to the extent that actual sales differ from forecasted sales.

Xcel proposed a mechanism that would refund customers for sales revenues above its forecast and would surcharge customers if decreased sales result in lower-than-forecasted revenues. Xcel did not propose a limit on refund or surcharge amounts. Xcel modeled its proposal on its previously approved true-up methodology,[69] with modifications to 1) exclude the metered lighting category; 2) use the C&I Demand adjustment factor for interdepartmental sales; and 3) eliminate the sales-growth adjustment that has been used for the C&I class.

B. Positions of the Parties

1. Xcel

Xcel argued that decoupling mechanisms help ensure that neither customers nor the Company are financially harmed when actual sales diverge from the forecast due to pursuit of policy objectives like energy conservation and demand response. Xcel emphasized that receiving revenues at the level approved by the Commission is necessary to maintain its safe, reliable, and environmentally responsible service.

Xcel argued to exclude metered lighting from the decoupling mechanism consistent with the rest of lighting services that are effectively decoupled. Xcel explained that metered-lighting revenue, which constitutes 7% of lighting class revenue, is consistent from year to year, and excluding it would be a practical simplification of the mechanism.

Xcel explained that its modification to use the C&I Demand adjustment factor for interdepartmental sales is consistent with base rates used for interdepartmental sales. Xcel further explained its modification to eliminate the sales-growth adjustment that had been used for the C&I class, noting that this adjustment was applicable for sales true-up calculations for 2017 through 2021 to acknowledge that the Company adjusted its revenue deficiency to recognize future forecasted sales growth in the C&I class in the 2015 MYRP, but no such adjustment is made this case.

Xcel opposed a cap on surcharges, arguing that the Company’s transition from existing rates to three-period TOU rates for the Residential and demand-billed classes will have unknown and potentially significant impacts, and a symmetrical decoupling mechanism similar to what the Commission has already approved was reasonable and fair for the Company and customers under these circumstances. In its Exceptions to the ALJ Report, Xcel argued that lowering the

[69] *See In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Ups with Modifications and Requiring Xcel to Withdraw its Notice of Change in Rates and Interim Rate Petition (April 2, 2021).

customer charge would increase revenue volatility and increase the likelihood of hitting the surcharge cap, hindering Xcel's ability to recover its revenue requirement.

Xcel further argued that XLI's opposition to any decoupling mechanism was contrary to sound public policy and would make Xcel an outlier compared to proxy electric utilities considered in this proceeding. Xcel dismissed XLI's alternatives as unsupported by the record.

2. The Department

The Department recommended approval of Xcel's proposal subject to modifications of a 3% hard cap on customer surcharges, inclusion of the metered lighting class, and compliance reporting requirements. The Department noted that the proposal will reduce sales-related risk typically borne by investors while also decoupling energy sales and revenue, which can facilitate other energy conservation policies.

The Department explained that a 3% hard cap on customer surcharges would limit surcharges to 3% of Xcel's annual revenues and bar Xcel from recovering amounts exceeding the cap in future years. The Department argued that this hard cap more equitably distributes the risk of lower sales due to unexpected weather and economic conditions, because Xcel is simply authorized a reasonable opportunity, not a guarantee, to recover its approved revenue requirement. The Department further argued that utility investors are compensated for assuming such business risks. The Department cited the unforeseen circumstance of the COVID-19 pandemic to argue that a hard cap ensures that these types of unforeseen risks are equitably shared between customers and the Company consistent with the statutory requirement. The Department also noted that based on how the cap would have impacted past sales, a hard cap would rarely curtail surcharges. The Department referenced the 4% cap on Otter Tail Power's sales true-up and argued that Xcel's larger size and more diversified customer base makes it better positioned to share the risks of unexpected changes in sales.

The Department argued that the characteristics of the metered lighting class make it an appropriate candidate for decoupling. The Department argued that the size of the class did not impact its ability to invest in energy efficiency and some customers' use of less-efficient bulbs means that improved efficiency is attainable.

The Department opposed XLI's proposed system-wide decoupling mechanism factor because it was unsupported by the record. The Department argued that this proposal did not account for the unique circumstances of each class and would likely insulate one class from a surcharge by spreading it across all classes.

Lastly, the Department recommended compliance reporting requirements consistent with its current true-up, and that the deadline move to April so the report can incorporate Conservation Improvement Program savings from the prior year. The Department also recommended the Commission postpone implementation of any sales true-up adjustments from the current date of April 1 until June 1, so that the Commission and parties have an opportunity to review Xcel's report.

3. XLI

XLI opposed Xcel’s proposal, arguing it is not associated with energy efficiency but rather a failsafe against sales forecast errors and was single-issue ratemaking. XLI argued that it would shift all sales forecasting risk away from the Company and onto ratepayers, providing the Company with a guaranteed revenue stream. XLI noted that when sales to certain classes increase or decrease, the cost to serve that class also changes. XLI argued that the sales true-up has been extremely punitive and that Xcel has not shown it will result in just and reasonable rates.

XLI proposed an alternative mechanism of refunds and surcharges based on the Company’s earnings relative to its authorized return on equity. XLI also argued that if the true-up is approved, it should be applied on a system-wide rather than class-specific basis.

4. Clean Energy Organizations

The Clean Energy Organizations recommended that annual surcharges under the Company’s proposed decoupling mechanism be limited to a soft cap of 3% by customer class. They explained that under a soft cap, in years that the calculated surcharges are greater than 3% of Xcel’s annual revenue, the excess amount would roll over into the following year’s adjustment. They touted the soft cap as a customer protection measure that would prevent an unreasonable and extreme annual rate increase. They noted that though a hard cap would limit the rate increase, the purpose of decoupling is to remove a utility’s disincentive to promote energy conservation and not to limit rate increases. They argued that a 3% soft cap strikes the appropriate balance between maintaining the purpose of decoupling while providing needed customer protection.

5. OAG

OAG agreed with XLI that it would be reasonable to reject the Company’s proposal, but argued that if the proposal is approved, there should be a 3% hard cap on surcharges and decoupling adjustments should be calculated class by class. OAG argued that a hard cap is fully consistent with the requirement that decoupling mitigate the impact on a utility of Minnesota’s energy-savings goals because there would still be surcharges to make up for a substantial amount of any reduced sales. OAG opposed XLI’s proposal for a system-wide decoupling mechanism factor because it ignores the unique characteristics of each class and could adversely impact a class that had already contributed more than its share of base revenues.

6. SRA

SRA supported Xcel’s exclusion of metered lighting from its decoupling proposal, arguing that decoupling risked exposing the class to a surcharge resulting from significant changeover to LED lighting, which could disincentivize LED adoption. SRA indicated that a 3% hard cap greatly reduced the risk of an outsized cost impact to street lighting customers and would therefore not oppose a decoupling mechanism with a 3% hard cap.

7. Commercial Group

The Commercial Group opposed the proposal. The Commercial Group cited surcharges resulting from Xcel’s last true-up mechanism that surcharged C&I Demand customers for lower sales without accounting for the lower cost of serving those classes because of the lower sales. The Commercial Group argued that if the proposal is adopted, the Commission should adjust Xcel's return on equity downward to compensate.

C. Recommendation of the Administrative Law Judge

The ALJ recommended approval of Xcel's sales true-up mechanism for the duration of the MYRP, subject to the 3% hard cap recommended by the Department. The ALJ reasoned that a hard cap best balances the statutory requirements for decoupling mechanisms, because it would balance the financial interests of investors and ratepayers by ensuring that financial risks of unexpected sales declines are shared. The ALJ noted that the hard cap partially addresses the concerns of XLI and the Commercial Group and rejected XLI's alternative proposals as unsupported by the record.

The ALJ noted that, while a soft cap would prevent dramatic one-year rate spikes, it would fundamentally shift the risk of lower sales onto ratepayers. The ALJ concluded that this is inconsistent with Minn. Stat. § 216B.2412, subd. 2, which requires sales decoupling mechanisms to avoid "adversely affecting utility ratepayers." It's also inconsistent with the utility regulatory framework which only ensures the Company a reasonable opportunity to recover its revenue requirement and a rate of return to compensate investors for assuming these business risks.

The ALJ agreed with the Department that the metered lighting class should be included in the sales true-up mechanism, because there are still energy efficiency opportunities among this class. The ALJ was unpersuaded by SRA's arguments as unsupported by the record.

Lastly, the ALJ recommended that the Commission adopt the Department's proposed sales true-up compliance filing requirements.

D. Commission Action

In its order approving Xcel's 2021 sales true-up recovery, the Commission explained that rates are designed based on sales forecasts for each class, but the imperfect nature of forecasts can justify a sales true-up that corrects for inaccurate sales forecasts through refunds and surcharges to account for the difference in forecasted and actual revenues.[70]

The Commission has authorized Xcel to implement previous sales true-ups, and the Commission agrees with the majority of parties and the ALJ that a sales true-up with a 3% hard cap on surcharges is warranted in this case in order to protect the Company from potential lower-than-forecasted sales revenues and protect ratepayers from excessive and unreasonable rate increases. Like decoupling, a sales true-up counteracts Xcel's disincentive to reduce energy sales through important efforts like energy conservation and demand response.

A hard cap appropriately distributes the risk of an unforeseen drop in sales between shareholders and ratepayers. Absent a hard cap, that sales risk is borne entirely by ratepayers, which is

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[70] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of 2021 True-Up Mechanisms*, Docket No. E-002/M-20-743, Order Approving True-Up Adjustments at 3 (August 5, 2022).

inconsistent with the regulatory principle that ensures the Company a reasonable opportunity—not a guarantee—to recover its revenue requirement, and which provides a rate of return to compensate investors for assuming these business risks.

The Commission also agrees with the Department and the ALJ that the metered lighting class should be included in the true-up, and the Commission appreciates SRA's acceptance of this provision subject to the 3% hard cap. And the Commission finds the Department's recommended compliance requirements to be reasonable and appropriate.

For these reasons, the Commission will approve Xcel's sales true-up for the term of the MYRP, modified to establish a 3% hard cap on surcharges and to include metered lighting. The Commission will order Xcel to submit an annual compliance filing on April 1, with a June 1 sales true-up effective date, as recommended by the Department.

LIV. Other Rider Issues

A. Introduction

Riders are special cost-recovery mechanisms that allow utilities dollar-for-dollar recovery of costs directly from ratepayers outside the context of a rate case. Some riders, such as the Conservation Improvement Program (CIP) rider, the Transportation Cost Recovery (TCR) rider, and the Renewable Energy Standard (RES) rider, allow automatic recovery of eligible costs in order to encourage specific policy objectives like energy conservation and construction of transmission infrastructure and renewable energy projects.

The Fuel Clause Adjustment (FCA) rider provides quick reconciliation of fuel costs that are generally beyond a utility's control. After a thorough investigation into the FCA process, the Commission recently modified how the process works.[71] Each utility now forecasts its monthly fuel costs for the upcoming year in an annual filing and charges those forecasted rates unless the utility can show a significant unforeseen impact on those rates during the forecasted year. At the end of the forecasted year, each utility compares its forecasted rates with its actual fuel costs incurred throughout the year and refunds any overcollections or shows the prudence of costs before recovering any undercollections.

CUB proposed the following three restrictions of Xcel's use of riders going forward:

1. Revenue caps on the TCR and RES riders;

2. Limits on the Company's ability to propose new riders throughout the course of the MYRP;

3. Requiring Xcel to propose an FCA risk-sharing proposal in the Commission's FCA investigation docket and the Company's own FCA docket.

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[71] *See In the Matter of an Investigation into the Appropriateness of Continuing to Permit Electric Energy Cost Adjustments*, Docket No. E-999/CI-03-802, Order Approving New Annual Fuel Clause Adjustment Requirements and Setting Filing Requirements (Dec. 19, 2017).

B. Positions of the Parties

1. CUB

CUB noted that Xcel is proposing to recover approximately 26% of its revenue requirement through riders, which amounts to over $3 billion over the course of the MYRP. CUB argued that Xcel's indiscriminate use of riders obscures the true financial impact of capital investments and skews the Commission's ability to comprehensively evaluate rider impacts. CUB also argued that riders increase the administrative burden for stakeholders and cause customer confusion. CUB maintained that riders should be limited to extraordinary costs that are large, volatile, and outside of a utility's control, and the costs flowing through the RES and TCR riders no longer meet those criteria, nor the original policy purposes for those riders.

CUB further argued that despite the Commission's recent reform of the FCA process, the FCA continues to disincentivize Xcel from efficiently managing its fuel costs by placing the risk of higher and more volatile fuel costs on ratepayers rather than the Company. CUB noted that multiple parties, including Xcel, proposed variations of risk-sharing mechanisms during the FCA investigation and indicated support for reevaluating those options in the future. CUB argued that while fuel costs themselves may largely be beyond utilities' control, the impact of fuel cost volatility can be lessened through resource management and transitioning away from fuel-intensive generation.

2. Xcel

Xcel opposed CUB's proposals to restrict the Company's use of riders. Xcel argued that before TCR and RES project costs can be recovered through riders, those projects have been subject to extensive review by the Commission and stakeholders for eligibility and prudency. Xcel further argued that the scope and ownership of these projects often cannot be known during a rate case, and therefore it is not possible to develop capital budgets for this work. Xcel argued that any changes to rider design or operation should be considered in rider specific dockets.

In response to CUB's proposal for an FCA risk-sharing mechanism, Xcel argued that CUB provides no evidence that the Commission's FCA reform efforts are failing to achieve their goals or that a risk-sharing mechanism is a better means of achieving those goals. Xcel also argued that it was unreasonable to engage in a reform effort on a piecemeal basis rather than through an industry-wide proceeding.

C. Recommendation of the Administrative Law Judge

The ALJ recommended denial of CUB's proposal to impose revenue caps on the TCR and RES riders. The ALJ found that CUB had not met its burden to prove the reasonableness of its proposed revenue caps, explaining that CUB had not demonstrated that its proposal is a reasonable or necessary way to incentivize Xcel to control the costs of projects eligible for rider recovery. The ALJ noted that Xcel is required to justify the expenses proposed for rider recovery and the Commission has an opportunity to review such proposals for prudence when they are filed. The ALJ further cautioned that limiting the use of the riders before the Commission has had an opportunity to consider a proposed investment could prevent investments that would serve the riders' policy objectives and benefit ratepayers and the public.

The ALJ also recommended rejecting CUB's proposal to prohibit new riders during the MYRP. The ALJ explained that prohibiting new rider proposals during the MYRP term raises more concerns that it alleviates. It would unreasonably limit the Commission's discretion to consider and approve a future, justified rider proposal. The Commission can determine whether to approve a new rider if and when one is proposed.

The ALJ recommended that the Commission adopt CUB's proposal to require the Company to propose a risk-sharing mechanism in its lessons-learned report and cross-file its proposal in its own fuel clause adjustment docket. The ALJ found that CUB's arguments and position were supported and reasonable, and that such a proposal may be contentious is not a reason to avoid addressing it while evaluating the FCA process.

D. Commission Action

The Commission agrees with the ALJ that CUB's proposals to cap the RES and TCR riders and prohibit new riders during the MYRP should be denied. The Commission is confident that the current process for reviewing and approving RES and TCR projects for rider recovery adequately protects ratepayers and helps achieve the applicable policy goals. And the Commission will continue to carefully review any proposed new riders in the future rather than prohibit the Company from proposing new riders.

The Commission disagrees with the ALJ that Xcel should be required to file an FCA risk-sharing mechanism. The current FCA process was developed after years of hard work by many stakeholders, and CUB has not sufficiently demonstrated any significant problems with the current process. The Commission declines to make utility-specific changes to a process that applies to all utilities.

ENERGY JUSTICE AND REMAINING ISSUES

LV. Energy Justice

A. Introduction

Just Solar Coalition recommended that the Commission apply the principles of Energy Justice to this rate case, stating that these tenets provide a critical lens through which the Commission should examine setting rates. The tenets of Energy Justice, as described within The Energy Justice Workbook, were developed by the Initiative for Energy Justice and comprise four constituent principles or tenets: Recognition Justice, Procedural Justice, Distributional Justice, and Restorative Justice.[72] These are defined as:

- Recognition Justice – understanding the history and context of energy decisions that have created inequitable benefits and burdens in the past and in the present. This focuses on identifying and advocating for communities that are ignored or misrepresented in energy decisions.

[72] Initiative for Energy Justice, THE ENERGY JUSTICE WORKBOOK at 9, 66–68.

- Procedural Justice – meaningful and equitable participation and representation in energy decision making.
- Distributional Justice – ensuring benefits and burdens are equitably distributed.
- Restorative Justice – facilitating healing and harmony by improving conditions within communities and providing for remediation of legacy harms.

B. Positions of the Parties

1. Just Solar Coalition

Just Solar recommended that the Commission find that setting equitable, just, and reasonable rates includes consideration of Energy Justice. Just Solar argued that Commission decisions should not only incorporate equity and Energy Justice but endeavor to remedy inequities in the provision of electrical services, particularly for low-wealth customers and Black, Indigenous, and People of Color (BIPOC) communities. Further, Just Solar argued that the inclusion of Energy Justice would facilitate a clearer determination of whether the legal burden of just and reasonable rates has been met by the Company. Just Solar argued that the tenets of Energy Justice are embedded in the multitude of factors the Commission must weigh in its determination of just and reasonable.

2. Xcel

The Company agrees with Just Solar that Energy Justice is an important issue, stating that the issue is one the Company continues to focus through a variety of efforts, such as participation in an Equity Stakeholder Advisory Group (ESAG), its development of community-focused projects (such as the Resilient Minneapolis Project), and its partnership with Native Nations.

The Company recognizes that it can continue to develop its efforts in these areas and more effectively involve BIPOC communities it serves by, in part, explicitly centering equity in its energy plans and programs. The Company, however, believes that some of Just Solar's recommendations could be counter-productive to both parties' goal of a more just energy future and recommended against adopting Just Solar's recommendation that the Commission explicitly apply Energy Justice tenets to its rate-case decisions, stating that these issues can often be more effectively solved by engaging with stakeholders on issues that directly affect them. The Company is actively working to do so in a variety of proceedings, including general rate cases.

3. Xcel Large Industrial Customers

XLI recommended against adopting the principles of Energy Justice, stating that they are irreconcilable with standard, accepted ratemaking practices. XLI proposed that the Commission find the Energy Justice tenets recommended by Just Solar are properly included in the various non-cost factors that may already be considered by the Commission when making revenue allocation determinations.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that disputes within ratemaking routinely reduce to disputes over what constitutes just and reasonable rates. The ALJ further found that the ratemaking process is a mechanism for balancing the arguments and interests of many parties, including the interests of Energy Justice, as part of determining just and reasonable rates. The ALJ, however, found that the rate case of a single utility was an inadequate forum for addressing broad societal and systemic matters raised by Just Solar. Given the Commission's ordinary legal standard, which requires it to balance competing interests to determine just and reasonable rates, the ALJ recommended that the Commission apply its ordinary legal standard in this proceeding.

D. Commission Action

The Commission recognizes the importance of Energy Justice tenets as recommended in its proceedings, including general rate cases. While the Commission must decide issues in each rate case based on the record before it in such proceedings, the Commission finds that the tenets of Energy Justice recommended by Just Solar are relevant to setting rates in this proceeding.

LVI. Term of the Multiyear Rate Plan

A. Introduction

The Company proposed a three-year term for its MYRP for forecasted test years 2022, 2023, and 2024 in compliance with Minn. Stat. § 216B.16, subd. 19, (the MYRP Statute), which provides that "the term '[MYRP]' refers to a plan establishing the rates a utility may charge for each year of the specified period of years, which cannot exceed five years." Additionally, the Company provided additional financial information, beyond the MYRP, for years 2025 and 2026 as part of its five-year capital forecasts.

B. Position of the Parties

1. CUB

CUB recommended that the Company be required to file, in its next general rate case, a five-year MYRP, or in the alternative, forecasts to study the costs and benefits of a three- and five-year MYRP. Such an analysis, CUB asserted, would evaluate the advantages and disadvantages of the proposed MYRP compared to the capital forecast and help inform the Commission's decision on whether the Company's rate design is just and reasonable.

2. Xcel Energy

Xcel opposed CUB's recommendations and argued against the requirement to file either a three-year or a five-year MYRP in its next filing and to conduct a cost/benefit analysis to compare its chosen MYRP term and its capital forecast. Xcel noted that the MYRP statute allows a filing of an MYRP term of any period up to five years and that the selection of a three-year term strikes a balance between Xcel's ability to adapt to market conditions and rate stability.

Xcel stated that this could result in an MYRP based on outdated information. Xcel also noted that IDPs change during the development process, in separate proceedings that develop discrete issues, and in annual filings that include updates to its capital forecast data.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that mandating a five-year term removes the flexibility granted in Minn. Stat. § 216B.16, subd. 19. Additionally, the ALJ stated that CUB's recommendation could discourage utilities from requesting a MYRP and concurred with Xcel that later years in the plan would not be based on the most up to date information. The ALJ concluded Xcel has demonstrated that five-year MYRPs are not required to ensure up-to-date information. She recommended that the Commission take no action on CUB's proposal.

D. Commission Action

The Commission agrees with the Administrative Law Judge and the Company that requiring a cost/benefit analysis is unnecessary to effectively scrutinize the Company's future petition and will reject CUB's recommendations to require Xcel to file a five-year MYRP in its next general rate case and will not require Xcel to file a study of the costs and benefits of a three- and five-year MYRP in its next rate case.

LVII. Corporate Governance – Dividend Policy

A. Introduction

Xcel Energy is a wholly owned subsidiary of Xcel Energy, Inc. (XEI), a holding company that holds the controlling stock of the Company. XEI, as an investor-owned utility holding company with publicly traded stock, also issues its own debt in the form of senior unsecured bonds. The Company acknowledged in its federal 10-K filing (a form required by the Securities and Exchange Commission that companies are required to file on their financial performance) an operational risk that XEI's cash requirements could result in an increase in cash dividends that the Company needs to pay to XEI. This, in turn, could result in the need to seek out alternate sources of funding.

The Office of the Attorney General (OAG) recommended that the Commission initiate an investigation or the creation of a stakeholder group to examine the Company's corporate governance and dividend policy.

B. Position of the Parties

1. OAG

The OAG argued that the current corporate structure could result in the Company transferring excessive payments to its parent XEI. The OAG noted that while XEI makes capital contributions to the Company, the contributions are hundreds of millions less than those made by the Company to XEI.

The OAG stated that the dividend payments to XEI could be better used to finance the Company's energy transition as its position would benefit from the reinvestment of capital into expanding operations and that dividend payments could limit the Company's access to needed capital.

2. Xcel

The Company argued against the OAG's recommendation, noting the importance of dividend payments to the Company's shareholders. Additionally, the Company stated that a change in the policy governing dividends, or its level of dividends, would have an adverse effect on the Company's ability to access capital markets, in turn driving up the cost of capital. The Company also noted that capital contributions are one of the tools used to maintain the Company's equity ratio as approved by the Commission and require no additional fees or interests that would otherwise impact ratepayers. The Company further noted that the current capital structure procedures and policies are reviewed by the Commission and that the OAG's recommendation would be an inefficient use of resources.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge was not convinced by the OAG's recommendation and found that the risk identified in the Company's 10-K is hypothetical and that there is a lack of record evidence to establish a likely benefit to ratepayers of further investigations. The ALJ recommended that the Commission reject the OAG's proposal to require a proceeding or stakeholder group to examine the Company's governance and dividend policy.

D. Commission Action

The Commission is not convinced by the OAG's statements concerning the risk created by the Company's structure of dividend payments to its parent XEI. The Commission agrees with the Administrative Law Judge and the Company that the risk of driving up capital costs while offering no clear corresponding benefit is unavailing, and the Commission will therefore reject the OAG's recommendation and decline to require the Company to initiate a proceeding or create a stakeholder group to examine its corporate governance and dividend policy.

LVIII. Distributed Energy Resources – Circuit Breakers, Reclosers, and Regulator Replacement Prioritization

A. Introduction

The distribution system's hosting capacity is limited in part by the many different components that make up the system. Among those components are circuit breakers, reclosers, and regulators (these devices are commonly described as earth leakage relays, or ELR). The Company's Earth Leakage Relay (ELR) programs are designed to identify and replace aging distribution equipment. The current programs do not consider hosting capacity increases as a factor in determining when equipment is replaced.

Just Solar Coalition recommended the Commission direct the Company to modify its ELR programs to include the prioritization of replacements that would increase hosting capacity.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that the replacement of these components could help to increase the hosting capacity of the system and that currently, potential hosting capacity improvement is a factor not considered by the Company in its ELR programs. Just Solar contended that considering hosting capacity is needed to ensure the distribution system has adequate hosting capacity for DERs as the energy transition continues.

2. Xcel

The Company argued that its current ELR programs are designed to mitigate the risk of equipment failure and service interruption to customers, whereas replacement factors currently used by the company include age, condition, and the criticality of the asset to the distribution system. These factors help the Company identify equipment reaching its end-of-life that would, if they were to fail, have the greatest impact on the Company's customers. The Company explained that the purpose of ELR programs is not to increase hosting capacity, and hosting capacity is therefore not appropriate as a required factor when determining what equipment needs to be replaced by these programs.

The Company acknowledged that budgets for ELR programs are expanding but explained that the primary reason for this is the increasing age of the distribution system's assets. If the Company were required to include hosting capacity as a factor, the Company would begin replacing newer equipment before replacing older equipment, inadvertently increasing the risk of customer outages.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that the Company effectively prioritizes asset replacement in a manner that is based on maintaining the reliability of the distribution system. Since the Commission is already investigating the ability to balance the Company's planned investments and increasing hosting capacity within the Company's IDP, the ALJ recommended the Commission not adopt Just Solar's recommendation to include hosting capacity as a factor in the replacement of circuit breakers, reclosers, and regulators.

D. Commission Action

The Commission agrees with the Administrative Law Judge and Company's position. The Commission finds it reasonable for the Company to prioritize asset replacement based on maintaining reliability of the distribution system through replacing equipment with the greatest risk of harming customers. The Commission therefore declines to adopt Just Solar's recommendations relating to circuit breakers, reclosers, and regulator replacement prioritizations.

LIX. Distributed Energy Resources – EV Charging Studies

A. Introduction

EV charging represents a new source of load stress to the current distribution system. To counteract this increase in load, existing and proposed pilots and programs attempt to shift EV charging energy use to time frames outside of system peak load. This is done to minimize the impact that EV charging loads have on the distribution system capacity and on large distribution capacity investments. In part, EV charging load is shifted to off-peak charging times through the Company's programs that incentivize off-peak charging with lower rate structures.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that these EV programs create an inherent misalignment between solar DER generation and EV charging. Just Solar recommended that the Commission direct the Company to conduct additional studies to assess the potential costs and benefits that may result from encouraging EV charging during high solar generation periods. Additionally, Just Solar Coalition recommended that the Company coordinate with MISO to explore how the changing solar and DER landscapes may result in EV charging rates being dynamic based on location, solar resource availability, or other variables.

2. Xcel

In response, the Company stated that its current EV programs generally promote off-peak charging, which encourages EV charging at times beneficial to both the customers and its distribution system. The Company contended that Just Solar's recommendations relate to system planning issues outside the scope of this rate case and broader than distribution system planning, and thus would be better addressed in other forums such as an integrated resource plan proceeding. Additionally, the Company emphasized that if the Commission determines that from a policy perspective, the studies recommended by Just Solar are appropriate, it could impact other utilities not represented within this docket.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge agreed that the recommendations on EV charging studies are outside of the scope of the rate case and would be better addressed in other forums where all potential stakeholders could engage in the proceedings. She recommended that the Commission take no action on JSC's recommendation.

D. Commission Action

The Commission agrees with the ALJ's and the Company's position that EV charging studies would be better addressed in other proceedings. As a result, the Commission will not require additional studies into EV charging as recommended by Just Solar.

LX. Distributed Energy Resources – Smart Inverters

A. Introduction

Smart Inverters is a general term used to describe inverters that meet and are certified by the Institute of electrical and Electronics Engineers (IEEE), a national testing lab. Minnesota has not yet adopted the applicable IEEE standard as part of its statewide Minnesota DER Technical Interconnection and Interoperability Requirements. As a result, certification is currently pending for available smart inverters. Smart Inverters give additional functionality including volt/watt functions[73] and volt/var curves[74] that could be utilized by DER customers.

Just Solar recommended that the Commission require the Company to leverage the capabilities of smart inverters and evaluate their ability to defer voltage-driven capital investments.

B. Position of the Parties

1. Just Solar Coalition

Just Solar argued that smart inverter capabilities have been used by peer utilities for years, and that when existing equipment is compliant and would not result in adverse system impacts, DER customers be allowed to utilize the equipment's full functionality.

2. Xcel

In its most recent IDP annual update, the Company filed a roadmap outlining a three-phase transition to the use of Smart Inverter capabilities in Minnesota. The first phase of this program is expected to be completed in the second quarter of 2023. Given the Company's roadmap and current transition, the Company argued it would be premature to assume the use of their capabilities in its planning studies or to require an evaluation of their impact. The Company noted that the use of Smart Inverters is already being addressed in the Company's IDP proceeding, which it contends is the proper venue for these issues.

C. Recommendation of the Administrative Law Judge

Since the Commission has separately addressed the implementation of Smart Inverters,[75] the Administrative Law Judge recommended that the Commission take no action on Just Solar's recommendations related to Smart Inverters.

D. Commission Action

The Commission recognizes the importance of Smart Inverters but agrees with the Administrative Law Judge and the Company that the issue is better addressed in other

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[73] Volt/watt functionality allows smart inverters to monitor voltage within a local area and adjust the amount of power DERs sends to the distribution system to optimize system efficiency.

[74] Volt/var curves provide information for smart inverters to optimize photovoltaic generator efficiency.

[75] *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E-999/CI-16-521

proceedings. The Commission will not adopt Just Solar's recommendations related to the Company's use of smart inverters and the associated analysis of potential impacts on capital investments.

LXI. Distributed Energy Resources – Load Forecasting

A. Introduction

Current Company distribution planning load forecasts and capacity planning processes intentionally exclude peak load reduction effects caused by DER during peak time frames in both the present year and future forecast years. Since the Company's process operates by first removing the DER power injections, it would be possible to re-incorporate that data and examine whether any capacity investments could be deferred.

Just Solar recommended that the Company explore the impacts of DER on planned capacity investments and accordingly consider changing its approach to load forecasting.

B. Position of the Parties

1. Just Solar Coalition

Just Solar stated that integrating DERs into load forecasting would help enable the clean energy transition and modernization of the distribution system. The current system of removing DERs from load forecasting, Just Solar contends, detracts from some of the benefits that DERs provide the system. This recommendation includes requiring the Company to study the impact of its current native load compared to net load approach in system plannings. Following Commission approval of the Company's 2022 IDP, Just Solar believes the Company has begun to move in the direction of Just Solar's recommendation.

2. Xcel

The Company opposed Just Solar's recommendation on load forecasting for three reasons. First, the Company stated that it already incorporates DER forecasts into the evaluation of certain distribution capacity projects but does not include DER forecast information in some evaluations for reasons including the size of the project. The Company does not expect DER capacity to have any impact on capacity projects less than $2 million currently planned in the 2022–2024 timeframe. Second, the Company is already evaluating granular DER forecasts and scenario planning through the use of LoadSEER, to incorporate DER into its forecasting for distribution system and planning and budgeting processes. Third, the Company is preparing its 2023 IDP, through which it is assessing the current treatment of DER-derived capacity as it relates to prioritizing net load.

The Company also opposed Just Solar's recommendation to study the impact of native or net load approaches in system planning. The Company is already working on incorporating DER forecasts into its load forecasts but has not yet completed this work. DER forecasts, the Company contends, are currently not granular enough for their use in forecasting as DERs are developed for larger areas than the forecasts, causing significant uncertainty as to where the forecasted DER generation would be used. Certain DERs also cannot be relied upon for capacity reductions as certain DERs do not provide consistent capacity reductions and others have limited energy durations. Finally, the Company explained that tools such as LoadSEER require refinement over time as not only are they new to the Company, but to the industry as a whole. As a result, the Company does not plan on using short-term forecasts.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge found that Just Solar did not demonstrate the reasonableness of requiring the Company to study changing its approach to load forecasting and therefore recommended that the Commission take no action on Just Solar's recommendations relating to DER impacts on load forecasting and load approaches in system planning.

D. Commission Action

The Commission is not convinced by Just Solar's arguments relating to DERs and load forecasting. Given the direction the Commission has already moved in other proceedings and the recommendations of the ALJ and the Company, the Commission will not adopt Just Solar's recommendation to require Xcel to study DER impacts on load forecasting.

LXII. Grid Modernization Investigation

A. Introduction

The Company has requested cost recovery of two types of grid modernization projects: Distributed Intelligence (DI), and Fault Location, Isolation, and Service Restoration (FLISR). These projects aim to modernize the grid and assist in the Company's service of reliable energy to its customers. DI gives more insight into system issues such as outages and impedance, while FLISR allows for the Company to more quickly and accurately pinpoint where issues are occurring on the distribution system.

As part of this rate case, the Department recommended that the Company be required to comply with future grid modernization filing requirements.

B. Position of the Parties

1. Department

The Department argued that the FLISR and DI projects are discretionary grid modernization proposals that were pursued in a fashion that makes their benefits hard to ascertain. The Department recommended requiring the following standardized information in all future proposals: a road map with all planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernizations costs and all anticipated future grid modernization costs.

2. Xcel

The Company recommended not adopting the Department's proposal because while it supports efforts to improve efficiency in the regulatory process, it maintained that the Department's recommendation goes beyond the scope of this case. Additionally, the Company contended that the Department's proposed filings are overly broad and may not apply to all grid modernization proposals, and in most cases, not be possible because they would require a significant amount of speculation. The Company explained that the Commission has already issued orders implementing a framework for proposals and filing requirements which are different between cost recovery proceedings and IDP filings. The Company noted that the Department's recommendations were also proposed within the Company's 2021 IDP and the 2021 Transmission Cost Recovery Rider proceedings, and the Commission declined to adopt them at that time.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission adopt the Department's proposed filing requirements. The ALJ recognized the benefits of the information filed in aiding the understanding of grid modernization technologies and their long-term costs and benefits. The ALJ found that while the Commission did not adopt the proposals for filing requirements as part of the Company's 2021 IDP and the Transmission Cost Recovery Rider proceedings, it was to ensure flexibility to evaluate utility proposals on a case-by-case basis. The ALJ contended that adopting the Department's proposed filing requirements is consistent with the Commission's decisions in those cases by tailoring the requirements to Xcel, and additionally, that adoption of the Department's proposal in this case, does not exceed its scope.

D. Commission Action

The Commission agrees with the Department's and the Administrative Law Judge's assessment that the information contained within the Department's recommended filing requirements would be useful. The requirement would help ensure all parties have enough information in the decision-making process so that programs are thoughtfully and thoroughly designed in the future. The Commission will therefore adopt the Department's proposed filing requirements.

LXIII. Energy Assistance

A. Introduction

Energy assistance programs, such as LIHEAP, are programs that serve to aid low-income customers. LIHEAP requires customers to verify their income as part of the application process. The Company's own assistance program, PowerOn, requires customers to have applied to LIHEAP, which is a common requirement among energy assistance programs.

Just Solar Coalition proposed a set of energy assistance recommendations to address some of the issues faced by the Company's low-wealth customers.

B. Position of the Parties

1. Just Solar Coalition

Just Solar believes that the Company could improve its outreach and service to these customers to increase understanding of their economic and demographic circumstances and better protect them from service disconnections.

Just Solar contended that the Company has not given sufficient attention to issues of equity and justice affecting these consumers and recommended that the Company work with other utilities to develop a strategic plan for funding and delivering energy assistance. Just Solar recommended incorporating a reevaluation of Company budgets for low-income assistance programs to identify and assist a larger number of customers. Just Solar also recommended quantifying the difference between costs to serve single-family and costs to serve multi-family homes be quantified for consideration when setting rates. Lastly, Just Solar also recommended that the Commission require the Company to study how its demand response programs could minimize bill volatility, establish a permanent moratorium on disconnections, and remove income verification from accessing assistance programs.

2. Xcel

The Company acknowledged many of the issues raised by Just Solar are many with which it agrees; the Company shares Just Solar's objectives in assisting its members through affordable electricity. The Company, however, stated that its Energy Equity docket[76] is aimed at addressing issues surrounding the burden that energy bills place on customers. The Company's Energy Equity docket has laid a groundwork dedicated to addressing concerns regarding barriers to energy assistance programs, and the Company therefore recommended that these issues continue to be addressed in that proceeding rather than adopting Just Solar's recommendation.

C. Recommendation of the Administrative Law Judge

Recognizing the separate proceedings designed to fully consider the issues raised by Just Solar, the ALJ recommended that the Commission take no action on Just Solar's energy-assistance recommendations.

D. Commission Action

The Commission will decline to adopt Just Solar's energy-assistance recommendations, instead concurring with the Company's position that the issues of energy assistance are more appropriately addressed in the Company's Energy Equity docket where the Company is identifying proposals for consideration to address the issues surrounding its energy assistance program.

LXIV. Locational Reliability and Service Quality

A. Introduction

The concepts of locational reliability and service quality work to measure the differences seen in the service received by different communities within the Company's service area. The Company is currently working to map reliability, service quality, and equity issues in other proceedings before the Commission.[77]

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[76] *In the Matter of Efforts to advance workforce diversity, inclusive participation, and equitable access to utility services for Xcel Energy*, Docket No. E002/M-22-266.

[77] *In the Matter of the Commission Investigation to Identify and Develop Performance Metrics and Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E-002/CI-17-401 and *In*

Just Solar requested that, consistent with the Commission's decisions in related dockets, the Company be required to conduct analyses related to locational differences in reliability, disconnections, and service quality, specifically related to low-income and energy justice communities.

B. Position of the Parties

1. Just Solar Coalition

The proposed analysis would help inform the Company's future distribution investments and planning. Just Solar stated that the risk of disconnections and power outages have a greater disruptive effect on low-income communities. Just Solar stated that the Minneapolis Green Zone more commonly experienced outages lasting greater than 12 hours than other parts of the Company's service area.

2. Xcel

The Company stated that it has not seen systemic differences in reliability or significant patterns of poor reliability between the Minneapolis Green Zones and its other service areas. The Company is working on continuing to measure the differences in reliability and service quality across the communities it serves in its annual service quality and performance-based ratemaking dockets. The Company recommended rejecting Just Solar's proposal; the Company will instead continue its efforts in other dockets to identify and further examine these issues.

C. Recommendation of the Administrative Law Judge

Stating that the issue is more appropriately addressed within the Hosting Capacity and Grid Security Dockets cited by the Company, the Administrative Law Judge recommended that the Commission take no action on Just Solar's recommendation.

D. Commission Action

The Commission will continue to explore the issues of locational reliability and service quality within other dockets with the assistance of the Company and other interested parties. The Commission therefore declines to adopt Just Solar's recommendation related to locational reliability and service quality.

LXV. Company Audit of Third-Party Sales Forecast Data

A. Introduction

The Company currently audits economic and demographic data obtained from third-party sources and then uses the data in the development of its test year sales forecast. These audits were required by the Commission in the Company's 2008 rate case requiring the Company to work with the Department to achieve "greater data transparency." Since the 2008 rate case, the Company has audited data provided by the IHS Markit databases, which has resulted in no

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the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality and Petition for Approval of Electric Reliability Standards, Docket No. E-002/M- 20-406.

discrepancies being found. IHS Market is an information services company that provides information and research to its customers. Customer reliance on the information IHS provides incentivizes IHS to ensure the accuracy of the information provided.

The Company requested to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit.

B. Position of the Parties

1. Xcel

The Company stated that the audits do not add value to the sales forecasts. Given the lack of discrepancies found within all the past audits, the Company argued, demonstrates that it would be reasonable to remove the audits. The Company acknowledged that updates to previous economic data have occurred but states that these updates would not have been corrected as part of the Company's audits. The data that was updated in the past was preliminary, historical economic data that is used when current data is unavailable. This preliminary data is updated when the most recent economic data becomes available, and the Company commits to resolving any third-party data issues that are identified in its sales forecast without the need to audit third-party data.

2. Department

The Department was concerned with the Company's request to eliminate the audits and cited past instances in which significant revisions to prior actual economic data occurred as support for continuing the audit requirements. The Department argued that the Company bears the burden of proving that the data and models used in creating its forecasts are reasonable. Given the need to update past economic data, the Department maintained that the continued requirement of audits ensures the data that is obtained from third parties is reasonable for use in the sales forecast modeling.

C. Recommendation of the Administrative Law Judge

The ALJ found that the Company demonstrated that it would be reasonable to end the audit requirement and that the Department had not identified errors in preliminary historical data that the audits would have corrected. The ALJ further recommended that the Company and Department work closely to respond to issues with third-party data. The ALJ therefore recommended adoption of the Company's request.

D. Commission Action

The Commission will decline to adopt the Company's request to eliminate the required audits of data it obtains for sales forecasting from third parties. The requirement to independently audit third-party data ensures the accuracy of information used in the Company's sales forecasting. While no discrepancies have occurred in previous audits and IHS is incentivized to ensure the accuracy of data it provides, the audits continue to provide an important function of ensuring accuracy within the Company's sales forecasting.

LXVI. Regulatory Sandbox

A. Introduction

A "regulatory sandbox" is a streamlined regulatory policy meant to encourage the efficient deployment of pilot projects. The key components of a regulatory sandbox program are focused on scope, oversight and governance structure, project eligibility criteria, evaluation and reporting requirements, and methods for cost recovery or funding. Several other states currently have some form of regulatory sandbox in effect.

The Clean Energy Organizations recommended that Xcel be required to work with interested parties and other utilities to discuss methods for improving the effectiveness and efficiency of pilot programs.

B. Position of the Parties

1. Clean Energy Organizations

The benefits of such an investigation are the efficient deployment of pilot projects through a streamlined and a consistent regulatory policy that replaces the current *ad hoc* approach used for pilot projects. Additionally, this approach would ensure that the information learned during pilot projects is available to all parties and transferred into future projects.

The investigation would also facilitate coordination in the ongoing energy transition. The first issue the sandbox addresses is the frequently unreasonably long duration, from conceptualization to implementation, of pilot projects. The second issue is that pilot programs focus on individual development, not utility-wide improvements. Third, the current system operates on proposals by electric utilizes and neglects to fully incorporate ideas and experiences of third parties.

2. Xcel

The Company is concerned that a full regulatory sandbox proceeding would require extensive resources. The Company instead supports the Clean Energy Organizations' recommendation to require it to work with interested parties and other utilities to discuss methods of improving the pilot program process.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Commission initiate an investigation into creating a framework for rate-regulated utility projects as originally recommended by the Clean Energy Organizations. The ALJ stated that ratepayers and the public would benefit from the framework that a regulatory sandbox would provide by promoting innovation within the energy sector, innovating clean energy offerings for ratepayers, and reducing the regulatory burden of pilot programs by introducing a standardized process.

D. Commission Action

The Commission finds that initiating an investigation into the creation of a regulatory sandbox would not necessarily be more beneficial than continuing to develop these issues in individual dockets. The Commission has approved numerous pilot programs over the years, recognizing their importance in innovation within the energy sector. The Commission is not concluding that a regulatory sandbox as seen within other states would not benefit ratepayers. Rather, the Commission recognizes that such an investigation is likely to increase the scope of resources needed for such an effort, while many of these issues are under development in existing dockets. The desire to broadly coordinate efforts is not likely resolved in one proceeding.

The Commission will therefore require Xcel to work with interested parties and other utilities as relevant to discuss methods for improving the effectiveness and efficiency of pilot projects, accelerating the timeline for scaling successful pilot programs into full offerings, and increasing innovation in the energy sector, consistent with the public interest. The Commission finds that this recommendation, supported by the Clean Energy Organizations and Xcel, would benefit ratepayers and utilities without the need to create a regulatory sandbox.

LXVII. Quantifying Incremental Hosting Capacity and Beneficial Electrification

A. Introduction

The Electric Power Research Institute defines hosting capacity as the amount of Distributed Energy Resources that can be accommodated on the existing utility system without adversely affecting power quality or reliability under existing configurations and without requiring infrastructure upgrades.[78] The Company makes replacements and upgrades to its distribution resources based on asset age and renewal. These replacements and upgrades are not made with consideration to expanding hosting capacity for DER purposes.

The Clean Energy Organizations recommended that the Commission require Xcel to determine the incremental hosting capacity and beneficial electrification accommodation resulting from planned Asset Health and Reliability (AH&R) capital Expenditures.

B. Position of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that this requirement would provide insight into how Xcel's current planned Asset Health and Reliability expenditures are providing increases in hosting capacity that will be needed as the use of Distributed Energy Resources continues to expand.

2. Xcel

The Company recommended that the Commission not adopt the Clean Energy Organizations' proposal on incremental hosting capacity and beneficial electrification as the issues are outside the scope of the proceeding, and more in line with its upcoming IDP filing.

[78] Rebuttal Testimony and Schedules at 57, Marty D. Mensen, (No. E002/GR-21-630), Nov. 8, 2022.

C. Recommendation of the Administrative Law Judge

The Administrative Law Judge recommended that the Clean Energy Organizations recommendation be adopted. The ALJ noted that the recommendation would allow interested parties and the Commission to better assess proposed investments and prioritize those that facilitate the expansion of DERs and beneficial electrification.

D. Commission Action

The Commission will adopt the Clean Energy Organizations' recommendation to require Xcel to quantify, in its next Integrated Distribution Plan, the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments. The Commission recognizes the benefits of expanding the information available to all interested parties and the necessity of considering hosting capacity as the amount of DERs continues to expand on the electric grid.

LXVIII. Unintentional Islanding

A. Introduction

Unintentional islanding occurs when distributed energy resources (DERs) become isolated from the distribution system and continue to independently serve load. DERs are generally located near the load they serve and generally interconnect to the grid at the distribution level. This condition can be harmful to customer and utility equipment if the utility loses control of voltage and frequency. The Company's proposed solution to the problem of unintentional islanding is to upgrade substations with Voltage Supervisory Reclosing (VSR) before additional distributed generation projects can interconnect on the feeders.

The Clean Energy Organizations recommended that the Commission ask the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to investigate the problem of unintentional islanding and to research less costly alternatives to VSR to address the risk of unintentional islanding.

B. Position of the Parties

1. Clean Energy Organizations

The Clean Energy Organizations argued that the Company's solution to address the low-probability event(s) of unintentional islanding is too expensive. They expressed concerns that the proposed VSR investments would be too costly for DER customers and therefore recommended that Xcel file a report on the TSG's findings by July 31, 2024.

2. Xcel

The Company generally opposed the recommendations made by the Clean Energy Organizations because they are outside the scope of this proceeding. The Company also stated that the composition of the DGWG TSG has changed from technical experts to attorneys and policy advocates, a new composition which would not be effective in addressing the issue of unintentional islanding. The Company reiterated the dangers of unintentional islanding for customers and utility equipment, noting that the Company's responsibility for safe, adequate, and reliable service means that the responsibility to establish technical standards remains with the Company.

C. Recommendation of the Administrative Law Judge

The ALJ recommended requiring Xcel to examine the issue of unintentional islanding, finding that the information gathered would assist parties in addressing the risk of unintentional islanding.

D. Commission Action

The Commission concurs with the ALJ and Clean Energy Organizations to require the Company to examine this issue. While the Company's proposal of upgrading substations with VSR would provide protection against the possibility of unintentional islanding, VSR would be a costly upgrade to solve a potential problem. The Clean Energy Organizations' recommendation balances the risk of unintentional islanding against the costs of the Company's goal of preventing the problem in a manner to ensure that unintentional islanding is addressed without burdening ratepayers.

The Commission will therefore require the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to convene to examine the possibility of unintentional islanding caused by interconnection of DERs. As part of the examination, the TSG will identify additional screens that utilities can perform to assess the risk on unintentional islanding and determine if there are less costly alternatives to Voltage Supervisory Reclosing (VSR) for addressing any perceived risk. The TSG will seek feedback from the DGWG during this examination and file a report with its findings and recommendations by July 31, 2024.[79]

LXIX. Resolved Issues

On a number of issues, the parties reached agreement or resolved outstanding issues by the time the Commission met to consider the matter. The Commission concurs on the reasonableness of the resolutions reached by the parties and will adopt them, as set forth in the ordering paragraphs below.

LXX. Motion to File Late Exceptions

The Commission will grant Just Solar Coalition's motion for leave to file late exceptions to the Administrative Law Judge's Report; no party opposed this request.

LXXI. Compliance Filings

The Commission will authorize comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Xcel's proposed customer notice.

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[79] The report will be filed in: *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E-999/CI-16-521

ORDER

1. Except as otherwise set forth within this order, the Commission adopts the Administrative Law Judge's March 31, 2023, Findings of Fact, Conclusions of Law, and Recommendations.

2. The Commission authorizes the Executive Secretary to open a new docket to investigate depreciation accounting or other ratemaking issues for retiring generating facilities. Any depreciation adjustments required for Sherburne County Generating Station Unit 3 or Allen S. King Generating Station will be implemented in Xcel's next rate case or other appropriate proceeding.

3. The Commission denies Xcel's recovery request of Minnesota Jurisdictional 2022-2024 long-term incentive compensation expense of $7.877 million, $8.178 million, and $8.531 million, respectively.

4. Xcel must cap its recovery of annual incentive plan compensation expense at 15% of individual base pay and 100% of target payout.

5. For each test year in the multiyear rate plan, Xcel electric's Minnesota jurisdictional annual cost recovery is limited to $1.5 million in total for the top ten highest-paid employees and officers.

6. The annual incentive plan compensation of Xcel's top ten highest-paid officers and employees is not recoverable.

7. Xcel must provide the calculation of the Minnesota jurisdictional top ten adjustment in this docket and in the annual compliance filings of the annual incentive compensation plan docket.

8. The Commission approves Xcel's 2022-2024 Minnesota jurisdictional annual incentive plan compensation expense of $22.878 million, $23.589 million, and $24.324 million, respectively which results in 2022-2024 revenue requirement reductions of $1.127 million, $1.161 million and $1.197 million, respectively.

9. Xcel must continue filing annual compliance filings evaluating the operation and performance of its incentive compensation plan and the associated refund with no changes to reporting requirements.

10. Xcel must provide support in its next annual incentive compensation compliance filing for any requested reporting changes.

11. The Commission denies Xcel's request to include its Prepaid Pension Asset in rate base to earn a weighted average cost of capital return.

12. Xcel must not recalculate its qualified pension expense without applying the expected return to the prepayment portion of the pension trust to reflect the revised pension expense in rates.

13. The Commission denies Xcel's proposal that the accrued liabilities for retiree medical and post-employment benefits be included in the rate base and earn a weighted average cost of capital return.

14. The Commission approves Xcel's 2022-2024 business systems Operations and Maintenance expenses of $89.9 million, $96.2 million, and $103.8 million, respectively.

15. The Commission denies Xcel's request to recover its income tax tracker amount, which results in a 2022-2024 revenue requirement reduction of $2.492 million, $2.300 million, and $2.110 million, respectively.

16. The Commission approves recovery of Xcel's 2022–2024 Energy Supply Operations and Maintenance expenses totaling $154.6 million, $160.8 million, and $157.7 million, respectively.

17. The Commission denies Xcel's request to recover the Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and South Dakota Public Utilities Commission proxy price which results in a 2022-2023 revenue requirement reduction of $2.857 million and $2.689, respectively.

18. The Commission denies Xcel's request to recover, through the Fuel Clause Adjustment, starting January 1, 2024, Aurora Solar Project's deferred costs for the difference between the contracted power purchase agreement price and the South Dakota Public Utilities Commission proxy price.

19. The Commission approves a reserve reallocation of no more than $2.14 million for recovery of a reasonable cost to dismantle, dispose of, and fully restore the site associated with the Wind2Battery system and requires Xcel to perform the proposed "inverse reverse allocation" of reallocated amounts if actual costs are lower than the $2.14 million. The Company shall not subsequently seek additional reserve allocations from assets in the Other Production plants account. The Company shall not seek recovery of any additional costs associated with the Wind2Battery.

20. The Commission approves Xcel's proposal to include Construction Work in Progress (CWIP) in rate base as an average of projected CWIP beginning and ending balances.

21. The Commission finds that Xcel's cost-benefit analysis for Fault Location Isolation and Service Restoration (FLISR) is reasonable.

22. The Commission approves Xcel's request to recover 2022-2024 FLISR program costs.

23. The Commission approves Xcel's proposed FLISR cost allocation.

24. The Commission approves Xcel's FLISR deployment strategy.

25. Xcel must track and report on reliability performance for circuits equipped with FLISR as recommended by the Department.

26. The Commission finds that any future FLISR cost recovery may be based on reliability improvements compared to targets or other demonstrated benefits attributable to FLISR.

27. Prior to seeking future cost recovery for any incremental FLISR investments, Xcel must propose a mechanism by which to base cost recovery for FLISR investments on reliability improvements:

    a. Xcel must track and report, beginning in its next Service Quality, Safety, and Reliability report due April 2024, on reliability performance for circuits equipped with FLISR investments approved in the present rate case as recommended by the Department, indicating in the Company's safety, reliability, and service quality filings which circuits have been equipped with FLISR. Allow Xcel to modify the requirements on circuit level performance reporting in its annual Service Quality, Safety, and Reliability reports to align with the Department's recommendation.
    b. Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.
    c. In its next rate case or in any future proceeding where it seeks cost recovery for incremental FLISR investments, Xcel must propose performance targets for SAIDI, SAIFI, and CAIDI, and, if applicable, any additional aspect of FLISR, based on data collected for circuits equipped with FLISR approved in the present rate case.
    d. In the Company's next rate case or in any future proceeding where it seeks cost recovery for FLISR investments, Xcel must propose a Performance Incentive Mechanism for reliability performance demonstrated benefits of circuits equipped with FLISR, using the PIM Design Process outlined in Docket No. E002/CI-17-401. Xcel's PIM proposal shall include, at minimum, the following elements:
        i. PIM structure
        ii. The dates when the PIM will take effect and terminate
        iii. Determination of the quantifiable and verifiable incentive values associated with performance in terms of SAIDI, SAIFI, and CAIDI above and below future associated targets. This may include a neutral zone around any particular target for acceptable performance.
        iv. Specific mechanisms for effectuating a penalty or incentive on the Company
        v. An explanation of how stakeholders were engaged in the creation of PIMs
    e. Xcel must file all data as a live, .xls spreadsheet and where the data cannot be provided, explain why.

28. The Commission approves Xcel's 2022-2024 Minnesota jurisdictional distribution capital addition costs for asset health and reliability of $168.9 million, $180.8 million, and $205.0 million, respectively.

29. In its next Integrate Distribution Plan (IDP), Xcel must propose and discuss ways for the IDP process to inform financial and cost recovery issues in rate cases, including but not limited to:

a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget;
b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP.

30. Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information in its next rate case filing.

31. Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.

32. The Commission rejects Xcel's distribution capital addition costs for the grid reinforcement program for the 2022–2024 test years.

33. The Commission rejects Xcel's proposal for the Distributed Intelligence program without prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement.

34. The Commission approves the Department's recommended baseline Production Tax Credits update which reduces 2022-2024 revenue requirements by $27,584,000, $1,288,000 and $1,353,000, respectively.

35. The Commission approves Xcel's proposal to recover costs for the load flexibility program that were not deferred which increases 2023-2024 revenue requirements by $0.870 million and $1.136 million, respectively.

36. Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.

37. Xcel must base 2022 insurance premium costs on historical averages as proposed by the Department which results in 2022-2024 revenue requirement reductions of $9.274 million, $10.017 million, and $11.311 million, respectively.

38. The Commission approves Xcel's request to recover Edison Electric Institute dues.

39. The Commission rejects Xcel's request to recover American Gas Association dues.

40. The Commission approves Xcel's request to recover 50% of its Chambers of Commerce dues.

41. Xcel must continue providing information mandated by Minn. Stat. § 216B.16, subd. 17, for all costs of dues it seeks to recover regardless of the type of membership (individual, corporate, or chamber).

42. The Commission disallows all 2022-2024 Carbon-Free Future Minnesota Coalition costs.

43. The Commission approves recovery of Xcel's advertising expenses.

44. Xcel must use full-time equivalent hours for its General Allocator calculations which results in 2022-2024 MN jurisdictional revenue requirement reductions of $5.900 million, $6.241 million and $6.613 million, respectively.
When allocating shared costs between its Minnesota and Wisconsin operations, Xcel shall use the 2022 Interexchange Agreement approved by FERC, thereby increasing the revenues allocated to Xcel's Minnesota operations for 2022 by $149,983, reducing jurisdictional expenses by $1,332,358, and thus reducing the overall 2022 Minnesota Jurisdiction revenue requirement by $1.482 million; Xcel must use its updated 2022 allocators in 2023 and 2024 as well.

45. The Commission adopts Xcel Energy's proposed capital structure.

46. The Commission adopts the Department's proposed cost of long-term debt.

47. The Commission adopts the Department's proposed cost of short-term debt.

48. The Commission adopts a return on equity of 9.25%, inclusive of flotation costs.

49. The Commission determines that the overall cost of capital reflects the authorized return on equity.

50. The Commission denies Xcel's proposed return on equity adjustment mechanism.

51. The Commission determines that each CCOSS model provides useful information and declines to adopt any specific model.

52. The Commission approves Xcel's proposal to classify and allocate production costs using the Stratification method.

53. Xcel must calculate the D10S allocator in its next rate case based on its system peak coincident with the MISO system peak using historical data.

54. The Commission classifies joint transmission costs as 70% demand and 30% energy.

55. The Commission allocates demand-related transmission costs using the 12CP allocator.

56. Xcel must classify and allocate distribution system costs using multiple methods, including the Minimum System Method, the Basic Customer Method, and the Peak and Average Method.

57. Xcel must file multiple CCOSSs using the following methodologies to classify and allocate distribution system costs in its next rate case:

    a. Minimum System Method
    b. Basic Customer Method, with Peak & Average Method used to classify non-Customer related cost

c. Basic Customer Method, with non-Customer related costs classified as Demand related.

58. Xcel must file a proposal for an alternative class allocation methodology for Community Solar Gardens costs recovered in the fuel clause in order to address class benefits and costs of the program. The proposal should be filed in Docket No. E-002/AA-03-802 (the fuel investigation docket) as part of the required Lessons-Learned report. The Commission will consider the issue at an agenda meeting by February 1, 2024.

59. The Commission adopts the Department's proposed 2022 test year revenue apportionment for the entire multiyear rate plan.

60. The Commission sets the monthly Small Commercial & Industrial (C&I) customer charge at $6.00.

61. The Commission sets the monthly residential customer charge for all residential customers at $6.00.

62. Xcel must work with stakeholders in Docket E-002/M-20-86 to address C&I fixed customer charges, demand rates, demand-related costs, seasonal costs and rates, and other DR and DER initiatives.

63. Xcel must implement the Low-Income, Low-Usage Discount Program as proposed by Energy Cents Coalition.

64. Xcel must make the program available to customers the later of the effective date of final rates or October 1, 2023. The Company will be required to file a program status update on December 1, 2023, and annually thereafter with its electric low-income annual report.

65. The Commission approves Xcel's practice to waive the cost-sharing requirement for electric vehicle (EV)-rate customers and require Xcel to file amended tariffs that permit Xcel to exclude EV-rate customers from the general cost-sharing tariff.

66. Xcel must include its proposal to waive cost sharing requirements for EV-rate customers to Xcel's Transportation Electrification Plan.

67. In its next general rate case, Xcel must further segment the C&I Demand class based on factors such as size, load factor, and coincidence factor to facilitate the creation of a C&I TOU rate.

68. Xcel must file a proposed permanent Residential Time-of-Use rate by December 31, 2023.

69. The Commission denies Xcel's proposed changes to its Residential Space Heating tariff without prejudice; Xcel must refile its proposal in a new docket within 90 days of the final order in this case.

70. The Commission allows Xcel to discontinue its Real Time Pricing Service tariff.

71. Xcel must work with stakeholders in the development of a new Real Time pricing offering.

72. The Commission approves the Joint Stipulation between Xcel and the Suburban Rate Authority.

73. The Commission approves the structure of the rate design for street lighting as proposed by Xcel and amended by the stipulated agreement between the SRA and the Company and as recommended by the ALJ.

74. The Commission approves the new Light-emitting Diode (LED) option for Directional Lighting in the Automatic Protective Lighting Service tariff.

75. The Commission allocates $1,756,000 in pole costs across the other customer classes using the allocation factors for the Overhead Lines category as proposed by the Suburban Rate Authority.

76. The Commission opens an Advanced Rate Design docket and directs Xcel to work with stakeholders to develop a proposed scope and process for this docket.

77. Xcel must, in the advanced rate design docket, include an analysis on its compliance with Minnesota's goal for rates to be 5% lower than the national average, Minn. Stat. § 216C.05, subd. 2(4), including a minimum of the following issues:

    a. The impact of its proposed rate increase on compliance with the statutory goal;
    b. The impact of conservation on bills and its relevance to the statutory goal;
    c. Strategies that could be employed to improve compliance with the statutory goal; and,
    d. An alternate rate increase proposal that would be in compliance with the statutory goal, and Xcel's justifications for proposing any rate increases in excess of the alternate plan.

78. The Commission approves a sales true-up and not a decoupling mechanism for the multiyear rate plan.

79. The Commission modifies Xcel's proposed sales true-up as follows:

    a. Establish a 3% hard cap on surcharges.
    b. Include metered lighting in the true-up.

80. Xcel must file an annual compliance filing on April 1, with a June 1 sales true-up effective date, as recommended by the Department.

81. The Commission approves Xcel's adjustment to the Conservation Cost Recovery Factor Rider, and directs Xcel to adjust the Conservation Improvement Program Adjustment Factor (CAF) in its annual CAF filing.

82. Except as otherwise directed, the Commission approves Xcel's proposal to roll costs into final rates and carry certain projects forward in riders.

83. The Commission approves Xcel's revised Winter Construction Charges.

84. The Commission approves the Company's proposal to provide a dollar-based credit to customers on the Residential Controlled Air Conditioning and Water Heating Rider.

85. The Commission approves Xcel's 2022-2024 property tax expense recoveries of $165.930 million, $169.889 million, and $173.946 million, respectively which results in a 2022-2024 revenue requirement reduction of $14.082 million, $22.681 million, and $34.107 million, respectively.

86. The Commission approves the property tax true-up mechanism for the duration of the multiyear rate plan.

87. The Commission approves Xcel's request to amortize deferred COVID-related Business Incentive Sustainability Rider expenses.

88. The Commission approves Xcel's amortization period of three years for LED street lighting, rate expense and deferred pension expense.

89. Xcel must use its actual 2022 beginning of the year plant balance of $9,835,166.000, which reduces 2022 average rate base by $21.164 million and 2022 revenue requirements by $2.005 million.

90. The Commission reduces Xcel's 2022-2024 Nuclear Carbon Free Power Project revenue requirements by $774,000, $798,000, and $821,000, respectively.

91. Xcel must make a compliance filing that separately identifies the costs for each employee who was transferred from Xcel Energy Service to Nuclear Energy Services and that shows how the adjustments were calculated.

92. Xcel must remove $0.2 million in IVVO investments from the 2023 test year.

93. The Commission approves Xcel's proposal to remove from rate base $1.8 million in IVVO investments from 2024 test year, which results in a 2024 revenue reduction of $376,000.

94. The Commission approves Xcel's proposal to apply the return on equity approved in this rate case, instead of the Federal Energy Regulatory Commission (FERC) return on equity, to its transmission investments.

95. The Commission approves Xcel's proposal to include Workforce Development costs in this rate case, which results in 2022-2024 MN jurisdictional revenue requirement increases of $75,000, $2.000 million, and $1.670 million, respectively.

96. The Commission approves the compliance filing requirements listed in the Commission's October 23, 2009, Order in Docket No. E-002/GR-08-106.

97. The Commission approves Xcel's and the Department's proposal to remove demand-side management and distributed generation solar adjustments from the sales forecast.

98. The Commission approves Xcel's updated sales forecasts for 2022, 2023 and 2024.

99. The Commission approves Xcel's Business Incentive and Sustainability (BIS) Rider as filed.

100. The Commission approves Xcel's nuclear decommissioning accrual of $21,571,110, Minnesota jurisdictional, thus reducing the revenue requirement by $5,375,117 from each test year.

101. The Commission approves the Department's recommendation to reduce Xcel's 2022-2024 nuclear hydrogen Operations and Maintenance expense of $1.099 million, $0.509 million, and $1.345 million, respectively.

102. Xcel must extend the depreciation life of the Monticello nuclear plant by 10 years.

103. The Commission approves Xcel's 2023-2024 revenue requirement reduction of $34.5 million and $33.3 million, respectively.

104. Xcel must extend wind farm lives from 25 to 35 years, which results in 2022-2024 revenue requirement reductions of $20.809 million, $19.330 million, and $17.864 million, respectively.

105. The Commission approves Xcel's request for recovery of pension expense associated with Xcel Plan using Aggregate Cost Method, and XES Plan using FAS 87 along with amortization of the XES Plan deferred balance over three years.

106. The Commission approves Xcel's adjustments related to the three transformer sales in 2022, which result in 2022-2024 revenue requirement reductions of $0.612 million, $0.210 million, and $0.169 million, respectively.

107. Xcel must include the Minnesota portion of the North Dakota Investment Tax Credit in the revenue requirement calculations, which results in 2022-2024 revenue requirement reductions of $0.347 million, $0.496 million, and $0.712 million, respectively.

108. The Commission approves recovery of EV deferred costs, updated as of December 31, 2021, over a 3- year amortization period, which results in 2022-2024 revenue requirement increases of $0.305 million, $0.287 million, and $0.270 million, respectively.

109. The Commission approves the removal of proposed EV costs totaling: $6,238,000 in 2022; $16,124,000 in 2023; and $21,577,000 in 2024.

110. Xcel must remove EV program costs from this rate case, which results in 2022-2024 revenue requirement reductions of $1.067 million, $2.528 million, and $6.517 million, respectively.

111. The Commission approves Xcel's request to transfer any remaining book value of legacy meters at the time of complete advanced meter deployment to a regulatory asset and defer for recovery to its next rate case.

112. The Commission approves Xcel's updated revenue requirement impact of removing certain transmission cost recovery rider costs and revenues from this rate case, which results in 2022-2024 revenue requirement reductions of $0.386 million, $1.172 million, and $2.012 million, respectively.

113. The Commission approves Xcel's Nuclear Production Tax Credit tracker and refund in the annual Fuel Clause Adjustment Rider.

114. The Commission approves Xcel's proposals to include EV Program Operations and Maintenance Expense in FERC Account 912.

115. The Commission approves Xcel's proposal that the final revenue requirement be updated for secondary calculations such as cash working capital, interest synchronization, and the application of the rate of return.

116. The Commission approves Xcel's offer to withdraw its request for deferred accounting for SaaS.

117. The Commission approves Xcel's proposed capital true-up.

118. The Commission approves Xcel's proposal to continue its Property Tax True-Up during this multiyear rate plan.

119. The Commission adopts Xcel's proposal to suspend the allocation reporting requirements for Xcel Energy's transmission affiliates unless or until such work is undertaken by Xcel Energy Transmission Development Company, LLC, or Xcel Energy Southwest Transmission Company, LLC.

120. The Commission grants Just Solar Coalition's motion for leave to file late exceptions to the Administrative Law Judge's Findings of Fact, Conclusions of Law, and Recommendations.

121. The Commission finds that the Energy Justice tenets recommended by Just Solar Coalition are relevant to setting rates in this proceeding.

122. The Commission rejects CUB's recommendation to require a five-year multiyear plan.

123. The Commission rejects the OAG's proposal to require a proceeding or stakeholder group to examine the Company's corporate governance and dividend policy.

124. The Commission declines to adopt Just Solar Coalition's recommendation relating to circuit breakers, reclosers, and regulator replacement prioritization.

125. The Commission declines to adopt Just Solar Coalition's recommendation to require additional EV charging studies.

126. The Commission declines to adopt Just Solar Coalition's recommendations related to the Company's use of smart inverters and the associated analysis of potential impacts on capital investments.

127. The Commission declines to adopt Just Solar Coalition's recommendation to require Xcel to study DER impacts on load forecasting.

128. The Commission adopts the Department's recommended grid modernization filing requirements.

129. The Commission rejects Just Solar Coalition's energy-assistance recommendations.

130. The Commission reject Just Solar Coalition's recommendation related to locational reliability and service quality.

131. The Commission declines to approve Xcel's request to eliminate its requirement to independently audit data obtained from third parties such as IHS Markit.

132. Xcel must work with interested parties and other utilities as relevant to discuss methods for improving the effectiveness and efficiency of pilot projects, accelerating the timeline for scaling successful pilot programs into full offerings, and increasing innovation in the energy sector, consistent with the public interest.

133. Xcel must quantify, in its next IDP, the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments.

134. The Commission directs the Distributed Generation Working Group's (DGWG) Technical Subgroup (TSG) to convene to examine the possibility of unintentional islanding caused by interconnection of DERs. As part of the examination, the TSG will identify additional screens that utilities can perform to assess the risk of unintentional islanding, and determine if there are less costly alternatives to Voltage Supervisory Reclosing for addressing any perceived risk. The TSG will seek feedback from the DGWG during this examination, and file in Docket No. E999/CI-16-521 a report with its findings and recommendations by July 31, 2024.

135. Xcel must make the following compliance filings within 30 days of the date of the final order in this case:
    a. Revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions herein, along with the proposed effective date, and including the following information:
        i. Breakdown of Total Operating Revenues by type;
        ii. Schedules showing all billing determinants for the retail sales (and sale for resale) of electricity. These schedules shall include but not be limited to:
            - Total revenue by customer class;

- Total number of customers, the customer charge and total customer charge revenue by customer class; and
- For each customer class, the total number of energy and demand related billing units, the per unit of cost of energy and cost of demand and the total energy and demand related sales revenues.

iii. Revised tariff sheets incorporating authorized rate design decisions.

iv. Proposed customer notices explaining the final rates, the monthly basic service charges, and any and all changes to rate design and customer billing.

b. Revised fuel adjustment tariffs to be in effect on the date final rates are implemented.

c. A summary listing of all other rate riders and charges in effect, and continuing, after the date final rates are implemented.

d. A computation of the CCRC based upon the decisions made herein for inclusion in the final Order. Direct Xcel Energy to file a schedule detailing the CIP tracker balance at the beginning of interim rates, the revenues (CCRC and CIP Adjustment Factor) and costs recorded during the period of interim rates, and the CIP tracker balance at the time final rates become effective.

e. If final authorized rates are lower than interim rates, a proposal to make refunds of interim rates, including interest to affected customers.

136. The Commission authorizes comments on all compliance filings within 30 days of the date they are filed. However, comments are not necessary on Xcel's proposed customer notice.

137. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Lauren C. Bethke for

Will Seuffert
Executive Secretary

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CERTIFICATE OF SERVICE

I, Robin Benson, hereby certify that I have this day, served a true and correct copy of the following document to all persons at the addresses indicated below or on the attached list by electronic filing, electronic mail, courier, interoffice mail or by depositing the same enveloped with postage paid in the United States mail at St. Paul, Minnesota.

Minnesota Public Utilities Commission
FINDINGS OF FACT, CONCLUSIONS, AND ORDER

Docket Numbers: **E-002/GR-21-630**

Dated this **17th** day of **July, 2023**

/s/ Robin Benson

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