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

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

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

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

REPLY BRIEF OF NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY

February 25, 2026

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INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, (Xcel Energy, Company, or NSPM) submits this Reply Brief in support of its proposed Multi-Year Rate Plan (MYRP) and responding to certain arguments and issues raised by Intervenors in their Initial Briefs.[1] As discussed below, and as demonstrated in the Company's Initial Brief and Exhibits, the record demonstrates the Company's MYRP fairly balances customer interests in safe, affordable, reliable, equitable, and environmentally sustainable service with the need for the Company to cover the reasonable and necessary costs of providing that service.[2] The record fully supports the Company's positions on the remaining disputed issues, and those positions are consistent with established Minnesota law.

In the face of the robust evidentiary and legal support for the Company's request, Intervenors object to various aspects of the Company's MYRP. In a plain attempt to deny the Company recovery of its actual costs of providing service, many of these parties fundamentally misstate the Company's request and put forth legal arguments inconsistent

[1] The following parties (collectively, Intervenors) filed Initial Briefs: the Minnesota Department of Commerce (Department or DOC), Office of the Attorney General – Residential Utilities Division (OAG), Xcel Large Industrials (XLI), Citizens Utility Board (CUB), Joint Intervenors (JIN), Suburban Rate Authority (SRA) and Walmart (WAL) (collectively, Intervenors). The Energy CENTS Coalition (ECC) also intervened and provided testimony in this proceeding, but did not file an Initial Brief.

[2] This Reply Brief focuses on select issues and arguments where additional discussion may assist the Administrative Law Judge (ALJ) and Minnesota Public Utilities Commission (Commission) in their consideration of the applicable law as it applies to the record of this proceeding. Therefore, the Company does not address again a number of issues, including customer care operations and maintenance expenses, organizational dues, time-of-use rate implementation costs and others. On any contested issue not addressed in this Reply Brief, the Company continues to rely on its Initial Brief as the statement of its position.

with Minnesota Statutes and well-established case law. For example, when arguing about the appropriate authorized return on equity for the Company, these parties claim the Commission and other regulators have been getting it wrong for the past one hundred years of rate regulation in the United States. Their arguments must be rejected.

A full and fair analysis of the Company's MYRP request must begin with an accurate description and understanding of that request and its record support. Intervenors fail to do so. Instead, they create a false narrative that distorts the Company's case, resulting in inaccurate and misleading attacks. The Company's actual case, as shown in the extensive record and as supported by the law, is quite different than the one Intervenors describe.

In the very first paragraph of its Initial Brief, the Department incorrectly states:

> [T]he Company asks the Minnesota Public Utilities Commission to sanction a 9.4% rate increase ($344.3 million) for 2025 and a 3.3% increase ($129.4 million) for 2026. The Commission should deny Xcel [Energy]'s outsized and unsupported proposal. Xcel [Energy] needs far less to deliver safe and reliable service and fairly compensate investors.[3]

The Department returns to this and similar inaccurate recitations that misstate the Company's case throughout its Initial Brief.[4]

Similarly, XLI begins its "analysis" of the Company's request by stating:

> In the current MYRP, the Company seeks a $353.3 million increase in 2025 (9.6%), and an incremental $137.5 million increase in 2026 (4.8%), totaling approximately $490.7 million (13.2%) over the two-year period. The

[3] DOC Initial Brief at 1.

[4] *See, e.g.,* DOC Initial Brief at 9 (repeating these same dollar amounts), 11 and 93 (characterizing the request as "a half billion" dollars and creating a "needless windfall.")

> Company's $490.7 million increase represents an unsustainable, significant increase for all ratepayers under present circumstances.[5]

Both the Department's and XLI's claims are false. As both the Department and XLI know, the Company is *not* asking for the level of increases they allege in their Initial Briefs. In its Rebuttal Testimony, filed October 10, 2025, the Company revised its request by appropriately incorporating new information that was unavailable when the case first was prepared and filed nearly one and a half years ago, reflecting new regulatory decisions, and agreeing to certain Intervenor recommended adjustments. These reasonable and appropriate adjustments collectively lowered the Company's request by approximately $145 million in 2025 alone.[6] And the Company has further lowered its request since that time, incorporating additional adjustments.[7] In short, the Company is not asking the ALJ to recommend or the Commission to approve rate increases anywhere near the levels alleged by both the Department and XLI.

Intervenors also object to the Company's MYRP on the basis of its impact on customers, arguing that this case will make the Company's rates less affordable at a time when customers already feel financial pressure.[8] Intervenors therefore urge the Commission to address affordability issues throughout its consideration of this case, including when determining the Company's cost of service.[9] In other words, it appears that

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[5] XLI Initial Brief at 5. XLI and the DOC rely on the Company's Initial Filing and Supplemental Direct filing, respectively, for the numbers they present.
[6] *See* Exhibit (Ex.) Xcel-16 at 3, 17-21 (Liberkowski Rebuttal); Ex. Xcel-19 at 4-29 (Halama Rebuttal); Xcel Energy Initial Brief at 11, Table 2 (errata).
[7] Xcel Energy Initial Brief at 12.
[8] *See, e.g.*, DOC Initial Brief at 1; OAG Initial Brief at 1; CUB Initial Brief at 12-13.
[9] *See, e.g.*, DOC Initial Brief at 14; OAG Initial Brief at 25; CUB Initial Brief at 11-12.

these parties argue that, to the extent that the ALJ and Commission determine that the Company's reasonable and necessary costs of providing service have increased, these reasonable and necessary increased costs can and should be ignored to some degree (perhaps entirely) so that customers simply do not have to pay them. As discussed in the following section of this Reply Brief, this approach is not consistent with Minnesota law. Nor is this approach consistent with sound public policy, as denying a utility recovery of its cost of service will ultimately result in higher costs for customers, service degradation, or both.[10]

The Company understands that rate increase requests are never welcomed and that such increases can disproportionately impact its most energy-burdened customers. That is why, throughout this case, the Company has acknowledged the importance of focusing on appropriate cost containment and maintaining the overall affordability of its service.[11] And while the Company recognizes the challenges faced by its most energy-burdened customers, the record reflects both the Company's overall success compared to its utility peers in maintaining *affordable overall bills*[12] and its extensive efforts to target relief to its

[10] *See* Elizabeth Warren, *Regulated Industries' Automatic Cost of Service Adjustment Clauses: Do They Increase or Decrease Cost to the Consumer*, 55 Notre Dame L. Rev. 333, 343-344 (1980) (noting that commissions who do not provide for recovery of the costs of the service, including a reasonable return, ultimately "save the consumer nothing").
[11] *See* Ex. Xcel-15 at 10, 18-20 (Liberkowski Direct); Ex. Xcel-16 at 2-15 (Liberkowski Rebuttal); Xcel Energy Initial Brief at 7-13.
[12] Ex. Xcel-15 at 15-17 (Liberkowski Direct); Ex. Xcel-16 at 13-15 (Liberkowski Rebuttal).

most energy-burdened customers[13] -- efforts discussed at length in the Company's Initial Brief but ignored or glossed over by Intervenors.[14] Instead, Intervenors narrowly focus on the Company's rates (rather than customers' overall bills), presenting a fundamentally incomplete picture of the actual costs the Company's customers pay for service.[15]

As the record shows, since 2014, electric utility customers nationally, in the upper Midwest and in Minnesota have seen greater increases in their monthly bill, compared to the Company's customers.[16] In fact, Xcel Energy's customers' bills have grown *substantially* slower than other Minnesota, regional or national utilities, across *every* rate class – residential, commercial, and industrial.

Table 1. Comparison Of Annual Changes In Average Bills[17]

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

[13] *See, e.g.,* Ex. Xcel-15 at 17 (Liberkowski Direct); Ex. Xcel-38 at 23-35 (Lindgren/Howard Direct) Ex. Xcel-81 at 2 (Howard Rebuttal); Ex. Xcel-70 at 10-12, 28-35 (Martin Direct).
[14] Xcel Energy Initial Brief at 7-13.
[15] *See, e.g.,* DOC Initial Brief at 5-7; OAG Initial Brief at 29-20.
[16] Ex. Xcel-16 at 14 (Liberkowski Rebuttal).
[17] Ex. Xcel-16 at 14 and Schedule 1E (Liberkowski Rebuttal).

Paralleling this slower growth in Xcel Energy customers' average bills, the record also demonstrates that Company has seen slower revenue growth than other state, regional and national utilities, again across customer classes.

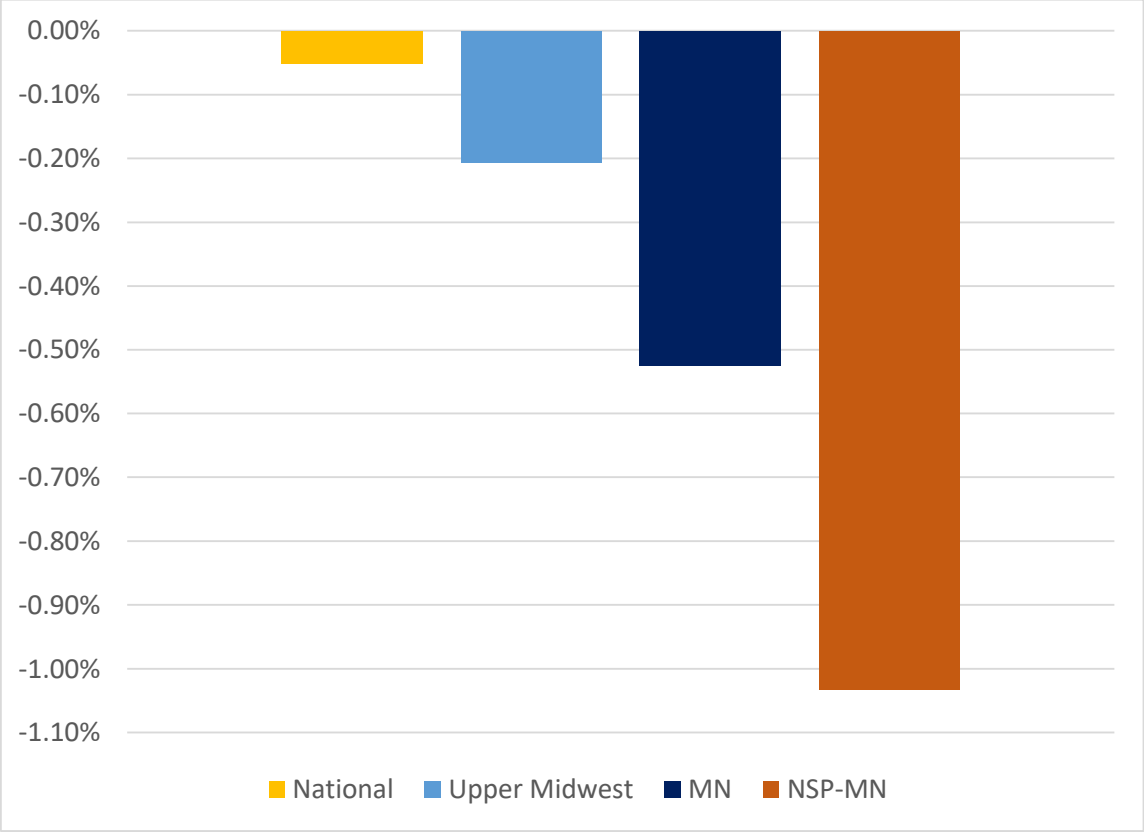
Table 2. Comparison Of Annual Change In Utility Revenue[18]

2014-2024 Compound Annual Growth Rate	NSP-MN	National	MN	Upper Midwest
Revenues				
Residential	2.78%	3.05%	3.02%	2.82%
Commercial	1.61%	1.58%	3.13%	2.18%
Industrial	0.67%	0.75%	4.17%	0.82%
Retail	1.87%	2.18%	3.68%	2.18%

Finally, both this slower average bill growth and slower revenue growth reflect the fact that the Company's sales have declined at an annual rate 20 times greater than the national utility average and five times greater than regional utilities, even as the Company has increased its customer count.[19]

[18] Ex, Xcel-16 at 13 and Schedule 1D (Liberkowski Rebuttal).
[19] Ex. Xcel-16 at 7-9 and Schedules 1A and 1B (Liberkowski Rebuttal).

Figure 1. Comparison Of Annual Change In Retail Sales 2014 - 2024[20]



To be clear, these decreases in sales for the Company are a positive story. They reflect concerted, successful efforts by the Company to achieve energy savings consistent with Minnesota law.[21] But they also come with a necessary output: These decreased sales have impacted the Company's need to request *rate* increases, particularly given its need to make the necessary investments to transform its generation fleet, modernization its distribution system and meet the overall increased cost of business.[22] However, while Intervenors have a singular and inappropriately narrow focus on rates, the record of this

[20] Ex. Xcel-16 at 7-8 and Schedule 1A (Liberkowski Rebuttal).
[21] *See, e.g.*, Minn. Stat. § 216C.05, subd. 2(1).
[22] *See*, Ex. Xcel-16 at 5-12 (Liberkowski Rebuttal).

proceeding demonstrates that the Company has outperformed its utility peers in limiting the impact on overall customer bills, and has seen slower revenue growth than its utility peers in the process. Given these facts, the record does not support Intervenors' claims of an over-arching "affordability crisis" related to the Company's service.[23]

Further, while affordability is one appropriate non-cost factor to consider when designing rates, the Commission must also consider a number of other such factors in a general rate case, including supporting environmentally sustainable, safe, reliable service that meets customer expectations (including those related to new and emerging technologies, clean energy, improved communications and increased ability for customers to control their energy use), and the financial health of the Company. This work requires the Company not just to maintain its critical core assets, but to continue transforming its fleet and enabling new technologies, all while navigating a constantly changing and dynamic energy marketplace.[24] At the end of the day, if Xcel Energy is to provide the level and quality of service that customers, the Commission and stakeholders expect, the Company *must* make the necessary investments and incur the necessary expenses to deliver that service and recover those reasonable and necessary costs. As Company witness Ms. Liberkowski testified:

> These efforts require resources, and the Company will be competing for the necessary capital with others inside and outside of Xcel Energy. To attract that capital, the sound financial footing provided by a reasonable return on equity and a regulatory construct that provides for recovery of [the

[23] *See, e.g.*, OAG Initial Brief at 3.
[24] *See* Ex. Xcel-15 at 6-15, 18-21 (Liberkowski Direct).

> Company's] prudent investments and reasonable and necessary costs is crucial.[25]

As discussed below, "a reasonable return on equity and a regulatory construct that provides for recovery of [the Company's] prudent investments and reasonable and necessary costs" is precisely what Minnesota law requires. By approving this MYRP request, the Commission can set the path for continued safe, reliable, sustainable, equitable *and* affordable electric service. The Company has met its burden of proof, and its rate increase request should be granted.

I. INTERVENORS ASK THE ALJ AND COMMISSION TO IGNORE OR OVERTURN DECADES OF ESTABLISHED CASE LAW IN SETTING THE COMPANY'S REVENUE REQUIREMENT

As the Company discussed in its Initial Brief, Minnesota Statutes and case law have long provided clear and consistent guidance as to how the ALJ and Commission should review and analyze Xcel Energy's MYRP request. Minnesota Statutes provide that the burden of proof to show that a rate change is just and reasonable shall be on the public utility seeking the change.[26] For a utility to meet this burden, the utility must demonstrate the facts at issue by a preponderance of the evidence.[27]

In setting overall just and reasonable rates, Minnesota Statutes direct that the Commission must consider (1) the public's need for "adequate, reasonable and efficient service"; and (2) the need of the utility "for revenue sufficient to enable it to meet the cost

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[25] Ex. Xcel- at 9 (Liberkowski Direct).
[26] Minn. Stat. § 216B.16, subd. 4.
[27] Minn. R. 1400.7300, subp. 5; *In the Matter of the Petition of Minnesota Power and Light Company, d/b/a Minnesota Power, for Authority to Change its Schedule of Rates in Minnesota*, 435 N.W.2d 550, 554 (Minn. Ct. App. 1989) (*review denied*).

of furnishing the service," including a fair and reasonable return on its property used in furnishing that service.[28] As set out in the Company's Initial Brief, within this broad guidance, Minnesota Courts and a long line of Commission decisions have recognized the different types of issues that must be resolved in a general rate case – establishment of a fair return, determination of the utility's reasonable revenues and expenses, and the allocation of revenue responsibility among and within the various customer classes – and the different legal standards that apply when examining those issues.[29] In their Initial Briefs, Intervenors often fail to apply or inappropriately mix those different standards and at times appear to encourage the Commission to abandon cost of service ratemaking entirely. Therefore, the Company again sets out the appropriate legal standards to be applied in this proceeding.

A. The Commission Acts In Its Quasi-Judicial Capacity When It Determines The Cost Of Capital

With respect to the cost of capital and the determination of a reasonable rate of return on equity (ROE), the Minnesota Supreme Court adopted the *Bluefield* and *Hope* requirements for determining a reasonable return in a 1980 case, and included *Bluefield's* observation that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[30]

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[28] Minn. Stat. § 216B.16, subd. 6.
[29] Xcel Energy Initial Brief at 14-19.
[30] *Hibbing Taconite Co. v. Minnesota Public Service Commission*, 302 N.W.2d 5, 10 (Minn. 1980) (citing *Bluefield*, 262 U.S. at 690, 43 S. Ct. at 678).

The *Hibbing* Court also clearly stated:

> The single term "ratemaking" has been used to describe what is really two separate functions (1) *the establishment of a rate of return, which is a quasi-judicial function,* and (2) the allocation of rates among various classes of utility customers, which is a legislative function. The court's failure to be more precise when discussing the two phases of ratemaking has led to the *inappropriate statement that "ratemaking is a legislative process."*[31]

In establishing a rate of return, the *Hibbing* court further explained the Commission "is bound to follow certain legal criteria" and acts as a fact-finder that weighs the evidence as would a judge in a court trial.[32] Specifically, the Commission's task is to review the evidence and:

> establish a fair rate of return which will provide earnings to investors comparable to those realized in other businesses which are attended by similar risk, will allow the company to attract new capital as required, and will maintain the company's financial integrity.[33]

These standards can be summarized as calling for the Commission to provide the Company an ROE that is:

- Adequate to allow the Company to attract the capital necessary to provide safe and reliable service (the capital attraction standard);
- Sufficient to ensure the Company's ability to maintain its financial integrity (the financial integrity standard); and
- At a level comparable to returns on investments of similar risk (the comparability standard).[34]

For decades, the Commission has applied these standards by engaging in its quasi-judicial capacity and analyzing expert testimony regarding both reasonable ROE ranges

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[31] *Hibbing,* 302 N.W.2d at 9 (emphasis added).
[32] *Hibbing,* 302 N.W.2d at 9-10.
[33] *Hibbing,* 302 N.W.2d at 10.
[34] Ex. Xcel-24 at 10 (Nowak Direct).

and specific ROEs within those ranges that meet these legal criteria. Further, the Commission has appropriately balanced the interests of customers and the utility as it considers this record evidence in determining the final allowed ROE. This process has been consistent, transparent, in line with the practices of other regulatory commissions and has resulted in just and reasonable rates.

To varying degrees, Intervenors urge jettisoning this long-standing law and process, and turning ROE determinations into pure policy decisions that are completely divorced from the established legal standards. Joint Intervenors, for example, do not even mention the *Hope*, *Bluefield* and *Hibbing* requirements. Instead, Joint Intervenors "recommend that the Commission give primacy to energy affordability as it determines a return on equity,"[35] without explaining how that can provide the Company a reasonable return consistent with Minnesota law. CUB, whose witness Dr. Kihm states that ROE determinations are "outside the realm of financial issues and in the public policy arena,"[36] similarly emphasizes affordability issues as central to determining the allowed ROE.[37] Finally, the Department also states that affordability "must be high on the list of pragmatic concerns" guiding the Commission's ROE determination.[38] Each of these recommendations, if followed, would turn the Commission away from factual analysis and the well-established legal requirements for determining an allowed ROE and introduce a level of subjectivity and

[35] JIN Initial Brief at 32.
[36] Ex. CUB-1 at 44 (Kihm Direct).
[37] *See* CUB Initial Brief at 24.
[38] DOC Initial Brief at 14.

potential arbitrariness incompatible with the Commission's exercise of its quasi-judicial powers.

B. Minnesota Law Provides For Recovery Of The Company's Cost Of Service, And The Commission Acts In Its Quasi-Judicial Capacity In Deciding These Issues

Regarding other "revenue requirements" issues such as the recovery of expenses, Minnesota courts have stated that, here too, the Commission acts in its quasi-judicial capacity.[39] To make its determination of these issues, the Commission reviews the utility's claimed expenses to determine whether they are reasonable and necessary for the provision of "adequate, efficient and reasonable service" to the public, such that recovery is appropriate.[40] Minnesota courts have explained that on such issues, "under normal ratemaking policy, *a utility is entitled to recover necessary, ongoing expenses incurred in the business of providing utility service.*"[41] The utility carries the burden to demonstrate that such expenses are, indeed, reasonable and necessary for the provision of service,[42] and Xcel Energy has provided substantial and detailed evidence supporting each of the investments and expenses for which it seeks recovery. The task for the ALJ and Commission, therefore, is to review that evidence to determine if the Company has carried its burden.

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[39] *See, e.g., St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 251 N.W.2d 350, 358 (Minn. 1977).
[40] *See* Minn. Stat. § 216B.16, subd. 6.
[41] *In the Matter of a Request of Interstate Power Company For Authority To Change Its Rates For Gas Service In Minnesota*, 559 N.W.2d 130, 134 (Minn. App. 1997), *affirmed* 574 N.W.2d 408 (Minn. 1998) (emphasis added).
[42] Minn. Stat. § 216B.16, subd. 4.

The Department argues that such a detailed review of financial issues, or even separate review of the various financial, revenue apportionment and rate design issues in a rate case is not required, inexplicably calling such consideration "a matter of convenience, not legal necessity."[43] According to the Department "the Commission's sole obligation is to set a rate with a non-confiscatory net effect," citing *Federal Power Commission v. Natural Gas Pipeline Co. of America*, 315 U.S. 575, 585 (1942) (*Federal Power Comm'n*), a 1942 U.S. Supreme Court case that involved Federal Power Commission (FPC) regulation of natural gas utilities.[44] The Department's argument is contrary to Minnesota law as well as practice throughout the Commission's history and must be rejected.

As recently as last year, the Court of Appeals considered, and rejected, the Department's argument that "the Commission's sole obligation is to set a rate with a non-confiscatory net effect," when it considered the appeal of the Company's last rate case. When discussing the standard of review, the court stated:

> As a preliminary matter, we reject the Department's argument that, before Xcel can obtain review of the three decisions it challenges, Xcel must successfully argue that the rates approved in the final rate order are "confiscatory." The department contends that, because Xcel did not argue that the rates are confiscatory, the argument is forfeited and we should affirm the final rate order without addressing Xcel's challenges. We disagree. . . .
>
> Xcel does not argue that the Commission's final rate order is unconstitutional. Instead, Xcel seeks relief under MAPA and MPUA, both Minnesota statutes. And, in other utility-rate cases in which a utility sought relief under MAPA, we have not required the utility to establish that the total effect of the commission's order is confiscatory in order to receive relief on appeal. *See, e.g.*, *Minn. Power* 2024, 12 N.W.3d at 488, 494 (determining

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

> that record did not demonstrate confiscatory rates but reversing part of commission's decision because it was unsupported by substantial evidence and arbitrary and capricious).[45]

The Department's reliance on *Federal Power Comm'n* is also misplaced. That case concerned the FPC's first time application of the Natural Gas Act of 1938[46] to the subject companies.[47] The NGA provided for federal regulation of natural gas providers and specifically provided that the FPC "may order a [rate] decrease where existing rates are unjust . . . unlawful, or are not the lowest reasonable rates."[48] While the *Federal Power Comm'n* Court noted that the "lowest reasonable rate," as used in the NGA, is a rate "which is not confiscatory in the constitutional sense," this simply recognizes the basic constitutional prohibition against takings. *Federal Power Comm'n* provides no guidance as to the proper analysis under Minnesota States Chapter 216B. Moreover, after observing this constitutional minimum, the *Federal Power Comm'n* Court proceeded to examine the record evidence supporting each of the FPC's discrete financial findings challenged by the utilities to determine whether they were supported by substantial evidence.[49] Consistent with a long line of Minnesota case law and every rate case the Commission has ever considered, the Commission must similarly examine the various issues in this case under the appropriate legal standard, as set forth above. If the claimed investment or expense is

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[45] *In re Application by N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn. (NSP),* No. A23-1672, 2025 WL 249995 at *10, fn. 3 (Minn. Ct. App. Jan. 21, 2025)
[46] Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. § 717, *et seq*. (NGA).
[47] *Federal Power Comm'n v. Nat. Gas Pipeline Co. of Am.,* 120 F.2d 625 (7th Cir. 1941).
[48] NGA at § 5(a); *Federal Power Comm'n,* 315 U.S. at 585.
[49] *See Federal Power Comm'n v. Nat. Gas Pipeline Co. of Am.*, 315 U.S. at 586-599.

reasonable and necessary in the provision of adequate, efficient and reasonable service to customers, the Company must be allowed recovery.

CUB similarly strays from the requirements of Chapter 216B and Commission precedent in arguing that cost and non-cost factors must be considered *throughout* the rate setting process, regardless of the specific issue involved.[50] However, the *Permian Basin* case relied on by CUB for this proposition concerned a different scenario entirely than the test year, cost-of-service regulation established by Minnesota law. Specifically, *Permian Basin* related to the FPC's attempts to regulate natural gas producers following a court ruling that such producers were subject to regulation under the NGA. The Court noted the difficulty in attempting to apply the NGA, "an ill-suited statute," to the producers, given the sheer number of these producers, the fact that they "cannot usefully be classified as public utilities," that they are "intensely competitive" with one another, and that "their unit costs may rise or decline with the vagaries of fortune."[51] These factors made individual company cost of service regulation of natural gas producers untenable, causing the FPC to instead open proceedings to set maximum producers' rates for each of the major natural gas producing areas.[52] After producers challenged these actions, the Court found the FPC to have both the constitutional and statutory authority under the NGA to adopt a system of "area regulation," as opposed to examining each producer's cost of service.[53] Notably, not

[50] CUB Initial Brief at 7-8, citing *In re Permian Basin Area Rates*, 390 U.S. 747 (1968) (*Permian Basin*).
[51] *Permian Basin*, 390 U.S. at 757-758.
[52] *Permian Basin*, 390 U.S. at 758.
[53] *Permian Basin*, 390 U.S. at 768-790.

only did the *Permian Basin* Court state that the businesses challenging the FPC's actions "cannot usefully be classified as public utilities," nowhere did either the challengers or the Court point to language in the NGA such as that in Minnesota Statutes Chapter 216B, which provides that "a utility is entitled to recover necessary, ongoing expenses incurred in the business of providing utility service,"[54] as the NGA contains no such directive.[55] Thus, the *Permian Basin* case concerned a scenario both factually and legally distinct from the cost of service ratemaking required by Minnesota Statutes Chapter 216B and practiced for decades by the Commission.

CUB also implies that Minnesota Courts have adopted the reasoning of *Permian Basin*, citing *St. Paul Chamber*, again implying that cost and non-cost factors must be considered throughout the rate setting process, including in the determination of the Company's revenue requirement.[56] However, the *St. Paul Chamber* Court stated that it adopted the Permian Basin reasoning only "as the standard in Minnesota *when courts are called upon to review the allocation of rate increases among consumer classes*." The Court then noted the difference between revenue allocation issues and other issues in rate cases, stating:

> Combining this rule with that adopted above for *factual* determinations, we may summarize as follows:
>
> (a) When the Public Service Commission acts in a judicial capacity as a factfinder, receives evidence in order to make factual conclusions, and

[54] Minn. Stat. § 216B.16, subd. 6.
[55] *See* 15 U.S. § 717, *et. seq.*
[56] CUB Initial Brief at 8.

> weighs that evidence as would a judge in a court trial, it will be held on review to the substantial-evidence standard.
>
> (b) When the Public Service Commission acts in a legislative capacity as in *rate increase allocations, balancing both cost and non-cost factors and making choices among public policy alternatives,* its decisions will be upheld unless shown to be in excess of statutory authority or resulting in unjust, unreasonable, or discriminatory rates by clear and convincing evidence.[57]

Any suggestion by Intervenors that the Commission stray from cost of service regulation to determine the Company's revenue requirements to address affordability concerns directly contradicts established Minnesota law. As the Minnesota Supreme Court has stated:

> In order to establish "just and reasonable retail rates," the [Commission] must consider the right of the utility and its investors to a reasonable return, while at the same time establishing a rate for consumers *which reflects the cost of service rendered* plus a reasonable profit for the utility. To accomplish this purpose, the [Commission] must ascertain the operating expenses, or cost of service, of the utility.[58]

The Court has also stated that this cost of service typically includes items such as labor, materials and supplies, taxes, insurance, and depreciation.[59] Notably, the Court has rejected the notion that the Commission's determination of revenues and expenses in a rate case presents a question of "fairness." Rather, the Supreme Court in *Minnegasco* stated that such determinations are issues of statutory construction.[60]

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[57] *St. Paul Chamber,* 251 N.W.2d at 358.
[58] *Northern States Power Company v. Minnesota Public Utilities Commission,* 344 N.W.2d 374, 378 (Minn. 1996); *see also Minnegasco v. Minnesota Public Utilities Commission,* 549 N.W.2d 904, 908 (Minn. 1996).
[59] *Minnegasco,* 549 N.W.2d at 908.
[60] *Minnegasco,* 549 N.W.2d at 909.

In addition to rejecting the Department's "confiscation" argument, on appeal of the Company's last rate case the Court of Appeals addressed and rejected the argument that the Commission can consider non-cost factors or acts in its quasi-legislative capacity when determining the Company's revenue requirements. The court stated:

> The Department, [OAG], and XLI argue that the Commission acted in a quasi-judicial capacity when it determined whether Xcel introduced sufficient evidence to establish a given cost as a judicial fact but acted in a legislative capacity when balancing the needs of the utility and the interests of ratepayers and, therefore, both standards apply, depending on the decision. Xcel argues that the issues on appeal are quasi-judicial decisions governed by the substantial-evidence standard, and the commission also applies the standard for quasi-judicial decisions in its briefing.
>
> We disagree that the standard of review for quasi-legislative decisions applies to any of the challenged actions here. In *Northern States Power*, the Minnesota Supreme Court recognized that the Commission may act in both a quasi-judicial and a legislative capacity in a rate case, ***but it applied the quasi-judicial substantial-evidence standard to the Commission's disputed revenue-requirement determinations***.[61]

The Commission's determination of the cost of service thus focuses on whether the Company has demonstrated first that it will incur the cost and second that the cost is reasonable and necessary to the provision of safe and reliable service, such that it should be included in rates. While costs found to be imprudent or unnecessary under this analysis may be denied, utilities cannot be denied their prudent and necessary costs simply because doing so would result in lower rates.

[61] *NSP*, 2025 WL 249995 at *9, fn. 2 (citing *Northern States Power*, 416 N.W.2d at 722-724).

C. Revenue Allocation And Rate Design

In contrast to the legal requirements for determining a fair return or the cost of service, the Commission and courts have long recognized the appropriateness of considering ability to pay, among other non-cost factors, in revenue allocation and rate design determinations.[62] Indeed, all parties agree that in allocating revenue responsibility among the rate classes and in designing rates within those classes, the Commission considers both cost and non-cost factors and acts in its "quasi-legislative" capacity, rather than in a "quasi-judicial" capacity, reflecting the policy nature of rate design determinations. As the *St. Paul Chamber* Court noted, on these issues the Commission's "careful balancing of public policies and private needs is not a matter for the courts, unless statutory authority has been exceeded or discretion abused."[63] Moreover, the legislature has provided for specifically-targeted rate design to address affordability concerns of energy burdened customers, both in establishing a low-income electric rate discount[64] and in providing for other affordability programs that meet specified criteria.[65] These are the appropriate channels to address affordability issues, as opposed to denying recovery of reasonable and necessary expenses or failing to provide a reasonable return on investment.

II. RETURN ON EQUITY

As discussed in the Company's Initial Brief, the record demonstrates that the Company's recommended 10.30 percent return on common equity is well-grounded in

[62] S*t. Paul Chamber*, 251 N.W.2d at 357.
[63] S*t. Paul Chamber*, 251 N.W.2d at 357.
[64] Minn. Stat. § 216B.16, subd. 14.
[65] Minn. Stat. § 216B.16, subd. 15.

multiple cost of equity analytical models, is consistent with results of the Commission's preferred Two-Growth Discounted Cash Flow (DCF) model, best meets the requirements of Minnesota law and best reflects the current market when compared to Intervenor ROE recommendations.[66] In contrast, and as discussed further below, the Department and CUB ROE recommendations abandon regulatory precedent and assume a disconnect between the regulatory process of setting an authorized return on equity and the results of cost of equity models. Moreover, the Department's recommendation ignored key pieces of its own cost of equity analysis and instead looked to "Multi-Stage" DCF models never before relied on by the Commission. And XLI, while presenting a recommendation somewhat more grounded in its analytical results, failed to update those results with more current information and failed to apply the Commission's preferred Two-Growth DCF analysis, leading it to understate the Company's ROE. Finally, the record does not support XLI's recommendation to lower the Company's otherwise appropriate ROE on the basis of alleged "risk reduction mechanisms." For all of these reasons, and as discussed below and in its Initial Brief, the Company continues to recommend use of an allowed ROE of 10.30 percent for setting rates in this proceeding.

A. Intervenor ROE Recommendations Fail To Provide The Company A Return That Is Consistent With Court And Commission Precedent

Intervenors objected to the Company's recommendation and, collectively, argue for an ROE of no greater than the 9.25 percent approved by the Commission in the Company's last rate case, with CUB claiming the "zone of reasonableness" for the Company's ROE

[66] Xcel Energy Initial Brief at 19-31.

starts at just 7.7 percent.[67] These recommendations fail for multiple reasons, including: (1) their reliance on a methodology consistently rejected by the Commission; (2) their failure to incorporate the results of multiple sound financial analyses historically relied on by the Commission; (3) their failure to recognize multiple easily observable data points indicating the appropriateness of an increase in the Company's ROE and; (4) if adopted, these recommendations would upend decades of Commission and court precedent, making Minnesota an outlier on ROE determinations.

1. The Commission Should Once Again Reject Methodologies Incorporating Long-Term, Economy-Wide Growth Rates In Their Analyses

In order to claim analytical support of their ROE recommendations, the Department, CUB and XLI recommendations all rely on methodologies that reject the use of industry-specific growth rates in their analyses on the basis of witness claims that such analyst growth rates are biased.[68] Instead, each of these Intervenors relies on models incorporating estimates of long-term overall U.S. Gross Domestic Product (GDP) growth.[69] Yet, as Department witness Mr. Addonizio acknowledged, the Commission has never relied on such an analysis.[70] In fact, the Commission has explicitly rejected both the Intervenors' analyses and their underlying rationale. For example, in its 2023 Order for Minnesota Power, the Commission stated:

> The Department's recommended cost of equity of 9.30% is informed by an underlying assumption that the cost of equity and the return on equity are

[67] *See* CUB Initial Brief at 22-24.
[68] *See, e.g.*, Ex. DOC-12 at 48-49 (Addonizio Direct); Ex. CUB-1 at 33 (Kihm Direct).
[69] *See, e.g.*, DOC Initial Brief at 18; Ex. CUB-1 at 31 (Kihm Direct).
[70] Transcript (Tr.) Volume (Vol.) 2 (Dec. 18, 2025) at 464 (Addonizio).

> distinct concepts in the sense that utility earnings exceed the cost of equity over time. This understanding, according to the Department, undermines the reliability of earnings' estimates in predicting long-term growth and instead justifies the use of a multi-stage DCF analysis that uses GDP to forecast the long-term cost of equity.
>
> The Commission does not share this concern. While general statements about GDP and earnings estimates may offer broad perspectives on their overall usefulness, the parties' positions reflect philosophical and methodological differences that are qualitative in nature. But the Department has not demonstrated inaccuracies in Minnesota Power's earnings estimates in this case to justify dismissing them from consideration. *The investment community relies heavily on earnings estimates, which are rigorously audited to ensure compliance with accounting principles. And in the case of utilities, earnings estimates reflect industry-specific considerations, include assumptions based on quantitative market data, and have not been shown to produce unreasonable returns.*[71]

In addition to their unfounded claims of analyst bias, Intervenors argue that GDP growth is more reasonable than industry-specific growth rates because no company can grow faster than the GDP in perpetuity or it would eventually become larger than the economy as a whole.[72] Again, while perhaps superficially appealing, this argument has been offered and rejected in the past. And the record of this case includes compelling evidence that utility growth should not be arbitrarily limited by estimates of long-term U.S. GDP growth when determining the Company's ROE in this proceeding. From 2010 through the end of July 2025, the S&P 500 Utilities Index had a compound annual growth rate ("CAGR") of 6.71 percent, when looking at price-only growth – a growth rate in line

[71] *In the Matter of the Application of Minnesota Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota (Minnesota Power)*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS AND ORDER (Feb. 28, 2023) at 44-45

[72] *See, e.g.*, Ex. DOC-12 at 42 (Addonizio Direct); DOC Initial Brief at 20.

with the analyst growth rates used in a traditional Two-Growth DCF analysis (over 6 percent).[73] In contrast, the Department uses a terminal growth rate of 3.87 percent in its Multi-Stage analysis.[74] Moreover, from 1947 through 2024, the utility sector as a component of GDP has grown at a faster compound average annual rate than the overall GDP growth rate, and other sectors of the economy have grown both significantly faster (for example, educational services, health care and social assistance) and significantly slower (for example agriculture, forestry, fishing and hunting) than the overall U.S. GDP growth rate.[75] This is not surprising, since the U.S. long-term average GDP growth rate estimates are just that – estimates that average both over-performing and under-performing industries.

Finally, while recommending the Commission ignore its precedent and chart an entirely new course to determine ROE, Intervenors ignore the impact of such a fundamental shift in regulation in Minnesota. As Company witness Mr. Wehner testified, credit rating agencies place significant emphasis on the regulatory environment in which a utility operates, including focusing on: (1) the legal foundation for utility regulation, (2) the ratemaking policies and procedures that determine how well the utility is afforded the opportunity to earn a reasonable return with reasonable cash flow, and (3) the history of regulatory behavior by regulators applying those laws, policies and procedures.[76] These agencies also place high value on transparency, predictability, and consistency in

[73] Ex. Xcel-25 at 25 (Nowak Rebuttal).
[74] *See* Ex. Xcel-25 at 25, 27 (Nowak Rebuttal).
[75] Ex. Xcel-25 at 25-26 (Nowak Rebuttal).
[76] Ex. Xcel-20 at 19-20 (Wehner Direct).

regulatory outcomes.[77] Regulatory frameworks and practices that are viewed as constructive, transparent, consistent, and predictable allow rating agencies to more accurately project future cash flows and debt leverage and will result in a better business risk profile, lowering the borrowing costs to the benefit of customers.[78] Abandoning long-standing precedent as urged by Intervenors, runs directly counter to such sound practices.

For all of these reasons, and as further discussed in the Company's Initial Brief,[79] the Commission should once again reject the Multi-Stage DCF and other analyses relying on economy-wide growth rate estimates.

2. All Analyses In The Record That Comport With Commission Precedent Support A Higher ROE Than Intervenors Recommend

The record contains multiple Constant Growth and Two-Growth DCF analyses, conducted in line with past Commission practice. Those analyses yielded overall results ranging from 9.36 percent to 11.84 percent and averaging over 10.50 percent. When focused just on the Two-Growth DCF and applying the Two-Growth methodology specifically relied on by the Commission over the past many years, the results ranged from 10.22 to 11.03 percent.[80] Going even deeper into the analyses in the record, not one of the proxy group companies in either the Department's or the Company's updated Two-Growth DCF analyses had an indicated ROE below 9.50 perfect, once flotation costs are

[77] Ex. Xcel-20 at 20 (Wehner Direct).
[78] Ex. Xcel-20 at 20 (Wehner Direct)
[79] Xcel Energy Initial Brief at 39-42.
[80] Xcel Energy Initial Brief at 52 (not considering XLI's 9.58 percent Two-Growth DCF result, given its inconsistency with the Commission's methodology).

considered.[81] The Intervenor ROE recommendations, stretching over 100 basis points lower than the average results, and well below the lowest single point observation, bear no resemblance to these analytical results, demonstrating their departure from Commission precedent.

While neither the Department nor CUB Initial Briefs acknowledge this departure from precedent, their ROE witnesses did. Department witness Addonizio stated that his recommendation was "anchored" in his Multi-Stage DCF analysis, while acknowledging the Commission has never relied on such an analysis.[82] According to both Mr. Addonizio and CUB witness Dr. Kihm, regulators, including the Commission, have inappropriately been setting ROEs above utilities' cost of equity for many years.[83] They seek to change that alleged deficiency, first by employing different models than have been used by the Commission and then, given their unreasonably low model results, setting those results aside and recommending an ROE well above those results. However, as the Company explained, had the Department and CUB used the reasonable, market-based models looked to by the Commission for decades, their criticism of past decisions would vanish and their subjective, post hoc adjustments to the ROE would be unnecessary.[84]

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[81] Department witness Mr. Addonizio's and Company witness Mr. Nowak's updated Two-Growth analyses each show individual company results ranging from approximately 9.55 percent, once flotation costs are considered, to above 12.0 percent. *See* Ex. DOC-13 at Schedule 9 (Addonizio Surrebuttal); Ex. Xcel-25 at Schedule 1 (Nowak Rebuttal).
[82] Tr. Vol. 2 (Dec. 18, 2025) at 464 (Addonizio).
[83] *See, e.g.*, Ex. DOC-12 at 70-71, 75, 78 (Addonizio Direct); Ex. CUB-1 at 12, 38 (Kihm Direct).
[84] Ex. Xcel-25 at 3 (Nowak Rebuttal).

3. The Record Demonstrates The Company's Higher Cost Of Equity Today, Compared To Its Most Recent Approved ROE

Multiple uncontestable data points indicate the appropriateness of an increase in the Company's ROE from that established in its last rate case. For example, in that case the Commission reiterated its reliance on the Two-Growth DCF model and based its 9.25 percent determination on the average of the Company's Two-Growth analyses[85] -- analyses that now result in an ROE of over 10.0 percent. Additionally, the record demonstrates that average authorized ROEs for vertically integrated utilities have increased since the Company's last rate case along with rising capital costs. At the time of the Company's last rate case filing in October 2021, the 18-month trailing average authorized ROE for vertically integrated electric utility was 9.52 percent. By the time of the Initial Filing in the current case, the average authorized ROEs increased by approximately 30 basis points to 9.83 percent and average returns have remained at that level through 2025.[86]

Along with increasing authorized ROEs, the average yield on the 30-year Treasury has increased, from 2.06 percent to 4.54 percent at the time on the Company's Initial Filing in this case and continued to increase to 4.88 percent by August 2025, with the increases in Treasury yield and increases in authorized ROEs closely tracking one another.[87] Finally, in both the prior case and this case, the Department provided Two-Growth DCF analyses consistent with the Commission's preferred ROE analytical approach. The mean result

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[85] *In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 91 (July 17, 2023).
[86] Ex. Xcel-25 at 3 (Nowak Rebuttal).
[87] Ex. Xcel-25 at 4, 10 (Nowak Rebuttal).

from the Department's Surrebuttal Two-Growth DCF analysis in this case is 10.57 percent,[88] nearly a 70 basis point increase relative the Department's Surrebuttal Two-Growth DCF analysis in the Company's last case.[89] Intervenors do not address these objective measures, every one of which demonstrates the appropriateness of, and need for, an ROE that is materially higher than that authorized in the Company's last rate case. Thus, while CUB may argue, contrary to readily observable data, that the Company's ROE recommendation "defies common sense,"[90] it is the Intervenor recommendations that fail their recommended eyeball test.

4. Intervenor Recommendations Would Make Minnesota An Outlier On ROE, Negatively Impacting Minnesota Utilities And Customers

Finally, the Intervenor recommendations, if followed, would establish Minnesota as an outlier with respect to ROE determinations for its utilities. The Commission has recognized that ROE decisions from other jurisdictions can provide useful data, stating in a 2023 Order:

> The Commission also notes that the national average return of vertically integrated utilities since 2018 is 9.66%. And, while the decisions of other jurisdictions are not binding and have limited persuasive value because of the fact-intensive nature of cost-of-equity decision-making, they do provide a check, of sorts, on reasonableness.[91]

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[88] Ex. DOC-13 at 5 (Addonizio Surrebuttal).
[89] *See* Ex. Xcel-25 at 23 (Nowak Rebuttal) (filed prior to the Department filing its Surrebuttal Testimony in this case).
[90] CUB Initial Brief at 18.
[91] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSION, AND ORDER at 45 (Feb. 28, 2023)

Intervenors also acknowledge that it is appropriate to consider other authorized ROEs for utilities in determining the appropriate ROE for the Company.[92] As the record demonstrates, since the Company's last rate case was filed, *every subsequent authorized ROE for a vertically integrated electric utility has been higher than the Company's currently authorized ROE of 9.25 percent*.[93] The record further establishes that over the 18 months ending August 2025 the national average authorized ROE for vertically integrated electric utilities was 9.83 percent,[94] after being 9.80 percent in 2023 and 9.84 percent in 2024.[95] Despite this and the objective indicators of a higher ROE noted above, no Intervenor recommends any change from the Company's 2021 rate case ROE, with CUB arguing that "the zone of reasonableness" for the Company's ROE starts at 7.70 percent – over 150 basis points below any authorized ROE in the past several years and over 200 basis points below these national averages.[96]

Despite the fact that it is the Intervenor recommendations that fall outside the range of ROEs allowed since the Company's 2021 rate case decision, CUB attempts to characterize the Company's ROE recommendation as the "outlier."[97] It is not. Not only is the Company recommendation more in line with national averages than the Intervenor recommendations, regulatory commissions elsewhere have approved both settled and

[92] *See, e.g.*, Tr. Vol. 2 (Dec. 18, 2025) at 461-462 (Addonizio) (agreeing that he considered other authorized ROEs in developing his own recommendation).
[93] Ex. Xcel-25 at 3-4 (Nowak Rebuttal).
[94] Ex. Xcel-25 at 83 (Nowak Rebuttal).
[95] Ex. XLI-1 at 15 (LaConte Direct).
[96] Ex. Xcel-25 at 51 (Nowak Rebuttal).
[97] CUB Initial Brief at 20-23.

litigated ROEs for vertically integrated electric utilities at or above the level recommended by the Company.[98] Intervenors' recommendations simply are not consistent with Commission precedent, sound financial analysis, observable market data trends, or the decisions of other jurisdictions. As such, they fail to provide investors in Xcel Energy a return comparable to returns on investments in other enterprises having similar risk, violating long-established law.

B. Xcel Energy's Recommended ROE Complies With Commission And Court Precedent And Fairly Balances The Interests Of The Company And Its Customers

As the Company has discussed, its ROE recommendation applies the *Hope*, *Bluefield* and *Hibbing* standards, is consistent with Commission precedent, and represents a conservative estimate of the Company's cost of equity by falling at the low end of a reasonable range and below the ROE suggested by the Commission's preferred Two-Growth DCF analysis.[99] Intervenors criticize the Company's recommendation on various grounds, none of which finds support in the record or the law.

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[98] *See, e.g., In Re Petition For Rate Increase By Tampa Electric Company*, Florida Public Service Commission (FPSC) Docket No. 20240026-EI, FINAL ORDER GRANTING IN PART AND DENYING IN PART TAMPA ELECTRIC COMPANY'S PETITION FOR RATE INCREASE (Feb. 3, 2025) at 73 (setting the approved ROE at 10.50 percent); *In Re Petition For Rate Increase By Florida Power & Light Company*, FPSC Docket No. 20250011-EI, FINAL ORDER APPROVING 2025 STIPULATION AND SETTLEMENT AGREEMENT (Jan. 22, 2026) at 27-30 (approving a Stipulation and Settlement between certain parties that provided for a 10.95 percent ROE); *Application of Pacific Gas and Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 and to Reset the Cost of Capital Adjustment Mechanism and Related Matters*, Public Utilities Commission of California Docket Nos. 22-04-009 et al, Phase 2 Decision at 36 (Oct. 22, 2024) (setting the approved ROE for Southern California Edison Company at 10.33 percent).

[99] *See* Xcel Energy Initial Brief at 19-31.

Intervenors criticize the Company for allegedly not balancing the interests of the utility and customers in recommending a 10.30 percent ROE.[100] In doing so, Intervenors ignore not only the law, as discussed above, but also a number of facts, including that this recommendation: (1) is below the midpoint of Company witness Mr. Nowak's recommended range of 10.0 to 11.0 percent;[101] (2) is below both the average and the mean ROE indicated by Mr. Nowak's updated primary analyses (10.79 and 10.72 percent, respectively);[102] (3) is below both the average and the median of Mr. Nowak's Two-Growth DCF analysis, traditionally relied on by the Commission (10.38 and 10.52 percent, respectively);[103] (4) is below the average of Department witness Addonizio's updated Two-Growth DCF analysis (10.57 percent);[104] (5) is below XLI witness LaConte's Two-Growth DCF analysis, when conformed to the Commission's methodology (10.36 percent);[105] and, as presented in the Company's Initial Brief, is below the average of the 25 different analytical results in this record that used either the Constant Growth or Two-Growth DCF models relied on by the Commission for decades (over 10.50 percent).[106] Each of these data points demonstrates the conservative nature of the Company's ROE recommendation, in favor of customers' interests.

[100] *See, e.g.*, DOC Initial Brief at 29; CUB Initial Brief at 17.
[101] Ex. Xcel-24 at 4-5 (Nowak Direct).
[102] Ex. Xcel-25 at 13 (Nowak Rebuttal).
[103] Ex. Xcel-25 at 13 (Nowak Rebuttal).
[104] Ex. DOC-13 at 5 (Addonizio Surrebuttal).
[105] Ex. Xcel-25 at 72 (Nowak Rebuttal).
[106] *See* Xcel Energy Initial Brief at 52, Table 7.

Customer interests, particularly their long-term interests, are also recognized and served by meeting the capital attraction, financial integrity and comparability standards of *Hope*, *Bluefield* and *Hibbing*. A fair and reasonable return that meets these standards contributes to the Company's overall financial integrity and enables it to maintain access to capital markets at reasonable terms.[107] This ensures that the Company is able to incur lower borrowing costs for the investments necessary to provide safe and reliable service while also meeting customers' evolving needs.[108]

The Department also critiques the Company's ROE recommendation based on Mr. Nowak's selection of models to inform this recommendation. The Department faults the inclusion of models such as the Bond Yield Plus Risk Premium and Expected Earnings analysis and suggests Mr. Nowak should have performed a Multi-Stage DCF analysis for this proceeding, noting that he has previously presented such models.[109] Regarding the use of the Bond Yield Plus Risk Premium and Expected Earnings analyses, Mr. Nowak explained the value in looking to multiple models, consistent with common practice, to provide a full picture of a company's ROE.[110] In fact, the Commission has used the same models used by Mr. Nowak as a check on the reasonableness of its ROE determinations. In Otter Tail Power Company's most recent case, the Commission relied on the Two-Growth DCF, and noted that this modeling:

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[107] Ex. Xcel-24 at 10-11 (Nowak Direct).
[108] Ex. Xcel-24 at 10-12, 53-54 (Nowak Direct); Ex. Xcel-20 at 11-13; 25-26 (Wehner Direct).
[109] DOC Initial Brief at 19, 29-30.
[110] Ex. Xcel-24 at 34-35 (Nowak Direct).

> continues to offer analytically rigorous, substantial evidence to support a determination of the Company's cost of equity, with the reasonableness of the *results checked by CAPM and Risk Premium analyses, and in this case, by the additional Expected Earnings methodology* Otter Tail also used.[111]

Moreover, while Mr. Nowak's consideration of additional models confirmed the reasonableness of his recommendation, they did not change the overall conservative nature of his recommendation when compared to Two-Growth DCF results, as demonstrated above.

With respect to the Multi-Stage DCF, the Company has already discussed the Commission's consistent and well-reasoned refusal to rely on such an analysis, which supported Mr. Nowak's decision not to present a Multi-Stage DCF analysis here.[112] And while the Department notes that Mr. Nowak has presented such analyses in a few cases in the past, the Department fails to note that Mr. Nowak explained:

> There have been instances where I've included [Multi-Stage DCF analyses] in other cases, *where it's been necessary due to precedent.* But in my view, it's largely unnecessary because I believe from a mature company's – mature stage companies, like utility companies, there's no reason to use a generic indicator for long-term growth.[113]

If precedent is similarly followed in this case, the Company's 10.30 percent ROE should be approved as a conservative estimate of the Company's cost of equity.

Finally, the Department faults the Company's recommendation for being above cost of equity estimates from other sources, such as equity research firm or investment banks,

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[111] *In re Application of Otter Tail Power Co. for Auth. to Increase Rates for Elec. Serv. In Minn.*, Docket No. E-017/GR-20-719, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 34 (Feb. 1, 2022).
[112] Xcel Energy Initial Brief at 39-42.
[113] Tr. Vol. 1 (Dec. 17, 2025) at 91 (Nowak) (emphasis added).

suggesting this proves the unreasonableness of the Company's recommendation.[114] As Mr. Nowak explained, though, the types of estimates pointed to by the Department, including broad surveys, raise a number of concerns.[115]

> Specifically, with regard to surveys, it is not clear how the survey respondents derived their inputs, such as the [market risk premium] and risk-free rate, as well as estimates for the market return. Further, it is not apparent for what purpose the respondents developed their responses (e.g., as individual investors or with return requirements used in their specific line of business). In short, we cannot easily verify the inputs and assumptions that the survey respondents relied upon to derive their cost of equity estimates in a regulatory setting.[116]

These other cost of equity estimates, not sponsored by any witness in this proceeding which would have allowed testing of the underlying inputs and assumptions, do nothing to undermine the substantial evidence provided by the Company in support of its ROE recommendation. This recommendation, based on the use of multiple models, provides the Company a return commensurate with those being earned by companies of comparable risk, balances the interests of customers and shareholders, conservatively reflects current market conditions and will maintain the financial integrity of the Company while allowing it to access capital at reasonable rates, providing long-term benefits to its customers.

[114] DOC Initial Brief at 23-24.
[115] Ex. Xcel-25 at 37 (Nowak Rebuttal).
[116] Ex. Xcel-25 at 37-38 (Nowak Rebuttal).

III. REVENUE REQUIREMENT ISSUES

To set just and reasonable rates, the Commission must determine both the utility's revenue requirement and its rate design.[117] The utility's revenue requirement "is the amount of revenue that the utility needs to meet the cost of providing service" and "includes 'the utility's costs and a rate of return on [the utility's] rate base."[118] This revenue requirement determination, therefore requires consideration of the utility's projected revenues under current rates, as well as consideration of the value of its investments (rate base) and its costs. In this Reply Brief the Company responds to Intervenor arguments on disputed revenue issues first, followed by response to the disputed rate base and expense issues.

A. Revenues

1. Late Payment Fees

The Citizens Utility Board argues that the Commission should eliminate late payment fees for the Company's residential customers.[119] This argument fails for three reasons. First, CUB has not demonstrated that the Company's *existing* Commission-approved rates are not just and reasonable. Second, CUB ignores record evidence that demonstrates the effectiveness of late payment fees. Finally, CUB relies on conclusions of a study conducted for a different utility in a different jurisdiction that had results counter to the Company's experience in Minnesota. CUB's recommendation must be rejected.

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[117] *NSP*, 2025 WL 249995 at *7 (citing *In re Application by Minnesota Power for Authority to Increase Rates for Electric Service*, 12 N.W.3d 477, 486 (Minn. App. 2024).
[118] *Id*. at 7-8.
[119] CUB Initial Brief at 28; Ex. CUB-4 at 20 (Levenson-Falk Direct); Ex. CUB-8 at 18 (Levenson-Falk Surrebuttal).

The Company has not requested a change to its existing Commission-approved late payment fees. Despite the fact that the Company has not requested a change to these fees, CUB argues that the Company failed to prove its late payment fees are just and reasonable because Xcel Energy has not provided "substantiating documents and exhibits" supporting those fees.[120] This misrepresents the Company's burden of proof and must be rejected. As the Minnesota Supreme Court has reiterated, Commission-approved existing rates carry the presumption that they are just and reasonable.[121] In this proceeding, Xcel Energy does not request a change to the amount, terms or conditions of the late payment fee that is currently established in the Company's tariffs. The Commission previously approved Xcel Energy's existing tariffs, determining them to be just and reasonable, and CUB's argument that the Company's late payment fees are unsupported by evidence is an attempt to impermissibly shift the burden of proof back onto the Company.[122] Instead, as the party seeking a change to an existing rate, CUB must demonstrate the existing late payment fee to be unjust or unreasonable. CUB has failed to meet that burden and its recommendation must be rejected.

CUB's arguments fail to demonstrate that the Company's Commission-approved late payment fees are not reasonable. First, CUB argues that late payment fees have little effect on the timeliness of residential customer payments. This defies common sense; if

[120] CUB Initial Brief at 28.
[121] *See Reserve Min. Co. v. Minn. Pub. Util. Comm'n,* 334 N.W.2d 389, 392 (Minn. 1983); *St. Paul Area Chamber of Comm. v. Minn. Pub. Serv. Comm'n,* 251 N.W.2d 350, 358 (Minn. 1977).
[122] CUB Initial Brief at 28.

there is no fee for paying a bill late, presumably customers will be less concerned about paying a bill on time. More importantly, it ignores the Company's own experience demonstrating that the absence of late fees appears to disincentivize customers from paying their bills on time. During the COVID-19 peacetime emergency, the Commission requested that Minnesota utilities, among other actions, waive late payment fees for residential and small business customers.[123] This was an understandable action during an emergency such as a global pandemic. Xcel Energy agreed to take all voluntary actions requested by the Commission, including agreeing to waive late payment fees, halt disconnections of customers for non-payment of utility bills, and arrange payment plans with its customers.[124] During the period of this moratorium, arrearages nearly doubled, from roughly $44 million at the end of 2019 to $85 million at the beginning of 2022.[125] In addition, past-due balances grew from $57 million to $81 million.[126] This evidence suggests that late payment fees incentivize customers to pay their bills on time. At minimum, it demonstrates that the lack of late payment fees lead to increased past-due balances.

Despite this experience from the Company, CUB relies on the findings from the Kentucky Public Service Commission's review of the influence of late payment fees on the timeliness of customer payments during the COVID-19 pandemic to argue that the Kentucky Commission determined late payment fees have little effect on the timeliness of

[123] *Responsive Measures to the Outbreak of COVID-19*, Docket No. CI-20-375, MPUC Letter (Mar. 25, 2020).
[124] *Responsive Measures to the Outbreak of COVID-19*, Docket No. CI-20-375, Xcel Energy Letter (Mar. 26, 2020).
[125] Ex. Xcel-71 at 49 (Martin Rebuttal).
[126] Ex. Xcel-71 at 49 (Martin Rebuttal).

residential customer payments.[127] While the conclusions of the Kentucky Commission may be interesting, they are neither evidence nor precedent. And the actual evidence in this case directly contradicts the conclusions of this foreign regulatory body. There is no evidence that a similar evaluation has been conducted in Minnesota, and the Company's experience during the COVID-19 moratorium in Minnesota and the dramatic increase in past-due balances in the absence of late payment fees and disconnections that resulted, emphasizes the importance of such fees.

Further, CUB's recommendation would have negative impacts on the proposed low-income customer arrears payment assistance program the Commission ordered the Company to develop in this rate case. In compliance with the Commission's Order in Docket No. E002/M-24-27, Xcel Energy proposed a program to donate late payment fees to assist low-income customers address high arrears and threats of disconnection. The Company proposed the Residential Arrears Management Program (RAMP), which is discussed in more detail in a subsequent section of this Brief. The elimination of late payment fees would necessitate the rejection of RAMP, since RAMP uses these fees to pay down customer arrears. Further, the elimination of late payment fees for all residential customers would increase the revenue requirement, and thus all customers rates, without providing the benefits of RAMP.

If the Commission nonetheless chooses to modify the collection of late payment fees, the Company recommends waiving those fees for low-income customers only and

[127] CUB Initial Brief at 29.

retaining RAMP. As Company witness Mr. Martin explained, low-income customers are more likely to receive assistance under RAMP. While not the Company's preferred approach, exempting these low-income customers from late payment fees would provide an additional benefit to them that then could be considered by the Commission in the context of other low-income programs.[128] In addition to preserving RAMP, albeit in smaller form, this would minimize the resulting increase in revenue requirements due to waiving late payment fees borne by all other customers.

2. Reconnection Fees

For the reasons discussed in the Company's Initial Brief, CUB's recommendation that the Commission order the Company to waive reconnection fees should be rejected. Namely, Minnesota regulations specifically permit Xcel Energy to assess such fees based on the actual costs of reconnection.[129] Further, reconnection fees are an offset to the revenue requirement and waiving these fees would require all customers who have remained current on their bills, including most low-income customers, to absorb additional costs caused by customers who have been disconnected.[130]

CUB also recommended that if the Commission does not waive reconnection fees, the Commission should order the Company to remove labor expenses from the fee calculation.[131] Minnesota Rule 7820.2600 provides that a utility "may charge a reconnect fee based on the cost of reconnection as stated in the utility's tariff on file with the

[128] Ex. Xcel-71 at 30 (Martin Rebuttal).
[129] Minn. R. 7820.2600.
[130] Xcel Energy Initial Brief at 60; Ex. Xcel-71 at 27 (Martin Rebuttal).
[131] CUB Initial Brief at 37-38.

[C]omission." The cost that Xcel Energy incurs to reconnect customers necessarily includes the labor costs. It is for this reason that reconnections for customers with AMI technology, which do not require technicians to travel to a customer's home, are less costly than those for customers that have opted out of AMI technology. These are real costs that are incurred and by the Company. The Commission should reject CUB's recommendation to remove labor costs from reconnections fees as contrary to Commission Rules.

B. Rate Base And Expense Items

1. Energy Supply O&M

Despite the fact that the Company put forth undisputed evidence to support the reasonableness of its 2025 and 2026 Energy Supply O&M budgets, XLI continues to recommend a 4.3 percent reduction to these budgets based on a backwards look at past variances between Energy Supply's rate case approved O&M budgets and actuals.[132] This backwards approach fails to properly account for the real cost drivers supporting the Company's need for increased O&M in 2025 and 2026 to run its generation facilities.

As explained by Company witness Randy Capra, the Company's Energy Supply 2025 and 2026 budgets reflect increased O&M due in part to Sherco Solar I, II, and III coming online, combined cycle overhauls, combustion turbine inspections at Inver Hills plant, overhauls at Sherco Unit 3, and several other factors.[133] XLI did not dispute any of

[132] XLI Initial Brief at 25; XLI's proposed 4.3 percent adjustment to the Company's Energy Supply O&M budgets is based on the three-year average of the difference between actual 2022-2024 O&M expenses and the amounts approved in the Company's last electric rate case (Docket No. E002/GR-21-630).
[133] Ex. Xcel-46 at 6-7 (Capra Rebuttal).

these cost drivers in its testimony and does not address them in its initial brief.[134] Rather, XLI continues to focus on the fact that the Company's actual O&M expenses for 2022-2024 were lower than amounts approved in the last rate case. It is inappropriate, however, to reduce the Company's O&M recovery based on past conditions that have no bearing on future expenses. Setting aside the limited relevance of such an inquiry, the Company also explained the key reasons why actuals for these years were lower than the approved amounts. The primary reason was due to in-service delays for Sherco Solar I and II, waking damage payments, and liquidated damage payments.[135] The entire amount of the waking damages payment and nearly 70 percent of the liquidated damage payments during this period were credited back to customers through the Company's Renewable Energy Standards (RES) Rider.[136] Again, XLI does not dispute or even address these factors in its initial brief.[137] Instead, XLI tries to claim that the fact that actual expenses were lower than approved amounts means that the Company over recovered $14.7 million from customers from 2022-2024. This simplistic view ignores the fact that while the Company's Energy Supply O&M may have been lower than forecasted, other business areas of the Company experienced higher than forecasted O&M from 2022-2024. It also ignores that one of the benefits of an MYRP, as noted by the Department, is that utilities are incentivized to efficiently manage their budgets over the term of an MYRP.[138]

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[134] *See* XLI Initial Brief at 25.
[135] Ex. Xcel-46 at 4-5 (Capra Rebuttal).
[136] Ex. Xcel-46 at 5, 10 (Capra Rebuttal).
[137] XLI Initial Brief at 25.
[138] Ex. DOC-1 at 16 (Johnson Direct); DOC Initial Brief at 4.

Adopting XLI's proposed adjustment to the Company's Energy Supply O&M budget would have real impacts on the Company's ability to operate and maintain its generation fleet. As explained by Company witness Capra, Energy Supply's 2025 and 2026 O&M budgets reflect additional O&M needed to operate new solar facilities at Sherco as well as maintain existing generation facilities.[139] XLI tries to blunt the impact of its proposed adjustments by claiming that there will be no harm to the Company because the "Company's true-up mechanism already exists to make the Company whole should it incur higher costs that its predicted O&M expenses."[140] This is simply not correct. The Company only has a one-way capital true-up mechanism; it has no true-up mechanism for its O&M expenses.[141] But since the Company does not have an O&M true-up mechanism, XLI's proposed adjustment will leave the Company with no way to recover its prudently incurred costs when XLI's unsupported speculation that the Company's 2025 and 2026 are "overstated" Energy Supply O&M budgets are proven false.[142]

XLI further takes issue with the Company's Energy Supply O&M budget because the Company's rate case uses a forecasted rather than historical test year. XLI argues that use of a forecasted test year "may lead to excessive rates or biased projections."[143] But a goal of utility ratemaking is that the recovery of costs through rates during a specific period match the utility's prudently incurred costs during that same period and the use of a

[139] Ex. Xcel-46 at 6-7 (Capra Rebuttal).
[140] XLI Initial Brief at 25.
[141] Ex. Xcel-15 at 29-30 (Liberkowski Direct).
[142] XLI Initial Brief at 25.
[143] XLI Initial Brief at 25.

forecasted test year is the best way to achieve this goal. If rates are based on costs from a historical period, as XLI recommends, then they will not reflect the actual costs incurred by the utility during the year(s) the rates actually are in effect. The use of forecasted test years mitigates this problem. While forecasts are never 100 percent accurate, they still yield rates that are more reflective of a utility's actual costs during the period in which they are in effect than rates based on outdated costs and revenues for a historical period. As noted above, Energy Supply's 2025 and 2026 budgets include costs for operating new solar facilities, planned overhauls and generator inspections, as well as base pay increases.[144]

The Company has provided substantial evidence to support the reasonableness of the Company's Energy Supply O&M budgets for 2025 and 2026. In contrast, XLI's proposed adjustment is solely focused on past variances that have little bearing on the accuracy of Energy Supply's current 2025 and 2026 O&M budgets. XLI's unsupported speculations and their proposed adjustments should be rejected.

2. Transmission O&M

The Department and XLI each continue to recommend that the Company's proposed Transmission O&M expense budgets for 2025 and 2026 should be reduced based on claims they make regarding the Company's past Transmission O&M expense, which have no bearing on the Company's current expenses. The Department's proposed adjustment would use the Company's 2024 actual Transmission O&M expenses of $17.4 million to set both the Company's 2025 and 2026 Transmission O&M budgets.[145] XLI's proposed 16.2

[144] Ex. Xcel-46 at 7-8 (Capra Rebuttal); Ex. Xcel-44 at 61-62 (Capra Direct).
[145] Ex. DOC-6 at 20-21 (Golden Surrebuttal).

percent adjustment to the Company's Transmission O&M budgets is based on the three-year average of the difference between actual 2022-2024 O&M expenses and the amounts approved in the Company's last electric rate case (Docket No. E002/GR-21-630).[146] As set forth in the Company's Initial Brief, the Department and XLI's recommendations do not take into account the substantial evidence provided by the Company to support its 2025 and 2026 Transmission O&M expense budgets.[147]

The Department claims that the Company does not fully explain the variance between its budgeted and actual Transmission O&M expense for 2022-2024,[148] but this is not true. The Company explained that the variance was attributable to internal reorganizations within the Company, including the formation of a new Integrated System Planning ("ISP") business unit and the shifting of certain fees and costs out of Transmission and into ISP and legal services, and reduced labor split rates.[149] The Department also states that "[e]ven if this explanation fully accounted for the difference, the expenses set in this case should reflect the ongoing nature of these expense reductions."[150] Yet, the Department overlooks the fact that the Company already accounted for the impact of these changes when developing its 2025 and 2026 Transmission O&M expense budgets.[151] Indeed, the Company explained that this is why the Company's 2025 and 2026 Transmission O&M

[146] Ex. XLI-1 at 53 (LaConte Direct).
[147] *See* Xcel Energy Initial Brief at 67-73.
[148] DOC Initial Brief at 75.
[149] Ex. Xcel-43 at 4-5 (Berklund Rebuttal).
[150] DOC Initial Brief at 75.
[151] Ex. Xcel-43 at 5-6 (Berklund Rebuttal).

expense budgets are lower than its 2022 actual Transmission O&M expense.[152] Further, contrary to the Department's suggestion that the Company noted that its 2025 and 2026 Transmission O&M budgets are lower than the most recent four-year (2021-2024) average of actual Transmission O&M expense "to obscure the unreasonableness of its requested expenses,"[153] the Company actually presented this evidence to further support that it already accounted for the organizational and other changes in its 2025 and 2026 budgets.[154]

In addition, the Department takes issue with the Company's 2025 and 2026 Transmission O&M expense budgets on the basis that its labor costs declined in 2022-2024.[155] Again, the Department ignores the Company's explanation that the decline was due to the above-mentioned internal reorganizations, which were a one-time event and would not reoccur in 2025 and 2026.[156] The Department also does not dispute or otherwise address the Company's evidence showing that the Company's 2025 and 2026 Transmission O&M expense is projected to increase because of increases in internal labor costs associated with annual base pay increases and line inspections for wildfire mitigation; increases in materials, maintenance, and employee training and travel; and significant increases in capital investments.[157]

[152] Ex. Xcel-43 at 6 (Berklund Rebuttal).
[153] DOC Initial Brief at 76.
[154] Ex. Xcel-43 at 3, 6 (Berklund Rebuttal).
[155] DOC Initial Brief at 75-76.
[156] Ex. Xcel-43 at 4-6 (Berklund Rebuttal).
[157] Ex. Xcel-42 at 84 (Berklund Direct); Ex. Xcel-43 at 6-10 (Berklund Rebuttal).

Lastly, the Department is critical of the accuracy of the Company's budgeting process.[158] But "[b]udget accuracy does not mean that every budgeted dollar is spent in exactly the same way that it is forecasted to be spent"[159] because the Company must have the flexibility to adjust its actual spending to respond to emerging needs that may not have been foreseen when the budget was created. Such deviations do not mean that the budget was not reasonable. This budget flexibility also means that the Company must have the ability to shift O&M dollars from one business area to another to address emerging needs. So while the Department notes that the first three quarters of the Company's 2025 actual Transmission O&M expense when annualized for the entire year are less than the Company's 2025 Transmission O&M expense budget, the Department does not consider that other business units could be higher than budget, with the net result at the Company level ending up closer to the authorized budget, and that such flexibility is needed for the Company to effectively manage its overall O&M.[160]

XLI's arguments should be rejected for the same reasons as the Department's arguments. However, XLI also recommends that "NSP should be required to reduce the Transmission O&M expense in this proceeding, which will shift the burden to recover potentially higher expenses through its true-up mechanism to NSP."[161] This recommendation is nonsensical. Here again, XLI appears to be referring to the Company's

[158] DOC Initial Brief at 75.
[159] Ex. Xcel-26 at 29 (Robinson Direct).
[160] Tr. Vol. 1 (Dec. 17, 2025) at 233-234 (Berklund); Xcel Energy Initial Brief at 72-73.
[161] XLI Initial Brief at 26.

capital true-up,[162] which is designed to cover variances in capital additions, not O&M expense.[163] For all of these reasons, the Company maintains that the Commission should reject the Department and XLI's recommendations and approve the Company's proposed Transmission O&M expense budgets for 2025 and 2026.

3. Distribution O&M

The Department recommends a reduction to the Company's proposed Distribution O&M budgets for 2025 and 2026 based on a focus on only one component of the Company's Distribution O&M budget: vegetation management. As set forth in the Company's Initial Brief, the Department's recommendation does not take into account the substantial evidence provided by the Company to support its 2025 and 2026 Distribution O&M expense budgets. It also ignores the fact that the Company manages its O&M budget—including its Distribution budget—as whole, and decreasing costs in one area are often balanced by increasing costs in other areas.[164] The Commission should reject the Department's recommendation and approve the Company's Distribution O&M budgets for 2025 and 2026 as proposed.

The Department challenges the reasonableness of the 2025 and 2026 vegetation management budgets because they are higher than the actual vegetation management costs for 2022-2024.[165] But the Department does not dispute – or even address – the Company's evidence explaining the need for higher vegetation management budgets in 2025 and 2026.

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[162] XLI Initial Brief at 26 (citing Ex. XLI-8 at 15:14-18 (LaConte Surrebuttal)).
[163] Ex. Xcel-15 at 37-39 (Liberkowski Direct).
[164] *See* Xcel Energy Initial Brief at 73-77.
[165] DOC Initial Brief at 67.

As Company witness Marty Mensen testified, the need for higher vegetation management expenses in 2025 and 2026 is driven by: (1) work that was prudently deferred in prior years in order to address higher priority work such as outage restoration; (2) contractor rate increases; (3) additional vegetation growth due to higher-than-average rainfall; and (4) forecasted inflationary increases.[166] The Department does not refute any of these cost drivers.[167]

Second, the Department notes that actual vegetation management costs for 2022-2024 were lower than budgeted, and calls into question the accuracy of the Company's budget.[168] However, this is not evidence that budgeting process is flawed, but rather shows that the Company appropriately manages its overall O&M budget to address the highest priority needs of its customers which as noted earlier, one of the benefits of an MYRP is that it incentivizes utilities to efficiently manage their expenses.[169] Again, the Department's argument ignores the reasons for the deviation between test approved budgets and actual spending. For 2023, the year with the greatest deviation, the Company adjusted O&M spending, postponing planned vegetation management to reallocate resources for storm restoration work, the costs of which exceeded storm restoration costs in each of the prior four years.[170] This reflects that the Company appropriately manages O&M costs to respond to unanticipated circumstances and higher priority needs of its customers.

[166] Ex. Xcel-35 at 44-45 (Mensen Rebuttal).
[167] DOC Initial Brief at 67-68.
[168] DOC Initial Brief at 67.
[169] Ex. DOC-1 at 16 (Johnson).
[170] Ex. Xcel-35 at 47 (Mensen Rebuttal).

Finally, the Department notes that vegetation management costs for 2025 through September 30, 2025 were lower than budgeted.[171] The Company explained that while it had cleared more miles than initially budgeted in 2025, it was able to capitalize a portion of these costs as preparation work for distribution line rebuilds.[172] But again, the Department's focus on this single portion of the Distribution O&M budget ignores the fact that the Company manages its Distribution O&M budget on an overall basis. The Department's attempt to isolate vegetation management spending, without considering offsetting needs of other areas of the Company's Distribution O&M budget ignores how the Company manages its budgets to address the highest priority needs.

The Department's proposed adjustment is similarly flawed. The Department recommends applying a 3 percent annual inflationary increase over 2024 actual vegetation management costs to set the Company's 2025 and 2026 budgets.[173] This would result in reducing the Company's overall Distribution O&M budgets for both 2025 and 2026 to *below* actual 2024 levels – an unreasonable result given the need for additional O&M spending in 2025 and 2026 as set forth in Company witness Mensen's Direct Testimony.[174] Overall, the Company's proposed Distribution O&M budget in total is a modest 2.4 percent increase from 2024 actuals to the 2025 budget, and a 3.9 percent increase from the 2025 budget to the 2026 budget.[175]

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[171] DOC Initial Brief at 67-68.
[172] Ex. DOC-8 at AAU-S-1, Page 3 (Uphus Surrebuttal).
[173] DOC Initial Brief at 68.
[174] Ex. Xcel-34 at 144 (Mensen Direct)
[175] Xcel Energy Initial Brief at 76.

For all of these reasons, the Company maintains that the Commission should reject the Department's recommendation and approve the Company's proposed Distribution O&M budgets for 2025 and 2026, which represent a modest 2.4 percent increase from 2024 actual expenses.

4. Customer Care O&M

For the reasons discussed in the Company's Initial Brief, XLI's recommendation that the Commission should deny recovery of the Company's reasonable and necessary Customer Care O&M expense must be rejected. Namely, XLI's recommendation should be rejected because it is not based on an analysis of the reasonableness of the expense, but rather is proposed as a punitive measure for alleged customer service and billing issues as they relate to unidentified Building Owner and Managers Association of Greater Minneapolis (BOMA) members. XLI's and BOMA's reticence to identify the BOMA members allegedly experiencing issues to allow the Company to address any errors, in addition to the lack of any assessment whatsoever of the portion of the Customer Care O&M expense that relates to these alleged issues, is unreasonable and XLI's recommendation must be rejected.

In its Initial Brief, XLI noted that XLI and the Company agreed that the Commission's investigation into Xcel Energy's residential billing errors should be expanded to include commercial customers such as BOMA.[176] During a recent Commission hearing held on February 19, 2026 in the Company's Annual Safety,

[176] XLI Initial Brief at 33 (citing Tr. Vol. 1 (Dec. 17, 2025) at 247:2-248:5 (Howard)).

Reliability and Service Quality Report,[177] the Company agreed to expand the scope of Docket No. E,G002/CI-25-341, the Company's residential billing investigative docket, to include commercial and industrial customers and comply with reporting requirements consistent with those required for residential customers in the Commission's Order Initiating Investigation in that docket.[178]

5. Liquidated Damages

The Department urges a $945,000 reduction to Company's Energy Supply 2025 and 2026 O&M expenses to account for potential liquidated damage payments from its wind service providers.[179] The Department argues that it is appropriate to include an offset for these potential payments because doing so is consistent with the test year concept of providing a snapshot of the utility's likely costs and revenues.[180] But while the Company has received liquidated damage payments since 2022, there is no guarantee that these payments will continue indefinitely, the amount of these payments, or that the facilities that generate these payments will be for non- RES rider facilities.

Liquidated damages are paid to the Company when the Company's wind facilities operate less than the amount outlined in the O&M service agreement. By their nature, liquidated damages are not guaranteed annual payments and are quite variable in their amount. In fact, the liquidated damage amount that the Company received in 2024 was

[177] *In the Matter of Xcel Energy's 2024 Annual Safety, Reliability and Service Quality Report*, Docket No. E002/M-25-27.
[178] The Commission has not yet issued an Order incorporating the Company's agreement to expand the scope of the investigative docket or the reporting requirements.
[179] DOC Initial Brief at 78.
[180] DOC Initial Brief at 78.

$2.6 million less than what it had received the year prior.[181] The variable and unpredictable nature of these expenses make them inappropriate for inclusion in a rate case as the goal of a test year is to represent normal, ongoing operational costs and revenues of the utility.

In addition, the Company demonstrated that future liquidated damage expenses in 2025 and 2026 are likely to be less than historical 2022-2024 amounts that the Department uses to calculate its proposed adjustment. This is because the Company has been working with its wind service providers to increase the availability of its wind facilities, which would reduce or even eliminate future liquidated damage payments.[182] Also, to the extent that there are liquidated damage payments in 2025 and 2026, the majority of these payments are likely to be refunded to the customers through the Company's RES rider. This is because the highest portions of liquidated damages typically occur during the first few years that a wind facility is in operation, when its costs are being recovered through the RES rider.[183] Indeed, from 2022-2024 nearly 70 percent or $7 million in liquidated damages was credited back to customers through the RES rider.[184] The unpredictable and variable nature of liquidated damage payments combined with the Company's showing that these amounts are likely to decrease in 2025 and 2026 or already be credited back through the RES rider, warrant rejection of the Department's proposed adjustment.

[181] Ex. Xcel-46 at 12 (Capra Rebuttal).
[182] Ex. Xcel-46 at 11-12 (Capra Rebuttal).
[183] Ex. Xcel-46 at 13 (Capra Rebuttal).
[184] Ex. Xcel-46 at 10-11 (Capra Rebuttal).

6. Compensation And Benefits

a. Base Pay

The Department seeks to cut the Company's base pay request by $19.1 million in 2025 and $11.7 million in 2026 simply because the Company cannot provide forecasted full-time equivalent (FTE) employee headcount data for its State of Minnesota Electric Jurisdiction, data that the Company does not maintain. This recommendation ignores the substantial, unrebutted evidence supporting the reasonableness of the Company's base pay request and would materially impact the Company's ability to recover the base pay and wages that the Company must pay its bargaining and non-bargaining unit employees who are critical to providing safe and reliable service to customers.

The Department alleges that without forecasted Minnesota jurisdictional FTE counts for 2025 and 2026, it cannot "meaningfully analyze the reasonableness of Xcel's proposed base-pay figures a per employee basis."[185] However, the Department's singular focus on this one data set that the Company does not maintain disregards the extensive evidence put forth by the Company to support its base pay request. The Company's requested base pay increases for 2025 and 2026 were developed using current salary information with a 3.0 percent annual increase for bargaining unit employees, based on their current union contract, and a 3.0 percent annual increase for non-bargaining unit employees, based on market data.[186] Since base pay amounts also include amounts for overtime and paid-time off, the Company's request also includes forecasted overtime

[185] DOC Initial Brief at 44.
[186] Ex. Xcel-28 at 26 (Robinson Rebuttal); Ex. Xcel-63 at 7-8 (Ly Rebuttal).

amounts for scheduled outages and overhauls at the Company's generation facilities.[187] Each of these factors reflect real, known, and measurable labor cost obligations of the Company and the Department has not claimed that any of these inputs or assumptions are inflated, unreasonable, or imprudent.

While the Company acknowledges that drastic changes in headcount could call into question the reasonableness of the Company's base pay requests, the Company provided evidence to demonstrate that its actual headcount numbers for NSPM were steady through June 2025[188] and stated that the Company has no plans for any major labor restructuring in 2025 or 2026.[189] Again, the Department did not dispute the Company's evidence on this point. However, in its initial brief the Department speculates that because the Company's overall base pay expense request is below the 3 percent salary increase this "implies that there are some workforce projections impacting this analysis."[190] This allegation is simply not accurate for 2025. For 2025, the Company's base pay request is 3.8 percent higher than its 2024 actual costs which the Department's own witness concluded "appears fairly

[187] Ex. Xcel-28 at 26-27 (Robinson Rebuttal) ("For instance, there were planned outages at our two nuclear facilities in the spring and fall of 2025, as discussed by Company witness Christopher R. Church, and a planned overhaul at Sherco Unit 3 in 2026, as discussed by Company witness Randy A. Capra.")
[188] Ex. DOC-3 at MBK-D-13, Page 1 (Kehrwald Direct) ("Regarding the June 1, 2025 NSPM employee count . . . the full-time employee count (3,098) is the same as the FTE count (3,098) … as of the calendar year 2024").
[189] Ex. DOC-4 at MBK-S-3, Page 2 (Kehrwald Surrebuttal); Ex. DOC-3 at 9 (Kehrwald Direct).
[190] DOC Initial Brief at 45.

reasonable" given the 3 percent annual increase in base salary and wages.[191] While the Company's base pay request for 2026 is only 0.8 percent higher than its request for 2025,[192] the Company explained that its base pay amounts include not just salary and wages for the Company's employees but also overtime pay that can fluctuate year-over-year depending on the number and length of scheduled outages and overhauls. Accordingly, the Company's base pay amounts do not increase in a linear 3 percent per year manner due to these other components of base pay – not because of forecasted workforce reductions as suggested by the Department.

The Company also explained the reasons why it could not provide the forecasted FTE counts on a State of Minnesota electric jurisdiction basis as requested by the Department. This is due to the fact that the Company allocates *labor costs* rather than *specific employees*.[193] This allocation of labor costs rather than specific employees is necessary because the Company must first allocate its labor costs to capital or O&M, then allocate those costs to a specific operating company, and then allocate those costs yet again to either the electric or gas utility.[194] In addition, NSPM uses Xcel Energy Services Inc. (XES), a centralized service company, to provide enterprise-wide functions. The costs for these XES employees, not specific FTE headcounts, are allocated to specific operating companies and then to the electric or gas jurisdiction based on the Company's

[191] Ex. DOC-4 at 11 (Kehrwald Surrebuttal) ("Given the Company's planned 3% annual merit increase in 2025, this appears fairly reasonable…."); Ex. Xcel-28 at 26 (Robinson Rebuttal).
[192] Ex. Xcel-28 at 26 (Robinson Rebuttal).
[193] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[194] Ex. Xcel-28 at 28 (Robinson Rebuttal).

Commission-approved Cost Allocation and Assignment Manual.[195] Given these facts, the absence of jurisdiction-specific forecasted FTE counts does not undermine the accuracy of the Company's base pay forecast. Rather, it is consistent with how the Company has allocated these costs for years based on the Commission's approved manual.

Not only is the Department's proposed adjustment unsupported by record evidence but so is its method for calculating its proposed adjustment. The Department proposes to use the Company's 2024 base pay amounts approved in the Company's last rate case as the baseline for its 2025 and 2026 base pay amounts. Using the 2024 test year approved amount will inevitably lead to substantial under recovery of the Company's actual costs. This is because the Company's actual 2024 base pay amounts were nearly $16 million higher than the amount approved in the Company's last rate case.[196] However, the Department claims that it cannot use 2024 actuals as a baseline for its adjustment because the Company "failed to explain why the 2024 actual base-pay exceeded the 2024 approved amount…."[197] Again, this is simply not the case. The Company explained that the 2024 test year approved amount was based on a budget that the Company developed in July 2021 prior to filing its last rate case and this budget did not sufficiently account for significant and well-documented inflation in the labor market that occurred after this budget was developed.[198] Specifically, the Company paid a 6.1 percent increase to bargaining unit employees in 2023 based on their new union contracts and paid a 4.0 percent increase to

[195] Ex. Xcel-28 at 28 (Robinson Rebuttal).
[196] Ex. Xcel-28 at 31 at Table 3 (Robinson Rebuttal).
[197] DOC Initial Brief at 44.
[198] Ex. Xcel-28 at 31 (Robinson Rebuttal).

non-bargaining unit employees to maintain market-competitive salaries.[199] These higher than forecasted base pay increases in 2023 compounded into 2024, causing actual 2024 base pay amounts to exceed the amounts approved in the last rate case.

In sum, the Department unreasonably asks the Commission to deny more than $30 million in necessary labor costs, a key component of the Company's cost of service. Adopting the Department's recommendation would result in substantial under recovery of the base pay and wages that the Company is required to pay to the very employees that are responsible for maintaining the system and ensuring reliable electric service for customers. The Department's proposed adjustment should be rejected and instead the Company's base pay request should be approved in full because it is supported by the record in this case, grounded in union contract obligations and market data, and accurately reflects the costs to be incurred by the Company to pay the skilled workforce needed to provide electric service to customers.

b. Incentive Compensation

(i) AIP

(a) AIP Cap Amount

Both the Department and XLI ask the Commission to maintain its outdated 15 percent cap on Annual Incentive Program (AIP) compensation and to deny the Company's request to increase the cap to 20 percent, consistent with that granted to other Minnesota utilities. The rationale put forth by the Department and XLI is the same: they allege that

[199] Ex. Xcel-63 at 6 (Ly Rebuttal).

the Earnings Per Share (EPS) threshold demonstrates that AIP compensation is shareholder-focused and has little benefit for customers.[200] This assertion does not withstand scrutiny.

The EPS threshold is simply a gating criteria designed to ensure that the Company is performing at a minimum sustainable financial level before AIP compensation is paid.[201] This is a conservative approach that protects customers from the utility having to pay AIP compensation in years of financial underperformance.[202] However, the AIP metrics themselves are strictly customer-focused.[203] Xcel Energy's Corporate Scorecard, which establishes the AIP goals, reflect this customer focus—advancing the clean energy transition, improving the customer experience, maintaining affordable bills, and ensuring safety and reliability.[204] Employee performance in achieving these goals is measured through objective, customer-centered metrics such as customer satisfaction, electric system reliability, public safety outcomes, and effective use of wind powered resources to curtail fuel costs for customers.[205] Both the Department and XLI try to diminish the importance of these customer-centric goals by noting that no AIP compensation is paid out until the EPS threshold is reached.[206] These arguments ignore the flip side, that even if the EPS threshold is reached, there will be no AIP compensation payout unless specific customer-

[200] DOC Initial Brief at 48-49; XLI Initial Brief at 20.
[201] Ex. Xcel-63 at 17 (Ly Rebuttal) ("the EPS threshold is simply a prudent management tool to ensure that the Company is financially stable enough to pay out AIP.").
[202] Ex. Xcel-67 at 10-11 (Mustich Rebuttal).
[203] Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct).
[204] Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).
[205] Ex. Xcel-62 at 20-21 (Ly Direct); Ex. Xcel-63 at 17 (Ly Rebuttal).
[206] DOC Initial Brief at 48-49; XLI Initial Brief at 20.

focused metrics are also achieved. As just one example, the Company could achieve its EPS threshold requirement, but if the Company fails to meet its electric system reliability target, the portion of AIP compensation tied to achievement of that goal would not be paid.[207]In this way, the AIP program is structured to incent employees to focus on these customer-focused metrics. The presence of an EPS threshold does not change these incentives. Instead, the EPS threshold functions as safeguard to ensure AIP compensation can safely be paid without risking the financial health of the utility. This benefits customers as well as shareholders.

This type of financial safeguard is also not uncommon.[208] But what is unique about Xcel Energy's AIP plan is that EPS acts as a circuit breaker rather than being one of the AIP goals of the plan itself.[209] This difference benefits customers by keeping the focus of Xcel Energy's AIP plan on customer metrics rather than on Company financial performance. And the fact that the Company has a financial mechanism included in its AIP plan is not a reason to deny these reasonable costs. In fact, the Commission has allowed higher recovery of AIP costs for plans that have a greater focus on a utility's financial metrics than the Company's circuit breaker approach. As noted in the Company's initial brief, the Commission previously approved a 20 percent cap for Minnesota Power's AIP, where *90 percent* of the AIP costs were tied to utility net income, cash from operating

[207] Ex. Xcel-62 at Schedule 4 at 6 (Ly Direct); Tr. Vol. 1 (Dec. 17, 2026) at 191 (Mustich) ("That if the EPS expectations are met, the plan is funded at 100 percent. It doesn't mean the top executives will get 100 percent. They could get zero if they don't hit their customer and operational metrics, which the plan is very focused on.").
[208] Ex. Xcel-67 at 10 (Mustich Rebuttal); Tr. Vol. 1 (Dec. 17, 2026) at 191 (Mustich).
[209] Tr. Vol. 1 (Dec. 17, 2026) at 191 (Mustich).

activities, and utility competitiveness goals.[210] In that case, the Commission explained that this level of AIP recovery was appropriate, despite these goals tied to financial metrics because "without AIP, Minnesota Power's total cash compensation for eligible employees would be below the market rate."[211] The Company is in the same position. Like Minnesota Power, Xcel Energy's AIP compensation is needed to bring total cash compensation in line with the market. Without AIP and LTI, Xcel Energy's total cash compensation is between 16.7 percent to 19.9 percent below the median compensation levels of other utility employers.[212] The Department and XLI offer no coherent rationale for why Xcel Energy– whose employees' AIP compensation is based solely on customer-aligned metrics – should be treated less favorably in rate recovery than Minnesota Power.

The Department's and XLI's focus on the EPS threshold also overlooks the other customer benefits of AIP compensation in addition to the customer-centric AIP goals. First, while AIP compensation is needed to ensure that Xcel Energy's employees' compensation levels are market competitive, AIP compensation is still pay-at-risk compensation.[213] This compensation structure benefits customers because it allows the Company to tie a portion of its employee's pay to the achievement of objective, customer-focused goals.[214] Second, providing a portion of employees' compensation as incentive compensation, rather than

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[210] *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 32 (Mar. 12, 2018).
[211] *Id*. at 33.
[212] Ex. Xcel-64, Schedule 5 at 20 (Ly Direct).
[213] Ex. Xcel-62 at 13 (Ly Direct).
[214] Ex. Xcel-62 at 15 (Ly Direct) ("AIP promotes higher performance, sets clearer expectations, and recognizes and drives continuous improvement.").

base pay benefits customers by substantially lowering the Company's fixed labor costs.[215] Lower fixed labor costs further benefit customers by lowering other costs that are directly tied to fixed labor costs such as 401K matches, pension benefits, life insurance, long-term disability premiums, and short-term disability expenses.[216]

The record in this case supports an increase of the AIP cap amount to 20 percent. AIP is a necessary component of providing employees with market-competitive compensation levels and Xcel Energy's AIP design ensures that employees' focus is on achievement of AIP goals that directly benefit customers.

(b) AIP Cap Calculation

The Commission should also approve the Company's request to administer the AIP cap on an aggregate rather than individual employee basis. Administering the AIP cap on an aggregate basis preserves the same total recovery limit while allowing the Company the flexibility to offer different AIP compensation to different employees based on their individual performance. The Department's concern that an aggregate cap would reduce customer refunds confuses the issue.[217] The AIP recovery cap set in this proceeding determines the Company's maximum recoverable amount; any payment of AIP compensation less than that amount is refunded to customers. The only thing that changes by allowing the Company to administer AIP on an aggregate basis is the fact that the Company can better tie compensation to performance.[218] This would further strengthen the

[215] Ex. Xcel-62 at 16 (Ly Direct).
[216] Ex. Xcel-62 at 17 (Ly Direct).
[217] DOC Initial Brief at 50.
[218] Ex. Xcel-63 at 18 (Ly Rebuttal).

link between pay and performance and further motivate employees to achieve the Company's customer-focused AIP goals.[219]

(ii) LTI

Both the Department and XLI urge the Commission to deny recovery of an essential component of the Company's market-based compensation for its employees – environmental and time-based Long-Term Incentive (LTI) compensation. Both parties criticize the goals of LTI compensation as not being sufficiently beneficial for customers and the Department critiques the form of the Company's LTI compensation and the employees to which it is paid. These misplaced critiques ignore the fundamental facts of this record. LTI compensation is a standard component of the compensation packages for all of Xcel Energy's peer utilities and this compensation is necessary to ensure that overall total amount of compensation paid to the Company's employees is line with the market. The fact that the Company is able to tie this portion of compensation to goals that directly benefit both customers and the state of Minnesota is just an additional benefit of providing compensation in this form.

LTI compensation programs are widely used compensation vehicles for executive employees. A 2024 Willis Towers Watson study (electric and gas utilities only) shows that 100 percent of the 53 utility companies submitting survey data provide LTI as a component of total compensation for executive roles.[220] As noted above, without AIP and LTI, the Company's total cash compensation is between 16.7 percent and 19.9 percent below the

[219] Ex. Xcel-63 at 18 (Ly Rebuttal).
[220] Ex. Xcel-62 at 21 (Ly Direct).

market median.[221] As a result, LTI compensation is not an optional add-on or a "bonus" as the Department and XLI seem to allege. Rather it is an essential part of the providing a market competitive compensation package. The Department's and XLI's recommendation to deny recovery of this key component of compensation is unsupported and harms the Company's ability to attract and retain the skilled leaders needed to run the utility.

The Department and XLI nevertheless recommend denial of LTI recovery because they allege that Company's LTI goals do not sufficiently benefit customers.[222] A simple examination of the Company's LTI goals proves the opposite.

First, Xcel Energy's environmental LTI goal is not simply a reward for complying with environmental goals that are "already mandated by state law."[223] Although Xcel Energy's LTI environmental objectives align with Minnesota's carbon-free standard, the two are not equivalent. Xcel Energy's environmental LTI metric focuses on continuous reductions in carbon emissions, measured relative to 2005 emission levels associated with the Company's electric service.[224] By contrast, compliance with Minnesota's carbon-free standard requires utilities to meet specified carbon-free generation percentages—80 percent by 2030, 90 percent by 2035, and 100 percent by 2040—based on electricity generated or procured for Minnesota retail customers.[225] These statutory requirements reflect five-year compliance milestones rather than annual performance standards.

[221] Ex. Xcel-64, Schedule 5 at 20 (Ly Direct).
[222] DOC Initial Brief at 46; XLI Initial Brief at 24.
[223] DOC Initial Brief at 46.
[224] Ex. Xcel-62 at 24-25 (Ly Direct).
[225] Minn. Stat. § 216B.1691, subd. 2g.

Accordingly, Xcel Energy's LTI program imposes a more rigorous, year-over-year expectation for carbon-emissions reductions, not just achievement of carbon-free generation targets every five years.[226]

Further, the Department's and XLI's contention that Xcel Energy's environmental LTI goal simply requires compliance with state law, ignores the fact that compliance with Minnesota's carbon-free standard will not be easy and will require dedicated focus by Xcel Energy's top leadership to achieve. This is especially true given current federal headwinds against coal plant retirements and new renewable generation. Indeed, this is a fact that the Minnesota legislature acknowledged by authorizing the Commission to grant utilities delays or modifications if meeting the standard would create significant compromises to customer affordability or reliability.[227] Tying the at-risk compensation of Xcel Energy's leadership to achievement of environmental goals that align with the State's carbon-free goals is something that the Commission should support. In addition to aligning with the State's carbon reduction goals, the Company's environmental LTI goals also benefit customers by incentivizing investments in renewable generation resources that have both lower carbon emissions and lower fuel costs. Again, these are outcomes that the Commission should incentivize rather discourage.

Second, the Company's time-based LTI goals also provide benefits for customers. By requiring a three-year vesting period, time-based LTI promotes workforce stability, reduces turnover, reduces hiring and training costs, and ensures that experienced and

[226] *Id.*
[227] *Id.*

skilled employees remain with the Company. And Xcel Energy's time-based LTI has had the desired effect as the Company demonstrated that more than 96 percent of employees receiving time-based LTI grants remained with the Company through the vesting period, providing needed continuity in the leadership of the Company.[228]

In addition, while the Department criticizes the Company's AIP as being too focused on "short-term results,"[229] Xcel Energy's environmental and time-based LTI are focused on long-term goals that require sustained focus and commitment by eligible employees to achieve.

The Department further argues that because LTI compensation is delivered in the form of stock, it improperly aligns employees with shareholder interests.[230] But the fact that LTI compensation is paid in the form of stock does not change the performance metrics to which these pieces of compensation are tied. Providing company stock as a form of compensation is also a common practice among publicly traded companies and for good reason. Providing compensation in the form of stock gives employees a stake in the success of the Company and incentivizes them to work for the long-term financial health and stability of the Company, which benefits both the Company and its customers.

The Department's final critique of the Company's LTI compensation is the fact that it is paid to the top executives of the Company.[231] But these are the employees that are driving key strategic decisions and providing leadership on how to implement the

[228] Ex. Xcel-62 at 27 (Ly Direct).
[229] Ex. DOC-3 at 28 (Kehrwald Direct).
[230] DOC Initial Brief at 46.
[231] DOC Initial Brief at 46.

Company's carbon-free transition such that it is appropriate to tie their compensation to achievement of these goals. The competition for these key leaders is the national labor market and by not providing industry-standard LTI compensation to these executive employees, the Company would not be able to retain and attract appropriately qualified leadership.

The Company's environmental and time-based LTI compensation are reasonable, market-aligned, and tied directly to outcomes that benefit customers. These two components of compensation are essential elements in the Company's overall compensation package that ensures that the Company can attract and retain the workforce needed to provide safe and reliable electric service to customers. The Commission should reject the Department's and XLI's proposed disallowance and approve the Company's LTI request in full.

c. Executive Compensation

The Department and the OAG urge the Commission to disallow recovery of all of the compensation paid to the Company's top ten highest paid employees, arguing that such compensation is "shareholder-focused,"[232] "exorbitant,"[233] and unsupported by record evidence. The evidence in this case does not support these claims. To the contrary, the evidence shows that the Company's compensation for its top ten highest paid employees is market-competitive both in amount and structure, is necessary to attract and retain qualified leadership, and is structured to advance customer-focused outcomes. As a result,

[232] OAG Initial Brief at 35.
[233] OAG Initial Brief at 24.

the Department's and OAG's proposed disallowance of all of the compensation paid to these top ten highest paid employees is neither supported by law nor the record in this case and should be rejected.

(i) The Reasonableness Of The Company's Executive Compensation Request Is Supported By Robust And Unrebutted Evidence

To support its executive compensation request in this case, the Company submitted an independent third-party executive compensation study.[234] Based on a thorough review of Xcel Energy's compensation levels and programs and a comparison to 18 peer utilities, this third-party compensation study concluded:

> Xcel Energy's total direct compensation levels are consistent with market median levels (consistent with its compensation philosophy), and the design of the short- and long-term incentive compensation programs are consistent with market practices of utility peers.[235]

In addition, the Company supplied testimony from a third-party executive compensation expert and a Company witness both with years of expertise in compensation matters.[236] Neither the Department nor the OAG submitted any competing compensation study, expert testimony, or any empirical evidence contradicting these findings.[237] Rather, all that the other parties offered was policy testimony from witnesses with no compensation experience or expertise.[238] This testimony is insufficient to rebut the evidence presented by

[234] Ex. Xcel-66 at Schedule 2 (Mustich Direct).
[235] Ex. Xcel-66 at Schedule 2 at 10 (Mustich Direct).
[236] Ex. Xcel-66 at Schedule 1 (Mustich Direct); Ex. Xcel-62 at Schedule 1 (Ly Direct).
[237] Ex. Xcel-63 at Schedule 1 (Ly Rebuttal).
[238] Ex. Xcel-63 at Schedule 1 (Ly Rebuttal).

the Company or to support the Department's and OAG's recommendation for full disallowance of an essential cost of service.

The Department attempted to diminish the value of the third-party executive compensation study by alleging that it does not speak to "what portion, if any, of that salary is properly recovered from ratepayers."[239] But what portion the Company is allowed to recover from customers does not change the Company's obligation to offer market-competitive compensation. The Company cannot expect to retain qualified executives if it offers below market compensation.[240] Therefore, the Company's proposal to recover significantly less than its full executive-level compensation—a necessary cost of providing service—is reasonable and should be approved.

The Department further argues that the compensation study only examined incentive compensation at the target amount even though executives could be paid higher amounts depending on performance.[241] But the Company's request in this case is limited to incentive compensation at target and any compensation paid out above these target amounts are necessarily paid for by shareholders, not customers.[242]

[239] DOC Initial Brief at 52.
[240] Ex. Xcel-67 at 5 (Mustich Rebuttal) ("Whether a company seeks or gains rate recovery of its compensation does not impact what a company needs to pay.").
[241] DOC Initial Brief at 52.
[242] *See e.g.*, Ex. Xcel-62 at 17 (Ly Direct) ("We are requesting recovery of only the target-level of AIP amount, subject to a 20 percent recovery cap.").

(ii) The OAG Misreads The Court Of Appeals' Prior Decision On Executive Compensation

The OAG brief leans heavily on the Minnesota Court of Appeals decision, arising from the Company's last electric rate case, to support its contention that the evidence proffered by the Company in this case is insufficient to support full recovery of its requested executive compensation costs.[243] What the OAG overlooks is that the evidence provided by the Company in this case is very different than the evidence provided by the Company in its last rate case that was the subject of that appeal. In the Company's last electric rate case, the reasonableness of the compensation paid to the Company's top ten highest paid employees was not an issue that was raised by any party to the case and was not specifically addressed by the ALJ.[244] In fact, it was not until Commission deliberations, after the evidentiary record had closed, that questions were raised about the reasonableness of the amount of executive compensation.[245] As a result, the only evidence in the record was the Company's third-party compensation study that supported the market-competitiveness of the compensation packages offered to all employees.[246] The Company

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[243] *See* OAG Initial Brief at 26-28.

[244] *In re Application by N. States Power Co.*, No. A23-1672, 2025 WL 249995, at *2 (Minn. Ct. App. Jan. 21, 2025) ("Although the ALJ made findings, conclusions, and recommendations relating to employee-compensation costs generally, the ALJ did not specifically address Xcel's proposed expense for its ten highest-paid executives in the ALJ report, nor had that issue been specifically addressed in the evidentiary hearing before the ALJ.").

[245] *Id.*

[246] *Id.* at *10 ("In the contested-case proceedings before the ALJ, the vice president of an Xcel affiliate testified that Xcel sets compensation for non-bargaining employees near the median of similar positions in investor-owned utility and nonutility companies. There was no testimony or evidence specific to the compensation for Xcel's ten highest-paid executives.").

provided "no testimony or evidence specific to the compensation for Xcel's ten highest-paid executives."[247] In contrast to this prior case, the record here is replete with unrefuted evidence of the reasonableness of the amount and structure of the Company's executive compensation, including a compensation study that specifically addresses executive compensation and testimony from a third-party executive compensation expert with over 35 years of experience.[248]

While the OAG claims that the Company has not demonstrated that it is reasonable for customers to pay the necessary costs of executive compensation, it ignores that the Court of Appeals direction that the Commission must consider the needs of the utility, as well.[249] Here, the Company provided evidence of the need for its executives and the benefits that they provide to customers. As explained by Company witness Yen Ly, "like any large organization, Xcel Energy requires skilled, experienced leaders to carry out the long-term objectives and vision of the organization" in addition to directing day-to-day operation of the company.[250] The value that Xcel Energy's top executives provide can be seen in the industry-leading goals that have been set by these leaders. For example, Xcel Energy was the first major U.S. utility to announce its vision of providing 100 percent carbon-free electricity by 2050.[251] This announcement was industry-leading and years prior to the implementation of Minnesota's carbon-free standard.[252] In addition, the value of

[247] *Id.*
[248] Ex. Xcel-66 Schedule 2 (Mustich Direct); Ex. Xcel-66 Schedule 1(Mustich Direct).
[249] *Id.* at *12.
[250] Ex. Xcel-63 at 32 (Ly Rebuttal).
[251] Ex. Xcel-63 at 32 (Ly Rebuttal).
[252] Ex. Xcel-63 at 32 (Ly Rebuttal).

strong executive leadership can be seen in Xcel Energy's industry-leading reliability performance. Xcel Energy is one of the most reliable energy companies, delivering electric service at 99.98 percent reliability.[253]

In addition, the Company has already significantly limiting its recovery request. Specifically, the Company's request foregoes nearly 40 percent of Minnesota-jurisdictional portion of its executive compensation.[254] Despite the fact that the Company has demonstrated that these are necessary costs to provide adequate utility service, this lower request directly benefits customers. The Department's and OAG's request does not even attempt to consider the needs of the Company, since it simply denies the Company a necessary cost of providing service. This is unreasonable and should be rejected.

(iii) The Parties' Claims That Executive Compensation Is "Shareholder-Focused" Is Contradicted By The Actual Customer-Focused Metrics

The OAG asserts that because the majority of Xcel Energy's executive compensation is paid in the form of incentive compensation, this demonstrates the "primacy of shareholder value over ratepayer needs."[255] This assertion is flat wrong. First, as discussed above, the Company's AIP and LTI goals are customer-centered, and the presence of an EPS threshold is common-practice and beneficial to ratepayers.[256] customers.

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[253] Xcel Energy 2024 Sustainability Report at 51, available at: https://corporate.my.xcelenergy.com/s/about/report.
[254] Ex. Xcel-63 at 29 (Ly Rebuttal).
[255] OAG Initial Brief at 31.
[256] Ex. Xcel-67 at 7 (Mustich Rebuttal); Ex. Xcel-63 at 22, 34 (Ly Rebuttal).

Second, providing a greater percentage of executive compensation in the form of incentive compensation as opposed to base pay is consistent with market practice. In fact, among Xcel Energy's peer utilities, 89 percent of CEO compensation is paid in the form of incentive compensation.[257] And there are valid reasons that executive compensation programs are deliberately structured so that a large portion of total pay is at risk in the form of both short-term (AIP) and long-term (LTI) incentive compensation. Incentive compensation ties a significant portion of pay to measurable results. Specifically, roughly 23 percent of the compensation of Xcel Energy's CEO is tied directly to carbon reduction goals.[258] Not only that but structuring executive compensation without incentive compensation would require all compensation to be paid as base pay. This would increase fixed labor costs and labor costs tied to base pay such as disability premiums and 401K matches. It would also not allow the Company to tie compensation to metrics that benefit customers.

The Company has demonstrated that providing the bulk of executive compensation in the form of incentive compensation is beneficial for customers as it ties pay to achievement of customer-centric metrics and reduces fixed labor costs.

(iv) Parties' Focus On Formal Performance Evaluations And Calendars To Demonstrate Customer Benefits Is Misplaced

In this proceeding, the Department and the OAG examined the calendars and performance evaluations of the Company's top ten highest paid employees in an effort to

[257] Ex. Xcel-67 at 9 (Mustich Rebuttal).
[258] Ex. Xcel-63 at 32 (Ly Rebuttal).

identify and distinguish between the customer benefits and shareholder benefits provided by these employees. However, the Department's and OAG's efforts started from the false premise that customer and shareholder interests are at odds with each other and that there is some "bright line" distinction between the work that executives perform on behalf of customers versus shareholders.

As the Company has explained, there is no such distinction. Senior utility executives do not operate or perform tasks that can be isolated into customer versus shareholder interests. The work of these employees, and that of all of the Company's employees, is in furtherance of safely and efficiently operating the utility and providing reliable, affordable, and sustainable electric and gas service to customers.[259] Customers and shareholders both benefit when the utility operates successfully, efficiently, affordably, and is able to attract the capital it needs at reasonable cost.

The Department's and the OAG's argument also incorrectly assumes that the executives' focus on "customer benefits" or "shareholder benefits" can somehow be derived from their calendar entries and performance evaluations. This is nonsense. An employee's calendar provides very little insight into the day-to-day value provided by that employee as it only lists meetings or deadlines and does not describe the work that is being done each day by that employee. Likewise, a performance evaluation focuses on an individual employee's achievements, progress, and future goals but does not speak to the

[259] Ex. Xcel-63 at 4 (Ly Rebuttal).

work that an employee is performing on a day-to-day basis or the benefit that work provides to customers.

Nevertheless, in its brief, the OAG asserts that recovery of executive compensation should be denied because the calendar and performance evaluations provided by the Company demonstrate a "primacy of shareholder interests."[260] This is simply not the case. With regard to the calendars, the OAG's own witness admitted that these many of these entries "lacked specificity needed to determine whether the activity would be directed to ratepayer or shareholder benefits."[261] Yet to support its claim that shareholder interests are the focus of the Company's top executives, the OAG points to portions of these calendars and performance evaluations that focus on the financial health of the Company or that are related to Xcel Energy's annual shareholder meeting.[262]

Having a financially healthy utility is a benefit to both customers and shareholders. Likewise, shareholder meetings benefit customers by promoting corporate accountability, transparency, and responsible governance. These meetings allow investors to challenge management on long-term sustainability and operational performance. While the OAG cherry picks a few items from the Company's executive performance evaluations, the OAG conspicuously ignores the portions of these performance evaluations that discuss progress on customer affordability and carbon reduction goals.[263]

[260] OAG Initial Brief at 33.
[261] Ex. OAG-3 at 15 (Hinderlie Surrebuttal).
[262] *See e.g.*, Ex. OAG-4 at 15, 19 (Hinderlie Surrebuttal).
[263] Ex. OAG-4 at 19 (Hinderlie Surrebuttal).

The Department and the OAG also question the benefits provided by the Company's top executives because of the Company only provided written performance evaluations for two of its top ten highest paid employees.[264] While the Company does not conduct written performance evaluations for all its top executives, this does not mean that executive performance is not evaluated. In fact, the record demonstrates that executive performance is assessed thorough objective, measurable customer-focused AIP and LTI metrics that are directly tied to these employees' compensation. Thus, executives do undergo performance evaluation – just not the specific paper-review format the Department demands. Their performance is evaluated in a more rigorous way – by achievement of quantitative, customer-centric performance metrics.

(v) The Commission Cannot Simply Deny A Necessary Cost Of Providing Service In Order To Make Rates Lower

In its brief, the OAG emphasizes customer affordability concerns and economic hardships as another reason that the Commission should disallow all recovery of the Company's executive compensation costs.[265] The Company shares the OAG's concerns about affordability and has presented significant evidence showing that, through its efficient operations, the Company's bills have increased less than those of other utilities nationally, regionally, and within Minnesota. Regardless, the appropriate remedy for those customers who continue to struggle affording their utility bills is targeted affordability programs and measured changes to revenue apportionment – not categorical disallowance

[264] DOC Initial Brief at 52-53.
[265] OAG Initial Brief at 29-30.

of a necessary cost of service. Minnesota's legislature agrees. That's why it explicitly established that "ability to pay" should be considered as a factor in setting rates through the "establish[ment of] affordability programs for low-income residential ratepayers" and not through reduction in a utility's revenue requirement—whether tied to executive compensation or any other line item.[266]

Simply denying the recovery of all executive compensation, or any other expense. Simply to lower a proposed rate increase does not allow the Company to recovery its cost of service. Moreover, the Company has already agreed to exclude nearly 40 percent of the Minnesota electric jurisdiction portion of its top ten executives' compensation from rates.[267]

(vi) The OAG's Proposed "Affordability Performance Mechanism" Is Improper

The OAG further suggests that the Commission "could create a performance incentive mechanism that would allow rate recovery of a portion of executive compensation if Xcel meets Commission-defined affordability metrics."[268] The OAG's recommendation to condition recovery of a necessary cost of service that has been fully supported on this record on yet to be defined "affordability metrics" in a future docket is not the proper result. The Commission already approves the Company's rates, affordability programs, resource plans and acquisitions, and conservation-program budgets, among other things. In many of these dockets, the Commission must often weigh the impact of the

[266] Minn. Stat. § 216B.16, subd. 15.
[267] Ex. Xcel-64 at 29 (Ly Rebuttal).
[268] OAG Initial Brief at 35.

cost of these programs on rates against important customer benefits, such as reliability, resilience, service quality, environmental impact, and other considerations. The OAG's proposal, therefore, would seem to suggest that recovery of a necessary cost of providing service should be based on an undefined metric or set of metrics that seek to measure one customer benefit (affordability) that the Commission already oversees and routinely balances against other considerations. Moreover, the OAG's proposal would be unique to the Company, despite the fact that the Company's overall bills have increased less than those of other utilities during the last ten years. And as noted above, the Company's AIP and LTI compensation, which forms the basis for the majority of executive compensation, is already tied to customer-centric metrics such as reliability, customer satisfaction, and reduced carbon emissions.[269] For these reasons, the OAG's proposal should be rejected.

(vii) The Record In This Case Supports Recovery Of The Company's Executive Compensation Expenses

Executive leadership is indispensable to providing strategic direction, leadership, and directing the day-to-day operation of a utility. The Department and the OAG do not dispute that the Company's executive employees are necessary or that the Company must pay market-competitive compensation to attract and retain these key leaders. They simply argue that customers should not have to bear any of the cost of these executives' compensation – despite not providing any evidence that the amount of compensation that the Company is requesting is unreasonable. Such an outcome is not appropriate under Minnesota law as it impermissibly denies the entirety of a necessary and prudently incurred

[269] Ex. Xcel-64 at 32 (Ly Rebuttal); Ex. Xcel-67 at 7 (Mustich Rebuttal).

cost. The Commission should therefore reject the proposed disallowance and approve recovery of that portion of the Company's executive compensation included in the Company's MYRP request.

d. Misc. Benefit, Life, LTD Expenses

The Department continues to recommend a downward adjustment to the Company's miscellaneous benefit, life, and LTD expense.[270] The Department claims that "Xcel continues to oppose this adjustment, without additional explanation."[271] This statement is inaccurate, as the Company's evidence adequately demonstrates why the Department's recommendation should be rejected. As set forth in the Company's Initial Brief,[272] the Company provided substantial evidence supporting the amount of miscellaneous benefit, life, and LTD expense for 2025 and 2026.[273] The Company further supported these amounts by explaining that its forecasts "are formulaic, are calculated in accordance with accounting rules and standards, and are based on actuarial assumptions specific to the Company"[274] and that its forecasting approach is consistent with longstanding Commission practice and precedent in the Company's prior rate cases.[275] Moreover, the Company demonstrated that recovery of its miscellaneous benefit, life, and LTD expense is reasonable because the Company's health and wellness benefits are necessary to attract,

[270] DOC Initial Brief at 55.
[271] DOC Initial Brief at 55.
[272] *See* Xcel Energy Initial Brief at 116-119.
[273] Ex. Xcel-57 at 6-8, 84-85, Table 2, and Schedules 2 and 15 (Schrubbe Direct).
[274] Ex. Xcel-57 at 7-8 (Schrubbe Direct).
[275] Ex. Xcel-17 at 21-25 (Halama Direct).

retain, and motivate employees to provide quality service to customers,[276] and "reflect a reasonable and necessary level of expense."[277] In contrast, the Department failed to rebut the Company's evidence and put forth a recommendation unsupported by past Commission practice or precedent. Accordingly, the Commission should reject the Department's recommendation and permit the Company to recover its miscellaneous benefit, life, and LTD expense.

7. FERC Account 923 (Outside Services Employed Expense)

The Department seeks to limit the Company's recovery with regard to FERC Account 923, "outside services employed expense," which tracks professional services vendor costs not attributable to a particular operating function.[278] The Department's main argument is that the Company failed to support the proposed increases tracked in FERC Account 923 for the 2025 test year and 2026 plan year as compared to the average in FERC Account 923 for 2022-2024.[279]

The Company *did* adequately support the O&M expenses that are tracked in FERC Account 923. The Company explained that the key drivers for the increased anticipated level of expense in FERC Account 923 for the test year and plan year are overall O&M increases related to Technology Services, Enterprise Security Services, and the initiation of the wildfire mitigation program.[280] The Department complains that the Company "did

[276] Ex. Xcel-57 at 89 (Schrubbe Direct); Ex. Xcel-62 at 36 (Ly Direct).
[277] Ex. Xcel-57 at 89 (Schrubbe Direct).
[278] DOC Initial Brief at 68-69.
[279] DOC Initial Brief at 68-69.
[280] Ex. Xcel-28 at 23 (Robinson Rebuttal).

not provide so much as a single citation" supporting O&M increases in these areas.[281] But the Company provided extensive testimony supporting each of these areas of increased O&M.[282] There is no need for an additional, separate explanation of the increase for the subparts of these O&M expenses that are tracked in FERC Account 923. The Department seems to think that in addition to presenting testimony organized by business area, the Company must also reconfigure the presentation of its case and also provide testimony organized by FERC account. This would be needlessly duplicative, since the same expenses would be addressed in testimony by business unit and again in testimony by FERC account. There is no basis for such a requirement.

More broadly, the Department's attempt to limit rates by focusing on just one FERC account is improper. The Commission's ratemaking process should consider system and Company needs across the entirety of the Company, not sliced and diced by FERC account. Budget accuracy does not mean that every budgeted dollar is spent in exactly the same way that it was forecast to be spent, and that is even more true for FERC accounts, which are not used by the Company as the basis for budgeting.[283] The Department's recommendation to impose a cap on FERC Account 923 is baseless and should be rejected.

8. Insurance

Intervenors Department and XLI both propose substantial reductions to the Company's requested insurance expense, taking the position that the increase in insurance

[281] DOC Initial Brief at 70, note 353.
[282] *See generally* Exs. Xcel-33 (Scheller Direct) and Xcel-47 (Sherwood Direct).
[283] Ex. Xcel-28 at 20 (Robinson Rebuttal).

premium cost was not properly supported by the Company and that the Company is unfairly subsidizing insurance costs associated with wildfire risk in other jurisdictions. Neither of these complaints are accurate. Nor do they justify the under-recovery of prudently-incurred insurance premium expenses[284] proposed by the Department and XLI.

a. The Company Supported Its Forecasted Insurance Premium Expense Increase

The Company supported its request for recovery of insurance premium expense through the testimony of Robert Miller, an experienced risk management professional who has served as the Director, Hazard Insurance for Xcel Energy, Inc. for over a decade.[285] By contrast, neither of the intervenor witnesses that testified regarding insurance premium costs, Ms. Jones for the Department and Ms. LaConte for XLI, have any experience in risk management or insurance.[286]

XLI states in its heading to its brief discussion of insurance premiums that the Company has failed to "justify its increased excess liability insurance" but provides no analysis in its brief as to the Company's failure to justify either the amount of excess liability insurance acquired or the premiums associated with that insurance.[287]

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[284] The Department contends that the Company's insurance premium expenses are "unreasonable," citing to Ms. Jones' testimony. DOC Initial Brief at 38. However, nowhere in Ms. Jones' Direct or Surrebuttal testimony does she contend that the insurance premiums, or the amount or types of insurance obtained, was in any way unreasonable.
[285] Ex. Xcel-54 at 1 and Schedule 1 (Miller Direct).
[286] Ex. DOC-23 at 1 (Jones Direct); Tr. Vol. 2 (Dec. 18, 2025) at 416 (Jones); Ex. XLI-2 at 1 and Appendix A (LaConte Direct).
[287] XLI Initial Brief at 26.

The Department bases its argument that the Company has not adequately supported its request for recovery on: (1) its claim that Xcel Energy's use of a two-year lookback period as the starting place for its forecast somehow renders that forecast unreliable,[288] (2) by pointing to the volatility of insurance expenses over time, and (3) its claim that the Company has failed to perfectly capture refunds and credits in its insurance expense forecast.

Notably, while questioning the two-year lookback period, Ms. Jones did not raise any concern about the Company's use of 2023 and 2024 actual insurance expense as a starting point for its forecast. Ms. Jones, in fact, used 2024 actual insurance expense as the starting point for her analysis.[289] In any event, the Department's analysis on this point willfully ignores the significant record evidence supporting the Company's forecast. First, the Department ignores Mr. Miller's testimony demonstrating that the Company's initial forecast for insurance expenses is far more than a simple two-year lookback:

> We develop our out-year budgets by consulting with our insurance brokers to anticipate if the general insurance markets will be trending up, trending down, or staying relatively flat. In addition to that, we need to understand how our exposure metrics such as number of employees, miles of pipes and wires, or insurable value of our assets will be changing for the upcoming budget cycles. With this information, we then estimate the impact of insurance costs going forward. Generally, our test year budget is based on insurance premiums we paid in 2023 and 2024. For the plan years, we then analyzed these general trends and adjusted the budgets accordingly. I discuss these budgets for our different lines of coverage in further detail, below.[290]

[288] DOC Initial Brief at 38-39, 41.
[289] Ex. DOC-23 at 25 (Jones Direct).
[290] Ex. Xcel-54 at 20 (Miller Direct).

Mr. Miller's testimony contains pages and pages of analysis of insurance market trends, including discussion of the general hardening of insurance markets and drivers of increased premium costs[291] and specifically addresses the reasonableness of the Company's excess liability program and the drivers of its increased costs.[292] The Department's claim that the Company simply looked at the last two years of insurance premium expense and based its initial forecast on that information is wrong.

The Department also ignores the vast majority of Mr. Miller's rebuttal testimony, including the Company's updated forecast for excess liability premiums. In his direct testimony, Mr. Miller explained that because the renewal date for excess liability insurance fell on October 18, 2024, well after the finalization of rate case numbers for initial filing, he would provide updated excess liability cost figures in rebuttal testimony.[293] The updated excess liability premium numbers were based on actual excess liability premium expenses for January through June 2025 and forecasted premiums for the remainder of 2025. The updated numbers were also impacted by wildfire premium allocation, which is provided by the Company's insurers and brokers.[294] A comparison of the as-filed and the updated numbers demonstrate that the Company's forecast slightly under-forecasted expenses for 2025 (3.5 percent) and slightly over-forecasted costs for 2026 (2.4 percent).[295] These

[291] Ex. Xcel-54 at 22-23 (Miller Direct).
[292] Ex. Xcel-54 at 27-31 (Miller Direct); Ex. Xcel-56 at 4-5 (Miller Rebuttal)
[293] Ex. Xcel-54 at 31 (Miller Direct).
[294] Ex. Xcel-56 at 4 (Miller Rebuttal).
[295] Ex. Xcel-56 at 2 (Miller Rebuttal).

updated numbers demonstrate that the Company's predictions are aligned with actual expense experience.

The Department also contends that the Company failed to adequately support its general liability and excess liability increase, citing to Ms. Jones' direct testimony.[296] That testimony, however, is conclusory and devoid of any analysis, stating only that "the general liability and excess liability premiums increased dramatically . . . . from 2024 to 2025 forecast and the Company has not provided adequate support for its estimated test year expenses."[297] The only specific example Ms. Jones provides is related to the allocation of expenses due to wildfire exposure and liabilities in other states.[298] The remainder of the Department's analysis in Ms. Jones' Direct is limited to its contention that the increase in insurance expenses departs from the Department's anticipated trendline.[299] The volatility of expense alone, however, does not support a reduction in the recovery of otherwise prudently-incurred utility expenses.[300]

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[296] DOC Initial Brief at 41. The Department also seems to suggest that the Company failed to develop the record sought by the Commission with respect to insurance, despite its own witness stating in testimony that the Company complied with the Commission's Order on this point. DOC Initial Brief at 38, 42; Ex. DOC-24 at 23 (Jones Surrebuttal).

[297] Ex. DOC-23 at 24 (Jones Direct).

[298] Ex. DOC-23 at 25 (Jones Direct). The Company addresses this contention in detail below.

[299] *Id.*

[300] Minn. Stat. § 216.16, subd. 6 provides: "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* . . . ." (emphasis added).

The only evidence proffered by either Ms. Jones or Ms. LaConte regarding premium cost is related to how those costs have changed over time. Additionally, Ms. Jones provided a comparison of the forecasted increase from 2024 actual expenses to 2025-6, claiming that "the Company's estimates for insurance premium expenses are not consistent with . . . the previous years . . . and the trendline of previous years . . . ." The Company does not dispute that there is a significant increase from its 2024 actual expense to the amount of premium expense forecast for 2025. The Company has explained the reasons for that increase – specifically that the overall insurance market has hardened and that the insurance industry perceives an increased wildfire risk for utilities. Mr. Miller testified to a specific paradigm shift in excess liability underwriting:

> Beginning in late 2023, many ELI insurers modified their underwriting guidelines, particularly in the area of wildfire coverage, and took a close look at their renewals for the year 2024. In many cases, the amount of wildfire coverage provided was reduced and the premiums went up.[301]

This change impacted all utilities, not just Xcel Energy.[302]

Put plainly, despite the Company's efforts to manage costs by negotiating specialized coverages, layering its insurance and using the captive insurer structure, the Company is not immune to overall industry trends and the hardening of the insurance market.[303] There is no evidence in the record contradicting Company witness Miller's testimony that the excess liability insurance market has hardened as a result of industry-wide increase in risk or that underwriters have adjusted their practices with respect to

[301] Ex. Xcel-56 at 2 (Miller Rebuttal).
[302] Ex. Xcel-54 at 2 (Miller Direct); Xcel-56 at 14 (Miller Rebuttal).
[303] Ex. Xcel-54 at 23 (Miller Direct).

wildfire risk. It is undisputed that insurance costs are increasing, and that they are increasing as a result of market forces impacting the utility market. None of this renders the Company's insurance expense unreasonable.

The Department also contends that because the Company's forecast did not take into account the possibility of certain refunds or distributions, the forecast is not reliable.[304] As demonstrated by the information contained in Mr. Miller's rebuttal testimony, certain insurance refunds *are* included in the premium for those policies, and are therefore accounted for in the Company's forecasts. Other distributions are not issued in a predictable manner, but available information, such as guidance provided by those insurers, *is* incorporated into the Company's forecasts.[305] To address the Department's concerns regarding the potential for the receipt of unanticipated refunds or credits to cause over-recovery of insurance expense, the Company proposed a true-up for insurance costs.[306] The Company's proposal would avoid both the risk of over-recovery of insurance costs due to receipt of refunds and under-recovery of prudently-occurred insurance costs. The Department has not responded to this proposal in either testimony or briefing.

b. The Company Is Not Subsidizing Other Jurisdictions' Insurance Premium Costs

Both XLI and the Department find fault with the allocation of insurance premium expense to the Company, assuming that because certain other Xcel Energy operating companies have had wildfire claims experience while to date the Company has not, the

[304] DOC Initial Brief at 41-42.
[305] Ex. Xcel-56 at 10 (Miller Rebuttal).
[306] Ex. Xcel-56 at 11 (Miller Rebuttal).

Company must be subsidizing those other operating insurance companies' premium cost. This simplistic view is not supported by the record. As Mr. Miller testified, each operating company's risk profile and loss history are carefully considered in allocating premiums among those operating companies.[307]

Mr. Miller testified that there are different variables that impact premium costs. Some of those variables impact the insurance market for the entire utility industry and some variables, based on assessment of an individual company's risk, will impact only that Company. Overall market conditions, including market hardening and perception of industry risk impact the utility sector as a whole are caused by "large *industry-wide* losses due to events such as wildfires and gas explosions."[308] Individual loss loading and wildfire risk loading, on the other hand, impact individual operating companies.[309] The operation of these two different aspects of premium cost impact can be seen at work in the comparison between the Company's initial forecast of excess liability premiums at the time this case was filed and the Company's updated forecast provided as part of Mr. Miller's rebuttal. The updated forecast, which was based on six months of actual premium experience, shows that the 2025 forecasted overall excess liability expense to XEI increased by 75 percent, but the increase in the Company increased less than 4 percent.[310] This is because while the overall cost of insurance increased as a result of a combination of factors impacting premium expense, including overall market hardening and industry-

[307] Ex. Xcel-54 at 7 (Miller Direct).
[308] Ex. Xcel-54 at 30 (Miller Direct) (emphasis added).
[309] Ex. Xcel-56 at 15-16 and Schedule 4 (Miller Rebuttal).
[310] Ex. Xcel-56 at 3, Table 1 (Miller Rebuttal).

level risk perception, the percent of the excess liability insurance allocated to the Company *decreased* by 12 percent due to loss loading and wildfire loading. Similarly, while the 2026 updated forecast showed a 70 percent increase in overall costs from the initial forecast, the amount allocated to the Company actually *decreased*, with a 13 percent decrease in the amount allocated to the Company.[311] The Company, like any other utility company, regardless of individual risk profile, will be impacted by premium costs affected by overall market changes caused by industry-wide underwriting changes and market hardening.[312] The Company's premium costs are not, however, impacted by direct losses suffered by an affiliate due to loss loading and wildfire risk loading.[313]

The record demonstrates that the difference in wildfire risk and claims experience between the Company and other Xcel Energy, Inc. operating companies is taken into account in allocating excess liability premium costs. First, XEI has purchased stand-alone western wildfire policies as well as separate eastern wildfire policies, which cover only the Minnesota and Wisconsin jurisdictions.[314] Further, as stated in Mr. Miller's testimony, the Company's insurance brokers apply both wildfire loading and loss loading to ensure proper allocation of premium expenses.[315] A review of the excess liability premium allocation demonstrates that the Company receives a far lower allocation of the stand-alone wildfire insurance purchased by Xcel Energy when compared to western jurisdictions, with the

[311] *Id.*
[312] Tr. Vol. 1 (Dec. 17, 2025) at 256-57 (Miller).
[313] *Id.*
[314] Ex. Xcel-56 at 4 and Schedule 1 (Miller Rebuttal).
[315] Ex. Xcel-56 at 15 and Schedule 4 (Miller Rebuttal).

exception of the stand-alone eastern wildfire insurance, which it splits with Wisconsin. A review of the overall excess liability premium distribution shows that the Company is not subsidizing Xcel Energy's western jurisdictions' premium costs.[316]

Both XLI and the Department propose that the Commission use historical averages to limit the Company's recovery of insurance expense.[317] Each party arrives at a different proposed reduction, demonstrating the lack of a reasonable connection between these proposals to the reasons the intervenors advance for the reductions. Notably, despite access to information related to the allocation of wildfire risk to the different jurisdictions, neither intervenor provided testimony demonstrating how its proposed use of averaging addresses the alleged misallocation of premiums due to wildfire risk. Both the Department's and XLI's proposed adjustments should be rejected.

9. Prepaid Pension And Accrued Liabilities

The Department's arguments in its Initial Brief regarding Xcel Energy's request to include the prepaid pension asset in rate base and to earn a return at the Company's weighted average cost of capital (WACC) are flawed for several reasons. The Department argues that the Company "only has a contingent reversionary interest in pension trust property of nominal or no value,"[318] which is incorrect and confuses the pension trust balance with the prepaid pension asset. The prepaid pension asset is a regulatory asset that reflects the cumulative contributions made by shareholders to the pension fund that exceed

[316] *Id.*
[317] Ex. DOC-24 at 24 (Jones Surrebuttal); Ex. XLI-7 at 22 (LaConte Surrebuttal).
[318] DOC Initial Brief at 61.

pension expense – not the fund itself. As already explained by the Company, it is not seeking to recover the amount of either the full pension fund or recover the contributions it made to the prepaid pension asset; rather, as with all other prepayments and regulatory assets, it is seeking to earn a return on the cumulative contributions to the pension fund made by the Company that exceed the cumulative pension expense paid by customers – i.e., to compensate investors for the use of their money (the prepayment) to fund future employee pensions.[319] The undisputed evidence is that the prepaid pension asset consists of Company supplied funds that exceed pension expense, and that are providing a benefit both to current and future employees (in the form of funding for retirement benefits) and to current customers (in the form of market returns on the asset that reduce customers' pension expense in rates).

The Department's argument is unsupported by law. The Department relies almost entirely on law and treatises regarding property interests in pension trusts,[320] which have no applicability in this case where the Company is not seeking recovery of either the amounts in the pension fund nor the principal balance of the prepaid pension asset. The Department's argument also lacks any value because it ignores that the Company manages the trust, and the beneficiaries of the fund are Company employees, meaning that the trust exists precisely to serve the Company's employees and customers. The Department's position is also contrary to Minnesota case law regarding prepaid pension assets. In *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for*

[319] Xcel Energy Initial Brief at 135, 141-142; Ex. Xcel-58 at 6 (Schrubbe Rebuttal).
[320] *See* DOC Initial Brief at 61-63.

Authority to Increase Rates for Electric Service in the State of Minnesota, No. A23-1672, 2025 WL 249995, at *8-10 (Minn. Ct. App. Jan. 21, 2025), the Minnesota Court of Appeals held that the prepaid pension asset should earn a return so long as the asset consists of shareholder derived funds. There is no debate in this case that the prepaid pension asset consists solely of shareholder (Company) supplied funds.[321] Nor is the existence of a trust determinative of whether a utility is entitled to a return on funds contributed to the trust; rather, trusts are used for other types of costs (e.g., nuclear decommissioning costs), and the Company maintains control, reports balances of, and otherwise manages those funds.[322] Ultimately, it is not the legal form of the asset but the nature of it – is it a service producing asset consisting of Company-supplied funds? – that matters for cost recovery under *Hope* and *Bluefield*.[323] Lastly, there is never a guarantee that an asset that is providing service to customers today will have an asset balance at the end of its life; that is true of physical assets like poles and wires as well as prepayments such as Accumulated Deferred Income Taxes (ADIT).

Importantly, the Department fails to acknowledge or otherwise rebut Xcel Energy's evidence showing why it is reasonable for the Company to earn a WACC return on the prepaid pension asset. Without completely restating Xcel Energy's Initial Brief, the

[321] *See* Xcel Energy Initial Brief at 140; Ex. Xcel-57 at 81, 83, and Schedule 14 (Schrubbe Direct); Ex. Xcel-58 at 12 (Schrubbe Rebuttal).
[322] *In the Matter of the Petition of Xcel Energy for Approval of the 2025-2027 Triennial Nuclear Plant Decommissioning Study and Assumptions*, Docket No. E002/M-24-394, Order Point No. 6 (May 14, 2025).
[323] *See Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

Company's evidence demonstrates the following: (1) the prepaid pension asset benefits both Xcel Energy and customers because the pension benefit that gives rise to the prepaid pension asset helps the Company attract and retain employees needed to provide safe and reliable electric service to customers;[324] (2) recovery of Xcel Energy's operating costs related to pension expenses does not compensate the Company in any way for the prepayments that have created the prepaid pension asset;[325] (3) the Company's prepaid pension asset provides significant financial benefits to customers, reducing the cost of the pension expense that is paid by customers each year;[326] and (4) Minnesota case law as well as case law from other courts and commissions, including every other jurisdiction in which Xcel Energy provides utility service, support the conclusion that the prepaid pension asset is a shareholder funded service-producing asset that benefits customers and employees, and therefore belongs in rate base.[327] For all of these reasons, it is clear that the Company's prepaid pension asset should be included in rate base and earn a WACC return.

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[324] *See* Xcel Energy Initial Brief at 135-36; Ex. Xcel-57 at 24-25, 69 (Schrubbe Direct); Ex. Xcel-58 at 27-29 (Schrubbe Rebuttal); Ex. Xcel-62 at 41 (Ly Direct).

[325] *See* Xcel Energy Initial Brief at 136-37; Ex. Xcel-57 at 68-69 (Schrubbe Direct); Ex. Xcel-58 at 2, 21-22, and Schedule 1 at 4 (Schrubbe Rebuttal); Ex. Xcel-97 at 1 (Schrubbe Revised Witness Summary).

[326] *See* Xcel Energy Initial Brief at 137-39; Ex. Xcel-57 at 25, 64, and 69-73, Table 16 (Schrubbe Direct); Ex. Xcel-58 at 13 (Schrubbe Rebuttal).

[327] *See* Xcel Energy Initial Brief at 139-40; *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota*, No. A23-1672, 2025 WL 249995, at *8-10 (Minn. Ct. App. Jan. 21, 2025); Ex. Xcel-57 at 81, 83, and Schedule 14 (Schrubbe Direct) (citing *Public Service Company of Colorado v. The Public Utilities Commission of the State of Colorado*, Case No. 19CV31427, ORDER at 18 (Denver County District Court, Mar. 12, 2020); *New Mexico Attorney General v. New Mexico Public Regulation Comm'n*, 359 P.3d 133, 140 (N.M. 2015); *Application of Southwestern Public Service Company for Authority*

Although Xcel Energy maintains that it is entitled to earn a WACC return on the prepaid pension asset, it offered to accept the Department's surrebuttal recommendation for the Company to apply a rate of return at its cost of long-term debt to the prepaid pension asset and the associated FAS 106 and FAS 112 accrued liabilities *in this case only* in order to reduce the number of contested issues.[328] The Department did not accept this outcome despite the Department's only testimony regarding the prepaid pension asset expressly concluding that earning a return at the Company's cost of long-term debt on the prepaid pension asset is within the range of reasonableness.[329] Reasonable outcomes are not necessarily limited to a single result; rather, there can be a range of reasonableness and simply selecting the lowest number in that range is not permissible.[330] In addition, allowing the Company to earn a return at its cost of long-term debt is effectively the only position that is currently undisputed regarding the prepaid pension asset. If the CAH is disinclined to accept this position that aligns with both the Department's testimony and the Company's agreement to that outcome in this case, then the prepaid pension asset belongs in rate base, consistent with the Company's and Department's testimony, at a full WACC.

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to Change Rates, Docket No. 43695, ORDER ON REHEARING at 23 (Feb. 23, 2016)); Ex. Xcel-58 at 12 (Schrubbe Rebuttal).

[328] *See* Xcel Energy Initial Brief at 142-43; Ex. Xcel-97 at 2 (Schrubbe Revised Witness Summary).

[329] *See* Ex. DOC-11 at 15-19 (Hunt Surrebuttal).

[330] *See Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 11-12 (Minn. 1980); *see also, e.g., Duquesne Light Co. v. Barasch*, 488 U.S. 299, 312 (1989) (finding that there is a "constitutional range of reasonableness" within which state regulatory agencies may act); *Sw. Bell Tel. Co. v. State Corp. Comm'n*, 386 P.2d 515, 554 (Kan. 1963); *Cent. Me. Power Co. v. Pub. Utils. Comm'n*, 455 A.2d 34, 39 (Me. 1983).

10. Allocations

a. General Allocator

The Department argues that the Commission should reject the Number of Employees methodology in favor of the Full-Time Equivalent Employees (FTE) Hours methodology for the labor component of the Company's General Allocator.[331] The Department's argument for denial ignores the reality for Xcel Energy Services' (XES) employees supporting operating companies or affiliates, as set forth in the testimony of Company witness Nicole L. Doyle.[332]

The Commission's original concern about using the Number of Employee allocator within the three-part General Allocator pertained to the potential over-allocation of costs to regulated entities.[333] Here, however, the Company has demonstrated that using the FTE Equivalent methodology in all jurisdiction would increase the allocation of costs to regulated entities.[334] As set forth in Table 1 to witness Nicole Doyle's Direct Testimony and described in the Company's Initial Brief, the ratio of total XES costs allocated to non-regulated entities is smaller under the FTE Hours methodology than under the Number of Employees methodology.[335]

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[331] DOC Initial Brief at 65-66.
[332] Ex. Xcel-49 at 10 (Doyle Direct); Ex. Xcel-50 at 10-11 (Doyle Rebuttal); Xcel Energy Initial Brief at 144.
[333] DOC Initial Brief at 66 (*quoting In re N. States Power Co.'s Cost Allocation Procedures and General Allocator*, Docket No. E,G002/AI-10-690, ORDER REQUIRING CHANGE IN GENERAL ALLOCATOR AND REQUIRING FILINGS (Mar. 15, 2011).
[334] Ex. Xcel-49 at 20-21 and Table 1 (Doyle Direct); Xcel Energy Initial Brief at 146.
[335] Ex. Xcel-49 at 21 (Doyle Direct); Xcel Energy Initial Brief at 146.

Given that its past concern about over-allocation to regulated versus non-regulated entities has been fully disproven, the Department has changed its position in this case, now suggesting that using the Number of Employees methodology is "too crude to accurately reflect labor costs."[336] This is a hyperbolic and inaccurate statement. The Number of Employees methodology reflects the on-the-ground nature of XES work, where costs are driven by the number of employees working within NSPM rather than the day-to-day, variable nature of the operating company (NSPM) employees' work.[337] Whereas the Department relies on a theory about what is most accurate, NSP provided testimony explaining that the actual XES work being allocated is on behalf of operating companies as a whole and driven by the number of employees in each operating company, rather than by the number of hours worked by those operating employees.[338]

Indeed, the Department offers no facts or evidence that the quantity or type of XES employees' work is actually driven by the hours of the operating company employees to whom XES employees provide services, and its claim that using the Number of Employees methodology would result in no costs allocated to non-regulated entities without employees is incorrect. Further, it is undisputed that the Number of Employees methodology, unlike the FTE Hours methodology, ensures that neither non-regulated affiliates nor other jurisdictions are subsidizing the cost to support the Company's Minnesota customers.[339]

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[336] DOC Initial Brief at 66.
[337] Ex. Xcel-49 at 16-17 (Doyle Direct); Xcel Energy Initial Brief at 146.
[338] Ex. Xcel-49 at 18-19 (Doyle Direct); Ex. Xcel-50 at 6 (Doyle Rebuttal); Xcel Energy Initial Brief at 150.
[339] Ex. Xcel-49 at 18-19 (Doyle Direct); Ex. Xcel-50 at 11 (Doyle Rebuttal); Xcel Energy Initial Brief at 150.

The more accurate allocation of costs is necessary to be consistent with the obligation of Minnesota electric customers to pay for a reasonable and equitable share of costs they have incurred, under Minn. Stat. § 216B.16, subd. 6.

In sum, were the Commission to adopt the Department's recommendation to use the FTE Hours methodology, Minnesota customers would not be paying for their fair share of the Company's cost to furnish service to the Minnesota regulated electric utility.[340] Therefore, the Company's request to use the Number of Employees methodology in lieu of the FTE Hours methodology is appropriate to ensure (1) proper allocation of employee time to support the regulated Minnesota operating company; (2) that neither the non-regulated affiliates nor other operating companies are subsidizing the costs to support the regulated Minnesota operating company; and (3) reasonable business practices and rates. The Department's proposed adjustment is not appropriate based on proper cost causation principles and the record evidence in this proceeding.

b. Interchange Agreement Allocator

In its Initial Brief, the Department continues to recommend that the Commission require the Company to apply the 2025 Interchange Agreement demand allocator as filed with the Federal Energy Regulatory Commission (FERC) in March 2025 to determine the interchange costs and revenues in both 2025 and 2026.[341] The Company fully detailed in its Initial Brief why application of the 2025 demand allocator to the forecasted 2026 interchange agreement costs and revenues would not accurately reflect the 2026 cost of

[340] Ex. Xcel-49 at 24-25 (Doyle Direct); Xcel Energy Initial Brief at 144.
[341] DOC Initial Brief at 79-80.

service and forecasted peak demands in the 2026 plan year.[342] While the Company does not repeat those explanations in this Reply Brief, it is worth noting the Department's characterizations regarding this issue are inconsistent with the facts in the record. The Department states in its Initial Brief that "Xcel[ ] proposes to rely on even older allocators dating to 2023," concluding "Xcel's position that allocators dating to 2023 provide a more reliable estimate for 2026 than 2025 data makes little sense."[343] This is simply not accurate. As explained in testimony and the Company's Initial Brief, the *only* difference between the demand allocator accepted by FERC on May 6, 2025 and the 2025 demand allocator presented in the Company's supplemental direct testimony was the use of updated transmission loss multipliers based on the updated system loss study included in the FERC filing.[344] But as detailed in the Company's Initial Brief, using those updated transmission loss multipliers would increase both the 2025 and 2026 revenue requirements.[345] The Company used the older transmission loss multipliers because its supplemental direct was prepared before the FERC filing was finalized. However, use of the older transmission loss multipliers is not a "detriment to customers" as the Department claims; instead, it results in slight reductions to both the 2025 and 2026 revenue requirements.

[342] Xcel Energy Initial Brief at 151-159.
[343] DOC Initial Brief at 80.
[344] Ex. DOC-1 at MAJ-D-4, Page 4 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A). The transmission loss multiplier submitted to FERC on March 14, 2025 was updated based on data from 2020-2023 whereas the transmission loss multiplier utilized in the Company's supplemental direct testimony was based on data from 2019-2022.
[345] Xcel Energy Initial Brief at 154-155, 157-158.

Further, as explained in testimony and the Company's Initial Brief, the demand allocator approved by FERC in May 2025 does not include any more recent actual monthly coincidental peak demand data or any other updated actual data as compared to the demand allocators provided in supplemental direct. Both use actual coincidental peak demand data through June 2024.[346] Instead of basing the 2026 demand allocator on January 2024-December 2026 data, as proposed by the Company, the Department's recommendation would remove all 2026 forecasted peak demand data from the determination of 2026 interchange costs and revenues. The result would be to allocate the 2026 interchange costs and revenues on older data (January 2023-December 2025) that fails to accurately represent the 2026 plan year.

Finally, in response to the Company's explanation that the demand allocator is only one component of the Interchange Agreement billings with NSPW—and that isolating a single component using prior-year data does not accurately reflect the 2026 cost and revenue allocations[347]—the Department asserts that "Xcel failed to identify additional changes despite being invited by the Department to do so."[348] To the contrary, the Company did identify additional changes. In fact, the Company outlined eleven distinct components

[346] *Compare* Ex. Xcel-18 at Schedule 17, (Halama Supplemental Direct) (Interchange Demand Allocator) *with* Ex. DOC-1 at MAJ-D-4, Page 145 (Johnson Direct) (Xcel Energy's Response to DOC IR 1160, Attachment A) (using the same actual peak demand data through June 2024). For the 2025 test year, the demand allocator was computed based on 18 months of actuals (through June 2024) and 18 months of projected peak demands (through December 2025). For the 2026 plan year, the demand allocator was computed using six months of actuals (through June 2024) and forecasts through December 2026.
[347] Ex. Xcel-19 at 61 (Halama Rebuttal); *see also* Ex. DOC-2 at MAJ-S-2 (Johnson Surrebuttal) (Xcel Energy's Response to DOC IR 3107).
[348] DOC Initial Brief at 80 (citing Ex. DOC-2 at 6 (Johnson Surrebuttal)).

of the Interchange Agreement billings that can vary from year to year.[349] Additionally, contrary to the Department's claim, the Company provided details of these forecasted values for 2026 alongside 2025, showing how these components varied between 2025 and 2026.[350] These components, taken together, demonstrate that applying the prior year's demand allocator as recommended by the Department does not accurately reflect the full set of cost and revenue drivers for 2026. In contrast, the Company's 2026 forecasted demand allocator reflects a reasonable and supported projection based on the most current available data and analysis.

c. Wildfire Allocator

Both the Department and the OAG disagree with the Company's proposal to allocate wildfire mitigation costs using the Total Plant Ratio, incorrectly claiming that this methodology causes NSPM to subsidize other operating companies' wildfire costs. They recommend instead that indirect wildfire costs be allocated based on the ratio of direct wildfire costs allocated from XES to NSPM, although each goes about the allocation from

[349] Other components of the interchange agreement that change from year to year and are filed with FERC on an annual basis include energy allocators, electric plant in service, allowance for funds used during construction, accumulated provision for depreciation/amortization, property taxes, insurance expense, depreciation and amortization expense, O&M expense, purchased power costs, taxes and tax credits, and interest expense. *See* Ex. DOC-2 at MAJ-S-2 (Johnson Surrebuttal) (Xcel Energy's Response to DOC IR 3107); Tr. Vol. 2 (Dec. 18, 2025) at 384-392 (Johnson) (acknowledging the various components of the interchange agreement that change and are updated every single year).

[350] Xcel Energy Initial Brief at 158 (citing Ex. Xcel-101 Attachment C (Xcel Energy's Response to DOC IR 1160)); *see also* Tr. Vol. 2 (Dec. 18, 2025) at 389-392 (Johnson) (discussing differences between 2025 and 2026 Interchange Agreement revenues and expenses).

a different perspective. Specifically, the Department suggests that applying the 2025 direct cost allocation ratio to indirect costs results in a $1.7 million reduction in indirect costs in the 2025 test year, and applying the 2026 direct cost allocation ratio results in a reduction of $1.8 million in indirect cost allocation in the 2026 test year.[351] The OAG proposes the same dollar amount adjustment, but claims it is because the Company did not provide the direct cost allocation ratio (citing to OAG's surrebuttal, rather than the subsequent evidentiary hearing testimony where this was disproven)[352] and therefore all indirect wildfire mitigation costs should be removed.[353] Fundamentally, the Department and OAG misstate the subsidization risk and have confused their own methodologies entirely.

To begin with, the Company continues to support the long-standing, Commission-approved, cost causative methodology for allocating indirect costs to NSPM: XES wildfire mitigation costs are direct-charged to NSPM Minnesota where possible, and indirect costs are allocated to NSPM Minnesota using the Total Plant ratio.[354] The Total Plant ratio ensures that NSPM Minnesota customers are only bearing the share of indirect wildfire

[351] DOC Initial Brief at 73-74.
[352] Tr. Vol. 2 (Dec. 18, 2025) at 408:2-25 (Johnson).
[353] OAG Initial Brief at 51.
[354] Ex. Xcel-50 at 17-18 (Doyle Rebuttal). Notably, costs are not direct-charged or allocated from XES all the way to the NSPM Minnesota electric jurisdiction; rather, a jurisdictional allocator is applied to allocate total NSPM Minnesota costs to the Minnesota electric jurisdiction. *Id*. at Table 1. This is important because, as described below, the Department's new methodology in its Initial Brief compares the ratio of direct wildfire mitigation costs charged to the NSPM Minnesota electric jurisdiction to total XES costs to arrive at an indirect cost ratio, ignoring the jurisdictional allocation process.

mitigation costs proportional to NSPM Minnesota transmission and electric distribution assets, which is the most cost causative methodology.[355]

The Department and OAG both assert that this allocator could mean NSPM Minnesota customers would bear too large a share of wildfire mitigation costs, because the risk of wildfire occurrence is higher in other jurisdictions.[356] In doing so, they identify contributing risk factors and overall risks *that relate to discrete events and are therefore captured by direct cost assignment*.[357] The question for indirect cost allocation is what is driving (the correct cost causation of) those indirect costs, such as IT supporting situational awareness tools and fire science modeling IT costs. Those costs tend to be driven by the Company's assets that must be monitored, which the Total Plant Ratio represents.[358]

Second, the OAG and Department's methodologies for using direct cost assignment to allocate indirect costs do not make sense. As set forth in Company witness Nicole Doyle's Rebuttal Testimony, adjustments to remove $1.7 million in wildfire mitigation costs from 2025 and $1.8 million from 2026 would not remove a portion of indirect-charged wildfire costs to reflect the direct charged ratio; rather these adjustments would effectively mean that NSPM's Minnesota jurisdiction would remove *all* indirect charged costs from the test year.[359] This is not reasonable, as neither the Department nor OAG suggest the Company should not incur indirect wildfire mitigation costs, and it is

[355] Ex. Xcel-49 at 17-18 (Doyle Direct).
[356] DOC Initial Brief at 73-74; OAG Initial Brief at 50.
[357] Ex. Xcel-50 at 19 (Doyle Rebuttal).
[358] Ex. Xcel-50 at 20 (Doyle Rebuttal).
[359] Ex. Xcel-50 at 15, Table 1 (Doyle Rebuttal) (showing that the Total Minnesota Indirect Charges are $1.7 million for 2025 and $1.8 million for 2026).

undisputable that the Company will incur such costs in implementing a wildfire mitigation program in Minnesota.

The Department argued in Surrebuttal but not in its Opening Brief, and the OAG continues to argue, that removing all indirect costs is acceptable because the Company did not provide information allowing the OAG to calculate the proportion (ratio) of total wildfire mitigation costs direct charged to Minnesota versus the total costs.[360] This is not correct. The Company demonstrated at hearing that it provided the total XES wildfire mitigation costs, the indirect charged costs, and the direct charged costs in discovery and Nicole Doyle's Rebuttal Testimony.[361] While the Company did not calculate an adjustment with which it did not and does not agree, this data allowed the Department and OAG to make their preferred calculations (even though the methodology is not sound).

Fundamentally, the Department and OAG each misunderstand both the amount of the wildfire mitigation costs and the proper allocation process for them. Both the Department and OAG initially argued in Intervenor Direct that $3.3 million and $4.3 million in "indirect" wildfire mitigation costs should be removed from the 2025 and 2026 test and plan year, respectively.[362] Upon realizing these amounts reflected *all* wildfire mitigation costs (both direct assigned and indirect costs that are allocated to NSPM Minnesota), OAG and the Department reduced their recommended adjustments in Surrebuttal to remove $1.7 million and $1.8 million from the 2025 and 2026 test and plan

[360] OAG Initial Brief at note 308 (citing Ex. OAG-5 at 29, SL-D-14 (Lee Direct)).
[361] Tr. Vol. 2 (Dec. 18, 2025) at 408:2-25 (Johnson).
[362] Ex. DOC-1 at 46 (Johnson Direct); Ex. OAG-5 at 29 (Lee Direct).

years – the full amount of the indirect charges to Minnesota, based on the continuing argument the Company did not provide their preferred ratio. The OAG continues to support this errant position in its Initial Brief, even though the Company made the requested information fully available prior to Surrebuttal.

The Department, however, changed its position again between Surrebuttal and its Initial Brief, but based on recognition that the percentage of direct costs allocated to Minnesota has in fact been available. Therefore, the Department supplies a new table in its Initial Brief, arguing that "if Xcel's Minnesota operating company is responsible for only 10% of XES's direct wildfire costs, then it would only be allocate 10% of the indirect wildfire costs."[363] Applying this logic, the Department suggests that its proposed NSPM allocation of indirect wildfire costs is $1.6 million in 2025 and $2.4 million in 2026. While the Company does not agree with this methodology, the bigger problem is that the Department derives revenue requirement adjustments of $1.7 million in 2025 and $1.8 million in 2026 (roughly the same adjustments initially proposed that would have removed

[363] DOC Initial Brief at 74 (table not numbered/titled), but appears as follows without underlying calculations:

	2025	2026
Total Indirect Wildfire Costs	$16.5 million	$19.8 million
NSPM's Allocation of Direct Wildfire Costs	9.7%	12%
Department's Proposed NSPM Allocation of Indirect Wildfire Costs	$1.6 million	$2.4 million
Xcel's Proposed Allocation	$3.3 million	$4.3 million
Revenue Requirement Difference	$1.7 million	$1.8 million

all indirect costs) by subtracting the Department's proposed allocation of indirect costs from Xcel Energy's *total* wildfire mitigation costs.[364]

If the Department correctly subtracted its proposed indirect cost allocation from total Xcel Energy indirect wildfire mitigation costs, there would be no downward adjustment – in fact, the Department's methodology actually allocates more indirect wildfire mitigation costs to the Minnesota jurisdiction than the Company's own methodology. Specifically, in the table in its Initial Brief, the Department subtracts its $1.6 million indirect cost allocation from $3.3 million for 2025 to arrive at its $1.7 million adjustment.[365] However, the correct comparison is not to the total wildfire mitigation costs in the test year, but to the amount of indirect costs the Company proposed in the test year – a difference of only $0.1 million (NSP $1.7 million in 2025 indirect charges[366] vs DOC $1.6 million in 2025 indirect charges[367] = -$0.1 million), not $1.7 million. In 2026, the Department's methodology would actually increase the Company's allocated indirect wildfire mitigation costs (DOC $2.4 million in indirect costs[368] vs NSPM $1.8 million indirect costs[369] = +0.6 million increase in indirect costs).

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[364] In the Department's table on page 74 of its Initial Brief, "Total Indirect Wildfire Costs" is mislabeled – these amounts are Total XES Wildfire Costs (direct and indirect). Ex. DOC-1 at MAJ-D-7, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 186): "For 2025, the Wildfire Risk Management group had a *total* budget of $16.5 million." *Emphasis added.*

[365] DOC Initial Brief at 73-74.

[366] Ex. Xcel-50 at Table 1, line 22 (Doyle Rebuttal) (refer to "2025" column).

[367] Ex. DOC-1 at MAJ-D-7, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 186).

[368] Ex. DOC-1 at MAJ-D-8, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 187).

[369] Ex. Xcel-50 at Table 1, line 22 (Doyle Rebuttal) (refer to "2026" column).

Below, Table 3 works through the Department's incorrect methodology in more detail, including errors in addition to those discussed above. This Table reproduces the Table on page 74 of the Department's Initial Brief, with additional columns explaining the Department's errors:

Table 3. Correcting Department's Wildfire Mitigation Cost Allocation[370]

	2025	Correcting DOC Math	2026	Correcting DOC Math
Total Indirect Wildfire Costs	$16.5 million	$16.5 million represents the total XES wildfire costs, not total indirect costs.[371]	$19.8 million	$19.8 million represents the total XES wildfire costs, not total indirect costs.[372]
NSPM's Allocation of Direct Wildfire Costs	9.7%	=$1.6M/$16.5M. While the Department does not show its math, the Company was able to discern this calculation. However, $1.6M reflects the NSPM *Minnesota* direct charges, rather than the NSPM total company Allocation.[373] By DOC's method, this should be $1.8M/$16.5, or 10.9%. 87% jurisdictional allocator (not general allocator) then applied to $1.8M to get $1.6M; however, $1.6M is not a direct percentage of 16.5M.[374]	12%	=$2.4M/$19.8M. While the Department does not show its math, the Company was able to discern this calculation. However, $2.4M reflects the NSPM *Minnesota* direct charges, rather than the NSPM total company Allocation.[375] By DOC's method, this should be $2.8M/$19.8, or 14.14%. 87% jurisdictional allocator (not general allocator) then applied to $2.8M to get to $2.4M; however, $2.4M is not direct a percentage of 19.8M.[376]
DOC Proposed NSPM Allocation of Indirect	$1.6 million	=9.7%*$16.5M total XES wildfire, which is circular math in light of above facts. Further, this is actually an allocation of all XES wildfire costs, rather than an allocation of indirect costs.[377] Applying 10.9% to $16.5 million would increase DOC allocation to $1.80M (rounded). But because a portion of total costs are already direct charged, applying this ratio to total costs makes no sense.	$2.4 million	=12%*19.8M total XES wildfire, which is circular math in light of above facts. Further, this is actually an allocation of all XES wildfire costs, rather than an allocation of indirect costs.[378] Applying 14.41% to $19.8 million would increase DOC allocation to $2.90M (rounded). But because a portion of total costs are already direct charged, applying this ratio to total costs makes no sense.
Xcel's Proposed Allocation	$3.3 million	This is total allocation to NSPM – both direct and indirect.[379] It is not comparable to DOC's purported indirect allocation. Xcel Energy's proposed allocation of indirect costs is $1.7M[380] – roughly the same as DOC's incorrect math.	$4.3 million	This is total allocation to NSPM – both direct and indirect.[381] It is not comparable to DOC's purported indirect allocation. Xcel Energy's proposed allocation of indirect costs is $1.8.[382]
Rev Req Difference	$1.7 million	$0-+$0.1M	$1.8 million	-$0.6M

Putting these pieces together, the Company has presented the most reasonable and cost-causative methodology available, debunking the Department's and OAG's incorrect analyses. Both methodologies are fundamentally flawed, both in principle and mathematically, and do not properly reflect the data in the record. The quantity of wildfire mitigation costs included in the 2025 and 2026 test should be based on cost causative methodologies, with costs direct charged where possible and allocated based on the drivers of the indirect costs where necessary. The Company's proposed methodology accomplishes these goals.

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[370] Table 3 is provided to illustrate the full extent of the Department's incorrect methodology. For the purposes of the Wildfire Allocation, the salient issue is that when the math is done correctly, the Department's adjustments are roughly the same or more as initially as proposed by the Company.
[371] Ex. DOC-1 at MAJ-D-7, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 186) "For 2025, the Wildfire Risk Management group had a *total* budget of $16.5 million." *Emphasis added.*
[372] Ex. DOC-1 at MAJ-D-8, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 187) "For 2025, the Wildfire Risk Management group had a *total* budget of $ $19.8 million." *Emphasis added.*
[373] Ex. Xcel-50 at Table 1, line 18 (Doyle Rebuttal) (refer to "2025" column).
[374] Ex. Xcel-50 at Table 1, lines 17-18 (Doyle Rebuttal) (refer to "2025" column).
[375] Ex. Xcel-50 at Table 1, line 18 (Doyle Rebuttal) (refer to "2026" column).
[376] Ex. Xcel-50 at Table 1, lines 17-18 (Doyle Rebuttal) (refer to "2026" column).
[377] Ex. DOC-1 at MAJ-D-7, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 186).
[378] Ex. DOC-1 at MAJ-D-8, Page 2 (Johnson Direct) (Xcel Energy's Response to DOC IR 187).
[379] Ex. Xcel-50 at 15.
[380] Ex. Xcel-50 at Table 1, line 22 (Doyle Rebuttal) (refer to "2025" column).
[381] Ex. Xcel-50 at 15.
[382] Ex. Xcel-50 at Table 1, line 22 (Doyle Rebuttal) (refer to "2026" column).

11. Sherco Unit 3 And Allen S. King Coal Plants Remaining Lives

Pursuant to the Commission's order in the Company's most recent integrated resource plan (IRP), the Company's Sherburne County Generating Plant Unit 3 (Sherco 3) and Allen S. King Plant (King), both of which are coal-fired generating units, will be retired early in order to meet the state's clean energy goals.[383] In order to minimize rate increases tied to accelerating depreciation for these units, the Company proposes that a regulatory asset be created for each plant at the time of its retirement.[384] The Department however, proposes that the depreciable lives of Sherco 3 and King be shortened now to align to the new operating lives of those generating plants.[385] The Department's primary rationale is that matching depreciable lives to operating lives is the Commission's general practice.[386] This reliance on "general practice," however, ignores the Commission's decision to establish a docket dedicated to accounting and ratemaking treatment of early-retiring electric generating facilities (the Early Retirement Docket).[387] This docket was established specifically to address the retirement of coal-fueled generation plants in furtherance of decarbonization.[388] Had the Commission simply wanted to stick with its standard practice, it could have foregone establishing this docket, or could have determined in that docket to

[383] Xcel-17 at 76 (Halama Direct).
[384] Xcel-17 at 76 (Halama Direct).
[385] DOC Initial Brief at 56-57.
[386] *Id.*
[387] Docket No. E-002, E-015, E-017/CI-23-375
[388] *In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E-002, E-015, E-017/CI-23-375, ORDER ESTABLISHING FOUR-TIERED APPROACH FOR RATEMAKING TREATMENT OF EARLY-RETIRING GENERATING FACILITIES (May 14, 2025) (the Early Retirement Order).

simply stay the course with respect to aligning depreciable lives with operating lives. It did neither.

While the Department claims that its proposal aligns with the Commission's May 14, 2025 order in the Early Retirement Docket (the Early Retirement Order),[389] the Department fails to undertake the four-tiered analysis established by the Early Retirement Order.[390] Notably, Ms. Jones's direct testimony did not even reference the Early Retirement Order, despite the fact that the Order was issued on May 14, 2025, several months before that testimony was filed.[391]

The Department contends that its approach is preferable for two reasons in addition to its "standard practice" rationale – avoidance of intergenerational inequities and avoiding extra so-called "avoidable expense" that would result from regulatory asset treatment.[392] These reasons will always exist when an asset is retired early. But the order allows for regulatory asset treatment based on the Department's own proposal in the Early Retirement docket.[393] In any event, neither of the Department's arguments hold up to scrutiny on this record. The Department's view of intergenerational inequity is one-sided, as it focusses only on the potential for intergenerational inequity resulting from future customers paying for plant costs after the plants are no longer operating.[394] XLI and OAG both identify the

[389] DOC Initial Brief at 56.
[390] DOC Initial Brief at 57, citing Ex. DOC-24 at 18-19 (Jones Surrebuttal). The "pros and cons" discussion in Ms. Jones surrebuttal, however, is not an analysis under the Early Retirement Order.
[391] Ex. DOC-23 at 14-16 (Jones Direct).
[392] DOC Initial Brief at 57.
[393] *See* Early Retirement Order at 4-5.
[394] Ex. DOC-24 at 57 (Jones Surrebuttal).

potential for intergenerational inequity resulting from future Company customers benefitting from earlier adoption of cleaner generation resources without having had to pay the costs associated with that early adoption.[395] While acknowledging this potential, the Department's analysis treats this type of intergenerational equity as speculative.[396] This seeming dismissal of the benefits of the adoption of clean energy is not consistent with the goals set forth in the Early Retirement Order.[397]

The Department also appears to take issue with the Company's desire to fully recover its investment in these early-retired plants, contending that Xcel Energy's proposal is intended to "leverage" the asymmetrical adjustment of depreciation lives in a manner intended to somehow deceive customers and the Commission.[398] This is simply inaccurate. The Department also suggests that the Commission must seize the opportunity to shorten depreciable lives in this rate case because the increase in rates that would be caused by shortening the depreciable lives of King and Sherco 3 is smaller than the decrease in rates that will result from lengthening the lives of the Prairie Island and Monticello nuclear generation plants.[399] In the Department's view, therefore, the Department's proposal "results in a net decrease to depreciation expenses and therefore rates."[400]

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[395] *See* XLI Initial Brief at 29; OAG Initial Brief at 12.
[396] DOC Initial Brief at 59.
[397] Early Retirement Order at 7.
[398] DOC Initial Brief at 58 (stating that Xcel intends to use its proposal to "mask" its requested rate increase).
[399] DOC Initial Brief at 57.
[400] DOC Initial Brief at 59.

Viewing the impacts of shortening the coal-fired plants' depreciable lives on its own, however, it is undisputed that the Department's recommendation would increase depreciation expense in both 2025 and 2026, increasing rates compared to the Company's proposal. Further, if the Department is suggesting the Commission act now so that some unidentified amount of depreciation expense may go unrecovered, this argument ignores the Commission's desire as stated in the Early Retirement Order, of "achieving policy goals required in Minnesota."[401] Preventing utilities from recovering the value of early-retiring plants could disincentivize utilities from pursuing the early retirement of fossil fuel assets and moving towards clean energy.[402]

The Department's position here would render the Commission's work in the Early Retirement Docket a nullity. As discussed in the testimony of the Company's witnesses, the Company's proposal to create a regulatory asset at the end of each plants' operating life best balances the interest of the Company and customers, as contemplated in the Early Retirement Order.[403]

12. Riverside Generating Unit

The Department contends that the Riverside Generating Unit (Riverside or Unit) should be removed from rate base on a pro-rata basis for the period of time during 2025 and 2026 when it will be out of service, while allowing the Company to continue recovering Riverside's depreciation expense and property tax expenses associated with the Unit.[404]

[401] Early Retirement Order at 8.
[402] Early Retirement Order at 2-3, 7.
[403] Ex. Xcel-86 at 4 (Moeller Rebuttal); Ex. Xcel-19 at 51-52 (Halama Rebuttal).
[404] DOC Initial Brief at 59-60.

The Department argues this treatment is appropriate, since it states Riverside is not "used and useful" during the time it is out of service. The Company disagrees. As the Company discussed in its Initial Brief, despite currently being out of service, Riverside is continuing to benefit the Company and customers by generating over $26 million in capacity revenues.[405]

Alternatively, given the longer outage duration than initially expected, in the event the Commission decides to remove Riverside from rate base for a portion of the 2025 test year and part or all of the 2026 plan year, the Company agrees that it should continue to recover its property taxes and its depreciation expense during this period, consistent with the Commission's treatment of the outage impacting the Sherco 3 plant.[406] In addition, the Company should be permitted to retain capacity revenues from Riverside rather than having those revenues flow through the capacity tracker approved in the Company's last rate case. This is an equitable outcome, given that customers will not be paying any return on the Unit during this time. As noted by Company witness Ms. Liberkowski, there is no

[405] Xcel Energy Initial Brief at 164-168. The Company notes that at the time of its Rebuttal Testimony and Initial Brief, it estimated that Riverside would not return to service prior to June 1, 2026. *See* Ex. Xcel-84 at 13-14 (Detmer Rebuttal). The Company's most current information indicates the outage will last longer than initially expected. The Company will provide an update in its upcoming fuel clause Adjustment (FCA) filing on February 27, 2026, in Docket No. E002/AA-24-63.

[406] *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, ORDER at 20 (Sept. 3, 2013); DOC Initial Brief at 60; Ex. DOC-2 at 30 (Johnson Surrebuttal).

known ratemaking principal that would prohibit a utility from recovering a return on an asset while also paying out to customers capacity revenues from that same asset.[407]

Finally, the Company contends that any decision on whether to require a contested case, as well as the scope of any such case, should not be made at this time but only after a record can be developed based on comments from stakeholders.

13. Rate Case Expenses

In its Initial Brief, the OAG proposes Xcel Energy should be disallowed recovery of half of its forecasted rate case expense in this case,[408] "to recognize shareholders benefit from rate cases."[409] According to the OAG, rate cases "benefit shareholders by allowing the utility to increase its revenue requirement, which supports the utility's ability to issue consistent dividends."[410] As detailed in testimony and the Company's Initial Brief, the purpose of a rate case is not to increase the revenue requirement to fund shareholder dividends, as the OAG asserts.[411] Instead, rate cases provide the Commission and stakeholders with a transparent, structured process to establish just and reasonable rates and to address issues central to the provision of utility service.[412] This process benefits

[407] Ex. Xcel-16 at 23-24 (Liberkowski Rebuttal).
[408] OAG Initial Brief at 45-50.
[409] OAG Initial Brief at 45.
[410] OAG Initial Brief at 46 (citing Ex. OAG-5 at 17 (Lee Direct)).
[411] Xcel Energy Initial Brief at 170-171; Ex. Xcel-19 at 44 (Halama Rebuttal) ("Further, while a reasonable rate of return (ROR) is necessary to attract investors and allow the Company to secure the capital necessary for system investments, rate cases examine all costs and other factors impacting the revenue deficiency and return on equity (ROE) is but one of those factors.").
[412] *See* Ex. DOC-1 at 5 (Johnson Direct) ("Rate cases provide regulators and interested parties a forum to determine appropriate rates for the utility and address significant issues relating to the provision of utility service.").

customers by ensuring oversight, accountability, and a full review of the Company's costs and operations. The OAG conflates purpose with outcome by asserting that ROE and cost-of-capital witnesses "directly benefit shareholders" by seeking a higher return.[413] These witnesses provide the Commission with the data-driven modeling and financial analysis required to set a fair return that maintains the Company's access to capital and supports the sustained infrastructure investment needed for safe, reliable utility service.[414]

The OAG also asserts that disallowing recovery of 50 percent of rate case expense is necessary to incentivize the Company to manage these costs, arguing "if Xcel is allowed to recover all of its rate case costs from ratepayers, Xcel has no incentive to manage them."[415] To the contrary, the Company already has strong incentives to manage rate case expenses while ensuring the Commission has a complete and reliable record for setting just and reasonable rates. The record demonstrates that the Company exercises disciplined cost management throughout the rate case process, including establishing case budgets, tracking

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[413] OAG Initial Brief at 46 (citing Ex. OAG-5 at 18 (Lee Direct)).

[414] The Commission has consistently recognized the value of the data, modeling and financial analysis provided by the Company's ROE and cost-of-capital witnesses in setting a reasonable return and capital structure. *See, e.g., In the Matter of the Application of Northern States Power Company, dba Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 88-93 (July 17, 2023); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 57 (May 8, 2015) ("The Commission concurs with the Administrative Law Judge that the Company's and the Department's cost-of-equity studies are methodologically transparent, analytically sound, and ably executed. Together they represent the best evidence in the record on the cost of equity and provide a workable framework for determining where to set the cost of equity in this case.")

[415] OAG Initial Brief at 46.

costs against those budgets, applying the same internal review procedures used for all customer-funded work, and relying on internal resources whenever feasible.[416] The Company also retains outside counsel and consultants with deep experience in its operations and regulatory matters because their familiarity allows them to work more efficiently and at lower overall cost than practitioners who must first learn the Company's systems and history.[417] This reflects the nature of specialized professional services, where institutional knowledge and continuity produce meaningful efficiencies—much like individuals often continue with a long-standing physician because that provider already understands their history and needs.[418] Experienced legal and technical experts similarly avoid unnecessary ramp-up time and can complete work more cost-effectively. These actions demonstrate prudent cost control—not any lack of incentive to manage expenses.

Citing the fact that rate case expenses have increased over the past decade, the OAG asserts that some level of cost recovery should be disallowed.[419] But the fact that these costs have increased over time does not establish imprudence or justify limiting recovery. Rather, the level of rate case expense must be understood in the context of changes in regulatory expectations, case complexity, and the substantial growth of discovery and stakeholder participation since 2013. The Company's cases today involve significantly more granular information requirements, expanded cost-of-service studies, additional analysis of affordability and related policy factors, more intervenors, larger volumes of

[416] Ex. Xcel-19 at 45 (Halama Rebuttal).
[417] Ex. Xcel-19 at 46-49 (Halama Rebuttal).
[418] Ex. Xcel-19 at 47 (Halama Rebuttal).
[419] OAG Initial Brief at 47-48.

data requests, and more complex issues—none of which were present to the same degree even a decade ago. These external factors increase the resources required to develop and support a complete evidentiary record and are the primary drivers of the increase in rate case expenses over time. That major cost drivers are outside the Company's control is demonstrated by the Company's last electric rate case, in which regulatory fees alone exceeded forecast by more than $400,000.[420]

Finally, the OAG's references to policies and legislation in other states limiting recovery of rate case expenses do not justify the adoption of arbitrary limits on rate case expense recovery in this case.[421] First, the Minnesota Commission has previously considered and rejected proposals to split rate case expenses evenly between shareholders and customers.[422] Second, the examples referenced by the OAG reflect outliers; Minnesota's approach aligns with the prevailing regulatory approach in which public utility

[420] Xcel Energy Initial Brief at 172 (citing Ex. Xcel-19 at Schedule 5 (Halama Rebuttal) (Xcel Energy's Response to OAG IR No. 1009)). Contrary to the OAG's assertion that "[r]ate case expenses are not . . . outside of the Company's control" because the Company chooses "when the rate case is filed, which experts or lawyers to hire, and how to manage its internal staff, retained counsel, and retained experts to manage costs," the record supports the conclusion that the primary cost drivers are external rather than discretionary choices about timing or staffing. *See* OAG Initial Brief at 47.

[421] *See* OAG Initial Brief at 47-48. Because Minnesota employs a case-specific prudence review rather than caps on recovery, practices in other jurisdictions provide no meaningful guidance. The record confirms that the Company's expenses were necessary, efficient, and prudently incurred under Minnesota's evidence-based standard. Minnesota's approach is superior because it ensures that only costs that genuinely contribute to rate case record development are recoverable, while inappropriate or excessive costs can be disallowed based on the facts—not on predetermined caps.

[422] *See In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Nov. 2, 2010).

commissions recognize rate case expense as a legitimate and necessary cost of providing regulated utility service and assess such expenses through a case-by-case prudence and reasonableness review. Courts across numerous jurisdictions have acknowledged that, because regulated utilities must undergo formal rate proceedings to change their rates, rate-case expenses constitute a necessary and unavoidable cost of providing regulated service.[423] Further, even in jurisdictions such as those cited by the OAG where the legislature has directed the public utilities commission to "establish rules to limit the amount of rate case expenses that a utility may recover from ratepayers,"[424] the Commission has not imposed categorical caps on recovery. Rather, they acknowledge rate case expense as a legitimate and necessary cost of providing regulated utility service and

[423] *See, e.g., In re PNM Gas Servs.*, 1 P.3d 383, 406-07 (N.M. 2000) ("Because rate proceedings are a part of the normal course of business for a utility and because rate proceedings, by establishing just and reasonable rates, are conducted for the benefit of both ratepayers and shareholders, it is widely accepted that rate case expenses are one aspect of a utility's operating costs and are recoverable in a general rate proceeding."); *Driscoll v. Edison Light & Power Co.*, 307 U.S. 104, 120-21 (1939) ("Even where the rates in effect are excessive, on a proceeding by a commission to determine reasonableness, we are of the view that the utility should be allowed its fair and proper expenses for presenting its side to the commission."); *Butler Township Water Co. v. Pennsylvania Pub. Util. Comm'n*, 473 A.2d 219, 221 (1984) ("The general rule is that a public utility is entitled to recover in rates those expenses reasonably necessary to provide service to its customers and to earn a fair rate of return on the investment in plant used and useful in providing service. Operating expenses include prudently incurred rate case expenses."); *Citizens' Util. Ratepayer Bd. v. State Corp. Comm'n*, 284 P.3d 348, 359-360 (Kan. Ct. App. 2012) ("The general rule is that prudently incurred rate case expenses are among the reasonably necessary operating expenses that a public utility is entitled to recover in a rate-making proceeding. Rate proceedings are a part of the normal course of business for a utility and function to establish just and reasonable rates. These proceedings are conducted for the benefit of both ratepayers and shareholders. Consequently, it is widely accepted that rate case expenses are one aspect of a utility's operating costs and are recoverable in a general rate proceeding.")

[424] Colo. Rev. Stat. § 40-3-102.5 (2024).

evaluate those expenses through a fact-specific prudence and reasonableness review, including consideration of circumstances outside the utility's control, in a manner consistent with due-process requirements.[425] The Commission has repeatedly found the Company's outside legal and expert costs to be reasonable in prior proceedings, confirming that the Company's approach to cost management is reasonable. Taken together, the evidence in this proceeding demonstrates that the rate case expenses as proposed are necessary, reasonable, and prudently incurred, and that the proposed amortization for recovery of those costs is likewise supported. Accordingly, the OAG's recommendation to disallow recovery of half of those costs should be rejected.

14. Property Taxes

The Department opposes the Company's property tax forecasts for the 2025 test year and the 2026 test year, and instead advocates for a 2 percent annual increase over 2024 actuals to estimate property tax expenses for 2025 and 2026.[426]

First, there is no reasoned basis for the Department's recommendation of a 2 percent increase. The Department says it "determined that a 2% annual increase in 2025 and 2026 was appropriate,"[427] but it does not explain how it made this determination. The Department acknowledges that 2 percent is *not* the annual average increase of the prior

[425] *See* Proceeding No. 24R-0168EG, Decision No. R25-0215, Recommended Decision Adopting Rules and Closing Proceeding at 19 (Colo. P.U.C. Mar. 28, 2025) ("The ALJ does not believe that arbitrary limits will lead to a fair and just result. The ALJ declines to adopt a rule that summarily limits a percentage of recoverable expenses. A broad limitation to cost recovery could lead to unintended consequences, such as diminished records or perverse workarounds.").
[426] DOC Initial Brief at 70-71.
[427] DOC Initial Brief at 72.

years it focuses on.[428] In other words, the Department has conceded that its recommendation is wholly arbitrary.

In contrast, the Company's forecasts are based on a detailed methodology that uses the most recently available data. The Department repeatedly alleges that the Company has not "supported" its forecasts,[429] but the Company's forecast methodology is explained over dozens of pages of testimony and tables explaining exactly how the forecasts were derived (and then updated as new information became available).[430]

There is a critical difference between the Company's detailed forecast methodology and the Department's recommendation: the Department's recommendation implicitly makes assumptions about future economic conditions, whereas the Company's methodology does not do so and thus appropriately balances the risks of over-recovery and under-recovery.[431] The Department ignores the fact that the economic conditions present in 2021-2023 that contributed to over-recovery of property tax in those years might not continue through 2025 and 2026.[432] Indeed, the Department's 2 percent recommendation implicitly assumes that the effective local tax rate will continue to go down in 2025 and 2026, even though it has been already going down since 2020.[433] But the tax rate cannot

[428] DOC Initial Brief at 72.
[429] DOC Initial Brief at 70-71.
[430] Ex. Xcel-51 at 4-22 and Schedules 2-5 (Kowalowski Direct), Ex. Xcel-52 at 3-7 (Kowalowski Rebuttal).
[431] Ex. Xcel-52 at 19 (Kowalowski Rebuttal).
[432] Ex. Xcel-52 at 18-19 (Kowalowski Rebuttal).
[433] Ex. Xcel-52 at 16 (Kowalowski Rebuttal).

go down forever. The Department's post-hearing brief does not even acknowledge this glaring infirmity in its recommendation.

For the reasons stated above, the Department's recommendation should be rejected, and the Company's updated forecasts should be used as the starting point for property tax expense in the 2025 test year and 2026 plan year.

C. Revenue Requirements Conclusion

Full consideration of the Company's investments, expenses and cost of capital for the 2025 test year and 2026 plan year demonstrate that the MYRP proposed by the Company balances the interests of customers in receiving adequate, efficient, and reasonable service with the Company's need for revenue sufficient to enable it to meet the cost of furnishing that service. The Company's requests, discussed above and in the Company's Initial Brief, should be approved.

IV. CLASS COST OF SERVICE STUDY (CCOSS)

This section will respond to the arguments of other parties related to Class Cost of Service Study (CCOSS) design, including the recommendation of the Department to conduct a study on the allocation of costs related to advanced metering infrastructure (AMI).

A. Overall CCOSS Recommendation

The parties in this case do not agree about how the CCOSS should be designed. That is not a surprise. Changes to the CCOSS can impact whether classes appear to be above or below cost, and by how much. Advocates use these cost estimates to argue that their

preferred classes should receive a smaller rate increase while other classes should receive a larger rate increase.

One CCOSS in this case has the most support: the Company's Hybrid Minimum System CCOSS. The Company, the Department,[434] Walmart,[435] and SRA[436] each support the use of the Company's Hybrid Minimum System CCOSS. The only parties opposed to the use of the Hybrid Minimum System CCOSS are the parties that advocate for individual classes: the OAG and XLI.[437]

No other party recommended the use of the CCOSS models recommended by the OAG or XLI, and several parties specifically argued against reliance on the OAG and XLI models. For example, the Department recommended that the Commission should allocate demand-related transmission costs using the D10S allocator (contrary to the OAG), and use the stratification method for the classification and allocation of production costs (contrary to XLI).[438]

The Company's Initial Brief explains the technical reasons why its Hybrid Minimum System CCOSS is the most reasonable for this case.[439] Its reasonableness is

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[434] DOC Initial Brief at 81. The Department supports the Company's Hybrid Minimum System CCOSS, but also recommends the use of the Company's Basic Customer CCOSS.
[435] WAL Initial Brief at 11 ("Walmart advocates for setting rates based on Xcel's cost of service for each rate class.").
[436] SRA Initial Brief at 3 (recommending "The SRA supports the Company's proposed class revenue apportionment that results from its Class Cost of Service Study").
[437] The Joint Intervenors recommended the filing of a new CCOSS related to super-large tariff rate design, but did not recommend one methodology over another. JIN Initial Brief at 47-50. CUB did not take a position on the CCOSS. CUB Initial Brief passim.
[438] DOC Initial Brief at 83-84.
[439] Xcel Energy Initial Brief at Section V.

further demonstrated by the support from other parties, and because it represents a reasonable, moderate outcome compared to the extreme recommendations of the OAG and XLI.

B. Advanced Metering Study

The Department recommended that the Commission should require the Company to include a study comparing AMI and traditional meter costs in its next rate case, including the costs of reading both types of meters.[440] The Company respectfully disagrees because such a study is unlikely to provide information that would justify changing meter cost allocation.

The total cost of the meters in Xcel Energy's revenue requirement varies almost entirely based on how many customers receive service, because every customer needs a meter.[441] Xcel Energy does not add meters when customer energy usage or demand increases, which means they should be classified as customer-related in the CCOSS. A meter study would not change that underlying fact.

V. REVENUE APPORTIONMENT AND RATE DESIGN

The record demonstrates that the Company's recommendations on revenue apportionment and rate design are reasonable and should be approved. This section will respond to the other parties' arguments related to revenue apportionment, rate design, and several proposed tariff changes.

[440] DOC Initial Brief at 84.
[441] Ex. Xcel-74 at 28 (Barthol Rebuttal).

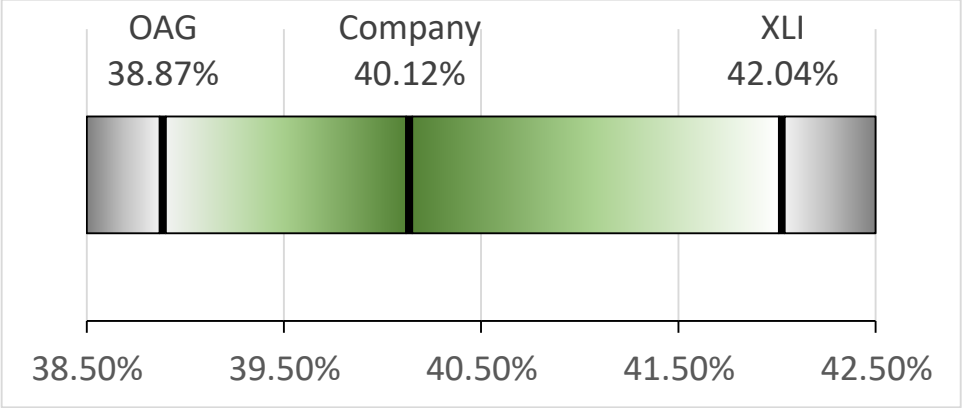
A. Revenue Apportionment

Parties do not agree on how much revenue should be recovered from each class. Unsurprisingly, the OAG recommends that residential and small business customers should receive far lower rate increases than other customers. On the other end of the spectrum, XLI recommends that large customers should receive far lower rate increases than other customers. The difference between these recommendations is approximately $120 million moving from one group of customers to another.[442]

The Company's recommendation is in the middle, between these two outliers.

[442] As noted in the Company's Initial Brief, based on the Company's proposed Rebuttal revenue requirement, each basis point of revenue apportionment represents approximately $375,000. Xcel Energy Initial Brief at 266. The OAG recommends that residential customers be apportioned 38.87 percent of revenues in 2025, Ex. OAG-10 at 40, Table 1 (Scharber Surrebuttal), while XLI recommends that residential customers be apportioned 42.04 percent of revenues. Ex. XLI-3 at Schedule 5 (Ly Direct). The 317 basis points between these recommendations times $375,000 results in an estimate of $118.9 million.

Figure 2. Spectrum of Residential Apportionment Recommendations[443]



The Company's revenue apportionment recommendation is a moderate result that has the support of multiple parties. The Department,[444] SRA,[445] and Walmart[446] each recommend that the Commission approve the Company's recommended apportionment for 2025. As above with the CCOSS, only the OAG and XLI – parties with clear preferences for certain customer groups over others – disagree.[447] The wide-ranging support for the Company's proposal, coming from disparate parties, further demonstrates its reasonableness.

The OAG makes several arguments in support of its recommendation, but none of them are persuasive. First, the OAG argues that it is the only party to make use of multiple

[443] Ex. Xcel-77 at 8, Table 1 (Paluck Rebuttal); Ex. Xcel-78 at 3, Table 1 (Paluck Surrebuttal).
[444] DOC Initial Brief at 87 (recommending that "the Commission should adopt Xcel's updated 2025 test year revenue apportionment proposal"). The Company notes that the table included in the DOC's Initial Brief on page 88 appears to differ slightly from the recommendation on page 266 of the Company's initial brief, likely as a result of rounding.
[445] SRA Initial Brief at 3-4.
[446] WAL Initial Brief at 12 ("Xcel appears to have met its burden of proof regarding its proposal to move all customer classes 20 percent towards cost of service.").
[447] Joint Intervenors did not make a recommendation on revenue apportionment, JIN Initial Brief passim, and neither did CUB, CUB Initial Brief passim.

CCOSS results.[448] But the Department also suggests the use of multiple CCOSSs and, based on that analysis, recommends approval of the Company's revenue apportionment recommendation.[449] Further, the third CCOSS relied on by the OAG, the Peak-and-Average CCOSS, is not supported by any other party and, as explained by Department witness Zajicek, is fundamentally unreasonable.[450] The OAG's subsequent revenue apportionment analysis – which relies on an unreasonable CCOSS model – should be disregarded.

Second, the OAG argues that it is the only party to assign the small general service class zero rate increase.[451] That is true, but that is a flaw rather than a benefit of the OAG's recommendation. The Company's recommendation appropriately recognizes cost factors for small general service customers by recommending a revenue apportionment that is smaller than other classes. The Company's recommendation would assign only $8.74 million in additional revenue requirements to Non-Demand customers in 2025,[452] representing just 4.2 percent of new revenue in that year.[453] Even this does not satisfy the OAG. While the Company agrees that rate increases to the Non-Demand class should be limited because of cost factors, the Company does not believe it is reasonable for one group

[448] OAG Initial Brief at 82.
[449] DOC Initial Brief at 83, 87.
[450] Ex. DOC-16 at 23:8-12 (Zajicek Direct).
[451] OAG Initial Brief at 84-85.
[452] *Compare* Ex. Xcel-76 at 11, Table 3 *with* Ex. Xcel-78 at 3, Table 1 (Paluck Surrebuttal) (showing $115.8 million in present revenue during 2025 in Direct Testimony, compared to $124.54 million in recommended revenue apportionment in Surrebuttal Testimony).
[453] Xcel Energy Initial Brief at 11-12, Table 2.

customers – alone among all classes – to be treated preferentially and receive no rate increase.

Third, the OAG argues that some non-cost factors justify a lower rate increase for residential customers. In particular, the OAG points to the fact that some classes, particularly businesses, have the ability to pass on rate increases to their customers,[454] and that some data show an increase in disconnections and arrearages for residential customers.[455] The Company agrees that non-cost factors are relevant and should be considered, and that is why the Company is recommending moving only 20 percent towards cost. The Company's recommendation to significantly limit movement toward cost shows that non-cost factors were considered and given substantial weight.

The Commission should not adopt the OAG's recommendation because it would disproportionately preference certain customer classes over others. Residential customers are apportioned 39.59 percent of the current revenue requirement.[456] The OAG is recommending that Residential customers be apportioned only 26 percent of the new revenues from this rate case,[457] which would increase rate impacts for other customers. While non-cost factors support limiting the movement towards cost, the OAG's recommendation would give unreasonable preference to a few customer groups over all others.

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[454] OAG Initial Brief at 85.
[455] OAG Initial Brief at 85-86.
[456] Ex. Xcel-78 at 8, Table 1 (Paluck Rebuttal).
[457] OAG Initial Brief at 93, Table 7 (comparing the 2026 in Residential class increase to the total). This recommendation results in the Residential class being apportioned only 38.87 percent of revenues. Ex. OAG-11 at 40, Table 7 (Scharber Surrebuttal).

XLI's recommendation suffers from the same flaws, from the opposite direction. XLI recommends that Residential customers should get a rate increase nearly triple that of C&I Demand customers.[458] While C&I Demand customers are currently apportioned 56.38 percent the revenue requirement,[459] XLI recommends that they be assigned only 28.7 percent of new revenues from this case.[460] XLI's arguments in support of this outcome ignore well-established precedent that revenue apportionment should consider both cost *and* non-cost factors.[461] XLI's recommendation would ignore nearly all non-cost factors in favor of moving to its perception of cost, which leads to an unreasonable result.

While the Company's recommendation moves classes closer to cost, it is also most similar to the current revenue apportionment, which supports the goal of rate continuity and avoids sudden changes in rate design that could disproportionately affect one class or another.[462] It has the support from the majority of parties that took a position on the issue, is based on sound analysis and data, and appropriately balances cost and non-cost factors.

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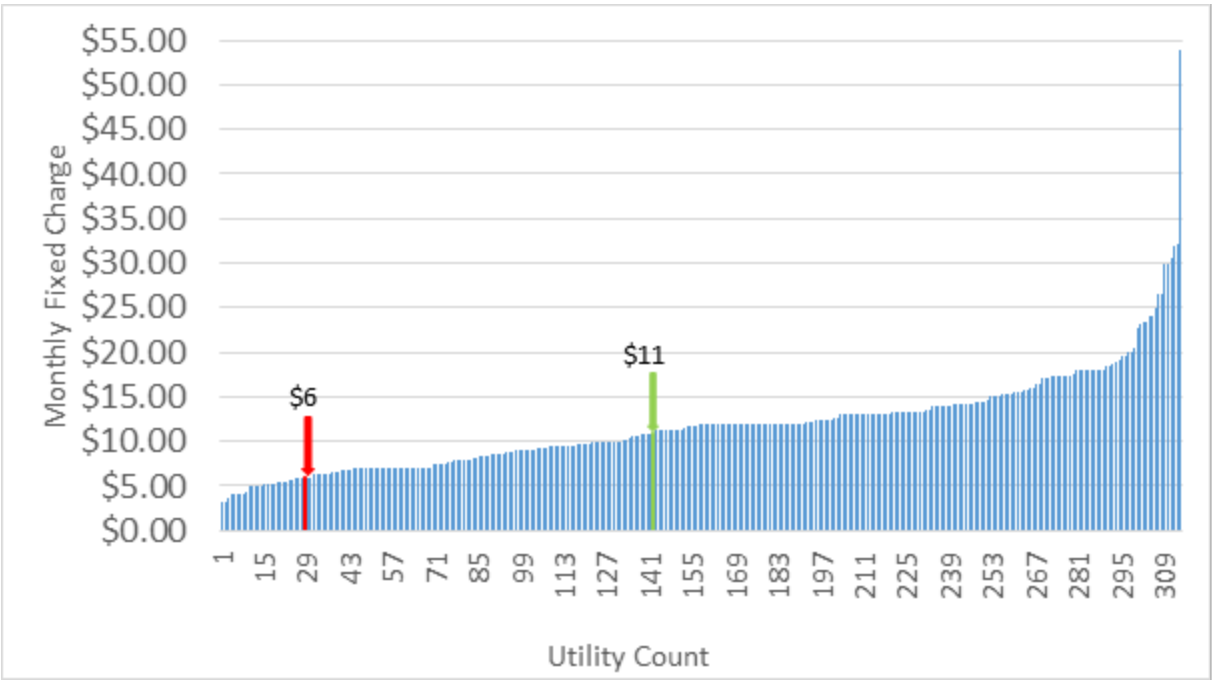
[458] Ex. XLI-3 at Schedule 8 (Ly Direct) (XLI witness Ly never updated the revenue requirement recommendation after Direct Testimony).
[459] Ex. Xcel-78 at 8, Table 1 (Paluck Rebuttal).
[460] Ex. XLI-3 at Schedule 8 (Ly Direct) ($101,387 for C&I Demand / $353,252 = 28.7 percent). This would represent a revenue apportionment to C&I Demand customers of 53.95 percent. Ex. Xcel-77 at 8, Table 1 (Paluck Rebuttal).
[461] St. Paul Area Chamber of Commerce v. Minn. Pub. Util. Comm'n, 251 N.W.2d 350, 358 (Minn. 1977); *see also In re Application of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 14 (May 14, 2012).
[462] *See In re Application of N. States Power Co. d/b/a Xcel Energy for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 14 (May 14, 2012).

For these reasons, the Company's revenue apportionment recommendation is the most reasonable in this case and should be adopted.

B. Rate Design -- Residential And Small Commercial Customer Charges

Most customers have a component of their rates that is a flat monthly charge, often referred to as the customer charge. The Company proposes to increase the customer charge for residential and small commercial customers to $11.00. As explained by Company witness Paluck, the current customer charge is lower than 90 percent of other utilities in the country, and an $11 customer charge would still be lower than the average utility nationally. The following chart shows the current $6.00 customer charge, and the proposed $11.00 customer charge compared to other utilities.

Figure 3. Residential Basic Service Fixed Monthly Charges
Investor Owned Utilities[463]



This proposal is reasonable and should be approved.

The OAG and the Department present several reasons why they believe the Company should be required to maintain a customer charge lower than 90 percent of utilities across the country. None of their arguments compel this result.

The OAG and the Department argue that the customer charge should be designed to recover only "customer-specific costs."[464] But this term is not defined in any Commission rule or statute, and there is certainly no Commission rule or statute requiring that customer charges recover only "customer-specific costs." Deciding what should be included in "customer-specific costs" requires an analyst to apply personal judgment, rather than hard

[463] Ex. Xcel-76 at 20 (Paluck Direct).
[464] DOC Initial Brief at 89; OAG Initial Brief at 95.

numbers, and is open to dispute. Instead, efficient and reasonable rate design should establish customer charges that are designed to recover a significant portion – but not all – of the system fixed costs.[465]

Xcel Energy's revenue requirement includes fixed costs, which do not vary month-to-month, or based on the usage of customers. The Company estimated that the customer-related fixed costs are approximately $24.00.[466] It is economic and efficient to use a fixed monthly charge to recover most of these fixed costs. In this way, the rate design flows from the manner in which costs are caused.

If these costs are not recovered through the monthly charge, they will be recovered through the volumetric energy charge instead. All customers contribute the same amount to costs recovered through monthly customer charges. But for costs recovered through the volumetric charge, customers contribute different amounts based on their usage. Including fixed costs in the volumetric charge results in an intra-class subsidy where customers with high consumption pay more for the fixed costs of the system than others. It also results in economic inefficiency, as customers are sent price signals that discourage use when in fact, it would be beneficial to use electricity as a form of energy. This is particularly problematic as the electric system becomes cleaner and therefore is a more environmentally-responsible form of transportation and heating fuel.

The flaw with the Department's and OAG reasoning can be seen with the Department's argument related to service drops. The Department argues that, in particular,

[465] Ex. Xcel-76 at 15:9-14 (Paluck Direct).
[466] Ex. Xcel-76 at 16, Table 6 (Paluck Direct).

the costs of monthly service drops should be recovered through the volumetric charge instead of the customer charge.[467] That argument does not make economic sense. The cost of the service drops on the system do not change based on how much electricity customers are using, and it is not reasonable to charge some customers more or less for service drops based on their consumption. In fact, doing so would be unfair to customers with higher-than-average usage. As the Department's witness admitted during the evidentiary hearing, some of these high-usage customers are low-income customers.[468] Low-income, high-usage customers likely include some of the most vulnerable customers with the highest energy burden, and it would not be reasonable to charge them more for service drops because of their usage pattern.

The DOC and OAG also argue that a lower customer charge is needed because of the statutory objective to encourage conservation to "the maximum reasonable extent."[469] The word "reasonable" is important, especially since the Commission has other obligations such as supporting electrification and economic efficiency.[470] It would be *unreasonable* to design rates to encourage conservation at the expense of other important policy goals such as electrification. Instead, the Commission should weigh a variety of factors and achieve a reasonable result. The Company's proposal is supported by the facts and evidence in the

[467] Ex. DOC-19 at 39-40 (Bahn Direct).
[468] Tr. Vol. 2 (Dec. 18, 2025) at 314:10-16 (Bahn).
[469] DOC Initial Brief at 90; Minn. Stat. § 216B.03.
[470] The Commission has long considered all relevant non-cost factors and policy objectives when designing rates. *St. Paul Area Chamber of Commerce v. Minn. Pub. Utils. Comm'n*, 251 N.W.2d 350, 354 (Minn. 1977) ("The process of establishing rate allocations among diverse consumer classes is one requiring both technical expertise on the one hand and a careful balancing of many complementary and competing interests on the other.").

record, and is consistent with Minnesota's policy goals of encouraging conservation *and* establishing efficient rates that are just and reasonable.

Finally, the OAG argues that its customer charge recommendation is supported by the NARUC Electric Cost Allocation Manual (NARUC Manual).[471] But the NARUC Manual is a guide to use for the design of the CCOSS, not rate design.[472] Further, it discusses two different types of CCOSS models, one to evaluate embedded costs and one for marginal costs. Minnesota rate cases involve the evaluation of embedded cost CCOSS studies.[473] The passages quoted by the OAG are related to marginal cost CCOSS studies,[474] but no party provided a marginal cost CCOSS in this case and the OAG's analysis is based on embedded, not marginal, cost.

The Company's recommendation will ensure that an appropriate amount of fixed costs are recovered through the fixed monthly rate, while still resulting in a customer charge that is lower than average nationally. This result is economically efficient, just, and reasonable.

[471] OAG Initial Brief at 95, n.551.
[472] This is clear because the title of the NARUC Manual is the "Electric Utility *Cost Allocation Manual*", not a rate design manual.
[473] *See* Minn. Stat. § 216B.16 (requiring that rates be based on the existing or forecasted – meaning embedded - cost of service, not marginal costs).
[474] Page 144 of the NARUC Manual, cited in footnote 551 of the OAG's Initial Brief, is included in the Marginal Cost Studies section of the NARUC Manual.

C. Tariff Changes

1. Residential Arrears Management Program (RAMP)

In the Company's Safety, Reliability and Service Quality Annual Report docket, the Commission ordered the Company to propose a program to use interest payments from residential late payments to mitigate costs for low-income customers similar to the program it administers in its Colorado.[475] The Company has proposed RAMP, as described in detail in the Company's Initial Brief.[476] The Department recommended approval of RAMP with modifications.[477] CUB recommended rejecting the Company's proposed program and waiving late fees for all residential customers, as discussed in a previous section of this Brief.[478] If the Commission does not waive late fees, CUB recommended that the late fees instead be applied to the Company's PowerOn program, rather than RAMP.[479]

In the course of this proceeding, the Company agreed to many of the Department's recommended modifications. First, Company witness Ms. Howard explained that the Company would agree to the Department's proposed modification to ensure eligible customers are placed on a payment plan arrangement or budget billing, at the customer's discretion.[480] However, as the purpose of RAMP is to avoid disconnection by applying late

[475] *In the Matter of Xcel Energy's 2023 Safety, Reliability and Service Quality Annual Report*, Docket No. E002/M-24-27, ORDER ACCEPTING REPORTS AND SETTING ADDITIONAL REQUIREMENTS (Jan. 13, 2025); Ex. Xcel-39 at 1 (Lindgren Supplemental Direct).
[476] Xcel Energy Initial Brief at 290-292.
[477] DOC Initial Brief at 92; Ex. DOC-20 at 22-23 (Bahn Surrebuttal).
[478] CUB Initial Brief at 27-30.
[479] CUB Initial Brief at 34.
[480] Ex. Xcel-81 at 10-11 (Howard Rebuttal).

fee payments towards the elimination of past due balances of low-income customers, many customers may have no need for a payment plan. If the amount of RAMP funds allocated to a customer does not eliminate that customer's arrears, the Company will ensure that customer is enrolled in a payment plan or budget billing.[481] Additionally, Ms. Howard explained that the Company planned to remove late fees as part of the RAMP enrollment process, consistent with the Department's recommendation. Further, the Company agreed that, due to the expected date of the Commission's decision in this rate case, it would be appropriate to not utilize 2025 late fees to fund the program, and the Company also agreed to provide an annual program status report and the Department's proposed reporting criteria.[482]

The only remaining modification for which the Company and Department disagree is the reduction of RAMP funding to 50 percent of the 2026 total residential late fee operating revenues. The Company recognizes that RAMP would not receive Commission approval until mid-2026. However, the Company has proposed to provide lump sum benefits based on available annual late payment revenues.[483] For this reason, the timing of the Commission's approval of RAMP in 2026 will not impact the amount of funding proposed in 2026.[484]

The Company also recommends rejecting CUB's proposal to eliminate late fees for all residential customers, as discussed previously in this Brief. The Commission ordered

[481] Ex. Xcel-81 at 11 (Howard Rebuttal).
[482] Ex. Xcel-81 at 11-12 (Howard Rebuttal).
[483] Ex. Xcel-81 at 10 (Howard Rebuttal).
[484] Ex. Xcel-81 at 10 (Howard Rebuttal).

Xcel Energy to propose a program to mitigate costs for low-income customers, and RAMP achieves that goal. CUB's proposal would eliminate the funding for RAMP and increase the revenue requirement for all Xcel Energy customers, without the corresponding benefit of a new targeted program that helps customers with high arrears avoid disconnection that RAMP provides.[485]

The Commission should also reject CUB's proposal to use late fee revenues to fund a different program, such as PowerOn. Unlike PowerOn, RAMP has an income eligibility threshold of 80 percent of Area Media Income, as opposed to 50 percent of State Media Income for PowerOn, LIHEAP-funded energy assistance and Company affordability programs.[486] Because RAMP would provide benefits to a greater number of Xcel Energy customers with high arrears that is not tied to the sometimes volatile nature of federal funding,[487] the Commission should approve RAMP and reject CUB's proposal to eliminate late fees or fund existing Company programs with late fee revenues.

2. Super Large Customer Tariff

XLI and the Joint Intervenors make several arguments about tariff design for data centers and other super-large loads.[488] As explained in the Responsive Testimony of Company witness Paluck and the Company's Initial Brief, the Commission has previously determined those issues should be resolved in Docket No. 25-289.[489] The recommendations

[485] Ex. Xcel-71 at 30 (Martin Rebuttal).
[486] Ex. Xcel-81 at 13 (Howard Rebuttal).
[487] Ex. Xcel-81 at 13 (Howard Rebuttal).
[488] XLI Initial Brief at 52-54; JIN Initial Brief at 47-50.
[489] Ex. Xcel-98 (Paluck Responsive Testimony); Xcel Energy Initial Brief at 296.

of the Joint Intervenors and XLI can and should be resolved in that docket, not this rate case, because that is what the Commission has previously directed.

XLI presents two arguments: that the new tariff should be a separate class from the existing C&I Demand class, and that the Company should change the way it allocates incremental revenues under the new tariff.[490] These issues cannot be decided at this time. The Company's tariff has not been approved and, as such, exists only as a proposal. There are not any costs or incremental revenues related to super-large customers in this rate case, both because the tariff has not been approved and because the Company does not currently have any customers eligible for the proposed tariff.[491] To the extent the Commission does not resolve these issues in Docket No. 25-289, they can be raised again in the Company's next rate case.

Both XLI and Joint Intervenors request that the Company be required to revise its CCOSS. XLI seems to argue that this filing should be required if a new customer taking service under the not-yet-approved tariffs exceeds 200 MW of new load.[492] The Joint Intervenors demand that a new CCOSS be filed "promptly after Docket No. 25-289 concludes."[493] These recommendations would require regulatory work for no purpose. A CCOSS is used to set rates in a rate case. The CCOSS requested by Joint Intervenors and XLI cannot be used to set rates in this case, because the data to create it does not exist and it would likely be created after final rates are established. If ordered, it would require

[490] XLI Initial Brief at 52-53.
[491] Ex. Xcel-98 at 3 (Paluck Responsive).
[492] XLI Initial Brief at 54.
[493] JIN Initial Brief at 48.

months of work from the Company, without any impact on this case.[494] Further, the work would be duplicative because the Company would have to create another updated CCOSS at the time of any future rate case. To the extent a new CCOSS is needed to evaluate the approval of electric service agreements with future large load customers, they can be completed during that process – which will have the benefit of actual customer data and an approved tariff. The Company respectfully requests that it not be ordered to complete a "compliance" CCOSS for this reason, as it would represent an increased regulatory burden to very little benefit.

3. Disconnection Moratorium

The Company understands that unique circumstances can warrant temporary disconnection moratoria and has voluntarily implemented such moratoria, both during the pandemic and for the month of February, 2026, in light of the impacted of the recent immigration enforcement activities in Minnesota. However, as discussed in the Company's Initial Brief, a disconnection moratorium like the one proposed by the Joint Intervenors is likely to increase arrears and bad debt and reduce opportunities for the Company to interact with its customers to connect them with energy assistance and affordability programs. Further, the Joint Intervenors' argument that Xcel Energy did not provide evidence sufficiently demonstrating a causal relationship between disconnections and public benefits improperly attempts to impose a heightened standard on the Company's

[494] Ex. Xcel-98 at 3 (Paluck Responsive).

compliance with Minnesota regulations. For these reasons, the Joint Intervenors' proposed indefinite disconnection moratorium should be rejected.

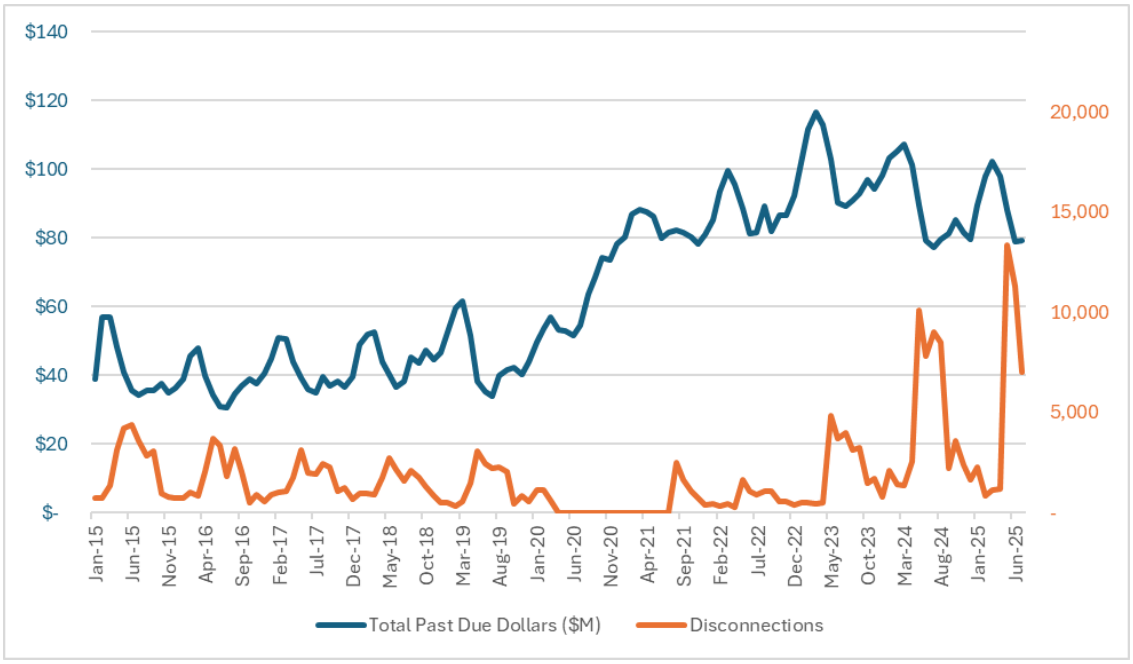
The Joint Intervenors argued that Xcel Energy has not demonstrated disconnections serve a public purpose and that the Commission should establish an indefinite moratorium on disconnections until the Company can demonstrate that the benefits of disconnection outweigh the costs. In doing so, the Joint Intervenors attempt to shift the burden to the Company to prove that its compliance with Minnesota regulations meets a heightened standard not established in those regulations. Although the Company disagrees with the Joint Intervenors' argument that the Company has not demonstrated a relationship between disconnections and customer payment, even if such were the case, Minnesota regulations do not impose such a requirement on the Company. Minn. R. 7820.1000 states that a utility may disconnect service to any customer for a variety of reasons, including failure to pay. Minnesota rules do not impose any requirement that a utility demonstrate that such disconnections serve a public purpose, as such determination was necessarily made when Minn. R. 7820.1000 was promulgated by the Commission.

Nevertheless, the Company provided evidence demonstrating that, as a general matter, disconnection moratoria negatively impact arrearages and negatively impact customers in the long run by eliminating opportunities for the Company to connect with customers and make them aware of affordability programs and payment plans, in addition to making some customers ineligible for some forms of crisis assistance that require a

disconnection notice.[495] As Company witness Mr. Martin noted, the Joint Intervenors' analysis of recent trends in arrears and disconnections omitted data prior to 2022, which not only ignores the impact of the COVID-19 disconnection moratorium on arrears in 2021 and 2022, but also fails to consider how the moratorium-related increase in arrears may be a significant causal factor in the higher past due amounts in 2022 through 2025.[496] Figure 4, reproduced from Mr. Martin's testimony, reproduces Dr. Chan's graph of monthly total residential past due balance but provides a longer timeframe, including years prior to and during the pandemic, to demonstrate the impact the disconnection moratorium had on arrears.[497]

[495] Ex. Xcel-71 at 50 (Martin Rebuttal).
[496] Ex. Xcel-71 at 49 (Martin Rebuttal).
[497] Ex. Xcel-71 at 49 (Martin Rebuttal).

Figure 4. Monthly Total Residential Past Due Balance (Blue Line, Left Axis) And Residential Disconnections (Orange Line, Right Axis) From 2015-2025*



***Data From YR-2 Dockets**

As evidenced by this graph, the pandemic-caused disruption to the economy and these post-COVID disconnection moratorium impacts remain a concern. There should be significant concern that an additional extended disconnection moratorium will further exacerbate the increase in arrears, as customers are disincentivized to pay past due balances.

The Company is also working to address these increases in arrears and disconnections. The Company has proactively worked collaboratively with parties to this proceeding to address these impacts. For example, the Company worked with CUB and ECC on a variety of initiatives to improve customer affordability and reduce disconnections.[498] In the Safety, Reliability & Service Quality (SRSQ) docket for 2023, the Company worked with CUB and ECC to reach agreement on reduced payment plan down

[498] Ex. Xcel-71 at 17 (Martin Rebuttal).

payments, higher past-due balances prior to disconnection, and additional outreach to connect customers with energy assistance programs.[499] The Company believes these measures will reduce disconnections going forward, relative to what they would have been without the changes. In the SRSQ docket for 2024, the Company again worked with CUB and ECC to develop plans to use Advanced Metering Infrastructure to suspend disconnections during periods of poor air quality, and to reconnect previously disconnected customers during extreme heat and poor air quality.[500] Those plans, approved by the Commission in July 2025, will help customers who are particularly vulnerable to heat and poor air quality to have power restored, regardless of their payment status, for air conditioning, medical devices, refrigeration and other critical services.[501]

For the reasons discussed here and in the Company's Initial Brief, the Joint Intervenors' proposed disconnection moratorium is likely to exacerbate arrears and bad debt by removing incentive for customers to stay current on their utility bills and remove opportunities for the Company to connect with customers to provide payment plans, enrollment in Company affordability programs, and information about other state and federal energy assistance programs.

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[499] Ex. Xcel-71 at 17-18 (Martin Rebuttal) (referencing the *Minnesota Disconnection Process* at https://mn.my.xcelenergy.com/s/billing-payment/manage-bill).
[500] Ex. Xcel-71 at 18 (Martin Rebuttal).
[501] Ex. Xcel-71 at 18 (Martin Rebuttal) (citing *In the Matter of Northern States Power Co. d/b/a Xcel Energy's 2024 Annual Safety, Reliability, and Service Quality Report*. Docket No. E-002/M-25-27, ORDER (July 25, 2025)).

4. Randomized Control Trial

Xcel Energy explained in its Initial Brief that the Randomized Control Trial (RCT) proposed by Joint Intervenor witness Dr. Chan would violate the requirements of Minn. Stat. § 216B.07 by granting some Xcel Energy customers an unreasonable preference or advantage.[502] Specifically, the proposed RCT would use actual Xcel Energy customers as test subjects to be divided into treatment groups, some of whom would receive significantly different consequences for non-payment of their utility bills.[503]

In its Initial Brief, the Joint Intervenors misapprehended the statute and argued that no customer would be treated "worse" than under the Company's existing disconnection policy, and thus no customer would be disadvantaged.[504] This reasoning is flawed. Although no customers would be disadvantaged as compared to existing practices—meaning disconnection for failure to pay after a nine-week outreach program by the Company to offer payment plans, affordability programs, and additional efforts to avoid disconnection—these customers would be disadvantaged as compared to customers in other "treatment groups" that would be exempted from disconnection despite similar failure to pay their utility bills. This is impermissible under Minn. Stat. § 216B.07, which prohibits the utility from *both* granting an "unreasonable preference or advantage" and an "unreasonable prejudice or disadvantage." Joint Intervenors' proposal is for some

[502] Xcel Energy Initial Brief at 301-02. Minn. Stat. § 216B.07 states: Rate Preference Prohibited. No public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage.
[503] Xcel Energy Initial Brief at 302.
[504] JIN Initial Brief at 24.

customers to receive advantages that other customers cannot receive, and that these advantages be awarded—as shown in the name of the proposal—randomly.

Nor is there merit to the Joint Intervenors' argument that, although some customers would be provided an advantage, it would not be unreasonable.[505] The Joint Intervenors' argued that the disparate treatment provided to the "treatment groups" would not be unreasonable because the "it would be for the critical purpose of determining whether Xcel's disconnection practices served their intended purpose and benefit all customers, or whether they require modification."[506] However, the purpose and intended results of the study does not change the fact that the Company would treat its customers materially differently from one another, and do so at random. This is not a reasonable basis to treat utility customers differently, and the RCT should be rejected.

For the reasons discussed here and in the Company's Initial Brief, the Joint Intervenors' proposed RCT as an alternative to a disconnection moratorium violates Minnesota law's prohibition on granting unreasonable preference or advantage to some customers and must be rejected.

VI. ADDITIONAL ISSUES

A. Definition Of Energy Justice

The Joint Intervenors proposed that the Commission adopt the definition of energy justice from the Initiative for Energy Justice that includes four "tenets": recognition,

[505] JIN Initial Brief at 24.
[506] JIN Initial Brief at 24.

procedural, distributional, and restorative justice.[507] Joint Intervenor witness Dr. Chan previously proposed this definition in the Company's last rate case, which the Commission declined to adopt.[508] As Company witness Mr. Martin explained, energy justice, along with equity and environmental justice, are relevant across many dockets and across all utilities that the Commission regulates.[509] Adoption of a definition of energy justice in this docket would deny those utilities, their customers, and other interested stakeholders the opportunity to meaningfully participate in the process of discussing and ultimately choosing a definition. As this would violate notions of procedural justice, the Company does not recommend adopting a definition of energy justice in this proceeding.

In the alternative, the Joint Intervenors support a broader proceeding where all utilities and stakeholders participate.[510] To the extent that the Commission feels it necessary to investigate and adopt a specific definition of energy justice, the Company agrees that a broader docket—most likely a rulemaking—involving other utilities and stakeholders would be the appropriate vehicle.

B. Recognition Of Energy Affordability And Elimination Of Energy Insecurity As Public Interest

The Joint Intervenors also recommended that the Commission formally recognize universal energy affordability and the elimination of energy insecurity to be in the public interest.[511] In particular, the Joint Intervenors request that the Commission consider the

[507] JIN Initial Brief at 8, 10.
[508] Ex. Xcel-71 at 45 (Martin Rebuttal).
[509] Ex. Xcel-71 at 45 (Martin Rebuttal).
[510] JIN Initial Brief at 10.
[511] JIN Initial Brief at 11-12.

ability to pay and to allocate costs broadly to consumers, including those with a greater ability to pay.[512]

These and other non-cost factors are already considered by the Commission as non-cost factors in rate design and have consistently been used when allocating revenue responsibility among customer classes and when designing rates within those classes. The Commission regularly considers affordability and the ability to pay when assessing the appropriate rates for all customers, frequently to the benefit of residential and small commercial customers. As such, no further Commission action is necessary.

[512] JIN Initial Brief at 11; Ex. JIN-2 at 27 (Chan Direct).

CONCLUSION

For all of the reasons discussed above, Xcel Energy's MYRP request, as modified through the course of this proceeding, fairly balances customer interests in safe, affordable, reliable, equitable, and environmentally sustainable service with the need for the Company to finance the investments and expenses necessary to provide that service. Therefore, the Company asks that it be approved.

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