

**BEFORE THE MINNESOTA OFFICE OF
ADMINISTRATIVE HEARINGS**

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

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

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

**POST-HEARING BRIEF OF THE
XCEL LARGE INDUSTRIALS**

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BOMA Greater Minneapolis; Flint Hills Resources Pine Bend, LLC; Marathon Petroleum Corporation; and USG Interiors, Inc. (collectively, the “Xcel Large Industrials” or “XLI”)¹ submit the following initial brief to address concerns with Northern States Power Company’s, a Minnesota Corporation d/b/a Xcel Energy (“NSP” or “the Company”) requested rate increases for 2025 and 2026, which XLI respectfully asserts should be substantially reduced. The Company has failed to meet its burden of proof on various aspects of its revenue requirement, and XLI has submitted uncontroverted evidence regarding the Company’s billing and customer service issues and the uncompetitive nature of rates and bills for Commercial & Industrial Demand (“C&I” or “C&I Demand”) customers.

XLI respectfully requests that the Administrative Law Judge (“ALJ”) find that the Company failed to satisfy its burden of proof on numerous elements of its requested relief in this multi-year rate plan (“MYRP”). Specifically, that its (1) proposed return on equity (“ROE”) is heavily weighted on methodologies that are inconsistent with Minnesota Public Utilities Commission (“Commission”) precedent, fails to account for the Company’s relatively low risk, and is unreasonable; (2) proposed test year revenue increase would result in unjust and unreasonable rates; (3) proposed class cost of service study (“CCOSS”) is obsolete and unreasonable; and (4) proposed revenue allocation is unreasonable and does not meaningfully address continuing unjust and unreasonable rates for C&I customers that fail to achieve explicit state energy policy. XLI further requests that the ALJ make appropriate recommendations to the Commission on the basis of these findings and arguments below.

I. INTRODUCTION

A. The ALJ Should Recommend the Commission Address Uncompetitive C&I Rates and Uncontroverted Misalignment Between Utility and Ratepayer Interests

As it stands, NSP’s C&I Demand customers’ rates and bills are uncompetitive. As the evidence in this brief will show, the Company’s MYRP proposals will drive rates even farther above both the state and national averages in direct conflict with the state’s goal to keep rates for

¹ XLI is an *ad hoc* consortium of C&I Demand class customers served by Northern States Power Company, d/b/a Xcel Energy (“NSP” or the “Company”).

all customer classes at least 5% below the national average pursuant to Minn. Stat. § 216C.05, subd. 2(4).

As this brief will demonstrate, the following five factors have been and continue to drive uncompetitive C&I rates on the Company's system, and demonstrate misalignment between utility and ratepayer interests: (1) excessive rate-base growth that fails to comply with state statute (i.e., Minn. Stat. § 216C.05, subd. 2(4)); (2) unnecessary revenue requirement increases, such as an unnecessarily high ROE calculated using methods rejected in several jurisdictions; (3) inappropriate incentive compensation, designed to reward net income growth rather than encourage achievement of key performance indicators aimed at benefitting ratepayers; (4) obsolete cost-of-service analyses, which serve as the starting point for revenue allocation decisions that have historically favored residential and small commercial classes; and (5) haphazard and ill-advised rate design proposals, that could further penalize C&I Demand customers through unsupported cost-shifting. Without a concerted effort to address the Company's uncompetitive rates through the mechanisms outlined below, C&I customers will be unable to compete within their respective organizations and the global marketplace.

B. The ALJ and Commission Should Begin to Address Uncompetitive C&I Rates and Bills in this Case

Three overarching issues appear in any general rate case: revenue requirement (i.e., how big the rate increase should be), revenue allocation (i.e., which customer classes pay for that rate increase), and rate design (i.e., how rates are designed to recover the costs allocated to each class). In the present rate case, the Commission directed the parties to develop a full record, addressing, at a minimum, the following issues:²

- A. The standard rate case issues, including the impacts of data centers.

² Based upon interventions, written testimony, and participation at the evidentiary hearing, XLI understands that the parties in this case are (1) the Company; (2) XLI; (3) the Minnesota Department of Commerce, Division of Energy Resources ("Department"); (4) Minnesota Office of the Attorney General—Residential Utilities Division ("OAG"); (5) Citizens Utility Board of Minnesota ("CUB"); (6) Energy Cents Coalition ("ECC"); (7) Suburban Rate Authority ("SRA"); and (8) Cooperative Energy Futures, Minnesota Interfaith Power & Light, Environmental Law & Policy Center, and Vote Solar (together, "Joint Intervenors").

- B. Whether it is appropriate to use the proposed hypothetical capital structure or whether an alternate capital structure should be adopted.
- C. Reasons for the significant changes of the following costs since the last rate case:
 - i. Customer Accounting – \$16.5 million.
 - ii. Customer Service and Information – \$34.0 million increase.
 - iii. Administrative and General – \$67.8 million increase.
 - iv. Depreciation – \$112.9 million increase.
- D. The increase in the distribution budget with a focus on how the increased spending will impact reliability.
- E. How much Top 10 executive compensation costs should be recovered in rates?
- F. What grid reinforcement program and associated costs should be approved.
- G. What wildfire mitigation costs should be approved, and the impact these measures will have on other areas of Company operations, including FLISR, ADMS, vegetation management, and pole replacements.
- H. Develop a full record that ensures decisions made in Docket E-002/CI-24-318 are properly reflected in the 2026 Test Year.
- I. Future ADMS functionalities, lifespan, and costs.
- J. The program, to be submitted in supplemental direct testimony, where interest payments and fees from late bill payments are donated to low-income customer assistance programs or are eliminated.
- K. Should Xcel's proposed 2025 and 2026 sales true-ups be approved.
- L. Develop a record for prepaid pension asset that, at a minimum addresses the following:
 - a. The contribution amounts to pension funds required by federal law for each year of the cumulative years for which the Company claims a prepaid pension asset.
 - b. The actual contributions amounts made by the Company for each of the years.
 - c. The amount of pension expense recovered from ratepayers as an O&M expense each year.
 - d. The amount of each of the five components of pension expense (ACM or FAS 87) for each year of the claimed asset and determine the extent to which the component:
 - i. increases or decreases of the claimed prepaid pension asset for that year relative to the previous year;

- ii. whether any of the increase or decrease in the year is attributable to shareholder funding and by how much.
 - e. Whether the method of calculating pension expense (ACM or FAS87) affects the extent to which the asset is shareholder funded and, if so, how.
 - f. Determine the overall extent to which the Company has established by a preponderance of evidence that the claimed amount of the prepaid pension asset is attributable to shareholder contributions (i.e. is shareholder funded), and not the result of market returns or other attributes of pension expense under ACM and FAS 87.
- M. Develop a record addressing whether the fuel to steel transition will result in inter-generational cost shifting and, if so, make recommendations addressing this issue.
- N. Develop a record for insurance premium expense that, at a minimum, addresses the following:
- a. Provide the forecasted and actual annual expenses for each subcategory of expenses and credits since 2017.
 - b. A detailed description of each subcategory and their business purpose.
 - c. The extent to which the Marshall Wildfire in Colorado and the 2024 Smokehouse Creek Fire Complex in Texas affect the insurance premium, rate of return, or borrowing costs for the MN jurisdiction.
 - d. A thorough description of each actual refund or credit the company has received for insurance premiums since 2017 and any supporting documentation explaining the source and reason for each refund or credit, including distributions from captive insurance and mutual insurance pools.
 - e. For all past refund and credit subcategories received between 2017 and 2024 provide a thorough description of the company's prediction for refunds or credits in their 2025 and 2026 budget including all subcategories that they may have predicted no budgeted refund or credit.
 - f. If refunds and credits lack sufficient predictability to ensure fair and just rates, provide proposed mechanisms by which rate payers can be appropriately reimbursed for insurance expenses refunds and credits they have paid for in base rates.³

³ Notice of and Order for Hearing at 3-4 (Dec. 30, 2024) (eDocket No. 202412-213391-01) (“Notice of and Order for Hearing”).

XLI will address issues related to revenue requirement (Section II.C), CCOSS (Section II.D), revenue allocation (Section II.E), and rate design (Section II.F) throughout the sections of this initial brief that follow. Before addressing these various issues, this brief will provide relevant context for XLI's positions in Section II.A and explain the burden of proof standard applicable to the Company in this proceeding in Section II.B.

II. ANALYSIS

A. Background

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.⁴ The Company's \$490.7 million increase represents an unsustainable, significant increase for all ratepayers under present circumstances.

1. The Company's C&I Rates Are Uncompetitive and Contravene Explicit State Energy Policy

The Company's relentless annual rate increases present an untenable environment for its C&I customers, whose existing rates and bills (including interim rates) already exceed the national average.⁵ Looking at rates, the Company testified that "the NSP Minnesota industrial rate for 2024 is about 18 percent above the national average."⁶ Looking at bills, the Company testified that "[c]ustomers seem to care most about the total bill,"⁷ and Company Witness Paluck agrees that beginning in 2014 through 2024, the Company's bills for C&I customers have been above the national average.⁸ This is reflected in Attachment A, pg. 3 of 3, of XLI-10, which is reproduced

⁴ Notice of and Order for Hearing at 1.

⁵ Ex. XLI-3 at 31:19-32:9 (Ly Direct).

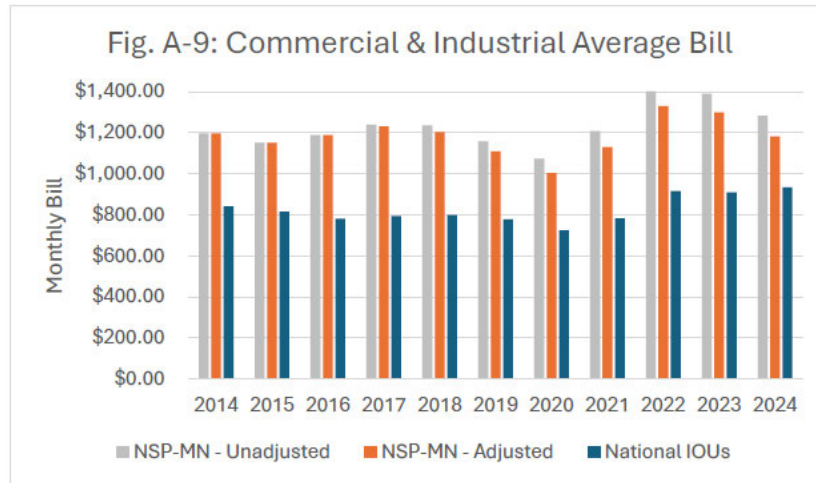
⁶ Hearing Transcript ("Tr.") Vol. 1 at 23:18-25 (Liberkowski).

⁷ Tr. Vol. 1 at 31:13-18 (Liberkowski).

⁸ Tr. Vol. 1 at 264:3-15 (Paluck) (citing XLI-10, which is *In the Matter of Commission Inquiry into Xcel Energy's Advanced Rate Design for Load Management*, Docket No. E002/CI-24-115, Compliance Filing (Mar. 31, 2025) (20253-217029-01) (showing average rates for retail, residential, and C&I customers)).

below as Table 1 of this brief. The Commission has not yet issued a Notice of Comment on the Company’s filing that is XLI-10.

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

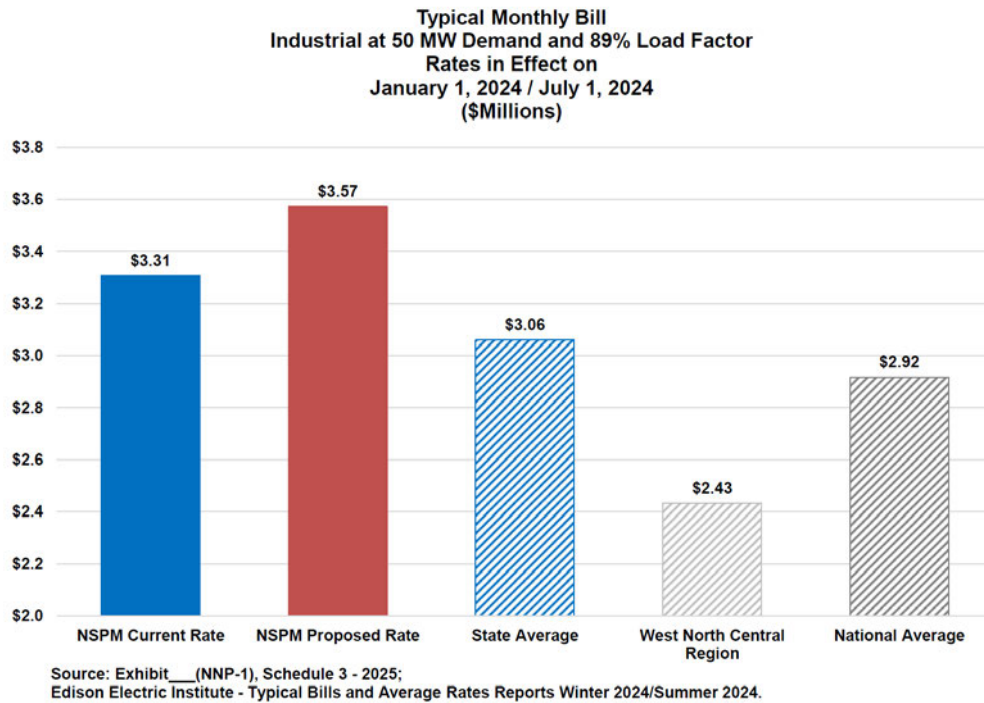


In reviewing the Company’s proposals, XLI Witness Ly prepared a similar analysis, focused on customer bills. This analysis compares NSP Residential bills (Schedule 6) and NSP C&I bills (Schedule 7) to the typical monthly bills for Residential and C&I bills across the state, region, and nation.⁹ Schedules 6 and 7 demonstrate that the Company’s as-filed request, if approved, would exacerbate the situation, driving costs for industrial customers from 13% to 22% above the national average.¹⁰ Schedule 7 is reproduced below as Table 2 in this brief.

⁹ Ex. XLI-3 at Schedules 6, 7 (Ly Direct).

¹⁰ Ex. XLI-3 at 32:13-17 (Ly Direct).

Table 2: Comparison of NSP-MN and State, Regional and National C&I Average Bills



Whether the ALJ reviews the evidence in terms of rates or bills, it is undisputed that the Company is failing to achieve the state energy policy goals of Minn. Stat. § 216C.05, subd. 2(4). Approval of the Company’s proposed rate increase would exacerbate that failure and disproportionately affect C&I Demand customers for two reasons. First, the existing uncompetitive industrial rates puts C&I customers already well above the national average. Second, the Company’s proposed revenue allocation increases the subsidy paid by C&I customers.¹¹ This pace of rate and bill growth cannot sustainably continue.

2. Several Factors Contribute to Uncompetitive C&I Rates, Which the ALJ and Commission Should Address

NSP ratepayers are no strangers to repeated rate increase requests, as the current MYRP follows years of dramatic and unfettered rate growth, which has historically foisted a heavier burden on C&I Demand customers than any other customer class. Whether this is due to an erroneous assumption that the C&I class has more flexibility to absorb or pass on increased

¹¹ Ex. XLI-3 at 31:1-16 (Ly Direct).

operational costs (including the cost of energy), a misunderstanding of other class's ability to pay, utilizing biased CCOSS, or some combination of these factors, the record in this case is that the C&I Demand class have high rates and bills compared to state, regional, and national averages. The Company has failed to provide evidence to support this unfettered growth of rate base, and its contentions fail to find support in the record.

Here, the Company seeks several unreasonable additions to its revenue requirement, such as a 10.30% ROE.¹² It should come as no surprise that the Company is seeking to continue to aggressively grow rate base, increase its rate of return, and increase its revenue requirement while seeking protections against any sales revenue losses—that is precisely what the Company's non-bargaining employees are incentivized to do through the earnings per share ("EPS") trigger¹³ in their compensation package. Yet the Company doubles down on this misalignment between Company and ratepayer interests by seeking to increase the ratepayer recovery cap on its employees' incentive compensation from the current 15% to 20% of aggregate base pay.¹⁴ It will be difficult, if not impossible, to slow down the increased upward pressure on rates without addressing incentive compensation. To counter the uncompetitive nature of C&I rates, XLI proposes several mitigation tactics, including directing a critical eye towards the Company's proposed revenue requirement, including its ROE; an analysis of the Company's proposed CCOSS, and whether the methodologies reasonably reflect cost-causation principles; and revenue allocation, and rate design strategies. Importantly, XLI's recommendations are grounded in the Company's affirmative burden of proof, which, in many instances, the Company fails to satisfy.

B. LEGAL STANDARD: The Company Bears the Burden of Proof to Demonstrate That Its MYRP Proposal Is Just and Reasonable

In reviewing a rate case, the Commission exercises two different aspects of its administrative authority: quasi-judicial and quasi-legislative. In its quasi-judicial capacity, the Commission has explained it acts on purely factual matters and weighs evidence in the same

¹² Ex. Xcel-24 at 4:27-5:1 (Nowak Direct).

¹³ Ex. Xcel-64 at 20:14-15 (Ly Direct).

¹⁴ Ex. XLI-2 at 43:11-12 (LaConte Direct).

manner as a district court, requiring facts to be proved by a preponderance of the evidence.¹⁵ In its quasi-legislative capacity, the Commission acts on issues involving policy judgments, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.¹⁶ As it pertains to revenue requirement, the Commission exercises its quasi-judicial capacity. As it pertains to revenue allocation and rate design, the Commission acts in a quasi-legislative capacity.¹⁷ Whether the Commission acts in a quasi-legislative or quasi-judicial capacity, when reviewing a proposed rate change, the Company's burden remains the same and never shifts to another party.¹⁸

The Company alone bears the burden to demonstrate its proposal is reasonable.¹⁹ "Every rate made, demanded, or received by any public utility ... shall be just and reasonable.... Any doubt as to reasonableness should be resolved in favor of the consumer."²⁰ The Minnesota Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding by stating:

[I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the ... case the accent is more on the

¹⁵ *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, PUC Docket No. E-017/GR-20-719, [Findings of Fact, Conclusions, and Order](#) at 3–4 (Feb. 1, 2022) (eDocket No. 29222-182349-01).

¹⁶ *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, [Findings of Fact, Conclusions, and Order](#) at 5 (Sept. 3, 2013) (eDocket No. 20139-90902-01).

¹⁷ *St. Paul Area Chamber of Commerce v. Minn. Pub. Serv. Comm'n*, 251 N.W.2d 350 (Minn. 1977). Even when acting in a quasi-judicial capacity on revenue requirement decisions, the Commission is not constrained to accept all evidence that a utility has incurred a cost—the just and reasonable standard outlined in Minn. Stat. § 216B.03 always applies.

¹⁸ *Northern States Power*, 416 N.W.2d 719, 726 (Minn. 1987) ("If there ever existed in this state a presumption to be applied in ratemaking, enactment of Minn. Stat. § 216B.16, subd. 4 (1986) effectively removed any presumption, and placed on the petitioning utility the burden of proving the proposed rate is fair and reasonable").

¹⁹ Minn. Stat. § 216B.16, subd. 4 ("The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.").

²⁰ Minn. Stat. § 216B.03.

inferences and conclusions to be drawn from the basic facts (i.e., amount of claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses.^[21]

The Commission built on the Minnesota Supreme Court’s language set forth in the *Northern States Power* case and recognized other Minnesota Supreme Court precedent to further clarify that when prosecuting a rate case

[u]tilities seeking rate changes must ... prove not only that the facts they present are accurate, but that the costs they seek to recover are rate-recoverable, that the rate recovery mechanisms they propose are permissible, and that the rate design they advocate is equitable, under the “just and reasonable” standard set by statute.^[22]

The CenterPoint Order recognizes this burden is only met when a utility can demonstrate reasonableness by a preponderance of the evidence.²³ The utility always retains the high burden of this standard,²⁴ a burden that differs from a civil case. The Minnesota Supreme Court has previously explained this distinction as follows:

The “weighing” by [a] court in a civil case applying the “fair preponderance” standard involves a determination by the court whether the proponent of the conclusion has produced sufficient credible evidence to sustain that conclusion. In contrast, the task of the MPUC is not so much concerned with the sufficiency and credibility of the evidence, as it is concerned with whether the

²¹ *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722–23 (Minn. 1987) (emphasis added).

²² *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, PUC Docket No. G-008/GR-15-424, [Findings of Fact, Conclusions, and Order](#) at 4–5 (June 3, 2016) (emphasis added) (eDocket No. 20166-121975-01); *see also St. Paul Area Chamber of Commerce*, 251 N.W.2d 350.

²³ *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, PUC Docket No. G-008/GR-15-424, [Findings of Fact, Conclusions, and Order](#) at 5 (June 3, 2016) (citing *In re Minn. Power & Light Co.*, 435 N.W.2d 550, 554 (Minn. App. 1989)).

²⁴ *In the Matter of a Commission Investigation into Xcel Energy’s Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, PUC Docket No. E-002/CI-13-754, [Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes](#), at 12–13, 13 n.20 (May 8, 2015) (eDocket No. 20155-110255-01) (citing Minn. Stat. § [216B.16](#), subd. 6).

evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates.^[25]

Synthesizing this authority, a rule emerges that requires satisfaction of two criteria: (1) the Company must establish the amount of a given cost as a judicial fact,²⁶ and (2) the Company must establish that it is just and reasonable for ratepayers to bear those costs, rather than the Company's shareholders.²⁷ The Company bears an appropriately heavy (but not insurmountable) burden, given its status as a regulated monopoly with captive ratepayers.

For the reasons set forth below, the Company has failed to make the required showing that its proposed rates are just and reasonable by a preponderance of the evidence. Specifically, and as it relates to the Commission's statement of issues in the Notice and Order for Hearing, XLI respectfully asserts the following:

1. The Company's proposed ROE of 10.30% is unreasonable and should be reduced, applying analyses long supported by the Commission;
2. The Company's ROE should be further reduced to account for the Company's low-risk and the Company's failure to provide the type of customer service Minnesota Rules require;²⁸
3. The test-year revenue increase sought by the Company is unreasonable;
4. The Company's shareholders, not customers, should be responsible for any incentive compensation above the 15% cap;
5. The Company's proposed Energy Supply O&M and Transmission O&M should be reduced;

²⁵ *In re Petition of N. States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987) (emphasis added).

²⁶ *In re Petition of N. States Power Co.*, 416 N.W.2d at 722 (Minn. 1987).

²⁷ *In re Petition of N. States Power Co.*, 416 N.W.2d at 723 (Minn. 1987) (finding that "by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating that it is just and reasonable that the ratepayers bear the costs of those expenses").

²⁸ Minn. R. 7820.3200 through 7820.3800.

6. The Company's CCOSS is not a just and reasonable starting point for revenue allocation and is based on an obsolete methodology, undeserving of any weight by the ALJ or the Commission;
7. The Company's proposed revenue allocation is unreasonable;
8. The Company's recovery of its Customer Care costs should be denied on the basis of its egregious billing errors and lack of response and resolutions;
9. In establishing the Large General Time of Day Service and Large Peak Controlled Time of Day Service tariffs, the Company should treat such customers as a new class separate from the C&I Demand class; and
10. The Company should allocate incremental revenues from the new large load customers to customer classes in the same manner as production and transmission plant.

C. REVENUE REQUIREMENT: The Company Failed to Meet Its Burden with Respect to Multiple Revenue Requirement Issues

1. The Company's Proposed ROE Is Unreasonable

The Company's MYRP includes a proposal for an ROE of 10.30%.²⁹ As demonstrated herein and through XLI's expert analysis, this value is overstated and would result in an unnecessarily high revenue requirement, placing unneeded burdens on ratepayers in the interest of shareholder gains. Based on the testimony of XLI Witness Billie LaConte, XLI supports adoption of an ROE of 8.96%.³⁰

The United States Supreme Court provides precedential guidance to determine a fair ROE through two cases: *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*³¹ ("Bluefield"), and *Federal Power Commission v. Hope Natural Gas Co.*³² ("Hope"). In *Bluefield*, when addressing how to define a reasonable return, the Court concluded that

²⁹ Ex. Xcel-24 at 4:27-5:1 (Nowak Direct).

³⁰ Ex. XLI-2 at 3:7-9 (LaConte Direct).

³¹ 262 U.S. 679 (1923).

³² 320 U.S. 591 (1944).

[t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.^[33]

“Reasonableness,” “sufficient,” and “adequate” are also terms used in Minnesota law. Of the factors to be considered in setting just and reasonable rates, the Commission is bound to consider

the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.^[34]

Neither the *Hope* and *Bluefield* decisions nor Minnesota law require the Commission to provide investors with above-average returns. Instead, utilities are simply allowed an opportunity to earn a return commensurate with risk.³⁵ The Company’s ROE witness, Joshua Nowak, acknowledged this reality in Direct Testimony.³⁶

The determination of a proper ROE is a pragmatic exercise. Both Witness LaConte and Witness Nowak acknowledge that there is an element of subjective judgment that factors into recommending an ROE.³⁷ While the cost of equity is a financial construct, “the ROE is a public policy variable that has financial implications, but there are other factors that drive that return.”³⁸ The Company offers no evidence that its current authorized ROE of 9.25% has been insufficient to maintain its very high credit rating. Further, the Company’s “credit metrics exceed, or are well within the range, required by S&P to maintain an A/A- credit rating which is the rating that NSPM wishes to continue to support and maintain.”³⁹ Therefore, based on the record before this ALJ, the

³³ *Bluefield*, 262 U.S. at 693 (emphasis added).

³⁴ Minn. Stat. § 216B.16, subd. 6 (emphasis added).

³⁵ See Ex. XLI-2 at 17:6-9 (LaConte Direct).

³⁶ Ex. Xcel-24 at 42:19-21 (Nowak Rebuttal).

³⁷ See Ex. Xcel-24 at 34:23-35:4 (Nowak Direct) (explaining his process of selecting various models to consider when determining the appropriate cost of equity); Ex. XLI-2 at 28:6-10 (LaConte Direct) (explaining her use of a risk adjustment).

³⁸ Ex. CUB-1 at 21:17-19 (Kihm Direct).

³⁹ Ex. XLI-2 at 8:4-6 (LaConte Direct) (internal quotations omitted).

Company has failed to meet its affirmative burden to show that its requested ROE is reasonable or that XLI's recommended 8.96% ROE (or lower) will deprive it of the opportunity to earn a return commensurate with its risk.

a. The Company's Proposed 10.30% ROE Defies the Commission's Reliance on the Two-Growth DCF Methodology and the Company's Own Modeling

Generally, the determination of a reasonable ROE is based on multiple methods and analyses. For example, the analysis underlying Mr. Nowak's ROE recommendation relies on several methodologies, including "the Constant Growth DCF Model, the Two-Growth DCF model, the CAPM, the Bond Yield Plus Risk Premium approach, and an Expected Earning analysis."⁴⁰ While several methods exist to make this determination, the Commission and other jurisdictions have expressed explicit preferences for certain models over others. For example, in Minnesota, the Commission explicitly expressed its view that the two-growth discounted cash flow ("DCF") method is the best approach to determine an ROE in a rate case setting,⁴¹ stating "the DCF analysis provides the best evidence in the record for establishing the Company's cost of equity,"⁴² and Commission precedent demonstrates that a straight-forward determination of the appropriate ROE should be based on the two-growth DCF model.⁴³ Following the Commission's guidance, XLI Witness LaConte built an ROE recommendation through use of three DCF models (a Constant Growth, Two-Stage, and Multi-Stage) and two CAPM analyses (historical and projected). The results of Witness LaConte's DCF analyses were a 9.56% ROE (before adjustment), a significantly lower ROE recommendation than the Company's 10.30%.⁴⁴

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

⁴⁰ Ex. Xcel-24 at 34:23-25 (Nowak Direct).

⁴¹ *In the Matter of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, PUC Docket No. E017/GR-20-719, Findings of Fact, Conclusions, and Order at 34 (Feb. 1, 2022) (concluding the two-growth DCF method is the best approach) ("OTP Rate Case Order").

⁴² OTP Rate Case Order at 34.

⁴³ *Id.*

⁴⁴ Ex. XLI-2 at 26:1-2 (LaConte Direct).

growth DCF analysis.⁴⁵ Witness LaConte relied on the same proxy group developed by Mr. Nowak to conduct her analysis.⁴⁶ Witness LaConte’s final recommended ROE was 8.96%, which was based upon a 9.56% ROE that was reduced by 50-basis points to account for the Company’s reduced financial risk (“due to its multitude of adjustment clauses, the sales true-up, its projected test-year and the MYRP,” which allow NSPM to increase rates outside of a single test-year), and reduced an additional 10-basis points to reflect a failure to provide customer service as required by Minnesota Rules.⁴⁷ Witness LaConte’s recommendation fits squarely within the results of her two-growth DCF model, reproduced in this brief as Table 3 below, in conformance with the Commission’s stated preferences, and therefore should be afforded more weight than the recommendation of Mr. Nowak.

Table 3: XLI Estimated ROE Using DCF Method

Table 8 Estimated ROE Using DCF Method	
Model	Value
Constant Growth Low	9.36%
Constant Growth Mean	10.38%
Constant Growth High	11.84%
Two-Stage	9.58%
Multi-Stage Low	8.29%
Multi-Stage Mean	8.58%
Multi-Stage High	8.91%
Average	9.56%
Source: Schedule Nos. 3 -7.	

⁴⁵ Ex. XLI-2 at 19:3 (LaConte Direct) (“The CAPM methodology was performed as a check on my DCF analyses.”).

⁴⁶ Ex. XLI-2 at 22:24-25 (LaConte Direct).

⁴⁷ Ex. XLI-2 at 19:11-17 (LaConte Direct).

Conversely, Witness Nowak’s analysis improperly applies several methods that have been rejected in other jurisdictions, such as by the Federal Energy Regulatory Commission (“FERC”)⁴⁸ (i.e., Risk Premium approach and the Expected Earnings method), and incorporates a flotation cost adjustment—none of these methods or adjustments are “widely used or accepted by this Commission or regulatory commissions in other jurisdictions.”⁴⁹

Along with the use of several inappropriate methodologies, Witness Nowak also conducted DCF analyses in making an ROE recommendation.⁵⁰ However, Witness Nowak’s DCF analyses were combined with the results of his CAPM, Risk Premium, and Expected Earnings analyses, several of which, as described above, are inappropriate for purposes of ROE determinations. To the extent Witness Nowak’s ROE recommendation incorporates use of those methodologies, the ALJ should recommend little to no weight be given to the recommendation. Given the Commission’s expressed preference for the two-growth DCF method, Witness LaConte’s pre-adjustment ROE recommendation with an average of 9.56% using DCF analyses,⁵¹ should be given priority in this proceeding.

In an effort to discount Witness LaConte’s analysis, Witness Nowak relies on an incorrect manipulation of the Commission’s Order from Xcel’s 2021 rate case, citing “over the course of more than 50 years at least seven industries, including utilities, had growth faster than the overall GDP” for the proposition that Witness LaConte’s multi-stage DCF analysis, which uses GDP growth rate as the terminal growth, should not be considered in a fair ROE determination.⁵² However, this quote is actually the Commission’s summary of the ALJ’s recommendation in that

⁴⁸ FERC explicitly determined that no evidence exists to suggest investors use the Risk Premium methodology or evidence that would resolve the circularity problems inherent in the Risk Premium model; therefore, FERC 1 excludes the Risk Premium model for estimating the ROE. *Association of Businesses Advocating Tariff Equity et al. v. Midcontinent Independent System Operator, Inc., et al.*, Docket Nos. EL14-12-016, Order on Remand at 16. (Oct. 17, 2024).

⁴⁹ Ex. XLI-2 at 3:1-6 (LaConte Direct).

⁵⁰ Ex. Xcel-24 at 39:12-19; 43:1-8 (Nowak Direct).

⁵¹ Ex. XLI-2 at 25:13-14 (LaConte Direct).

⁵² Ex. Xcel-25 at 71:12-17 (Nowak Rebuttal) (citing *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 88-89 (July 17, 2023) (eDocket No. 20237-197559-01) (“Xcel Rate Case Order”)).

case, not the Commission's opinion itself. In fact, the Commission quotes the ALJ's recommendation to disagree with it, stating "[i]n analyzing the parties' models and their results, [the ALJ] discounted the Department's reliance on GDP to estimate long-term growth in its multi-stage DCF analyses, finding that over the course of more than 50 years, at least seven industries, including utilities, have grown faster than the overall GDP."⁵³ Therefore, what Witness Nowak quotes is in fact not what the Commission stated at all. Witness Nowak admitted as much in evidentiary hearings.⁵⁴ In fact, he admitted that in its Order, the Commission went further and actually supported XLI's arguments, stating it found "value in XLI's arguments that Xcel's investors face lower levels of risk because of the regulatory tools used by the Company, which include multiyear rate plans and riders."⁵⁵ Witness Nowak's attempt to discount Witness LaConte's multi-stage DCF analysis is therefore undercut by the Commission's disagreement with the ALJ quotation used by Witness Nowak, as well as Witness LaConte's explicit conformance to the Commission's stated preference for DCF analysis when making an ROE determination.

Based on the Commission's explicit guidance that the DCF methodology is the best approach across methodologies, the ALJ should focus the ROE determination on the two-growth DCF modeling results, which may be further refined to reflect the Company's risk factors and additional adjustments proposed by Witness LaConte.⁵⁶

b. The Company's Risk Mitigation Mechanisms Also Support a Lower ROE

Both Witness LaConte and Witness Nowak adjusted their ROE modeling results to arrive at their respective recommended ROE in this case,⁵⁷ and the record supports Witness LaConte's 60-basis-point reduction from her starting point of 9.56%. In her final recommendation, Witness LaConte adjusted the results of her modeled ROE down by 50 basis points to account for the Company's reduced risk, and 10 basis points to account for NSP's failure to meet requirements for

⁵³ Xcel Rate Case Order at 88.

⁵⁴ Tr. Vol. 1 at 64:20-65:3 (Nowak).

⁵⁵ Tr. Vol. 1 at 66:21-67:3 (Nowak); Xcel Rate Case Order at 91.

⁵⁶ See Ex. XLI-2 at 18:5-7 (LaConte Direct).

⁵⁷ Ex. Xcel-24 at 63:18-25 (Nowak Direct); Ex. XLI-2 at 28:6-16 (LaConte Direct).

providing reliable billing and customer service.⁵⁸ To determine the 50 basis point reduction, Witness LaConte cited the Company's multitude of adjustment clauses, its sales true-up, its projected test-year, and the MYRP itself, which together facilitate NSP's rate increases for an additional year without filing a rate case.⁵⁹ To quantify the reduction needed to offset for these automatic rate recovery mechanisms, Witness LaConte analyzed the Company's Schedule 11,⁶⁰ which depicts each operating company in the proxy group of 58 companies and denotes whether the company uses any adjustment clauses that reduce its relative risk profile. Such adjustment clauses include "(1) Test Year Convention; (2) Rate Base Convention; (3) Revenue Decoupling; and (4) Capital Cost Recovery."⁶¹ Witness LaConte's review found that NSP holds six of these adjustment clauses, and only seven other companies in the proxy group hold six or more adjustment clauses.⁶² Witness LaConte thus determined that the Company's ability to utilize these automatic risk-reducing recovery mechanisms, which are viewed favorably by credit agencies, warranted a 50-basis-point reduction.⁶³

Additionally, as will be addressed in more detail below, BOMA members have experienced significant billing and customer care issues as NSP customers, including "delayed and inaccurate bills, misapplied payments, and ineffective communications and resolutions."⁶⁴ NSP has statutory and regulatory compliance requirements to provide customers with a certain level of care, yet has time and again failed to meet those expectations. Therefore, XLI finds it appropriate for the ALJ to recommend a 10-basis point reduction to the Company's ROE to reflect its failure to comply with Minnesota Statute to provide adequate customer service to ratepayers.⁶⁵

⁵⁸ Ex. XLI-2 at 28:13-16 (LaConte Direct).

⁵⁹ Ex. XLI-2 at 19:12-14 (LaConte Direct).

⁶⁰ Schedule 11 depicts all of the operating companies in the proxy group and whether they possess any adjustment clauses that reduce their relative risk profiles.

⁶¹ Ex. Xcel-24 at 55:7-10 (Nowak Direct).

⁶² Ex. XLI-2 at 29:15-18 (LaConte Direct).

⁶³ Ex. XLI-2 at 29:4-22 (LaConte Direct).

⁶⁴ Ex. XLI-2 at 59:3-6 (LaConte Direct).

⁶⁵ Ex. XLI-2 at 64:17-18 (LaConte Direct).

c. Concluding Remarks on ROE

The ALJ should disregard the Company's proposed 10.30% ROE in favor of Witness LaConte's recommendation. The Company has not sufficiently met its burden to show that it requires a significantly higher ROE, 105 basis points over its current 9.25%, and the Company's proposed 10.3% would result in unjust and unreasonable rates. Stated alternatively, the Company failed to show that the existing ROE is insufficient because it has not hindered it from achieving strong investor returns. XLI, therefore, urges the ALJ to recommend an 8.96% ROE.

2. The Company's Proposal to Increase the Incentive Compensation Cap from 15% to 20% Is Unreasonable and Overly Punitive to Ratepayers

Incentive compensation is the "additional payment to employees to reward certain behavior and/or results."⁶⁶ For each year of its MYRP, the Company requests incentive compensation, totaling \$23.5 million for 2025, and \$24.2 million for 2026, which is altogether too high.⁶⁷ While the Company has not made any design changes to its Annual Incentive Program ("AIP"), the Company's requested amount represents an increase to the cap on incentive compensation to 20% of aggregate base pay (up from the current 15% cap).⁶⁸

Under NSP's AIP, incentive compensation is available to exempt, non-bargaining employees, comprises a component of the employee's total compensation, and the Company claims it is intended to "align the focus and execution of key, strategic business goals."⁶⁹ Further, eligible employees' incentive is allegedly based off pre-determined individual performance goals and the Company's achievement of Corporate Key Performance Indicators ("KPI"), which are as follows: (1) Customer Satisfaction, (2) Public Safety, (3) Electric System Reliability, (4) Employee Safety, (5) Diversity, Equity, And Inclusion, and (6) Wind Availability.⁷⁰ Importantly, prior to any AIP award, there is a trigger in the form of an earnings per share ("EPS") threshold, meaning

⁶⁶ Ex. XLI-2 at 43:2-3 (LaConte Direct).

⁶⁷ Ex. XLI-2 at 43:6-9 (LaConte Direct).

⁶⁸ Ex. Xcel-64 at 15:22-25 (Ly Direct); Ex. XLI-2 at 43:11-12 (LaConte Direct).

⁶⁹ Ex. Xcel-64 at 13:16-27 (Ly Direct).

⁷⁰ Ex. Xcel-64 at 15:9-15 (Ly Direct); Ex. Xcel-64 at Schedule 4a (Ly Direct).

the Company must hit certain earnings goals before any employee can receive an incentive.⁷¹ While at first glance it may appear that KPIs are intended to provide ratepayer benefits, the fact that Company earnings and the EPS threshold is the trigger, not KPI, demonstrates earnings are the first priority in achieving a Year-End Award. XLI requests the ALJ reject the Company's proposal the Company failed to satisfy its burden of proof to justify a higher incentive compensation request.

NSP's request to increase the cap on incentive compensation should be rejected because NSP (1) proposes to apply the cap on an aggregate, rather than individual, basis, and (2) AIP still requires Xcel Energy to meet an EPS target before incentive compensation is paid.⁷² These facets are troublesome for two reasons. First, with regards to the aggregate treatment, the Commission stated in the Company's last rate case that aggregating the AIP:

could allow the Company to concentrate the total AIP budget on a small number of employees, a result that might inadvertently misalign employee incentives, potentially incentivizing those who earn AIP to prioritize shareholder interests and compromising their duty to exercise independent judgement on behalf of the Company to provide safe and reliable service at a reasonable cost to customers.⁷³

XLI retains the same concerns about aggregate treatment in this rate case and the Commission should not aggregate the AIP cap and instead it should remain implemented on an individual basis.

Second, XLI is particularly troubled because the Company is seeking to recover costs (i.e., AIP) that are not necessary to provide safe and reliable service, and are in fact based on the Company meeting its EPS target, meaning the Company is attempting to recover an expense from customers who do not benefit from that expense.⁷⁴ Company Witness Ly admitted the program functions in this way during the proceeding's evidentiary hearings. When asked if "employees that are eligible for the incentive plan ... perform well on the KPIs, but the Company does not hit the earnings per share threshold, there is no payout?," Company Witness Ly responded, "[t]hat is

⁷¹ Ex. Xcel-64 at 20:14-15 (Ly Direct).

⁷² Ex. XLI-2 at 43:15-17 (LaConte Direct).

⁷³ Xcel Rate Case Order at 19.

⁷⁴ Ex. XLI-2 at 44:14-45:4 (LaConte Direct).

correct.”⁷⁵ NSP’s program is structured such that if the EPS target is not met, no AIP is paid out, regardless of whether the Company has met other performance targets, many of which are intended to benefit ratepayers. The structure itself demonstrates NSP’s priorities, because “[s]etting an EPS target before any AIP compensation is paid clearly demonstrated that NSP values its EPS target above meeting performance metrics that benefit ratepayers.”⁷⁶ While Company Witness Ly states the “EPS trigger is not intended to divert employee efforts from these customer-facing goals,”⁷⁷ diverting employee efforts to shareholder value is the practical implication of a program that only pays out employees if earnings targets are hit, rather than performance indicators intended to benefit ratepayers.

Company Witness Ly attempts to deflect from this reality by asserting that the “EPS threshold is an affordability trigger that ensures the Company has sufficient funds to pay out AIP each year.”⁷⁸ But Company Witness Ly explicitly confirmed there will be no payout for employees who have hit their KPIs if the EPS is not met.⁷⁹ Therefore, employees have a perverse incentive to first achieve EPS targets, which are the trigger for their Year End Award, rather than on the achievement of customer-facing goals.⁸⁰ This is particularly harmful to ratepayers because this system drives increases to net income without protecting ratepayers from ever-increasing rates. Furthermore, the affordability target not only eliminates the need for NSP’s requested increase from ratepayers from 15% to 20%, it effectively eliminates the need for any cost recovery because the EPS trigger ensures the Company has sufficient funds to compensate employees who meet KPI (i.e., if the Company has more funds available, it is able to compensate employees without additional recovery from ratepayers). The fundamental structure and incentives of NSP’s AIP serve the interests of the Company’s shareholders, rather than ratepayers, and the Company should not be allowed to recover an expense from customers that does not benefit them.

⁷⁵ Tr. Vol. 1 at 148:19-25 (Ly).

⁷⁶ Ex. XLI-2 at 46:9-12 (LaConte Direct).

⁷⁷ Ex. Xcel-64 at 21:3-6 (Ly Direct).

⁷⁸ Ex. Xcel-64 at 20:14-15 (Ly Direct).

⁷⁹ Tr. Vol. 1 at 148:19-25 (Ly).

⁸⁰ Ex. XLI-8 at 16:12-18 (LaConte Surrebuttal).

NSP attempts to rely on the Commission’s approval of a 20% AIP cap for Minnesota Power in its own justification for an increase. However, the comparison is inappropriate here because it ignores the skewed incentives in favor of Xcel’s shareholders. These skewed incentives readily appear in Company’s EPS history, which has increased each year since 2015, as demonstrated by Table 11 of Witness LaConte’s Direct Testimony.⁸¹ This table is reproduced below as Table 4 in this brief.

Table 4: Xcel Energy’s 10-Year Historical Earnings Per Share

Table 11 Xcel Energy Historical EPS	
Year	EPS
2015	\$1.94
2016	\$2.21
2017	\$2.25
2018	\$2.47
2019	\$2.64
2020	\$2.79
2021	\$2.96
2022	\$3.17
2023	\$3.21
2024	\$3.44
Sources: Xcel Energy Annual Reports 2015 -2024	

These year-over-year increases provide a direct benefit to shareholders.⁸² To put this in context, there were roughly 563 million weighted average shares of stock outstanding as of the time Xcel Energy, Inc. completed its Form 10-K for the year ending December 31, 2024.⁸³ The ratio of Xcel’s net income of \$1.936 billion against these shares results in the reported EPS of \$3.44.⁸⁴ NSP contributed over 40% of the earnings in 2024—roughly \$794 million of Xcel Energy Inc.’s

⁸¹ Ex. XLI-2 at 45:6-8 (LaConte Direct).

⁸² See Table 11, Xcel Energy Historical EPS, at Ex. XLI-2 at 45:6-8 (LaConte Direct).

⁸³ Ex. DOC-26 at 48 (Xcel Energy Inc.’s 2024 Form 10-K).

⁸⁴ *Id.*

net income of \$1.936 billion—with an EPS of \$1.41.⁸⁵ Notably, over 50% of the increase in EPS for Xcel Energy, Inc. from \$3.21 in 2023 to \$3.44 in 2024 was due to NSP increasing its EPS by \$0.13 from \$1.28 to \$1.41.⁸⁶ According to the 10-K, “[o]ngoing earnings [for NSP] increased due to higher recovery of electric and natural gas infrastructure investments, partially offset by increased depreciation and interest charges.”⁸⁷ In other words, NSP’s continued focus on rate increases for recovery of infrastructure investments is helping Xcel Energy, Inc. achieve and exceed the EPS trigger and ensure substantial net income for NSP and Xcel Energy, Inc. These results, not KPI, are driving Company behavior, and as a result, Xcel Energy’s AIP is skewed to shareholders and not customers.

The fact that the Company’s AIP is skewed to financial results is a fatal flaw in its request to increase its cap to 20% like the Commission approved for Minnesota Power. In its order allowing Minnesota Power’s 20% AIP cap, the Commission explicitly based its decision on the fact that “Minnesota Power’s short-term incentive program was not shown to create skewed incentives or other public policy concerns.”⁸⁸ The Commission’s reasoning for approving Minnesota Power’s 20% AIP cap does not transfer to the case of NSP where there are “skewed incentives” to achieve the EPS trigger as described above.⁸⁹

For the reasons set forth above, the Company cannot satisfy its burden to show that its proposed incentive compensation cap increase to 20% is just and reasonable or will result in just and reasonable rates. XLI urges the ALJ to recommend disallowance of the Company’s proposed incentive compensation expense above the 15% cap, reject the Company’s request to aggregate the cap, for a reduction of the incentive compensation amount to \$21.9 million in 2025, to \$22.6 million in 2026.⁹⁰

⁸⁵ *Id.* at 25, 26.

⁸⁶ *Id.* at 26.

⁸⁷ *Id.*

⁸⁸ Xcel Rate Case Order at 19.

⁸⁹ Ex. XLI-2 at 46:5-7 (LaConte Direct).

⁹⁰ Ex. Xcel-65 at Exhibit __ (YL-2), Schedule 4 at 1 (Ly Rebuttal).

3. The Company Has Not Justified Recovery of Portions of Long-Term Incentive Compensation from Ratepayers

Ratepayers should not bear the burden of funding portions of the Company’s long-term incentive (“LTI”) compensative scheme that will further incentivize behavior that increases rates. In this case, the Company requested to recover \$11.5 million in LTI in 2025 and \$12.1 million in 2026.⁹¹ The Company’s LTI scheme is structured such that one component is tied to environmental goals, while the other is tied to time-based compensation.⁹² Time-based compensation refers to time-based vesting, wherein a portion of an employee’s LTI award is conditioned upon the individual remaining employed at the Company.⁹³ However, the Company has not justified cost recovery on the LTI because the environmental goals it proposes to achieve are similar or the same as Minnesota’s Carbon-Free Standard (“CFS”), which required “an electric utility to generate or procure electricity from carbon free technologies in an amount equivalent to 100% of the utility’s electric sales to retail customers in Minnesota.”⁹⁴ Ratepayers should not be responsible for funding utility incentives based on what the utility is already required to do by state law. That provides no incremental benefit to ratepayers. Further, regarding the time-based component of LTI, this component is based on achieving certain financial targets that benefit shareholders, not ratepayers, which should be disallowed.⁹⁵ Therefore, the ALJ should recommend the Company’s LTI proposal be rejected.

4. The Company’s Request Regarding Its Operations and Maintenance Expense is Unreasonable

The Company proposed to recover Energy Supply O&M expense (\$122.3 million and \$140.7 million in 2025 and 2026, respectively) and Transmission O&M expense (\$18.9 million and \$19.4 million in 2025 and 2026, respectively). This proposal is unreasonable and warrants adjustment because the Company’s historical performance consistently falls short of budgeted expenses.

⁹¹ Ex. XLI-2 at 48:3-4 (LaConte Direct).

⁹² Ex. XLI-2 at 48:6-8 (LaConte Direct).

⁹³ Ex. Xcel-3 at 23:2024 (Ly Direct).

⁹⁴ Minn. Stat. § 216B.1691, subd. 2g (2024).

⁹⁵ Ex. XLI-2 at 48:15-49:2 (LaConte Direct).

The Company has historically overstated its Energy Supply O&M, which relates to the Company's "generation fleet and include[s] Internal Labor, Contract Labor, Materials, Chemicals and Other,"⁹⁶ by an average of about 4.3% over the past three years.⁹⁷ This overstatement amounts to an additional approximately \$14.7 million recovered from ratepayers that was unnecessary over the past three years.⁹⁸ The Company has continued this trend to inflate these expenses in the present MYRP, budgeting \$122.3 million for Energy Supply O&M in 2025, and \$140.7 million in 2026.⁹⁹ "The 2025 budget is 7.8% higher than the forecasted 2024 expense and the 2026 budget is 24.5% higher than the actual 2024 budget and 15.4% higher than the 2025 proposal."¹⁰⁰ Based on its track record of over-estimating this expense, XLI believes the ALJ and Commission should be skeptical about the Company's proposed Energy Supply O&M expense, and reduce them to reflect the Company's actual historical O&M spend.

Further, the process through which the Company sets its expense is flawed. As explained in Witness LaConte's Surrebuttal Testimony, the Company uses a projected test year, rather than historical (where costs are known), when setting rates for customers, disadvantaging its customers because the use of a projected test year may lead to excessive rates or biased projections.¹⁰¹ If costs are lower, the Company benefits. Further, the Company's true-up mechanism already exists to make the Company whole should it incur higher costs than its predicted O&M expenses, so there is no harm to the Company if its inflated estimates are rejected. By approving lower Energy Supply O&M costs, the Commission can protect ratepayers and ensure they pay the lowest possible rate, while also assuring the Company can be made whole through its true-up mechanism.¹⁰² Allowing the Company to recover higher rates will directly deny customers the opportunity to benefit from the Company's lower Energy Supply O&M costs through lower rates. To better align cost recovery more reflective of historical performance and spending, XLI proposes to reduce the

⁹⁶ Ex. XLI-2 at 50:9-10 (LaConte Direct).

⁹⁷ See Ex. XLI-2 at 50:14, Table 12, NSPM Projected and Actual Energy Supply O&M Expense (LaConte Direct).

⁹⁸ Ex. XLI-2 at 51:1-11 (LaConte Direct).

⁹⁹ Ex. XLI-2 at 51:7-8 (LaConte Direct).

¹⁰⁰ Ex. XLI-2 at 51:8-10 (LaConte Direct).

¹⁰¹ Ex. XLI-8 at 13:22-25 (LaConte Surrebuttal).

¹⁰² See Ex. XLI-8 at 14:9-15 (LaConte Surrebuttal).

Company's Energy Supply O&M expense by 4.3%, the amount the Company over-earned in its last rate case for these expenses, translating to reductions of \$4.9 million in 2025, and \$5.7 million in 2026.¹⁰³

Regarding Transmission O&M, the Company anticipates an \$18.9 million Transmission O&M expense for 2025, and \$19.4 million for 2026.¹⁰⁴ Once again, the Company historically overestimates its Transmission O&M expenses, and thus, the ALJ should recommend a reduction for each year in the MYRP. The same issues apply with regard to the Company's use of a projected test year. "As explained in regard to the reduction in Energy Supply O&M, customers are at a disadvantage if the utility uses a projected test year because it may lead to excessive rates due to forecasting errors, as demonstrated above, or biased projections."¹⁰⁵ As shown in Table 13 of Witness LaConte's Direct Testimony, NSP's consistent overstatement of its Transmission O&M expense averages 16.2% over the last three years, resulting in customers paying an additional \$11.4 million for this expense.¹⁰⁶ For the reasons explained above, specifically NSP's ability to use a projected year and the delay in customers benefitting from a lower Transmission O&M expense, 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.¹⁰⁷

5. NSP Fails to Justify Its Increased Excess Liability Insurance or Demonstrate Appropriate Allocation to the Minnesota Jurisdiction

Xcel Energy, Inc., purchases Excess Liability Insurance ("ELI") as a component of its aggregated insurance and allocates a portion to NSP.¹⁰⁸ NSP's allocated ELI expense has increased by an overwhelming 160% from its last base rate case.¹⁰⁹ To demonstrate this dramatic increase, XLI Witness LaConte produced Table 14 in her Direct Testimony, which lists Xcel Energy, Inc., and NSP's historical and projected ELI expenses from 2014 through 2026. While

¹⁰³ Ex. XLI-2 at 51:18-22 (LaConte Direct).

¹⁰⁴ Ex. XLI-2 at 52:3-4 (LaConte Direct).

¹⁰⁵ Ex. XLI-8 at 15:10-13 (LaConte Surrebuttal).

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

¹⁰⁷ Ex. XLI-8 at 15:14-18 (LaConte Surrebuttal).

¹⁰⁸ Ex. XLI-2 at 54:7-10 (LaConte Direct).

¹⁰⁹ Ex. XLI-2 at 54:16-18 (LaConte Direct).

such increases may make sense for other Xcel Energy, Inc.’s subsidiaries due to increasing wildfire risks and mitigation costs, the same issues do not apply to NSP’s territory. In fact, “[s]ince 2015, [TRADE SECRET DATA BEGINS... ██████████ ... TRADE SECRET DATA ENDS]. NSP and its customers should only pay their fair share of the ELI premium and should not shoulder increased ELI expenses due to wildfire activity in other territories in the country.¹¹¹ Therefore, XLI supports limiting the allowed ELI expense to ensure NSP’s customers are not unfairly paying excessive wildfire costs not incurred in Minnesota. Accordingly, NSP’s ELI expense should be reduced to [TRADE SECRET DATA BEGINS... ██████████ ...TRADE SECRET DATA ENDS], for 2025, and [TRADE SECRET DATA BEGINS... ██████████ ...TRADE SECRET DATA ENDS] for 2026, as calculated by Witness LaConte in her Surrebuttal Testimony.¹¹² Witness LaConte calculated this recommendation by determining the average increase in the Company’s ELI periods from 2022 to 2024, [TRADE SECRET DATA BEGINS ... ██████████ ...TRADE SECRET DATA ENDS] then applying the average growth rate to the Company’s 2024 ELI expense.¹¹³

Reducing NSPM’s ELI expense will allow for recognition of the increased wildfire risk for all utilities, while preventing NSP customers from shouldering an outsized portion of Xcel Energy Inc.’s total ELI expense. XLI respectfully urges the ALJ to recommend the Commission limit NSP’s allowed ELI expense to ensure NSP customers do not subsidize customers in other jurisdictions that have experienced significant wildfires.

6. Adjusting Depreciation Expense for Coal Units Is Premature

The Department of Commerce, Division of Energy Resources (“Department” or “DOC”) proposes to adjust the depreciable lives of the King Plant, Sherco Unit 3, and the Monticello and Prairie Island Nuclear Plants to reflect NSP’s integrated resource plan’s (“IRP”) authorized operating lives, adjustments that would result in a \$10.9 million decrease in the revenue

¹¹⁰ Ex. XLI-2 at 56:18-20 (LaConte Direct).

¹¹¹ Ex. XLI-2 at 57:5-10 (LaConte Direct).

¹¹² Ex. XLI-8 at 22:3-9 (LaConte Surrebuttal).

¹¹³ Ex. XLI-8 at 22:8 (LaConte Surrebuttal). The date range was selected because the impact of wildfires in Xcel Energy, Inc.’s territories spans 2022 to 2024.

requirement in 2025, and a \$13.6 million decrease in 2026.¹¹⁴ The Department’s proposal with respect to the coal-fired units contradicts the Company’s proposal to maintain the current depreciation rates for the Sherco 3 and King plants, continuing to “recover the King and Sherco Unit 3 plants over the currently approved remaining lives reflected in based rates, which are based on a June 2037 and December 2034 closure date, respectively.”¹¹⁵ The Company proposes at the time of each plant retirement to transfer any remaining net book value and unamortized balance to a regulatory asset and earn a return at its weighted average cost of capital.¹¹⁶ As detailed below, the Department’s proposal for the coal fired units is based on unverifiable, inconsistent information and does not follow Commission direction. The Department’s proposal with respect to NSP’s nuclear units is not subject to the four-tiered approach required for early retirements and is reasonable.¹¹⁷

In May 2025, the Commission authorized four-tiered approach for the ratemaking treatment for plants retired before the end of their depreciable lives.¹¹⁸

Tier 1 is a data gathering phase. Tier 2 determines if the early-retiring assets qualify for accelerated depreciation as the appropriate ratemaking treatment, providing doing so does not result in rate shock. If that occurs, then Tier 3 should be used, which creates a regulatory asset with a possible return. Tier 4 is available for assets requiring additional analysis to determine the appropriate return, or no return, on the early-retiring plant.¹¹⁹

The Department’s proposed depreciation treatment in this proceeding is not based on verifiable data and neither the Department nor the Company have demonstrated the Commission-ordered four-tiered approach was correctly applied.

¹¹⁴ Ex. XLI-5 at 3:9-16 (LaConte Rebuttal).

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

¹¹⁶ Ex. XLI-8 at 22:3-5 (LaConte Surrebuttal).

¹¹⁷ Ex. XLI-5 at 9:22-10:5 (LaConte Rebuttal).

¹¹⁸ Ex. XLI-5 at 3:19-4:9 (LaConte Rebuttal).

¹¹⁹ Ex. XLI-5 at 4:1-7 (LaConte Rebuttal).

NSP has not provided the calculations used by the Department for the accelerated depreciation method.¹²⁰ As a result, XLI could not review or thoroughly vet any of the calculations. When asked for information, NSP provided a spreadsheet that was prepared and filed in MPUC Docket No. CI-23-375.¹²¹ Unfortunately, those figures do not match the figures used by the Department,¹²² and there is no record evidence in this proceeding to resolve this discrepancy or provide any foundational basis for the Department’s proposed depreciation adjustments.

Even if there were evidence to substantiate the Department’s proposal, the Department failed to show how its proposal complies with the four-tier approach approved by the Commission. For example, regarding Tier 3, neither the Department nor NSP indicated whether NSP “would apply to refinance the remaining book value of the King plant and Sherco Unit 3,” thus obfuscating whether the cost to ratepayers under this proposal represents the least cost option.¹²³ NSP and the Department also failed to produce the amortization period for any remaining net book value of the Sherco 3 and King plants.¹²⁴ Further, XLI is concerned that the approach proposed by the Department could lead to intergenerational inequity, which “occurs when ratepayers pay for an asset but do not receive the benefits of that asset, or ratepayers who do receive the benefit of the asset do not pay for it.”¹²⁵ In this case, if NSP were to accelerate recovery of the unamortized balance of the King plant and Sherco Unit 3, intergenerational inequity would be inevitable. The extremely early retirement of these coal plants in the pursuit of meeting the state’s CFS goals means “future NSPM customers will benefit from earlier adoption of cleaner resources, yet would not have been required to pay for the King plant and Sherco Unit 3,” creating intergenerational inequity.¹²⁶

Furthermore, the Department and Company fail to prove that the proposal would not result in rate shock. Minnesota statutes bind the Commission, directing rates be set, to the maximum

¹²⁰ Ex. XLI-5 at 4:19-5:22 (LaConte Rebuttal).

¹²¹ Ex. XLI-5 at 4:19-5:22 (LaConte Rebuttal).

¹²² Ex. XLI-5 at 4:19-5:22 (LaConte Rebuttal).

¹²³ Ex. XLI-5 at 6:5-17 (LaConte Rebuttal).

¹²⁴ Ex. XLI-8 at 23:1-4 (LaConte Surrebuttal).

¹²⁵ Ex. XLI-5 at 6:19-22 (LaConte Rebuttal).

¹²⁶ Ex. XLI-5 at 7:2-9 (LaConte Rebuttal).

reasonable extent, to meet the goals in Minn. Stat. 216C.05, subd. 2(4) (i.e., directing “retail electricity rates for each customer class be at least five percent below the national average.”).¹²⁷ In setting rates to conform with the statute, the Commission is charged to ensure “continuity with prior rates to avoid rate shock.”¹²⁸ To be certain, adjusting the depreciation rate for the King plant and Sherco Unit 3 would cause customer rates to skyrocket, which is the definition of rate shock.¹²⁹ In fact, the Commission cautions against this exact consequence of accelerated depreciation, which it concedes “may result in “rate shock” to customers or other “significant rate impacts.””¹³⁰ Rather than attempt to refute the undisputed impact of its proposal, the Department claims rate shock from its proposal is mitigated because the life extensions at Prairie Island and Monticello Nuclear Units offset the accelerated recovery of the King Plant and Sherco Unit 3.¹³¹ The Department fails to recognize two critical weaknesses of this argument. First, nothing in the four-tiered approach allows for consideration of other mitigating factors. Second, nothing in the four-tiered approach should allow for consideration of other factors because “otherwise the utility could claim a multitude of ‘offsets’ as a reason to accelerate depreciation.”¹³²

As the lack of a developed record shows, it is fundamentally premature to determine the ratemaking treatment for these plants, since (a) NSP has not provided sufficient evidence that the regulatory asset approach would balance the interests of customers and NSP, and (2) the

¹²⁷ Minn. Stat. § 216B.03.

¹²⁸ *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 36-37 (June 12, 2017) (eDocket No. 20176-132748-01).

¹²⁹ Ex. XLI-5 at 7:16-18 (LaConte Rebuttal).

¹³⁰ Ex. XLI-5 at 8:3-5 (LaConte Rebuttal) (citing *In the Matter of a Commission Inquiry into the Ratemaking Treatment for Early Retiring Generating Facilities Owned by Regulated Electric Utilities*, Docket No. E-002, E-015, E-017/CI-23-375, Order Establishing Four-Tiered Approach for Ratemaking Treatment of Early Retiring Generating Facilities at 5 (hereinafter referred to as “CI-23-375” or “Order Establishing Four-Tiered Approach for Ratemaking Treatment of Early Retiring Generating Facilities”) (May 14, 2025) (eDocket No. 20255-218956-01).).

¹³¹ Ex. XLI-5 at 7:21-23 (LaConte Rebuttal).

¹³² Ex. XLI-5 at 9:1-2 (LaConte Rebuttal).

amortization period for the regulatory asset would not be determined until the actual retirement of the plants.¹³³

Early retirement of coal-fired generation facilities should not burden ratepayers. XLI Witness LaConte analyzed the Department's proposal in her Rebuttal and Surrebuttal Testimonies, concluding the most reasonable path forward is to reject the Department's proposal for the ratemaking treatment of the King Plant and Sherco Unit 3, because the proposal has not been thoroughly vetted by all the parties, may result in rate shock and the ratemaking treatment should be determined at a later time when more definitive information is available and stakeholders have applied the Commission's four-tier methodology. This recommendation reflects the Company's own decision not to propose ratemaking treatment for these early-retiring plants in this proceeding.¹³⁴

Regarding the Department's proposal to extend the depreciable lives of the Prairie Island and Monticello Nuclear Plants, XLI agrees that this is a reasonable proposal, given the nuclear plants life extensions have been authorized by the Commission and are therefore not subject to the four-tiered approach required for early retirements.¹³⁵ Authorization of an adjustment to the annual depreciation expense for the nuclear plans to reflect the authorized, extended lives would result in a reduction to the revenue requirement of \$69.7 million in 2025, and \$68.9 million in 2026. Given the arguments put forth above, Witness LaConte's proposal is the most likely to result in just and reasonable rates for all ratepayers.

7. NSP's Billing and Customer Care Issues Warrant Downward Adjustments to Its ROE

NSP has a statutory mandate to provide a certain level of service to its customers, including a mandate to render bills regularly, and to forecast accurate monthly amounts for year-to-date tracking, budgeting, and reconciliation purposes.¹³⁶ Additionally, because NSP is a public utility, the Commission regulates its customer service. As a regulated monopoly, NSP's rates and billing

¹³³ Ex. XLI-8 at 23:9-24:1 (LaConte Surrebuttal).

¹³⁴ Ex. XLI-5 at 9:13-19 (LaConte Rebuttal).

¹³⁵ Ex. XLI-5 at 9:22-10:5 (LaConte Rebuttal).

¹³⁶ Minn. R. 7810.1400, subp.1.

practices must meet the requirements of Chapter 7820 of the Minnesota Rules, including but not limited to 7820.3200 through 7820.3800.¹³⁷ XLI member, BOMA Greater Minneapolis, a trade association representing commercial real estate interests in Minneapolis and neighboring communities, has experienced an inordinate volume of billing and customer service issues in the last few years, including “delayed and inaccurate bills, misapplied payments, and ineffective communications and resolutions” and erroneous disconnection notices.¹³⁸ NSPM has a Customer Care organization intended to provide effective customer service to ratepayers, but the organization has not met its obligation to provide NSP customers with adequate customer service.¹³⁹ For example, many BOMA members have experienced billing delays and incorrect invoicing. When BOMA members contacted NSP about these issues, the Company responded “[t]his has been escalated and passed up as far as we can. Unfortunately, this is the state of our billing currently.”¹⁴⁰ That same member had to contact NSP about the issue in nearly every month of 2024. When members made NSP aware of instances where they received bills for two service periods in one month, the Company responded that it was “still catching up on billing for a lot of customers.”¹⁴¹

When NSP fails to provide a basic level of customer service, many adverse impacts compound for BOMA members. For example, when members receive invoices late, they must estimate electric energy costs for monthly invoices for lessees, which will inevitably be under- or over-stated, and require significant time and resources to true-up.¹⁴² Beyond these billing issues, several BOMA members reported payment issues and noted repeated instances in which customers submitted checks to pay invoices, but NSP would either (1) not cash the checks, requiring members to void and reissue checks, or (2) cash checks but credit them to improper accounts, and then render

¹³⁷ Ex. XLI-2 at 64:2-7 (LaConte Direct).

¹³⁸ Ex. XLI-2 at 59:3-6 (LaConte Direct).

¹³⁹ Ex. XLI-2 at 59:17-20 (LaConte Direct).

¹⁴⁰ Ex. XLI-2 at 60:12-14 (LaConte Direct) (citing BOMA Public Comment (eDocket No. 20257-220649-01)).

¹⁴¹ Ex. XLI-2 at 60:17-61:2 (LaConte Direct) (citing BOMA Public Comment (eDocket No. 20257-220649-01)).

¹⁴² Ex. XLI-2 at 61:4-10 (LaConte Direct).

disconnect notices to customers who had timely paid.¹⁴³ BOMA members have experienced myriad other frustrating problems with NSP customer service, as detailed in Witness LaConte's Direct Testimony.¹⁴⁴ Further, the Company's customer service and billing issues are well-known—in fact, the Commission had to open a separate docket into this matter with regard to residential issues.¹⁴⁵

NSP has statutory and regulatory compliance requirements to provide customers with a certain level of care but has repeatedly failed to maintain those expectations. Therefore, XLI believes NSP's request for customer care O&M expenses in the amount of \$27.3 million in 2025 and \$27.1 million in 2026 should be disallowed in their entirety unless and until the Company can demonstrate it has remedied its customer service and billing issues.¹⁴⁶ Furthermore, XLI urges the ALJ to recommend a reduction of NSP's ROE by 10-basis points to reflect NSP's failure to comply with Minnesota Statute to provide adequate customer service to ratepayers.¹⁴⁷ Finally, XLI and Xcel Energy agree that the Commission's investigation into the Company's residential billing errors should be expanded to include the billing and customer service issues experienced by its commercial customers such as BOMA.¹⁴⁸

D. CCROSS: The ALJ Should Reject the Company's CCROSS to Ensure a Just and Reasonable Starting Point for Revenue Allocation and Rate Design

State law requires a CCROSS for any utility rate-case filing, which serves as the starting point to determine the appropriate revenue allocation of a utility's proposed revenue requirement.¹⁴⁹ As with the other aspects of the Company's Petition, NSP bears the burden to show its CCROSS is an appropriate starting point for designing just and reasonable rates. As XLI's evidence below will show, the Company has failed to meet its burden on this issue. Therefore,

¹⁴³ Ex. XLI-2 at 62:9-13 (LaConte Direct).

¹⁴⁴ See XLI-2 at 63:1-21 (LaConte Direct).

¹⁴⁵ See *In the Matter of an Investigation into Xcel Energy's Residential Billing Errors*, Docket No. E,G-002/CI-25-341, *Order Initiating Investigation* (Sept. 10, 2025) (eDocket No. 20259-222889-01).

¹⁴⁶ Ex. XLI-2 at 64:13-22 (LaConte Direct).

¹⁴⁷ Ex. XLI-2 at 64:17-18 (LaConte Direct).

¹⁴⁸ Tr. Vol. 1 at 247:2-248:5 (Howard).

¹⁴⁹ Minn. R. 7825.4300, subp. C.

XLI supports replacement of the Company’s CCOSS, which is based on the stratification methodology, with a CCOSS using the Average and Excess – Four Coincident Peak (“AED-4CP”) method.

1. Overview of Principles

A CCOSS is an analysis used to determine each customer class’s responsibility for a utility’s total costs and whether the revenues generated by each class can sufficiently cover the costs to serve those customers.¹⁵⁰ In this context, a class represents a customer group sharing similar usage patterns and service characteristics. Typically, a CCOSS is conducted in three phases: (1) a *functionalization* of costs (distinguishing costs by type—e.g., production, transmission, or distribution); (2) a *classification* of those costs’ primary causative factors (e.g., demand-related, energy-related, or customer-related); and (3) an *allocation* of those costs among the various customer classes (generally based on responsibility for incurring each cost—e.g., demand allocator for demand-related costs and energy allocator for energy-related costs).¹⁵¹

Because such a substantial portion of costs are functionalized as production, the manner by which the Company classifies and allocates these costs is critical to a just and reasonable CCOSS. As noted above, the Company proposed to continue using what it calls the “stratification method,” which relies on the proposition that production capital costs exceeding the cost of a combustion turbine (“CT”) peaking capacity of \$1,414 per kilowatt (“kW”) are a suitable substitute for fuel costs and thus energy-related (and assumes that year-round energy usage drives a utility to invest in capital-intensive generating plants).¹⁵² Consequently, stratification tends to classify and allocate “a larger share of production plant-related costs and purchased power capacity costs on year-round energy usage” than more traditional methods, the idea being that a proper application would result in high load factor customers being allocated higher production capital costs but also a larger share of the lower fuel costs.¹⁵³ Unfortunately, the Company’s CCOSS does not achieve this balance.

¹⁵⁰ Ex. XLI-3 at 5:2-4 (Ly Direct).

¹⁵¹ Ex. XLI-3 at 5:5-10 (Ly Direct).

¹⁵² Ex. XLI-3 at 6:16-18 (Ly Direct).

¹⁵³ Ex. XLI-3 at 7:4-10 (Ly Direct).

Under the stratification framework, the Company allocates demand-related costs among customer classes through the use of the D10S allocator, which measures each customer class's relative contribution to the Company's overall demand at the time of the MISO system peak.¹⁵⁴ The Company allocates energy-related costs using the E8760 allocator, which it bases on each customer class's hourly energy usage weighted by NSPM's marginal energy cost for each hour of the year.¹⁵⁵

As addressed herein, the Company's continued use of the stratification methodology is inappropriate because the methodology is obsolete. XLI Witness Ly's testimony provides evidence that the underlying benefits of stratification are no longer being realized, and a more appropriate CCOSS will result in just and reasonable data to inform the revenue allocation process.

2. The Company's Stratification CCOSS Methodology Is Outdated

XLI's concerns with the Company's CCOSS center largely on the continued use of the stratification methodology, particularly with respect to production plant classification. In short, the Company's reliance upon and application of stratification is no longer appropriate.

The stratification methodology is obsolete because it no longer functions as designed. Generally, stratification identifies plant investment incurred to provide capacity (i.e., demand-related) and investment that is a substitute for fuel costs (i.e., energy-related). As described by the Company, the Company classifies fixed production plant into capacity and energy-related portions in this manner:

The capacity-related portion of the fixed costs of owned-generation is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost and the highest operating cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized as energy-related. These costs are in excess of the capacity-related

¹⁵⁴ Ex. XLI-3 at 6:7-9 (Ly Direct).

¹⁵⁵ Ex. XLI-3 at 6:10-12 (Ly Direct).

portion, and as such, were not incurred to obtain capacity, but rather to obtain the lower-cost energy that such plants can produce.¹⁵⁶

Stratification, which the Cost Allocation Manual of the National Association of Regulatory Utility Commissioners (“NARUC CAM”) recognizes as the “Equivalent Peaker Method,” should function such that high-load-factor customers (customers who use more energy year-round) are allocated a proportionally larger share of fuel savings typically associated with the higher capital cost plants as a trade-off for being allocated a much higher percentage of production capital costs (i.e., “Capital Substitution”).¹⁵⁷ However, the stratification method no longer functions in this way.¹⁵⁸ To demonstrate this disconnect, XLI Witness Ly developed Schedule 1 of his Direct Testimony, to compare the allocation of non-fuel production costs and the corresponding allocation of fuel purchased power expense. Schedule 1 is reproduced below as Table 5.

Table 5: Comparison of Allocations of Non-Fuel Production Costs and Fuel Purchased Power Expense

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

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

Source: MN CCOSS 2025.

¹⁵⁶ Ex. Xcel-73 at 15:17-24 (Barthol Direct).

¹⁵⁷ Ex. XLI-3 at 9:11-13 (Ly Direct).

¹⁵⁸ Ex. XLI-3 at 9:13-14 (Ly Direct); *see* Ex. XLI-3 at Schedule 1 (Ly Direct).

XLI Witness Ly explains that if Capital Substitution were occurring, classes allocated a higher per kW non-fuel production costs via a properly designed demand allocator would benefit from the lower per MWh fuel and purchase power expense via a properly designed energy allocator. But as evidenced in Table 5 above, little to no symmetry exists.¹⁵⁹ Said plainly, “some classes that are allocated higher per kW non-fuel production costs are not also allocated commensurately lower fuel costs per MWh, and vice versa.”¹⁶⁰

To allocate fuel costs, the Company uses the E8760 allocator.¹⁶¹ As described by XLI Witness Ly, the E8760 “is the projected average load-weighted hourly marginal energy costs over the year.”¹⁶² While the allocator is designed to recognize the fuel costs to serve load can vary with time for different customer classes, XLI Witness Ly describes the disappearing distinction between the E8760 allocator and a pure energy allocator resulting from the increased incorporation of renewable resources.¹⁶³ Practically, while stratification allocates a larger share of more capital-intensive capacity to higher load factor customers with the intent that such customers will benefit from the associated lower fuel costs, XLI Witness Ly’s review of NSP’s CCOSS revealed no such savings for these customers.¹⁶⁴

As Table 5 above shows, rather than shift fuel savings to C&I customers (which is the underlying justification for stratification), the E8760 allocator compounds the issue by failing to lower energy costs to these customers. For example, the residential class is allocated non-fuel production costs 14% below the NSP average, but is allocated fuel and purchased power expenses just 2% above average.¹⁶⁵ This result contravenes Capital Substitution and perfectly captures that increasing penetration of intermittent renewable resources has rendered stratification unable to recognize the tradeoff between capital costs and fuel costs. Wind and solar make up some of the

¹⁵⁹ Ex. XLI-3 at 9:16-20 (Ly Direct).

¹⁶⁰ Ex. XLI-3 at 9:20-22 (Ly Direct).

¹⁶¹ Ex. XLI-3 at 9:3 (Ly Direct).

¹⁶² Ex. XLI-3 at 9:3-5 (Ly Direct).

¹⁶³ Ex. XLI-3 at 9:5-8 (Ly Direct).

¹⁶⁴ Ex. XLI-3 at 9:11-14 (Ly Direct).

¹⁶⁵ Ex. XLI-3 at 9:23-10:2 (Ly Direct).

most capital-intensive resources serving NSP's load.¹⁶⁶ While stratification assumes \$10,005 per kW (\$11,419 - \$1,414) of wind fixed costs in savings for fuel costs year-round, the intermittent nature of wind resources means they are only available or capable of generating under certain conditions and the utility cannot control the resource's availability.¹⁶⁷ Therefore, because wind and solar resources cannot lower fuel costs when they are not operating, it is illogical to spread the costs of this generation to all hours of the year. As XLI Witness Ly's analysis demonstrates, stratification no longer comports with system planning and cost-causation principles and is obsolete.¹⁶⁸ Even Company Witness Barthol agrees that new evidence exists to support other methods (e.g., AED-4CP method) over stratification.¹⁶⁹

The Office of the Attorney General – Residential Utilities Division (“OAG”) attempts to argue that XLI Witness Ly's fuel symmetry analysis fails to demonstrate the results of stratification defy the underlying theory of capital substitution—this is wrong. Witness Ly's Schedule 1 provides an apt analysis that clearly shows the absence of Capital Substitution occurring. OAG Witness Scharber concedes that Witness Ly's analysis in Schedule 1 “compares each class's actual shares of nonfuel production cost with each class's actual share of fuel and purchased power expense,” and does not contest the calculations are correct.¹⁷⁰ Notably, other regulatory jurisdictions have cited lack of fuel symmetry as the primary reason for rejecting production plant allocation methodologies like stratification.¹⁷¹

No other regulatory jurisdiction currently mandates utilities under its purview to use stratification or the equivalent peaker method. Conversely, several commissions have explicitly rejected the methodology (i.e., Michigan PSC, Florida PSC, PUC of Texas).¹⁷² In Colorado, where

¹⁶⁶ Ex. XLI-3 at 7:14-15 (Ly Direct).

¹⁶⁷ Ex. XLI-3 at 8:1-7 (Ly Direct).

¹⁶⁸ Ex. XLI-3 at 10:9-11 (Ly Direct).

¹⁶⁹ Tr. Vol. 1 at 103:22-104:5 (Barthol).

¹⁷⁰ Tr. Vol. 2 at 371:24-372:1, 374:12-19 (Scharber).

¹⁷¹ Ex. XLI-9 at 9:22-10:2 (Ly Surrebuttal).

¹⁷² Ex. XLI-3 at 10:14-18 (Ly Direct); *In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority*, Case No. U-20561, Proposal For Decision

one of the Company’s affiliates operates, the Public Service Commission of Colorado went so far as to criticize the stratification methodology in a recent rate case, citing an issue with the underlying premise of stratification, which is based on “the simple division of demand related costs and energy related costs,” taking issue that the method was developed before intermittent resources comprised such a significant portion of utility generation portfolios.¹⁷³ This critique perfectly captures XLI Witness Ly’s analysis in this case. Because the underlying trade-off between capital costs and fuel costs no longer exists with stratification, it is unjust and unreasonable to shift higher production capital costs to C&I customers when they are failing to receive the commensurate share of lower fuel costs. Based on the outdated and obsolete nature of the methodology, as well as other commission’s rejection of its use, XLI urges the ALJ and Commission to give it little weight in this case.

3. The ALJ Should Recommend Use of the AED-4CP CCOSS

Given that the stratification methodology no longer reflects cost causation and is obsolete, XLI requests that the ALJ recommend adoption of a version of the AED-4CP CCOSS outlined in XLI Witness Ly’s testimony as better reflecting cost causation on the Company’s system.¹⁷⁴ The AED-4CP is recognized explicitly in the NARUC CAM as considering energy usage in developing allocation factors, and all around more appropriately reflects cost causation.¹⁷⁵ Under this methodology, excess demand “is the higher of (1) the difference between a class’s demand and its

(Mar. 5, 2020) and Order at 220-221 (May 8, 2020; *Petition of Gulf Power Company for an increase in its rates and charges*; Docket No. 891345-EI, Order No. 23573 at 48 (Oct. 3, 1990); *see e.g., Application of Gulf States Utilities Company for a Rate Increase*, P.U.C. Docket No. 5560, 10 P.U.C. Bull. 405 (July 13, 1984); *Application of El Paso Electric Company for Authority to Change Rates et al.*, Docket No. 5700, 10 P.U.C. Bull. 1071 (Oct. 26, 1984; on modification Dec. 7, 1984); *Application of El Paso Electric Company for Authority to Change Rates and Application of El Paso Electric Company for Review of the Sale and Leaseback of Palo Verde Nuclear Generating Station Unit No. 2*, P.U.C. Docket Nos. 7460 and 7172, 14 P.U.C. Bull. 929 (Jun. 16, 1988); *Application of Lower Colorado River Authority for Authority to Change Rates*, P.U.C. Docket No. 8032, 14 P.U.C. Bull. 1566 (Sept. 22, 1988).

¹⁷³ Ex. XLI-3 at 11:1-9 (Ly Direct) (citing *In the Matter of Advice No. 1923-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reset the General Rate Schedule Adjustments, to Place into Effect Revised Base Rates, and to Implement Other Phase II Tariff Proposals to Become Effective June 15, 2023*, Proceeding No. 23AL-0243E, Rebuttal Testimony of Derek S. Klingeman at 26-27 (Nov. 17, 2023)).

¹⁷⁴ See Ex. XLI-3 at 11:12-15:13 (Ly Direct).

¹⁷⁵ Ex. XLI-3 at 11:12-15 (Ly Direct).

corresponding AD or (2) zero. Thus, a class operating at a 100% load factor, or a class that is entirely off-peak, such as lighting, would have little to no ED.”¹⁷⁶ The methodology recognizes two critical cost drivers: (1) off-peak loads do not drive a utility’s capacity needs to the same degree as on-peak loads; and (2) very high-load-factor loads are quite flat, and have significantly lower variability than low-load-factor loads.¹⁷⁷ Thus, this methodology recognizes NSP operates its generating fleet as an integrated system in a way stratification cannot, since the AED method “recognizes that load-following resources are an essential attribute of a reliable generation fleet and further, that certain customer classes require more load-following resources than other classes.”¹⁷⁸ With increasing penetration of intermittent resources, load-following resources have become more essential to maintaining reliability.”¹⁷⁹ Additionally, several other jurisdictions have adopted the methodology, including Arizona, Colorado, Kansas, Missouri, New Mexico, and Texas (note, NSPM affiliates, Public Service Company of Colorado and Southwestern Public Service Company, operate in three of these jurisdictions).¹⁸⁰ Even more aptly, the Commission itself has approved use of the AED-4CP methodology in Minnesota Power’s 2021 rate case to allocate the utility’s fixed production costs.¹⁸¹

Both the Company and the OAG have argued against use of the AED-4CP method, in favor of stratification, but these arguments are misguided. The Company argues that the Commission’s approval of the AED-4CP for Minnesota Power is inapplicable to NSP because Minnesota Power’s capacity and customer mix materially differ from NSP’s.¹⁸² However, the Company provides no reasoning as to why the methodology would only apply to utilities with the same or similar capacity and customer mix as Minnesota Power. Nor does the Company explain why stratification is inappropriate for its affiliates operating in other jurisdictions but appropriate in Minnesota. Furthermore, Witness Ly notes “many other utilities that also use AED-4CP do not have a similar

¹⁷⁶ Ex. XLI-3 at 12:9-11 (Ly Direct).

¹⁷⁷ Ex. XLI-3 at 12:11-16 (Ly Direct).

¹⁷⁸ Ex. XLI-3 at 13:15-18 (Ly Direct).

¹⁷⁹ Ex. XLI-3 at 13:15-19 (Ly Direct).

¹⁸⁰ Ex. XLI-3 at 14:16-19 (Ly Direct).

¹⁸¹ Ex. XLI-3 at 15:3-4 (Ly Direct).

¹⁸² See Ex. Xcel-74 at 13:19-14:10 (Barthol Rebuttal).

capacity/customer mix to Minnesota Power.” Many of these utilities have strong summer peaks, like NSP.¹⁸³ In fact, Witness Ly’s Schedule 2 of his Direct testimony shows NSP’s historical status as a summer-peaking system, and demonstrates that for 2023 through 2025, NSP’s annual system peak has, or is projected to, occur in a summer month.¹⁸⁴ And NSP’s own Wisconsin affiliate, Northern States Power Company-Wisconsin, supports use of the 4CP method, which is closely related to the AED-4CP method, to allocate demand-related production plant in recognition that itself and the MISO system are summer peaking.¹⁸⁵

The Company criticizes the methodology because it does not allocate production plant costs based on weighted hourly marginal energy costs, but these criticisms are also unfounded. There is no need for this methodology to consider marginal energy costs, and the Company has provided no evidence to the contrary. In fact, as Witness Ly explains, “[u]sing marginal energy costs would be circular logic; that is, if marginal energy costs determine, in part, how production plant should be allocated to customer classes, it would result in (marginal energy) costs causing the (production plant) costs.”¹⁸⁶

The OAG’s concerns with the method are similarly without merit. The OAG’s Witness Scharber¹⁸⁷ expresses concern that the AED-4CP method overstates the capacity value of renewable resources, and opposes Witness Ly’s derivation of the AED-4CP allocation factors.¹⁸⁸ The issue with Witness Scharber’s critique is it assumes renewable resources lack the capability of other generating resources to provide capacity—like all generating resources, renewable resources provide capacity and energy.¹⁸⁹ Alternatively stated, Witness Scharber fails to

¹⁸³ Ex. XLI-9 at 5:13-16 (Ly Surrebuttal).

¹⁸⁴ Ex. XLI-9 at 14:4-13 (Ly Surrebuttal).

¹⁸⁵ Ex. XLI-9 at 4-7 (Ly Surrebuttal). *See Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates*; Docket No. 4220-UR-127, Rebuttal Testimony of Ryan D. Moldenhauer at 5:3-8 (Sept. 19, 2025).

¹⁸⁶ Ex. XLI-9 at 7:14-17 (Ly Surrebuttal).

¹⁸⁷ OAG Witness Scharber had no utility ratemaking experience prior to her job at the OAG, a position which she began in 2025, and she has never testified in a proceeding before. Tr. Vol. 2 at 365:15-366:14 (Scharber).

¹⁸⁸ Ex. XLI-9 at 6:19-21 (Ly Surrebuttal).

¹⁸⁹ Ex. XLI-9 at 7:3-4 (Ly Surrebuttal).

acknowledge the inseparable nature of energy and capacity, or that no resources can be capacity-only or energy-only.¹⁹⁰ Because NSP dispatches its capacity resources on an integrated basis, it is illogical and contravenes cost-causation principles to allocate production plant costs differently solely based on varying plant attributes.¹⁹¹

Witness Scharber's alleged critique of Table 5 above also falls flat. She asserts a counterfactual modeling exercise is necessary, which amounts to nothing more than a red herring. As XLI Witness Ly testified, if application of stratification (i.e., Capital Substitution) does not result in capital cost/fuel cost tradeoffs, it is flawed.¹⁹² To be sure, NSP's Fuel Adjustment Factors have remained relatively stable since 2013, which the Company conceded in discovery, demonstrating that the increasing penetration of capital-intensive renewable resources have not achieved the goal of lowering fuel costs.¹⁹³

Witness Scharber's concerns with XLI Witness Ly's derivation of allocation factors lack merit. Witness Ly's allocation factors differed from the NARUC CAM only in ways that have already been approved by other regulatory jurisdictions (i.e., Arizona, Colorado, New Mexico, and Texas), and the changes consider year-round energy usage through the average demand component.¹⁹⁴ Further, Witness Scharber's critique ignores that excess demand measures variability of a class's load, and load variability is a critical attribute because it evidences the manner in which each class relies on load-following generation to meet time-varying demand in real time.¹⁹⁵ Witness Scharber's preferred methodology, the Twelve Coincident Peak ("12CP") allocator, is deeply flawed, and appears have been selected primarily on the basis that the Commission ordered this methodology in the last rate case, notwithstanding the fact that the OAG

¹⁹⁰ Ex. XLI-9 at 7:8-10 (Ly Surrebuttal).

¹⁹¹ Ex. XLI-9 at 7:14-17 (Ly Surrebuttal).

¹⁹² Ex. XLI-9 at 9:15-18 (Ly Surrebuttal).

¹⁹³ Ex. XLI-9 at 8:18-20 (Ly Surrebuttal); Ex. XLI-9 at 27-28 (Ly Surrebuttal) (citing NSP's response to XLI IR No. 91, which includes a schedule in live EXCEL format showing all Fuel Adjustment Factors in effect for the past ten years).

¹⁹⁴ Ex. XLI-9 at 10:13-11:4 (Ly Surrebuttal).

¹⁹⁵ Ex. XLI-9 at 11:7-10 (Ly Surrebuttal).

is the only party supporting it in this case.¹⁹⁶ And the OAG is the only party to recommend rejecting the minimum system method for classifying and allocating distribution costs.¹⁹⁷ Despite attempts to undercut Witness Ly's methodology, the OAG's naïve analysis amounts to nothing more than a results-driven attempt to divine a CCOSS to drastically minimize the Company's cost allocated to the residential class.

Consistent with the analysis above, the Company has failed to satisfy its burden with respect to putting forth a just and reasonable CCOSS. Witness Ly's thorough analysis demonstrates that the stratification methodology is obsolete and requires replacement. Instead, Witness Ly's recommended use of the AED-4CP methodology is both consistent with cost-causation principles and other jurisdictions in which the Company's affiliates operate. Therefore, the AED-4CP should be recommended as the methodology that best informs revenue allocation in this proceeding.

4. Other Flaws with the Company's CCOSS

In addition to the overarching flaws identified above, XLI Witness Ly points to several other concerns with the Company's CCOSS, namely the classification and allocation of (i) other production O&M expenses; (ii) transmission plant; and (iii) distribution plant.

XLI Witness Ly's first concern pertains to the Company's proposal to use the results of stratification to classify other production O&M expenses between demand- and energy-related costs (i.e., expenses directly associated with a specific generator type would be classified in the same manner as the underlying plant).¹⁹⁸ This proposal is fundamentally flawed for all the reasons listed above—stratification as a methodology is outdated. This fatal flaw is only compounded by NSP's failure to recognize that labor costs—costs that do not vary with energy costs—comprise an outsized portion of other production O&M expenses.¹⁹⁹ Regional market expenses, a vast majority of which are also labor-related, should be treated similarly and classified entirely to

¹⁹⁶ Tr. Vol. 2 at 366:19-23 (Scharber).

¹⁹⁷ Tr. Vol. 2 at 367:8-370:1 (Scharber).

¹⁹⁸ Ex. XLI-3 at 16:3-6 (Ly Direct).

¹⁹⁹ Ex. XLI-3 at 16:14-16 (Ly Direct).

demand, using AED-4CP and D10S allocators to reflect that those costs are incurred to monetize these assets' value.²⁰⁰ Any other treatment would be inconsistent with cost-causation.

The crux of XLI Witness Ly's concern with the Company's proposal for transmission plant is that while NSP asserts that "classifying 30% of transmission plant recognizes that some investment provides access to low-cost energy from various resources for its customers," NSP fails to provide any quantitative analysis to show that 30% is dedicated solely to such resources.²⁰¹ In addition, XLI Witness Ly supports the use of a D10S allocator for transmission demand costs, as does the Company.²⁰² XLI Witness Ly also agrees with the Company that the 12CP allocator is inappropriate. The transmission system is intended to accommodate peak power flows from remote and local resources to NSP's load centers and, because NSP is a summer-peaking system, if it designed its transmission system to only meet year-round average demand, it would fail to meet its customers actual peak demands during summer months.²⁰³ As stated in XLI Witness Ly's Direct Testimony, use of the average of the 12CPs to plan NSP's transmission system would result in not installing sufficient transmission to meet peak summer loads (i.e., 8,381 MW).²⁰⁴ Further, XLI Witness Ly contends that use of both a 12CP allocator for the demand-related portion and an E8760 allocator for the energy-related portion of transmission plant is duplicative, as both allocators acknowledge reliability risks throughout the year and assign production costs to all months and seasons.²⁰⁵ Therefore, XLI supports the Company's proposed use of a D10S allocator for demand-related transmission plant and related expenses.²⁰⁶

Regarding the Company's proposal for distribution plant classification, XLI Witness Ly identifies several concerns. In its last rate case, the Company was required to file three separate versions of its CCOSS to classify its distribution network: the Minimum System method, the Basic

²⁰⁰ Ex. XLI-3 at 17:2-16 (Ly Direct).

²⁰¹ Ex. XLI-3 at 18:5-10 (Ly Direct).

²⁰² Ex. XLI-3 at 18:13-19:7 (Ly Direct); Ex. XLI-9 at 14:6-8 (Ly Surrebuttal).

²⁰³ Ex. XLI-3 at 19:10-17 (Ly Direct).

²⁰⁴ Ex. XLI-3 at 19:18-20:2 (Ly Direct).

²⁰⁵ Ex. XLI-3 at 20:5-11 (Ly Direct).

²⁰⁶ Ex. XLI-3 at 20:13-14 (Ly Direct).

Customer method, and the peak and average (“P&A”) method.²⁰⁷ Each method is used to determine customer- and demand-related costs of the distribution network. To parse these costs, the NARUC CAM describes two methods: the minimum-size method (assumes a utility can build a minimally sized distribution network to serve the minimum electric load requirements of its customers), and the zero-intercept method (uses regression analysis of distribution network components to identify theoretical costs of equipment that serve no load).²⁰⁸ Incorporating both methodologies, the Company has opted to apply what it characterizes as a “Hybrid” Minimum System Study to identify the customer-related component of the Minimum System Method.²⁰⁹ This characterization is misleading because the “Hybrid” Minimum System Study devised by the Company “is nothing more than the zero-intercept method.”²¹⁰ While Witness Ly agrees with the Company that neither the Basic Customer nor the P&A methods are appropriate in this case nor do they comport with cost causation principles, he disagrees that the “Hybrid” approach is reasonable because the zero-intercept method does not explicitly recognize “the costs required to provide voltage support.”²¹¹ Therefore, XLI recommends the Company not use this “Hybrid” method in future rate cases, and instead apply the result of either the minimum-size or zero-intercept studies, which it has effectively done with the zero-intercept study here.²¹²

5. XLI’s Proposed Class Cost-Of-Service Study Is Reasonable and Most Likely to Result in Just and Reasonable Rates

As part of Direct Testimony, Witness Ly provides a revised 2025 Minimum System Method CCROSS (see Schedule 4 of Direct Testimony), which incorporates the AED-4CP method to allocate plant-related costs and purchased power capacity costs, classifies all labor-related other production O&M expenses to demand, allocates regional market expenses using a composite of production plant and transmission plant, and applies the D10S allocator for demand-related

²⁰⁷ Ex. XLI-3 at 20:17-20 (Ly Direct).

²⁰⁸ Ex. XLI-3 at 21:21-22:11 (Ly Direct).

²⁰⁹ Ex. XLI-3 at 22:14-21 (Ly Direct).

²¹⁰ Ex. XLI-3 at 23:4-5 (Ly Direct).

²¹¹ Ex. XLI-3 at 24:3-18 (Ly Direct).

²¹² Ex. XLI-3 at 25:2-7 (Ly Direct).

transmission plant and related expenses.²¹³ The results of Witness Ly’s study are reproduced below as Table 6 to this Brief.

Table 6: XLI’s Revised CCOSS Results

Table 1 Summary of XLI’s Revised CCOSS Results At Present Rates			
Customer Class	Rate of Return	Relative Rate of Return	Subsidy* (\$000)
Residential	4.74%	84	(\$78,659)
Non-Demand	6.18%	109	\$3,048
Demand	6.50%	115	\$77,750
Lighting	4.59%	81	(\$2,139)
Minnesota Retail	5.66%	100	\$0
* A positive amount means that revenues exceed cost. A negative amount means that costs exceed revenues.			

XLI respectfully asserts that the CCOSS summarized in Table 6 is more consistent with cost-causation than the other CCOSS submitted in this case. The Company has failed to meet its burden to prove that stratification remains relevant, or that the method is suitable for its CCOSS in this proceeding. Therefore, XLI recommends the ALJ recommend the Commission give the most weight to the results of XLI’s revised CCOSS to inform the determination of the appropriate revenue allocations to NSP’s rate classes.²¹⁴

E. REVENUE ALLOCATION: The ALJ Should Address the Company’s Uncompetitive Rates by Setting Rates at the Cost of Service

Electricity can be a significant operating expense for industrial customers, including XLI members, who face constraints due to increased global and domestic competition, especially for commodity-based industries.²¹⁵ Such competition limits industrial customers’ ability to pass on

²¹³ Ex. XLI-3 at 25:10-19 (Ly Direct).

²¹⁴ Ex. XLI-3 at 27:9-17 (Ly Direct).

²¹⁵ Ex. XLI-6 at 22:15-20 (Ly Rebuttal).

higher electricity costs; therefore, significant rate increases negatively impact C&I customers' ability to compete globally and domestically.²¹⁶ C&I customers also do not have an unlimited ability to pass on increases in energy costs.²¹⁷ Therefore, continuing the persistence of interclass subsidies on the Company's system has serious implications to the overall competitiveness for C&I customers and their ability to remain viable. The ALJ and Commission can begin to address these concerns by apportioning any rate-base revenue increase in a manner that would move customer classes closer to cost, specifically using Witness Ly's updated CCOSS. Recognizing industrial customers already pay uncompetitive rates for electric service, XLI requests the ALJ recommend the Commission give greater weight to XLI's recommended class revenue allocation to move customers closer to cost while protecting them from rate shock.²¹⁸

A just and reasonable CCOSS is a critical starting point to a fair revenue allocation. Notwithstanding XLI's critiques of the Company's CCOSS, it is important to recognize that both the Company's CCOSS and XLI's recommended AED-4CP CCOSSs demonstrate that C&I customers are subsidizing the Residential class, which is illustrated by Table 7 below provided by Witness Barthol in Surrebuttal Testimony.²¹⁹

²¹⁶ Ex. XLI-6 at 22:20-23:2 (Ly Rebuttal).

²¹⁷ Ex. XLI-6 at 22:15-17 (Ly Rebuttal).

²¹⁸ Ex. XLI-3 at 34:4-10 (Ly Direct).

²¹⁹ Ex. Xcel-75 at 8:1-3, Table 2 (Barthol Surrebuttal). Table 7 is a re-creation of Table 2 in Witness Barthol's Surrebuttal Testimony and incorporates the same data.

Table 7: 2026 CCOSS Results Comparison - Deficiency %

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

Through eliminating existing interclass subsidies on the Company's system, benefits will confer on the Company, C&I customers, and other customers by promoting efficiency, stability, and conservation while also providing just and reasonable rates to all customer classes. Conversely, the Company's proposed revenue allocation will not make meaningful movement to cost, continuing the trend of overburdening C&I customers.

In the instant proceeding, the Company seeks to allocate a \$353.3 million base revenue increase across customer classes. In compliance with ratemaking principles and cost causation, base revenues should reflect the actual costs of providing service to customer classes, whether that is immediately or gradually (to prevent rate shock).²²⁰ As Witness Ly explains, the Commission generally supports moving rates to cost.²²¹

²²⁰ Ex. XLI-3 at 28:11-15 (Ly Direct).

²²¹ Ex. XLI-3 at 28:18-19 (Ly Direct).

Relevant here, cost of service is an explicit factor the Commission considers when setting rates, which the public utility requesting the rate increase bears the burden to prove.²²² Considering cost of service is significant for several reasons, chiefly because acknowledging the cost to serve different customer classes provides a foundation for cost-based rates, which in turn sends appropriate price signals to the Company's customers. The price signals inform customers on how their usage impacts the utility costs needed to serve them, resulting in all classes being treated equally while promoting engineering efficiency and stability.²²³

The Company contends that its proposal for allocating its requested base revenue increase will move all customer classes 20% toward cost-based rates on the results of its CCOSS.²²⁴ However, while the relative rates of return might be approximately 20% closer to parity, the Company's proposal will not move rates 20% closer to cost. Instead, Witness Ly has compiled in Schedule 5 of Direct Testimony a more accurate measure of movement to cost by comparing the interclass subsidies at present and proposed rates, and demonstrates the Company's proposal does little to eliminate these subsidies.²²⁵ Schedule 5 shows that "the subsidies paid by the C&I Demand class would increase under NSPM's proposal and, as a result, the subsidies received by Residential and Lighting customers would increase. The C&I Non-Demand class would be the only customer class that would be moved closer to cost."²²⁶ Schedule 5 is reproduced below as Table 8 to this brief.

²²² *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-015/GR-21-335, Findings of Fact, Conclusions, and Order at 50 (Feb. 28, 2023) (eDocket No. 20232-193486-01).

²²³ Ex. XLI-3 at 29:16-22 (Ly Direct).

²²⁴ Ex. XLI-3 at 30:12-15 (Ly Direct).

²²⁵ Ex. XLI-3 at 31:3-6 (Ly Direct).

²²⁶ Ex. XLI-3 at 31:12-16 (Ly Direct).

Table 8: NSP’s Movement to Cost under Proposed Revenue Allocation

NORTHERN STATES POWER COMPANY - MINNESOTA
Movement to Cost Under NSPM’s Proposed Class Revenue Allocation
Test Year Ending December 31, 2025
(Amount in \$000)

<u>Line</u>	<u>Customer Class</u>	<u>Present Rates</u>			<u>Proposed Rates</u>			<u>Movement to Cost</u>
		<u>Rate of Return</u>	<u>RROR</u>	<u>Subsidy</u>	<u>Rate of Return</u>	<u>RROR</u>	<u>Subsidy</u>	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Residential	5.40%	95	(\$21,145)	7.25%	96	(\$25,039)	-18%
2	C&I Non-Demand	6.09%	108	2,522	7.94%	105	2,258	10%
3	C&I Demand	5.89%	104	21,990	7.83%	104	26,187	-19%
4	Lighting	4.06%	72	<u>(3,367)</u>	5.94%	79	<u>(3,406)</u>	-1%
5	Minnesota Retail	5.66%	100	\$0	7.56%	100	\$0	17%

Source: MN CCOSS 2025.

Further, the Company’s proposal fails to meet standards for rates set out in Minnesota statute. As discussed earlier in this brief, Minn. Stat. § 216C.05 directs the achievement of retail electricity rates that are at least 5% below the national average for each customer class, which the Commission is required to pursue achievement “to the maximum reasonable extent.”²²⁷ The Company’s failure to meet this goal for its industrial customers is especially pronounced. Schedule 7 of Witness Ly’s Direct Testimony shows the average monthly bill for a large industrial customer with a 50 MW demand operating at an 89% load factor is currently approximately 13% above the national average.²²⁸ With the proposals in this MYRP, this discrepancy would expand to 22% above the national average, which is an unacceptable divergence from state energy policy. Thus, approval of these increases as requested would move industrial customers further away from state policy goals and inflate the subsidy paid by C&I demand customers.

²²⁷ Minn. Stat. § 216C.05 (2024); Minn. Stat. § 216B.03 (2024).

²²⁸ Ex. XLI-3 at 32:5-9 (Ly Direct).

To address this issue, Witness Ly prepared a class revenue allocation in Schedule 8 of his Direct Testimony based on XLI’s revised CCOSS, including mitigating adjustments for potential rate shock, which would ensure that no customer class receives increases that exceed 150% of the system average, and bring all rate classes very close to cost of service.²²⁹ Schedule 8 is reproduced below as Table 9 to this brief.

Table 9: XLI’s Proposed Revenue Allocation

NORTHERN STATES POWER COMPANY - MINNESOTA
XLI’s Recommended Class Revenue Allocation
Test Year Ending December 31, 2025
(Amounts in \$000)

Line	Customer Class	Present Non-Fuel Base Revenue Including Riders	Recommended Base Revenue Allocation	
		(1)	Amount	Percent
1	Residential	\$1,152,541	\$222,599	19.3%
2	C&I Non-Demand	90,421	9,180	10.2%
3	C&I Demand	1,471,724	115,904	7.9%
4	Lighting	<u>28,834</u>	<u>5,569</u>	19.3%
5	Total Sales	\$2,743,521	\$353,252	12.9%

Moving C&I customers’ rates close to cost has a range of benefits for C&I customers and the Company’s ratepayers generally. Therefore, Table 9 comports with Commission precedent and would move the Company toward compliance with statutory mandates. As such, the ALJ should recommend the Commission give greater weight to XLI’s recommended class revenue allocation to move customers closer to cost while protecting them from rate shock.²³⁰

Based upon the evidence in the record, the Company has failed to meet its burden to demonstrate that its proposed revenue allocation will produce just and reasonable rates. The Company’s proposed revenue allocation ignores uncontested evidence that C&I rates are

²²⁹ Ex. XLI-3 at 33:10-23 (Ly Direct).

²³⁰ Ex. XLI-3 at 34:4-10 (Ly Direct).

uncompetitive and out of compliance with state statutes. Therefore, it is bound to repeat its history of unacceptable interclass subsidies on the Company's system. XLI urges the ALJ to recommend a revenue allocation that moves rates to cost, consistent with XLI Witness Ly's testimony.

F. RATE DESIGN: The Appropriate Forum to Address Concerns With the Proposed Large Load Tariff Is During a General Rate Case

XLI Witness Ly provided testimony regarding NSP's petition for a new tariff to serve large load customers ("Data Center Tariff") in Docket No. E002/M-25-289, wherein it proposes to (1) treat new large loads as sub-classes within the C&I Demand class and (2) allocate any additional revenues required from Large General Time of Day Service and Large Peak Controlled Time of Day Service customers as a result of the incremental cost test based on the test year base revenue allocation.²³¹ XLI identifies two material concerns with NSP's proposal. First, NSP has not explained how these new sub-classes would be recognized in the CCOSS, which NSP has acknowledged is a "foundational tariff design decision."²³² XLI respectfully asserts that customer classes should be defined such that customers with similar usage characteristics are grouped together, with primary differentiating characteristics being "size, how and when electricity is used (i.e., load factor and coincidence factor), whether service is firm or curtailable, and delivery voltage."²³³ Witness Ly's review of the Data Center Tariff revealed concerns that the usage characteristics of the proposed Large General Time of Day Service and Large Peak Controlled Time of Day Service sub-classes will vary significant from those of existing C&I Demand class customers. For one, Large General Time of Day customers will generally be much larger, accruing electrical demands of at least 100 megawatts.²³⁴ Additionally, data centers run nonstop, and operate at very high load factors (i.e., 90%+). With these operational characteristics in mind, every 100 MW of new data center load, compared to current C&I demand MWh sales, will account for a roughly 4-5% increase in NSP's annual MWh sales.²³⁵ Therefore, 200 MW of increased data

²³¹ Ex. XLI-9 at 21:4-11 (Ly Surrebuttal).

²³² Tr. Vol. 1 at 268:19-22 (Paluck).

²³³ Ex. XLI-9 at 21:16-20 (Ly Surrebuttal).

²³⁴ Ex. XLI-9 at 22:2-4 (Ly Surrebuttal).

²³⁵ Tr. Vol. 1 at 278:22-280:15 (Paluck).

center load would account for an 8-10% increase in MWh sales.²³⁶ It is thus likely these new customers will experience their maximum loads coincident with NSP system peaks.²³⁷

Considering the substantive differences between the broad customer types within the C&I demand class, it follows that creation of a distinct Large General Time of Day Service sub-class separate from the existing C&I Demand class would most appropriately acknowledge the unique characteristics of these new customer types.²³⁸ In fact, “many utilities plan to recognize very large load customers as separate customer classes in their CCOSSs.”²³⁹ Treatment of these customers as a distinct class would mitigate potential adverse impacts (e.g., if such customers do not generate sufficient revenues as forecasted, under-recovery would have the practical effect of lowering the C&I Demand class’s calculated rate of return).²⁴⁰ Determining whether new large load customers are adequately covering their own costs of service will be nearly impossible without the creation of a distinct class separate from existing C&I Demand customers.

Lastly, NSP has failed to provide sufficient support to justify its proposal to use base rate revenues to allocate incremental revenues that may be recovered from new large load customers. NSP proposed an Incremental Cost Test that it assures parties will ensure existing customers are not harmed by the addition of a new large load customer. Witness Ly’s review shows that incremental costs would be comprised of “energy costs based on forecast fuel rates, capacity costs based on the potential need for resource additions consistent with the Company’s latest Integrated Resource Plan, and the net increase in MISO-related costs, adjusted for the impact of any jurisdictional cost allocation increase.”²⁴¹ And, because fuel is a pass-through, a substantial amount of the incremental base rate costs would directly relate to production and transmission plant and related expenses.²⁴² Therefore, using base rate revenues to allocate the incremental

²³⁶ Tr. Vol. 1 at 280:19-21 (Paluck).

²³⁷ Ex. XLI-9 at 22:4-6 (Ly Surrebuttal).

²³⁸ Ex. XLI-9 at 22:11-14 (Ly Surrebuttal).

²³⁹ Ex. XLI-9 at 22:17-18 (Ly Surrebuttal).

²⁴⁰ Ex. XLI-9 at 22:22-23:1 (Ly Surrebuttal).

²⁴¹ Ex. XLI-9 at 23:12-19 (Ly Surrebuttal).

²⁴² Ex. XLI-9 at 23:12-19 (Ly Surrebuttal).

revenues would be inconsistent with cost causation.²⁴³ Following Witness Ly's reasoning, it is instead reasonable to allocate incremental revenues to customer classes using the same method as NSP's production and transmission plant.

In light of the concerns outlined above, XLI respectfully requests the ALJ recommend the Commission require NSP to revise its CCOSS in this docket to establish a new, distinct customer class for the Large General Time of Day Service and Large Peak Controlled Time of Day Service tariffs, and direct that any incremental revenues collected from new large load customers be allocated to customer classes the way NSP allocates its production and transmission plant.²⁴⁴ The fact that it will be difficult to incorporate XLI's proposals to address customer differences in the absence of new data center load on the Company's system does not detract from the need for a new CCOSS. Any debate on a new CCOSS should therefore not be a question of "if," but a question of "when." Considering the concession by Xcel that 200 MW of new data center load would be an increase of 8%-10% of current MWh sales, XLI believes this is a reasonable threshold for requiring the timing of an updated CCOSS. If NSP does not have an active general rate case pending at that time, and has not had an intervening general rate case, then NSP should be directed to make that filing in this docket.

III. CONCLUSION

XLI appreciates the efforts of the Company and other intervenors to develop a thorough record in this proceeding. As explained in detail above, the Company did not meet its burden of proof on several issues, failing to demonstrate by a preponderance of the evidence that its proposed rate increase, CCOSS, revenue allocation, rate design, and various other aspects of its case will result in just and reasonable rates for all customer classes and more specifically C&I customers. To address the deficiencies in the Company's proposed filing, XLI urges the ALJ to find and recommend the following:

²⁴³ Ex. XLI-9 at 23:12-19 (Ly Surrebuttal).

²⁴⁴ Ex. XLI-9 at 24:5-11 (Ly Surrebuttal).

- That the Company's proposed ROE is unreasonable and recommend that the Commission reduce the ROE to at least 8.96% based upon credible evidence submitted by Witness LaConte and other parties;
- That the test year revenue increase sought by the Company is unreasonable and recommend that the Commission reduce the proposed test year revenue increase via the following adjustments:
 - Rejecting the Company's proposal to increase the incentive compensation cap from 15% to 20%;
 - Rejecting the Company's proposal to collect portions of long-term incentive compensation from ratepayers;
 - Reducing the Company's Energy Supply O&M and Transmission O&M expenses;
 - Rejecting the Company's request to increase its ELI expense;
 - Rejecting the Department's proposal for ratemaking treatment associated with the King Plant and Sherco Unit 3; and
 - Rejecting the Company's customer care O&M expense;
- That the Company's CCOSS relies on an obsolete methodology and should be replaced by the AED-4CP methodology consistent with XLI Witness Ly's testimony;
- That the Company's proposed revenue allocation disregards cost causation and does not satisfactorily reduce the existing interclass subsidies on the Company's system, and recommend that the Commission adopt XLI Witness Ly's proposal to set rates based upon cost of service; and
- That the Company must file a revised CCOSS in this proceeding, or future rate case, establishing a new large load customer class entirely separate from the existing C&I Demand class.

Dated: January 28, 2026

Respectfully submitted,

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