MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers – Volume IV – Class Cost of Service

Meeting Date	**June 11 & 18, 2026**		**Agenda Item 1*** **
Company	Northern States Power Co. d/b/a Xcel Energy		
Docket No.	**E-002/GR-24-320**		
	In the Matter of the Application of Xcel Energy for Authority to Increase Rates for Electric Service in the State of Minnesota.		
Issues	Volume 4 - Should the Commission adopt the recommendations in the ALJ Report regarding Class Cost of Service?		
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✓ **Relevant Documents** **Date**

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I. Background

Utilities are required to include a class cost of service study (CCOSS or cost study) when filing a general rate case.[1] The purpose of a CCOSS is to evaluate how much of the revenue requirement is caused by each class, a concept that is often referred to as "cost causation." The results of the CCOSS are one factor, among many, that the Commission uses to decide on "revenue apportionment," which determines how much of the revenue requirement should be paid by each class. In short, the CCOSS tries to determine how much of the revenue requirement is caused by each class, and revenue apportionment decides how much each class should pay. While CCOSS analysis is complex, it is useful to keep in mind that it is theoretical but has a real-world impact on customers when the CCOSS information is used to make revenue apportionment decisions.

There are several CCOSS models in this record, and each produces different results. A positive percentage indicates that the revenues from that class are less than the costs it is assigned; a negative percentage means that the revenues are greater than the costs. In other words, assuming that the CCOSS is perfectly correct, the numbers reflect how revenue apportionment would be adjusted to match rate design with costs, not considering other policy factors, including rate shock. Table 1 shows the CCOSS party recommendations.

Table 1: CCOSS Results Summary[2]

Party	Method	Residential	SCI Non-Demand	Demand	Lighting
OAG	Peak & Avg	3.5%	-8.9%	15.7%	28.7%
OAG	Basic Customer	5.8%	-8.5%	13.9%	31.3%
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%

[1] Minn. R. 7825.4300(C)

[2] ALJ Report at 173 (The "Method" column represents the method used to classify and allocate distribution system costs, but there are other differences between the Cost studies presented by parties as described in the following sections.)

A. Cost Studies: Three Basic Steps

There are three steps in performing a CCOSS: functionalization, classification, and allocation.

First, costs are "functionalized" into various categories that reflect the electric system functions, such as production, transmission, distribution, and customer service. In some situations, they are "sub-functionalized" into smaller categories. Second, the costs are "classified," or further divided, into those components that are demand-related (also called capacity-related), energy-related, or customer-related. Third, the costs are "allocated" to specific customer classes. When costs are clearly caused by a specific class, they are directly assigned to that class. Most costs are jointly caused by multiple classes, and those costs are assigned using "allocators" or "allocation factors" that estimate the amount of cost caused by each class.

While the results depend on the specific allocators used, in general costs that are customer-related are allocated more heavily to residential customers; costs that are energy-related are allocated more heavily to larger customers; and costs that are demand-related are somewhere in between.

Deciding between competing classification or allocation methods can have very significant impacts on cost causation estimates. As described in Table 1, the various CCOSS models in this case suggest that residential class is somewhere between 3.5 percent under cost to 16.1 percent under cost—a range that represents hundreds of millions in cost responsibility.

B. Undisputed Issue

1. Allocation of CIP Conservation Cost Recovery Change (CCRC)

Consistent with the Commission's Order in the Company's 2015 rate case (Docket No. E002/GR-15-826), Xcel allocated both the CCRC and the CIP Adjustment Factor (CAF) using the per kWh method. In the proposed cost studies, CCRC costs are allocated to class using the test year sales forecast after subtracting sales to CIP exempt customers.[3] No party disputed this allocation.

C. Disputed Issues

The parties dispute five major issues related to the CCOSS:

- Classification and Allocation of Production Costs
  - Stratification Method
  - AED-4CP Method
  - Peak Demand Allocator (D10S)
- Classification and Allocation of Transmission Costs
- Classification and Allocation of Distribution Costs

[3] Xcel-73; at 28-29 (Barthol Direct).

- Classification and Allocation of Other Production O&M
- Allocation of Economic Development Discounts
- Classification and Allocation of Advanced Metering Infrastructure

II. Discussion

A. General

A CCOSS model is highly theoretical, and requires the application of substantial judgment in selecting classification and allocation methods, as well as selecting the data that is used to execute those methods. The Commission has found in one recent rate case that, "No single cost-study method can be judged superior to all others in all contexts, and the choice among methods involves disputes over assumptions, applications, and data."[4] The ALJ noted that it is not necessary for the Commission to approve, adopt, or reject any individual CCOSS or any one component within the CCOSS. Rather, the Commission should analyze the relative merits of the various cost studies presented and apply that analysis when deciding how much weight to give those results when setting the Company's revenue apportionment.[5]

1. Staff Analysis

Staff agrees with the ALJ that it is reasonable to consider the various CCOSS models, that each of the models in this record has some merit and should be considered, and that doing so is consistent with the Commission's recent decisions. Commissioners can evaluate whether any models should be given more weight based on the disputed modeling issues described in this briefing paper.

The most important thing to understand about the CCOSS is that it does not directly affect anything in the rate case, but it informs the revenue requirement and rate design processes. The CCOSS matters to the extent that the Commission uses the different models to guide its revenue apportionment decisions. Preferences for one model over another will not change any of the underlying costs in this Rate Case, but can guide the Commission's decision on revenue apportionment and provide directions on how the CCOSS should be performed in future cases.

2. General Decision Options

4001. Determine that each CCOSS model provides useful information and decline to adopt any specific model. (ALJ, Staff)

OR

4002. Determine that _____ CCOSS model is the most reasonable based on this record.

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[4] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota, Docket No. E-017/GR-20-719, Findings of Fact, Conclusions, and Order at 44 (Feb. 1, 2022).

[5] ALJ Report; at 159, Finding 997.

B. Classification and Allocation of Production Costs – Stratification Method

Xcel classifies fixed production plant into capacity versus energy-related sub-functions using the Plant Stratification process. Although refined over the years, the Company has used this process with Commission approval since the late 1970s.[6] Xcel stated that fixed production costs include, but are not limited to capital investment in generation plants and non-fuel operations and maintenance (O&M) expenses related to production that do not vary with output.[7]

XLI submitted that the AED-4CP is the production cost methodology that better reflects cost causation. It contended that due to the increasing dominance of intermittent renewable resources, Stratification no longer recognizes the trade-off between capital costs and fuel costs.[8] Furthermore, it observed that Xcel is a predominantly summer-peaking utility, and as such, the Commission should give more weight to the AED-4CP method.[9]

The Department and the OAG support the continued use of the Stratification method. The Department specifically recommended the Commission consider: 1) a Minimum-System study CCOSS using the Company's hybrid method but updated to allocate demand-related transmission costs using the D10S allocator and 2) a Basic Customer Method CCOSS also updated to allocate demand-related transmission costs using the D10S allocator.[10]

The OAG noted that the CCOSS submitted by Xcel, which used the Stratification method, was carefully constructed and contains mainly reasonable assumptions. Additionally, The OAG noted that classification of transmission costs as partly energy-related, and the allocation of demand-related transmission costs using the 12 CP allocator led to a greater alignment with cost causation and benefits accrual.[11]

1. Stratification Method

Under the Stratification method, the capacity-related portion of the fixed costs is based on the percentage of total fixed costs that is equivalent to the cost of a comparable peaking plant. The remaining percentage of generation costs that exceeds the cost of a comparable peaking plant is sub-functionalized as energy related. According to Xcel, these costs were not incurred to obtain capacity, but obtain the lower-cost energy that such plants can produce.[12]

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[6] Xcel-73; at 15 (Barthol Direct).

[7] Xcel-74; at 11 (Barthol Rebuttal).

[8] XLI-3; at 10 (Ly Direct)

[9] *Id*; at 3.

[10] DOC-16; at 42 (Zajicek Direct).

[11] OAG-8; at 33 (Scharber Direct).

[12] Xcel-73; at 15 (Barthol Direct).

Results of the Stratification method are presented in Table 2:

Table 2: Stratification Allocation by Plant Type[13]

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity Percentage	Energy Percentage
Peaking	$1,414	$1,414 / $1,414	100.0%	0.0%
Nuclear	$1,414	$1,414 / $6,972	20.3%	79.7%
Fossil	$1,414	$1,414 / $4,051	34.9%	65.1%
Combined Cycle	$1,414	$1,414 / $2,148	65.9%	34.1%
Hydro	$1,414	$1,414 / $7,584	18.7%	81.3%
Wind	$1,414	$1,414 / $11,419	12.4%	87.6%
Solar	$1,414	$1,414 / $3,736	37.9%	62.1%

Xcel noted that the main advantage of the Stratification methodology is that it appropriately reflects cost causation, because it recognizes that a significant portion of the fixed generation costs are incurred to obtain fuel savings that more than offset the higher fixed costs.[14]

The Demand-Related fixed production plant costs were allocated using the D10S allocator. It identifies the percentage of overall demand that is caused by each customer class for a specific time period. In the Company's last rate case (Docket No. E-002/GR-21-30), the Commission ordered that in Xcel's next general rate case, consistent with the suggestions of the utility and the OAG, the Commission directed Xcel to calculate the D10S allocator based on its system peak coincident with the MISO system peak using historical data.[15] In order to comply with the Commission's Order, Xcel looked at the hour that MISO's system peaked in 2023, the most recent year that has complete annual data. As a result, Xcel's calculation for the D10S allocator for the 2025 test year forecast assigned 40.41% of costs to the residential class, 2.48% of costs to the Commercial non-demand class, and 57.11% of costs to the C&I demand class.[16]

The Energy-related portion of fixed production plant and variable production O&M costs are calculated using the E8760 allocator, which assigns costs based on each class's hourly load for all 8,760 hours of the test year and weighing it by the corresponding hourly marginal energy costs. Xcel noted that the E8760 allocator is a reasonable allocator for fixed-production energy costs, because it weights each hourly load by the hourly marginal energy cost which takes into account the on- and off-peak nature of these costs. Xcel's calculation for the E8760 allocator

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[13] Xcel-73; at 15 (Barthol Direct); at 16.

[14] *Id*; at 17.

[15] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at Order Point 9(e)(ii) (July 17, 2023).

[16] Xcel-73; at 20 (Barthol Direct).

assigned 32.61% of costs to the residential class, 2.77% of costs to the Commercial non-Demand class, 64.27% of costs to C&I class and 0.34% of costs to the Lighting class for the 2025 test year.[17]

XLI contended that the E8760 allocator results in allocating nearly the same energy costs per megawatt-hour (MWh) to all customer classes, despite the differences in class load factors.

2. Classification and Allocation of Production Costs - AED-4CP Method

XLI stated that the Average and Excess - Four Coincident Peak (AED-4CP) method more appropriately reflects cost causation.[18] XLI recommended that as the Commission recently recognized for Minnesota Power, the AED-4CP four Coincident Peak method appropriately considers the attributes of different types of power plants.[19]

XLI explained that the AED-4CP allocation factor classifies production cost based on the system load factor, when it calculates a class share of Average Demand (or energy usage). The remaining costs are allocated as a class share of Excess Demand, which is the difference between a class's Coincident Peack Demand and its Average Demand.[20]

In its analysis of the average and excess method, XLI noted that:

> the average demand component of the AED method represents the average demand of each rate class throughout the entire year. Therefore, this metric recognizes that a portion of a utility's generating portfolio is necessary to meet energy usage throughout the year. In contrast, the excess demand component provides a measure of each class's contribution to a system's peak demand and recognizes that a utility must also include load-following resources in its generating portfolio to meet varying levels of demand throughout the year, including at the time of greatest need.[21]

3. Arguments regarding Stratification and AED-4CP

XLI contended that Stratification fails to comport with the underlying theory that capital is a substitute for fuel (i.e., Capital Substitution). This is because Stratification shifts more plant-related costs to higher load factor customer classes, yet it fails to also shift more of the fuel cost

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[17] Xcel-73; at 22 (Barthol Direct, Table 8)

[18] XLI-3; at 11 (Ly Direct).

[19] *Id*; at 4.

[20] *Id*; at 11.

[21] *Id*; at 13.

savings associated with higher capital cost power plants to these customers.[22] Additionally, due to the increasing dominance of intermittent renewable resources, Stratification no longer recognizes the trade-off between capital costs and fuel costs.[23] XLI further asserted that allocating the capital costs of intermittent resources as if they produce energy throughout the year demonstrates that Stratification no longer aligns with system planning and cost-causation principles.

Xcel disagreed with XLI's recommendation as unreasonable for the following reasons: First, it is not reasonable to utilize the AED-CP method simply because Minnesota Power used it. Minnesota Power customer base is primarily made of large industrial customers with high load factors. For instance, Minnesota Power's system load factor in their 2022 rate case was approximately 87%, while Xcel's forecasted load factor for 2025 is approximately 54%. AS such, it might be more reasonable for Minnesota Power to utilize the AED-4CP method.[24] Secondly, XLI's proposal is unreasonable because it uses a pure energy allocator based on hourly load data, unweighted by marginal energy costs, to allocate energy-related production costs. It does not consider the on- and off-peak nature of these costs like the Company's E8760 allocator, which takes each class's hourly load for all 8,760 hours of the test year and weighting them by the corresponding marginal energy costs.[25]

XLI responded by noting that Xcel currently is and is projected to remain a predominantly summer peaking utility. Thus, an allocation method, such as the AED-4CP method which recognizes Xcel's strong summer peak demands, is consistent with cost causation.[26]

The Office of the Attorney-General (OAG) disagreed with XLI's recommendation for use of the AED-4CP method, and concluded that allocating production plant costs using the AED-4CP method is less appropriate than Xcel's current Stratification Method approach.[27] Additionally, the OAG stated that classifying the labor-related portion of Other Production O&M expenses entirely to demand and allocating them using the AED-4CP method is inferior to Xcel's current Stratification Method. For instance, under the Stratification method, solar costs are classified as 62.1 percent energy-related and wind costs are classified as 87.6 percent energy-related, representing the cost per kW differential between these generation types and a peaking plant.[28] XLI argued that while wind and solar are more capital-intensive than a peaking plant, they do not save fuel costs during all 8,760 hours of the year, and therefore should not be

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[22] XLI-3; at 2 (Ly Direct).

[23] *Id*; at 10.

[24] Xcel-74; at 13-14 (Barthol Rebuttal).

[25] *Id*; at 14.

[26] XLI-9; 2 (Ly Surrebuttal).

[27] OAG-9; 30 (Scharber Rebuttal).

[28] Xcel-73; 16 (Barthol Direct).

classified as energy-related to such a high degree.[29] In rebuttal testimony, the OAG argued that while it is true that wind and solar resources are not available in every hour of the year, it does not follow that their costs should be classified primarily to the demand function.[30] Given the CCOSS convention that generation costs be classified as demand- and/or energy-related, the OAG maintained that it makes the most sense to classify both wind and solar as predominantly energy-related.

The Department supported the positions of OAG and Xcel, and recommended the Commission continue to use the plant stratification method rather than the AED-4CP method. The Department further noted that just because wind and solar resources are intermittent does not change the fact that they are largely baseload resources, especially since they are not dispatchable to respond to demand increases.[31]

4. ALJ Findings and Recommendations for Production Costs

The ALJ addressed Stratification and AED-4CP methods in Findings 999 to 1009, and recommended that because the Stratification method more accurately distinguishes energy-related and capacity-related costs, the Commission should give more weight to Cost studies that apply the Stratification method than Cost studies that apply the AED-4CP method.

5. Exceptions to ALJ Findings

a. Xcel Large Industrials

XLI stated that the record it submitted includes substantial evidence that demonstrates that Cost studies using the Stratification method should be rejected. It argued that by recommending that greater weight be assigned to those studies over AED-4CP-based analyses, the ALJ failed to address or meaningfully engage with XLI's evidence.[32]

XLI contended that Xcel offered no evidence to refute that the stratification methodology no longer functions as designed. XLI argued that ideally, stratification should function such that high-load-factor customers (meaning those using 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");[33] but this methodology no longer functions in that way.

XLI further stated that no other regulatory jurisdiction currently mandates utilities under its

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[29] XLI-3; at 7-8 (Ly Direct).

[30] OAG-9; 3 (Scharber Rebuttal).

[31] DOC-18; at 4 (Zajicek Surrebuttal).

[32] XLI Exception; at 20.

[33] *Id*; at 21.

purview to use stratification. None of this evidence, according to XLI, is accounted for in the ALJ Report. By contrast, the AED-4CP methodology, which the Cost Allocation Manual of the National Association of Regulatory Utility Commissioners explicitly recognizes as considering energy usage in developing allocation factors, more appropriately reflects cost causation.[34]

Additionally, XLI argued that the ALJ Report does not engage with its argument that use of an E8760 allocator for the energy-related portion of transmission costs improperly recognizes reliability risks throughout the year, assigning cost to customers on that basis. Moreover, XLI pointed out that the result of an E8760 allocator epitomizes that the increasing penetration of intermittent renewable resources has rendered stratification unable to recognize the tradeoff between capital costs and fuel costs[35]

6. Staff Analysis on Classification of Production Costs

The primary value of a CCOSS is to be a guide when making revenue apportionment decisions. If the Commission is persuaded that the Stratification method is superior, it could give more weight to the CCOSS models provided by Xcel and the OAG; in the alternative, if the Commission is persuaded that the AED-4CP method is superior, it could give more weight to the models provided by XLI.

7. Decision Options for Classification of Production Costs

4003. Approve Xcel's proposal to classify and allocate production costs using the Stratification Method. (Xcel, Department, OAG).

OR

4004. Order Xcel to classify and allocate production costs using the AED-4CP Method. (XLI)

C. Classification and Allocation of Production Cost – D10S Allocator

The D10S allocator is used to allocate demand-related costs after the plant stratification method is applied. It identifies the percentage of overall demand that is caused by each customer class for a specific time. In the Company's last rate case (Docket No. E-002/GR-21-630), the Commission ordered that "consistent with the suggestions of the utility and the OAG, Xcel calculates the D10S allocator based on its system peak coincident with the MISO system peak using historical data."[36] Xcel noted that as in the last rate case, MISO does not provide forecast estimates of the day and hour that their peak will occur. Consequently, as ordered by the Commission, the D10S allocator calculation for the 2025 test year is based on historical

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[34] XLI Exception; at 23.

[35] *Id*; at 24.

[36] Xcel-73; at 18 (Barthol Direct).

data.[37]

Table 3 below provides a comparison of the D10S allocator from the Company's last rate case with the 2025 test year result.

Table 3: 2022 vs. 2025 D10S Allocator[38]

Year	Residential	Commercial Non-Demand	C&I Demand	Lighting	Total
2022	39.78%	2.83%	57.39%	0.00%	100.00%
2025	40.41%	2.48%	57.11%	0.00%	100.00%

The OAG recommended that Xcel uses a MISO-coincident 12 CP peak demand allocator in future rate cases, unless the Commission believes that continuing to use a MISO-coincident 1 CP peak demand allocator is more appropriate.[39] The OAG added that in either case, the allocator should 1) use actual class load data from years corresponding to the years of the MISO peaks used, or if that is not available, 2) use forecasted class load data corresponding to likely MISO peak hours, with a clear explanation of how the likely MISO peak hours were selected. The OAG recommended the 12 CP method, that it provides a better approximation of the multiple possible periods of transmission reliability risk.[40]

1. Arguments

Xcel noted that prior to the Commission's Order, the Company calculated the D10S allocator based on its system peak coincident with the MISO Local Resource Zone 1 (LRZ-1) peak. Given that it was not possible to identify the specific MISO peak hour for the test year in that case, Xcel used historical data for the prior 12 years of the MISO Local Resource Zone-1 peak.[41] In its Order, the Commission directed the Company to continue to use historical data to calculate the D10S allocator, but to use the overall MISO system peak rather than the LRZ-1 peak.

The OAG stated that while the hour of the 2023 MISO peak could perhaps be considered historical data, the Company used forecasted data to construct the 2025 test year allocator.[42]

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[37] Xcel-73; at 19 (Barthol Direct).

[38] *Id*; at 20.

[39] OAG-8; at 16 (Scharber Direct).

[40] *Id*; at 18.

[41] Xcel-73; 18 (Barthol Direct).

[42] OAG-8; at 7 (Scharber Direct).

This resulted in a incongruity, where the historical month and day of the peak in 2023 fall on the weekend in 2025 and 2026. Rarely, if ever, is the peak load on weekends. The OAG noted Xcel's argument that using historical data for a future test year would create a mismatch and reduce the precision of the cost allocation process. On the contrary, the OAG argued that using class load data corresponding to the month, day, and year of the MISO peak would enhance the precision of the cost allocation process.[43]

The OAG calculated an alternate D10S peak demand allocator, given that neither historical class load data nor forecasted MISO system peaks are available.[44] It drew information from past MISO peaks to identify the range of days and times most likely to include the MISO peak. In analyzing the annual peaks reported by MISO in FERC Form 714 between 2011 and 2024, the OAG found that the earliest peak occurred on June 21 (in 2022) and the latest occurred on August 26 (in 2024). Based on the information, the OAG identified each row in Xcel's 2025 and 2026 CCOSS class load forecasts that represented weekdays between June 21 and August 26 at 3:00 p.m. and 4:00 p.m. The loads corresponding to flagged hours by class were summed and the class total divided by the system total for the hours, resulting in an alternate D10S allocator.[45]

In rebuttal testimony, the Company contested that the demand-related production costs be allocated based on the best estimate of system peak demand, not an average of peak demand.[46]

XLI argued that the OAG's revised D10S allocator is overly broad and includes a significant number of hours that do not reflect peak conditions. As a result, it dampens price signals and undercuts the very purpose of a peak demand allocator.[47]

The Department recommended no changes to how the D10S allocator is calculated at this time.

2. ALJ Findings and Recommendations for Production Costs (D10S Allocator)

The ALJ addressed the D10S allocator in Findings 1009 to 1022, and concluded that the Commission should not give greater or less weight to any of the CCOSS results presented in the case, based on how the proponent applied the D10S allocator. Rather, the Commission should consider these models in tandem and give due recognition to the fact that the disparate results

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[43] OAG-8; at 8 (Scharber Direct).

[44] *Id*.

[45] *Id*; at 12 (Scharber Direct - Table 2).

[46] Xcel-74; at 18 (Barthol Rebuttal)

[47] XLI-6; 5 (Ly Rebuttal)

of the models reflect their sensitivity to unavoidable limitations of the modeling process itself.[48]

3. Exceptions to ALJ Report

a. Xcel

A portion of production costs are classified as demand-related and allocated using the D10S allocator. In the Company's last rate case, the Commission directed the Company to calculate the D10S allocator "based on its system peak coincident with the MISO system peak using historical data."[49] The Company and the OAG have recommended different ways to perform this calculation. Xcel took exception to the ALJ's conclusion in Findings 1021 and 1022, that the Company and OAG recommendations should be given equal weight.

Xcel contended that the OAG's calculation is inconsistent with the Commission's order. It does not calculate an allocator based on a single system peak, but 190 peaks over multiple years, 188 of which are not the hour of peak demand.[50] The Company therefore concluded that the OAG's calculation is flawed and CCOSS models using its D10S allocator should be given greater weight when setting rates in this proceeding. Consequently, Xcel recommended that Findings 2021 and 1022 be replaced with either or both of the following alternatives:

> Commission's direction to use Xcel Energy's system peak coincident with the MISO system peak, and as a result is not reasonable. CCOSS models using the Company's D10S calculation should be given greater weight when setting rates in this proceeding."

Or

> In future rate case proceedings, the Company should calculate the D10S allocator based on the NSP system peak.

b. OAG

The OAG made several exceptions to the recommendations of the ALJ. First, that the Commission rejects certain findings related to the "D10S peak-demand allocator and require Xcel to move to an allocator that better reflects MISO's seasonal resource-adequacy construct. Second, the Commission should not adopt findings suggesting that the Peak-and-Average Method is an unreasonable method for classifying shared distribution costs. Third, the Commission should correct a clerical error in the Report's recommendation regarding advanced metering infrastructure (AMI) costs that could otherwise cause confusion. Finally, the

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[48] ALJ Report; at 163.

[49] In re Application of N. States Power Co., d/b/a Xcel Energy, for Authority to Increase Rates for Elec. Serv. In Minn., Docket No. E002/GR-21-630, FINDINGS OF FACT, CONCLUSION, AND ORDER at 99 (July 17, 2023).

[50] Xcel's Exception to the ALJ Report; at 68.

Commission should require Xcel, in its next rate case, to allocate the cost of economic-development discounts in a way that more appropriately reflects cost causation.[51]

The OAG took exception to the ALJ Report conclusion that the OAG's alternative D10S allocator is "severely flawed".[52] The OAG argued that its allocator carries out the Commission's directive in Xcel's last two rate cases that demand-related production costs be allocated based on the classes' loads at the time of the MISO system peak, rather than at the time of Xcel's system peak.[53] The report stated that the OAG's alternate D10S allocator is not truly a measure of Xcel's system peak, but an average peak that does not reasonably model Xcel's system and the cost causation of various aspects of the Company's peaking generations. The OAG contended that its D10S allocator better matches Xcel's peak than Xcel's own allocator does, due to Xcel's unreasonable selection of weekends to represent the "peak."[54]

Additionally, the OAG noted that by relying on a single summer peak, the D10S allocator fails to reflect MISO's seasonal resource-adequacy construct, which requires member utilities to demonstrate resource adequacy across all four seasons. Accordingly, the OAG recommended that in future rate cases, Xcel use a MISO-coincident 12CP allocator to better align with MISO's seasonal reliability criteria. As a result, the OAG recommended the Commission adopt the following new and modified findings in lieu of these ALJ findings: 1018, 1021 and 1022:

> 1018. Both versions of the D10S allocator proposed in this proceeding are imperfect because MISO does not publish a forecasted peak, requiring parties to use historical data to reflect that peak. Between Xcel and the OAG's allocators, however, the OAG's is more reasonable. ~~severely flawed. The OAG's alternate D10S allocator is not truly a measure of Xcel's system peak, it is an average peak that does not reasonably model Xcel's system and the cost causation of various aspects of the Company's peaking generation.~~ The OAG's approach to the D10S allocator avoids making it overly sensitive to the choice of peak hour, while also fulfilling the Commission's directive that the allocator reflect the classes' contributions to Xcel's load at the time of MISO's peak. Even if ascertaining class loads at the time of Xcel's system peak were the goal, which it is not, the OAG's D10S allocator better matches Xcel's peak than Xcel's own allocator does. This occurred because Xcel took the unreasonable approach of applying MISO's 2023 peak hour to its 2025 and 2026 sales forecasts "in a vacuum"—that is, without accounting for the fact that the hour fell on a weekend in both years.[55]
>
> 1021. Ultimately, with respect to the D10S allocator, the record in this

[51] OAG's Exceptions to the ALJ Report; at 32.

[52] ALJ Report, Finding 1018.

[53] OAG's Exception to ALJ Report; at 33.

[54] *Id*; at 34.

[55] See Ex. OAG-8 at 7 (Scharber Direct).

proceeding calls for a choice between two models that both suffer from flaws that have been shown to significantly impact the results of the CCOSS. This, perhaps more than any other dispute with respect to the CCOSS in this case, underscores the dangers of assuming that any one model, or even an amalgamation of models, can provide a precise and accurate measure of cost causation. However, the OAG's D10S allocator better reflects the MISO peak (and Xcel's own peak) than does Xcel's allocator due to Xcel's unreasonable selection of weekend days to represent the 2025 and 2026 peaks.[56]

1022. The Commission should accord relatively greater weight to the OAG's CCOSSes because they accurately reflect class load shares at the time of MISO's peak while avoiding making arbitrary peak-hour choices that "have economically significant effects on class cost shares."[57] ~~not give greater or less weight to any of the CCOSS results presented in the case based on how the proponent applied the D10S allocator. Rather,~~ In apportioning revenue, the Commission should consider these models in tandem and give due recognition to the fact that the disparate results of the models reflect their sensitivity to unavoidable limitations of the modeling process itself. These limitations should also limit the extent to which CCOSS results are perceived to imply any particular revenue apportionment proposal as an objective reflection of class cost causation.

OAG 1022a. For Xcel's next rate case, the OAG persuasively argued that Xcel should transition to a 12CP peak-demand allocator to reflect the impact of MISO's seasonal resource-adequacy construct.[58] As the Commission has recognized, MISO prescribes how much capacity that Xcel must maintain.[59] The Commission therefore directed Xcel to move to a MISO-peak-based allocator and further required Xcel to reflect in the allocator any future changes in MISO's resource-adequacy construct.[60]

OAG 1022b. MISO adopted a seasonal resource-adequacy construct beginning in the 2023–2024 planning year.[61] Xcel should likewise begin relying on a peak-demand allocator that accounts for MISO-driven reliability costs that occur year-round. Xcel can accomplish this by moving to a 12CP peak-demand

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[56] OAG Exception; at 36.

[57] Ex. OAG-8 at 9 (Scharber Direct).

[58] Ex. OAG-8 at 15–16 (Scharber Direct).

[59] Ex. OAG-10 at 9–10 (Scharber Surrebuttal) (citing *In re Application of N. States Power Co.*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 46 (June 12, 2017)).

[60] Ex. OAG-10 at 10 (Scharber Surrebuttal) (citing *In re Application of N. States Power Co.*, Docket No. E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 46 (June 12, 2017)).

[61] Ex. OAG-10 at 10 (Scharber Surrebuttal).

allocator.[62] Xcel is hereby ordered to do so in its next rate case.

OAG 1022c. Once Xcel has fully rolled out its AMI meters, actual class load data will be available to determine class load shares at the time of historic MISO peaks. In its next rate case, if such data are available, Xcel should base the peak-demand allocator on actual class load shares coincident with the MISO peaks used, adjusting those historical shares to account for forecasted load changes in the test year.[63] If actual data are not available, Xcel should construct its peak-demand allocator using forecasted class loads at the time of likely MISO peak hours, with an explanation of how the likely MISO peak hours were chosen.[64]

4. Staff Analysis on Classification of Production Costs (D10S Allocator)

The Commission Order in Docket 21-630 ordered that:

> Xcel must calculate the D10S allocator in its next rate case based on its system peak coincident with the MISO system peak using historical data.[65]

The Company, however, evaluated the forecasted loads of August 23, 2025 at 4:00 pm to apply the D10S allocator for the 2025 test year. The OAG considered this implementation unreasonably arbitrary. Consequently, the OAG designed an alternative D10S allocator to use in its Cost studies. XLI disagreed with the OAG's alternate D10S allocator, while the Department argued that it was an average summer demand allocator, which did not accurately reflect how the Company designs, builds, and operates its peaking generation resources.

The perceived impact of the variance between the two versions is reflected in the ALJ's conclusion that both are severely flawed.[66] Xcel's methodology reflects usage at the actual historical peak hour which potentially could have been idiosyncratic to that moment in time, and may or may not have usage representative of a future peak. OAG's methodology reflects usage at a broader set of hours smoothing out those idiosyncrasies, however usage during these hours, most of which were not at or necessarily close to peak load, may not necessarily reflect usage patterns at peak load. The modeling results reached through the Xcel and the OAG alternatives underscore the likely conclusion that no model can provide a precise and accurate measure of cost causation in the Company's CCOSS.

In Staff's view, the proper implementation of the Commission's Order would have been for Xcel

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[62] Ex. OAG-10 at 10–11 (Scharber Surrebuttal).

[63] Ex. OAG-10 at 12, 48 (Scharber Surrebuttal).

[64] Ex. OAG-10 at 12, 48 (Scharber Surrebuttal).

[65] Docket 21-630, Final Order of July 17, 2023, Ordering Paragraph 53.

[66] ALJ Report, Finding 1018.

to calculate the D10S allocator either based on historical data for the actual date of the MISO system peak, or the average of several years' worth of MISO system peaks. Using forecasted data, which by definition more reflects 'average' usage for a particular date and time of day rather than the unique characteristics of a period of peak usage, is inappropriate. As peak usage generally reflects a unique case, using actual historical peaks to 'forecast' the behavior of the system at a future peak is the appropriate approach. Thus, Xcel should have used either the actual data from the MISO system peak of August 23, 2023 at 4PM, or the average of several years' worth of historical usages at peak, not the forecast for August 23, 2025 and 2026, which are not likely even forecast to be a 'peak load' at any more than the intraday level, as they are on weekend. Using forecast data of any kind is inconsistent with the order to use 'historical data'. OAG's methodology has the same flaw – there is no reason to believe that an average of forecast usages for times when the peak has happened in the past reflects PEAK behavior of the system. So, both methodologies are flawed.

Staff believes that, given the choice between OAG and Xcel's approaches, the OAG's is less flawed, because it reflects system behavior at times 'more like' a peak. However, using the historical estimated data for the actual dates of MISO peak (i.e. August 23, 2023, or an average of prior years), however flawed it is due to its nature as 'estimated' loads due to the incomplete rollout of AMI, would have been better. Forecasted loads are, by definition, estimates themselves, and are based on 'typical' rather than peak system characteristics. That historically-based estimator is unavailable here.

As for the question of whether to use a single MISO system peak, or 12-CP, Staff believes that the single peak is slightly better here, though either would give a reasonable result, so long that either allocator reflects the MISO system peak(s), which will be the times MISO has dispatched the most production plant available. Similarly, using MISO 4-CP (the peaks for each of the months June, July, August, and September, which are the likely months for a system peak in a summer-peaking system), would also be reasonable as a hedge against an 'idiosyncratic' peak load at 1-CP, the concern of the OAG.

If the Commission is persuaded that one method for calculating the D10S allocator is more appropriate, it could give more weight to the CCOSS introduced by that party when it makes the revenue apportionment decision. The Commission may also provide specific directions about which CCOSS methods are the most appropriate.

5. Decision Options for Classification of Production Costs (D10S Allocator)

4005. Approve Xcel's calculation of the D10S allocator based on its system peak coincident with the MISO system peak, using historical data. (Xcel, Department)

OR

4006. Approve the OAG's alternative calculation of the D10S allocator. (OAG)

4007. Approve OAG's recommendation that the D10S allocator reflect usage at 12CP, rather than the MISO 1-CP peak, in future rate cases. (OAG)

4008. Order Xcel to use the best available actual system usage at historical peaks to calculate the D10S allocator in future rate cases. (Staff)

D. Classification and Allocation of Transmission Costs

Most transmission costs are assumed to be jointly caused by all customers and must be classified and allocated. In Xcel's last rate case, the Commission ordered the Company to classify transmission costs as 70 percent demand-related and 30 percent energy-related, and to allocate the demand-related costs using a 12 CP (coincident peak) allocator.[67] Xcel consented that it is reasonable to classify transmission assets as both energy- and demand-related because transmission assets permit the Company to gain access to low-cost energy for its customers. The Company, however, disagreed with the continued use of the 12 CP allocator for the demand-related portion of transmission assets.[68]

1. Arguments

Xcel asserted that the purpose of the CCOSS is to identify cost causation principles, and classify and allocate costs based on those principles. The Company contended that while transmission revenues are generated, in part, based on demand charges that are calculated monthly, the transmission costs are based on the need to meet customer demands at the single highest peak of the year, not an average peak across twelve months.[69] The Company further stated that if the transmission system were planned to meet an average peak across 12 months, the system would be inadequate to meet customer demand on the actual highest peak. Consequently, it does not reflect cost causation to allocate demand-related transmission costs using a method that gives equal weight to all 12 months of the year.[70]

The Company stated that rather than a 12 CP allocator, the demand-related transmission costs should be allocated using the D10S allocator. The D10S allocator appropriately identifies the extent to which customer classes contribute to demand at the time of the NSP load at the MISO peak, to ensure that the cost responsibility is shared fairly across classes.

Xcel noted that it filed the 2025 and 2026 test year Cost studies using the 12 CP allocator as directed by the Commission in the last rate case. However, the Company recommended that the D10S allocator be used to allocate demand-related transmission costs in its future rate

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[67] Xcel-73; at 22 (Barthol Direct).

[68] *Id*.

[69] *Id*; at 23.

[70] Xcel-73; at 24 (Barthol Direct).

cases.[71]

The OAG noted that both XLI and the Department agreed with Xcel's argument that a system planned to meet year-round average demand would not meet the actual peak demands of customers in the summer. The OAG, however maintained its position, stating that given MISO's adoption of a seasonal resource capacity construct, a 12 CP allocator now makes more sense for allocating the demand-related portion of both production and transmission costs.[72]

XLI and the Department disputed OAG's recommendation. XLI stated that allocation of the demand-related portion of the transmission system on 12 CP is inconsistent with cost causation.[73] As a result, XLI recommended the Commission approve Xcel's proposed allocator based upon class loads in the single hour coincident with the MISO system peak in Xcel's current and future rate cases. The Department concluded that Xcel transmission system must be planned and sized to accommodate the Xcel and MISO coincident peak. As this single peak determines the necessary size of the transmission system, the peak is the driver of the overall cost of the system and therefore the CCOSS allocation of these costs should reflect that to meet cost causation principles.[74]

2. ALJ Recommendation

The ALJ addressed this issue in Findings 1023 to 1029, and concluded that the Commission's reasoning in Xcel's last rate case was sound; that continued use of the 12 CP allocator addresses seasonal needs for system reliability and focusing on a single peak would fail to adequately address that reality.

3. Exceptions to ALJ Report

c. Suburban Rate Authority (SRA)

The SRA noted that Xcel, the Department and XLI witnesses provided persuasive arguments in favor of the demand Component of the transmission allocator being based on summer peak demand. SRA subsequently asked the Commission to reconsider the ALJ conclusion in paragraph 1029.[75] The SRA further stated that record evidence and rate making principles stipulate that costs should be allocated based on cost causing activities support using the D10S allocator.[76] Additionally, both the 8760 allocator and 12 CP demands are based on average

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[71] Xcel-73; at 26 (Barthol Direct).

[72] OAG-9; at 18 (Scharber Rebuttal).

[73] XLI-6; at 11 (Ly Rebuttal).

[74] DOC-16; 35 (Zajicek Direct).

[75] SRA Exception; at 2.

[76] *Id*.

year round usage and demands, respectively and fail to capture the summer peak demands that the transmission system must be sized to accommodate. The SRA recommended that the Commission adopt the use of a summer peak demand instead of the 12 CP allocator.

d. Xcel

Xcel noted that ALJ Finding 1025 indicates that the Company calculated its D10S allocator based on the six highest Xcel system peak hours, which, as acknowledged in ALJ Finding 1012, is inaccurate. The Company contended that ALJ Finding 1025 appears to have been taken from the ALJ Report in the Company's 2021 rate case,[77] including references to witnesses from that proceeding who did not participate in this case.[78] Xcel stated that it used a new design for the D10S allocator, as directed by the Commission, and it is accurately described in ALJ Finding 1012. The Company additionally took exception to the ALJ's recommendation on use of the 12 CP allocator for demand-related transmission costs, on the basis that the Commission approved the use of the it in the Company's last rate case.[79] The Company argued that the recommendation does not recognize that a new record was developed in this case, which demonstrates that the D10S allocation method best reflects cost causation.[80]

Additionally, Xcel noted that as indicated in Finding 1027, the Company plans the transmission system to meet system peak demand, not average demand over 12 peaks across the year.[81] As a result, the Company took exception to the ALJ recommendations and recommended that demand-related transmission costs be allocated using the D10S allocator.

4. Staff Analysis

Staff notes Xcel's argument that the transmission costs are based on the need to meet customer demands at the single highest peak of the year. The Company further asserted that the transmission system would be inadequate to meet customer demand at the actual highest peak, if the system were planned to meet an average peak across 12 months. The expressed capability of the D10S allocator, to appropriately identify the extent to which customer classes contribute to demand at the time of the NSP load at the MISO peak, seems to provide assurance that the cost responsibility is shared fairly across classes.

A credible consideration regarding the MISO's adoption of a seasonal resource capacity construct gives credence to use of the 12 CP allocator. Staff notes that in Xcel's last rate case, the Commission cited "growing acceptance of relying on a broader concept of peak demand"

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[77] Xcel's Exception to ALJ Report; at 71.

[78] ALJ Report; at 164 (Footnote 1109)

[79] ALJ Report Finding 1029.

[80] Xcel's Exception to ALJ Report; at 72.

[81] *Id*.

beyond just a single peak.[82]

If the Commission is persuaded by one of these methods, it could give more weight to the CCOSS introduced by that party when it makes the revenue apportionment decision. The Commission can also provide specific directions on which CCOSS methods are the most appropriate, but does not need to.

5. Decision Options for Classification and Allocation of Transmission Costs

4009. Approve Xcel's use of the 12 CP allocator to allocate demand-related transmission costs, for the 2025 and 2026 test year Cost studies. (Xcel, OAG,ALJ)

4010. Approve Xcel's proposal to allocate demand-related transmission costs using the D10S allocator in its future rate cases. (Xcel, XLI and Department)

4011. Approve the OAG's proposal for use of the 12 CP to allocate demand-related transmission costs in Xcel's future rate cases. (OAG, ALJ)

4012. Do not adopt the ALJ's Finding of Fact 1025, which inaccurately describes the allocator.(Xcel)

E. Classification and Allocation of Distribution Costs

As directed by the Commission's Order in the last rate case, Xcel provided three CCOSS models, using different methods to classify and allocate the costs of the distribution system: a Minimum System Method, a Basic Customer Method, and a method that identifies customer-related costs, using the Basic Customer Method and identified demand- and energy-related costs using the Peak-and-Average method.[83] The distribution system includes the local distribution conductors, transformers, service drops and meters.

Historically, the distribution system has been allocated based on the number of customers served. As the number of customers grows, the size and scale of the distribution system must also increase. Consequently, the costs of the distribution system have traditionally been classified as customer-related costs.[84] The Company however noted that not all the costs are related to the number of customers. Some portion of the distribution system costs are incurred to meet peak demand. Given that those costs vary based on peak demand, they are classified as demand-related costs.

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[82] Xcel 2021 Rate Case Order; at 12.

[83] Xcel-73; at 33-34 (Barthol Direct).

[84] *Id*; at 34.

The Company noted that this understanding of the distribution system is consistent with the guidance in the NARUC Manual, which explains that the distribution system should be classified into demand- and customer-related costs.[85] Xcel classified the distribution system costs using the Minimum System Study.

1. Minimum System Study

The Minimum System Study is used to estimate the percentage of the distribution system that is needed to connect customers but serves no demand. The NARUC Manual identifies two ways to perform a Minimum System Study: the Minimum Size Method and the Zero-Intercept Study.

The Minimum Size Method identifies the smallest-sized piece of relevant equipment that is used in the distribution system and assumes that any larger equipment must be selected to serve demand.

The Zero-Intercept Study is a more technical method used to estimate the same information as the Minimum Size Method. Instead of assuming that the minimum distribution equipment is the smallest equipment that is installed, as for the Minimum Size Method, the Zero-Intercept Study calculates the cost of equipment that actually has zero capacity.

Consistent with its practice in past cases, the Company used both methods and combined their results,[86] referred to as the Hybrid Minimum System Study. The Company then selected the results which provided the lower customer-related percentage, to ensure that the customer classification is not overstated.

2. Basic Customer Method

The Basic Customer Method classifies distribution plant that serves a single customer (such as meters) as 100 percent customer-related, because those costs vary based on the number of customers. All remaining costs do not vary based on the number of customers and are classified as demand related.[87]

3. Peak and Average Method

The Peak & Average Method assumes that some part of the distribution system is needed to deliver energy, and the rest of the system costs are needed to serve peak demand. The costs are allocated to customer classes using different allocators for each of the customer demand-related and energy-related costs. The Company noted that this method was recommended by

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[85] The NARUC Manual states that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system," and thus should be classified as customer-related costs. NARUC Manual at 90.

[86] Xcel-73; at 37 (Barthol Direct).

[87] *Id*; at 42.

the OAG in Xcel's last rate case, indicating that this calculation should be done using the Company's load factor.[88]

The Company created new allocators to calculate the Peak and Average method. Xcel stated that it needs to create new energy allocators that do not allocate distribution costs to customers who take serve at transmission voltages and also do not allocate secondary-related distribution costs to customers who take service at primary voltages. Table 4 below provides the new allocators and their definitions.

Table 4: Peak & Average Study New Allocators[89]

Allocator	Definition
E61PS	Based off the E8760 allocator. This allocator allocates the energy-related portion of multi-phase primary distribution line costs to all customers except those who take service at transmission voltages.
E61PS1Ph	Based off the E8760 allocator. This allocator allocates the energy-related portion of single-phase primary distribution line costs to all customers except multiphase customers and those who take service at transmission voltages.
E62Sec	Based off the E8760 allocator. This allocator allocates the energy-related portion of secondary distribution line costs.

4. Arguments and Recommendations

Xcel concluded that the Hybrid (Zero-Intercept) Method is the most reasonable because it follows cost causation and the well-established tenet that the addition of customers is a significant determinant of distribution system costs, which is supported by the NARUC manual.[90] The OAG stated that the Peak and Average method was preferable, on the basis that it 1) correctly allocates only customer-specific distribution system costs on a per-customer basis and 2) acknowledges that distribution system investments are driven by both peak demand and energy use.[91]

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[88] Xcel-73; 45 37 (Barthol Direct).

[89] *Id*; at 46.

[90] *Id*; at 48.

[91] OAG-8; at 26 (Scharber Direct).

XLI articulated no challenge to Xcel's Hybrid method, but recommended that in future rate cases, the Company should not rely on the results of a Hybrid Minimum System Study that mixes and matches the results of the minimum-size and zero-intercept studies; but should use only the results of one of these studies. Xcel recommended that the Commission rely on its Hybrid CCOSS, which combines the results of its Minimum Size and Zero Intercept methods.

The OAG recommended that the Commission continue to require the Company to submit Basic Customer and Peak-and-Average Cost studies along with the Company's preferred Minimum System Method in the next rate case. The Department argued that the Minimum-Size method is best reflective of cost causation, because it classifies some costs as customer, other costs as demand, and no costs as energy.[92] The Department supported the Basic Customer method and Xcel's Hybrid Minimum-System Study to inform rate design decisions.[93]

5. Criticisms of Xcel Hybrid CCOSS

The OAG finds Xcel's Hybrid methodology to be flawed for several reasons, including its claim that the Minimum System Studies are not widely accepted, and argued that the Basic Customer method is the most reasonable method for classifying shared distribution system costs.

The OAG stated that it is reasonable to assume that all customers require a meter. As a result, it is appropriate to allocate these costs on a per-customer basis. However, allocating the costs of shared conductors and transformers on a per-customer basis, using a Minimum System Method requires a variety of assumptions that are not reasonable. Additionally, the Zero Intercept variant of the Minimum System Method assumes that the installed costs of different types of shared distribution equipment vary with demand (specifically, capacity rating) and with customers. For each equipment category, bivariate regression is used to relate cost to capacity rating, and those costs that don't vary with capacity rating are assumed to be customer-related. The assumption embedded in the Minimum System Method—that the addition of any one customer increases the costs of shared distribution system components—is inaccurate and unfairly allocates a disproportionate share of distribution system costs to Residential customers who did not cause them.[94] The OAG concluded that this assumption is unreasonable, because the regression equation is mis-specified.[95]

In rebuttal, Xcel reiterated that the Peak & Average Method is inappropriate, because it ignores that distribution conductors and transformers are driven by the addition of customers.[96] Additionally, the Company stated that the NARUC Manual does not recognize that distribution

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[92] DOC-16; at 26 (Zajicek Direct).

[93] DOC-16; at 46 (Zajicek Direct).

[94] OAG-8; at 22-23 (Scharber Direct).

[95] OAG-9; at 21 (Scharber Rebuttal).

[96] Xcel-74; at 25 (Barthol Rebuttal).

costs are classified as energy related.[97]

6. ALJ Recommendation on Classification and Allocation of Distribution Costs

The ALJ addressed each of the methods for classifying and allocating distribution system costs in Findings 1030 to 1056, and concluded as follows:

(a) The Commission should continue to rely on multiple methodologies for classifying and allocating shared distribution costs. All models presented in this proceeding carry sufficient supporting testimony and theoretical support to preclude any model being entirely disregarded.[98]

(b) The ALJ noted that consideration of the multiple models in the record highlights the range of results that occur from the choice of these assumptions as well as the danger of accepting any one model as an objective representation of cost causation. The ALJ reasoned that the Peak-and-Average should be given significantly less weight than the Basic Customer Method or the Minimum System Method, when setting rates in this proceeding.[99]

(c) The ALJ concluded that neither Basic Customer Method or Minimum System Method is perfect, but together they form the bookends of a reasonable range of conclusions about the causation of shared distribution costs. Accordingly, the Commission should give both methods equal weight when setting rates in this proceeding.[100]

7. Exceptions to ALJ Report

a. Xcel

The Company took exception to the ALJ recommendation that the Commission should give equal weight to the Minimum System and the Basic Customer method for the classification and allocation of shared distribution costs. First, in Finding 1053, the ALJ concluded that none of the methods on this record are entirely reasonable because one key driver for distribution costs is "the size of a utilities' [sic] service territory." Xcel asserted that it is also true that the size of the utility's service territory is related at least in part to the number of customers served by the service territory.[101] This is an indication that at least some portion of the distribution system costs must vary based on the number of customers served. This undisputable fact is at odds with the Basic Customer method, which contains the assumption that the shared costs of the

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[97] Xcel-73; at 47 (Barthol Direct).

[98] ALJ Report, at 168 (Finding 1051).

[99] ALJ Report, at 168 (Finding 1055).

[100] ALJ Report, at 169 (Finding 1056).

[101] Xcel's Exception; at 70.

distribution system do not vary based on the number of customers. Based on these reasons, the Company took exception to ALJ's Findings 1053 and 1056, that the Basic Customer method be given equal weight when setting rates, and recommended the following alternative languages:

> "The size of the utility's system, and therefore the costs of its distribution system, are related at least in part to the number of customers it serves."
>
> "While reasonable analysts could disagree about the precise proportion of demand- or customer-related costs, the Basic Customer method's assumption that distribution lines are zero-percent customer related is unreasonable. For that reason, CCOSS analysis using the Minimum System method should be given greater weight in setting rates in this proceeding."

b. OAG

The OAG asserted that the Peak-and-Average Method is a reasonable method for classifying Shared Distribution-System costs because much of the cost of Xcel's Distribution System is energy-related. The OAG took exception to the ALJ report's conclusion that Peak-and-Average Method of classifying shared distribution costs is flawed.[102] The OAG stated that it provided a nonexclusive list of ways distribution investment is driven by energy use beyond the need to meet peak demand. For example, energy transfer in high-load (yet nonpeak designated) hours leads to heat buildup, which increases the sagging of overhead lines, speeds the aging of insulation in underground lines, and reduces the ability of lines and transformers to survive brief load spikes on the same day.[103] Additionally, costs incurred to reduce line losses provide energy-related benefits.

Moreover, the OAG pointed out that the Commission has long relied on the Peak-and-Average Method as one of several models that provide valuable insights about distribution-cost causation, and the Regulatory Assistance Project's cost-allocation manual recognizes this method as the best practice for classifying shared distribution costs. Additionally, the OAG pointed out that the Regulatory Assistance Project's cost-allocation manual recognizes this method as the best practice for classifying shared distribution costs. Based on the above information, OAG recommended the following modifications for ALJ findings: 1045, 1055, 1085, 1086 and 1106, to give as much weight to the Peak-and-Average method as the Basic Customer Method or the Minimum System Method.[104]

> 1045. The OAG recommends, and in fact prefers, the use of the Peak-and-

[102] OAG's Exception to ALJ Report; 37.

[103] *Id*.

[104] OAG's Exception to ALJ Report; at 38-39.

Average method for the CCOSS because it treats some distribution costs as energy-related under the assumption that some shared distribution costs would be needed even if all customers used power at a 100 percent load factor. ~~The OAG does not provide specific examples of what costs should be considered energy-related.~~ The OAG provides several examples, supported by both Xcel discovery responses and the RAP Manual, of distribution-system costs that are energy-related.[105]

1055. ~~While t~~The OAG provided ~~some~~ a persuasive justification for treating a portion of the shared distribution costs as energy-related~~, the Company, Department, and XLI provided persuasive arguments that the analytical framework of the Peak-and-Average Method is significantly flawed~~. Specifically, the OAG ~~has not~~ identified ~~any~~ specific cost items that ~~vary based on~~ are driven by customer energy usage. Accordingly, the Peak-and-Average should be given ~~significantly less weight than~~ at least as much weight as the Basic Customer Method or the Minimum System Method when setting rates in this proceeding.

1085. ~~The OAG's Peak-and-Average Model is entitled to significantly less weight than other models in the record because of theoretical shortcomings of that model. Also,~~ XLI's Hybrid model is entitled to significantly less weight because of its treatment of fixed production plant costs.

1086. The Commission should give the most weight to the Hybrid models proposed by the Department and Xcel as well as the Basic Customer models presented by the Department and the OAG, and the Peak-and-Average model proposed by the OAG. These CCOSSes reflect a variety of modeling decisions and assumptions that, as described above, are meritorious and defensible despite their respective flaws. Accordingly, the Commission should consider these models when evaluating the cost-causation of various customer classes. In doing so, the Commission should recognize that none of the models produce a result that can be said to be an objectively accurate reflection of class cost-causation. Any revenue apportionment result that falls within the results of these models can be said to be "at cost" to the extent cost can be fairly determined on this record.

1106. ~~One key weakness of the OAG's recommendation is the extent to which it is weighted by the Peak-and-Average model. That said, t~~The OAG's apportionment recommendation is the only one in this record that gives weight to all three methods that the Commission has found reasonable for informing revenue apportionment. Moreover, the OAG's recommended apportionment still falls within the range of results of its Basic Customer and Minimum System cost estimates for both the Residential and Large General Service classes. These are both defensible CCOSSes methodologies, which renders the OAG's proposal a cost-based recommendation, even if the Peak-and-Average Method is not considered, as recommended by some parties. It is further reasonable to exclude the Small General Service class from any increase based on the persuasive evidence that that class is

[105] Ex. OAG-8 at 25 (Scharber Direct).

already paying significantly above cost as estimated by ~~a range of~~ all models in the record.[106]

8. Staff Analysis

Based on the analysis of the three methods for classification and allocation of distribution costs, staff observes that each provides credible rationale for cost causation, all of which are however based upon imperfect assumptions. As a result, a reasonable conclusion can be reached that the multiple models cannot be weighted equally. Staff therefore recommends that the weight given to each model be based on whether Commissioners are persuaded by their underlying assumptions.

Staff notes that the Peak-and-Average method proposed by the OAG is fundamentally different from the other allocators. Minimum system, Basic Customer, and zero intercept methods are designed to divide "customer-related" from "non-customer related" costs, and allocates the former based on some form of customer count and the latter based on demand. Peak-and-Average is used to divide demand-related costs from energy-related costs. These methods can be used together, in sequence – using Minimum System or Zero-Intercept to divide customer-costs from non-customer and then using Peak-and-Average to divide non-customer costs between Demand and Energy. The OAG's approach can be distilled to use the Basic Customer method for the first step, and Peak-and-average for the second, but Peak-and-Average can be combined in the same way with minimum system approaches.

9. Decision Options for Classification and Allocation of Distribution Costs

4013. Approve Xcel's filing of the three Cost studies, using different methods to classify distribution system costs. (Xcel, Department, ALJ)

4014. Approve Xcel's classification and allocation of distribution costs using a hybrid of the Minimum Size Method and Zero Intercept Method. (Xcel)

OR

4015. Require Xcel to use the Basic Customer Method to classify and allocate distribution costs. (OAG)

OR

4016. Require Xcel to use the Peak-and-Average method to classify and allocate distribution costs. (OAG)

4017. Require Xcel to use only the results of one of the Minimum System Study to classify and

[106] See ALJ Report ¶ 1083.

allocate distribution costs. (XLI)

4018. Require Xcel to file an updated study calculating its demand adjustment applied to the Minimum System Method in its next rate case. (Department)

F. Classification and Allocation of Advanced Metering Infrastructure (AMI)

The OAG stated that the benefits AMI provide, compared to pre-AMI include more effective load management, reduced line losses, automated power outage detection, restoration capabilities, the ability to implement time-of-use rates, reduced meter reading costs, and more efficient integration of electric vehicles and renewables.[107] It provides range of energy-, demand-, and customer-related benefits not provided by pre-AMI metering infrastructure.

The OAG noted that AMI is more expensive than pre-AMI metering infrastructure. It observed that based on response to OAG Information Request (IR) 7031, Xcel estimated that the average cost of a residential pre-AMI automatic meter reading (AMR) meter at $49.73 and the average cost of an AMI meter at $95.65.[108] The OAG observed that Xcel justified the increased costs of AMI meters partially on the basis of the demand- and energy-related benefits.

In its 2025 and 2026 Cost studies, Xcel classified meter costs as 100 percent customer-related, as in previous rate cases.[109] Meter costs have historically been classified as customer-related because each customer requires a meter. The Company proposed that most AMI costs continue to be recovered through the Transmission Cost Recovery (TCR) Rider throughout the multiyear rate plan (MYRP), and these costs were removed from the revenue requirement used in the CCOSS. As such, the OAG contended that it is appropriate to classify the remaining meter costs in the Cost studies prepared for this rate case as 100 percent customer-related.[110] The OAG however reasoned that if AMI costs are recovered through base rates in future rate cases, the associated Cost studies should be classify these costs as partially energy- and demand-related.[111]

The OAG noted that if Xcel proposes to recover AMI costs through base rates in future rate cases, the associated Cost studies should classify these costs as customer-, energy-, and demand-related. Furthermore, the OAG recommended that based on the relative costs of AMI

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[107] *See, e.g., Xcel Energy, Advanced Grid and Smart Meters*, https://mn.my.xcelenergy.com/s/our-commitment/clean-energy-technology/agis-smart-meters [https://perma.cc/7LNK-HUG9] (last visited Aug. 6, 2025); RAP Manual at 83–84 (listing the benefits of AMI).

[108] OAG-8; at 27 (Scharber Direct).

[109] *Id*; at 28.

[110] *Id*; at 29.

[111] *Id*.

and pre-AMI meter infrastructure, as well as the precedent set in the Minnesota Power case,[112] that AMI meters and related costs be classified as one-third each energy-, demand-, and customer-related.[113]

1. Arguments and Recommendations

Xcel disagreed with the OAG's recommendation that AMI costs be classified as customer-, demand-, and energy-related once they are rolled into base rates; and argued that allocators must be based on cost causation and not the benefits that are provided by the technologies.[114] Xcel pointed out that the AMI meters are installed because each customer requires a meter in order to receive and be billed for electricity. The Company contended that while it is true that AMI meters have additional functionality, that functionality does not change the fact that the metering costs are driven by how many meters are needed to be installed, which is driven exclusively by the number of customers that are being served.

The Department made no recommendation or opposed any changes to the classification and allocation of AMI meters in this case. However, the Department recommended that the Commission require Xcel to provide a study of AMI meter costs as compared to traditional meters in its next rate case. Specifically, the Commission require Xcel to provide a study showing the costs of AMI meters compared to the costs of traditional meters, and the costs of reading those meters compared to AMI meters. Additionally, the Department reasoned that to the extent that AMI meters cost more than the traditional meter and meter reading costs, those costs should be classified as either demand- or energy-related, depending on the other uses, as those costs are specifically beyond what would be necessary to just connect the customer to service and report usage.[115]

The XLI expressed that equal classification of AMI Costs as 1/3 customer-related, 1/3 demand-related, and 1/3 energy-related, if AMI costs are being recovered in base rates in Xcel's future rate cases is arbitrary.[116] The one-third allocation to each of the factors essentially assumes that AMI meters serve each of these functions equally. XLI stated that without analysis supporting this proposal, it is improper to assume that AMI equipment serves each of these functions in identical capacities. As a result, XLI recommended the Commission rejects the OAG recommendation.

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[112] See In the Matter of the Application by Minnesota Power for Authority to Increase Electric Service Rates in the State of Minnesota, MPUC Docket No. E-015/GR-23-155, Direct Test. of Chad Stevenson at 39 (Mar. 18, 2024) (eDocket No. 20243-204447-01) (confirming that Minnesota Power complied with the directive to classify AMI costs as 1/3 customer-related, 1/3 demand-related, and 1/3 energy-related).

[113] OAG-8; at 30 (Scharber Direct).

[114] Xcel-74; at 28 (Barthol Rebuttal).

[115] DOC-18; at 6 (Zajicek Surrebuttal)

[116] XLI-6, at 17 (Ly Rebuttal).

2. ALJ Recommendation on Classification and Allocation of AMI

The ALJ addressed this issue in Findings 1057 to 1070, and concluded that the Commission approve the OAG's proposed classification on AMI costs for a relevant rate purpose between now and the decision in Xcel's rate case.[117]

The ALJ contended that the recommendation on this issue is for the Commission to effectively adopt the least flawed proposal in the record. Consequently, it recommended that the Commission adopts the Department's recommendation and require the Company to provide a study showing the costs of AMI meters compared to the costs of traditional meters and the cost of reading those meters compared to AMI meters, and to classify the difference between those costs as either demand- or energy-related in Xcel's next rate case.[118]

3. Exceptions to ALJ Report

c. Xcel

Xcel rejected the ALJ's recommended use of the OAG's recommendation of the AMI Cost Classification and Allocation, that meters should be classified as 1/3 customer, 1/3 demand, and 1/3 energy until the Company's next rate case,[119] in spite of referring to it as "arbitrary and lacking any record support".[120] Xcel contended that this recommendation is not supported by the factual record in this proceeding. The Company requested that the ALJ recommendation be rejected for several reasons, including: First, it is unreasonable to order the Company to use a classification method that the ALJ has found to be arbitrary, which could lead to unreasonable rates for customers. Second, Xcel argued that there is no record support for the ALJ's guess about why the Company selected AMI meters; and for the ALJ's statement that connecting customers to the system "could be accomplished at the reduced cost of a pre-AMI meter."[121] Third, no party has identified any AMI specific functions that are demand-related or energy-related, or demonstrated that such functions drive an increase in metering costs.

The Company asserted that in the absence of evidence, generic arguments about the potential uses for AMI meters do not provide a sound basis to change classification methods. Consequently, Xcel took exception to ALJ Findings 1069 and 1070, and recommended the following language instead:[122]

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[117] ALJ Finding 1069.

[118] ALJ Finding 1070.

[119] Xcel's Exceptions to ALJ Report; at 65.

[120] Xcel's Exceptions to ALJ Report; at 65-66.

[121] *Id*; at 66,

[122] Xcel's Exceptions to ALJ Report; at 67.

There should be no change to the classification of meters in this case. Instead, the Commission accepts the Company's agreement to conduct a study on the appropriate classification of AMI meters compared to traditional meters, and to provide the results of the study and a recommendation in its next electric rate case.

d. OAG

The OAG observed that ALJ Finding 1069 may contain a clerical error, with the statement: that the Commission "approve the OAG's proposed classification of AMI costs for any relevant rate purpose between now and a decision in Xcel's rate case."[123] The OAG recommended that the Commission makes the following clarifying change to Finding 1069: "The Commission should approve the OAG's proposed classification of AMI costs for any relevant rate purpose between now and a decision in Xcel's next rate case."[124]

4. Staff Analysis

Staff observes that Xcel's proposal to continue allocating AMI meters as 100 percent customer-related costs, excludes the energy- and demand-related components of the AMI costs. On the other hand, the OAG proposal that AMI costs be classified as one-third customer-related, one-third energy-related, and one-third capacity related assumes that AMI meters serve each of these functional areas equally, which is not confirmed with any supportive analysis. As such, staff agrees with the ALJ conclusion, for approval of the OAG's proposal and the Department's recommendation for Xcel to provide a study showing the costs of AMI meters, compared to the costs of traditional meters, and the costs of reading those meters compared to AMI meters.

5. Decision Options for Classification and Allocation of AMI

4019. Allocate AMI meters and related costs to be classified as one-third each energy-, demand-, and customer-related. (OAG, ALJ)

Or

4020. Require Xcel to provide a study showing the costs of AMI meters compared to the costs of traditional meters, and to classify the difference between those costs as either demand- or energy-related in Xcel's next rate case. (Department, ALJ)

G. Classification and Allocation of Other Production O&M

Xcel noted that in its 2013 rate case, the Commission required the Company to analyze Other Production O&M costs in order to identify those costs that vary directly with the amount of

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[123] OAG's Exception; at 40.

[124] *Id*.

energy produced.[125]

Based on its analysis, the Company noted that only Other Production O&M costs that vary directly with energy output (i.e., increase or decrease based on energy output) are chemicals and water use costs. Both chemicals and water use increase proportionately to increase in energy output. Total chemical and water use costs for the 2025 test year are $4.8 million and make up only 1.1 percent of total Other Production O&M costs.[126] The remaining $451.2 million of Other Production O&M does not vary directly with energy output.

Consistent with Ordering Paragraph 37 from the Company's 2013 rate case, (Docket No. E-002/GR-13-868), the CCOSS has classified the Other Production O&M costs that vary directly with energy usage as energy-related, and classified the remaining Other Production O&M that originate from a specific generator based on the type of production plant associated with the costs. The Company noted that there are $11.7 million in costs that are not specific to a generator type and $9.9 million of Regional Markets expense that is split into demand and energy components based on how total plant-specific expense is split.[127]

1. Arguments and Recommendations

XLI observed that except for chemical and water use costs that vary directly with energy, Xcel uses the results of Stratification to classify these expenses between demand-and energy-related costs. As previously contended, XLI maintained that Stratification is flawed; and that Xcel's approach failed to recognize that labor is a significant portion of other production O&M expenses (labor costs do not vary with hourly load-weighted marginal energy costs). XLI concluded that since labor expenses do not vary directly with energy production, they should be classified entirely to demand.[128]

The OAG disagreed with XLI, asserting that its recommendation reflects an outdated idea, that costs that do not vary directly with production are appropriately classified as demand related. For instance, like the costs of coal and wind generation, a significant share of the O&M costs required to support these plants are appropriately classified as energy-related on the basis that they are incurred to provide reliable energy throughout the year.[129] Additionally, the OAG contended that XLI does not provide a convincing argument for why labor costs are more appropriately classified as demand-related, when they do not vary directly with capacity.[130]

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125 Xcel-73; at 29 (Barthol Direct).

126 Xcel-73; at 29 (Barthol Direct).

127 *Id*; at 30.

128 XLI-3; at 17 (Ly Direct).

129 OAG-9; at 13 (Scharber Rebuttal).

130 *Id*.

In rebuttal testimony, Xcel argued that since the Company's 2013 rate case, the Commission has ordered Xcel to utilize its current methodology for classifying and allocating these costs.[131]

2. ALJ Recommendation on Classification and Allocation of Other Production O&M

The ALJ addressed this issue in Findings 1071 to 1074, concluding that consistent with its Order in Xcel's previous rate cases dating back to the proceeding filed in 2013, the Commission should approve the Company's proposal for classifying and allocating Production O&M costs.

3. Exceptions to ALJ Report

e. XLI

XLI further stated that the ALJ's recommendation regarding Classification and Allocation of Other Production O&M overlooked fundamental issues with Stratification. It noted that the ALJ's reasoning that "[t]he Commission rejected XLI's same argument in the 2013 rate case,"[132] ignores evidence XLI placed in the record that stratification is obsolete, a foundational flaw that is compounded by the Company's failure to recognize that labor costs, which do not vary with energy costs, comprise an outsized portion of other production O&M expenses.

4. Staff Analysis

Staff agrees with the ALJ, that the Commission should approve Xcel's proposal for classifying and allocating Production O&M costs, consistent with its Order in the Company's 2015 rate case (Docket No. E-002/GR-15-826).

5. Decision Options for Classification and Allocation of Other Production O&M

4021. Approve Xcel's classification of Other Production O&M costs that vary with energy usage as energy-related. (Xcel, OAG, ALJ)

OR

4022. Require Xcel to classify labor-related production O&M as demand-related, with the remaining costs classified as energy-related. (XLI)

H. Allocation of Economic Development Discounts

Economic development discounts are treated as a reduction in revenues from the Commercial

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131 Xcel-74; at 37-38 (Barthol Rebuttal).

132 XLI Exception; at 24.

and Industrial (C&I) Demand class.[133] As ordered by the Commission in the Company's 2013 rate case (Docket No. E-002/GR-13- 868), the Company used to allocate these costs using the Company's R01 (Total Revenue) allocator. However, Xcel asserted that this is not the most reasonable way to allocate economic development discounts. The Company's 2025 CCOSS economic development discounts are allocated using the Company's R02 (Base Revenue) allocator for the 2025 test year.[134]

In response to a Department Information Request, the Company stated that it changed its method of allocating economic development discounts because the base revenue allocator is "more appropriately based on cost causation," compared to the total revenue allocator; since "Economic Development Discounts are discounts on base rates, and don't include discounts for fuel or riders."[135]

The OAG noted that the rationale for allocating economic development discount costs using a revenue based allocator is that offering the discounts helps retain customers, allowing the Company to spread overhead costs broadly and benefiting all customers by lowering average bills.[136] Moreover, neither the R01 (total revenue) nor R02 (base revenue) allocator perfectly captures the proportion of benefits that accrue to each class.

1. Arguments and Recommendation

The OAG stated that the R02 allocator is less appropriate than the R01 allocator for allocating economic development discount costs. The Company's R01 allocator assigns 39.59 percent of the costs of economic development discounts to the Residential class in the 2025 CCOSS.[137] However, the Residential class does not benefit directly from these discounts, which accrue entirely to business classes, and whether the Residential class receives 39.59 percent of the indirect benefits of economic development discount is questionable.

The OAG pointed out that using the R02 allocator increases the Residential class's share of economic development costs to 42.21 percent in the 2025 CCOSS.[138] The Company should not increase the Residential class's share of these costs without providing evidence that the class is receiving an increased share of the benefits.

Allocating economic development discounts based on total revenue (R01) instead of base revenue (R02) in the Company's preferred 2025 CCOSS shifts less than $200,000 between

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133 Xcel-73; at 10 (Barthol Direct).

134 Xcel-73; at 10 (Barthol Direct).

135 OAG-8; 31 (Scharber Direct).

136 *Id*.

137 *Id*.

138 OAG-8; 32 (Scharber Direct).

classes.[139] Although the difference in results using the R01 and R02 allocators is small, the OAG argued that using the R02 allocator represents a change from Xcel's past CCOSS methods and the change does not follow either cost causation or benefit accrual. In the absence of evidence that the Residential class's share of benefits resulting from economic development discounts has increased since the last rate case, the OAG recommended that the Company continue using the R01 allocator.

In rebuttal testimony, Xcel noted that in the last rate case, XLI proposed that economic development discounts be allocated with a base revenue allocator, since these discounts pertain to base revenues and not fuel or riders. The Company agreed with the proposal and adopted the change in this rate case.

Xcel disagreed with the OAG's recommendation that the Company reverts to its previous methodology. The Company stated that Economic Development Discounts are not related to fuel costs, hence it makes more sense to allocate them using a revenue allocator that does not include fuel costs.

XLI disagreed with the OAG in rebuttal testimony, stating that the OAG's opposition to Xcel's proposed allocation of economic development discount costs is results-oriented and not based on cost causation.[140] XLI reasoned that large customers that receive the economic development discount generate incremental revenues which offset a portion of fixed system costs. They do not directly impact fuel costs or costs for other riders that are paid for by other customers. Hence, it is reasonable to allocate the costs for these economic development discounts on base revenues, since these are the only costs that are directly impacted by large customers.

The Department concurred with Xcel's position, noting that economic development discounts provide benefits for the entire system by attracting more customers, spreading fixed costs between more customers, and thus should be allocated to all customers.

2. ALJ Recommendation on Classification and Allocation of Economic Development Discount Costs

The ALJ addressed this issue in Findings 1075 to 1082, and concluded that given economic discount rates do not provide a discount on fuel costs, it would be unreasonable to use an allocator that incorporates fuel. As such, the Commission should approve use of the R02 (Base Revenue) allocators for Xcel's economic development discounts.

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[139] OAG-8; 32 (Scharber Direct).

[140] XLI-6, at 21 (Ly Direct)

3. Exception to ALJ Report

a. OAG

The OAG took exception to the ALJ Report's conclusion that economic-development discount costs should be allocated according to base revenues as proposed by Xcel.[141] The OAG contended that adopting the Company's proposed change would shift more costs to the residential and small general service classes without a proportionate increase in the benefits received. The OAG stated that Xcel should allocate economic-development discounts using an average of its energy and peak-demand allocators, which would better reflect how the benefits of economic-development discounts are distributed among its customer classes.[142] Furthermore, as noted by the OAG, the change is not tethered either to cost-causation or to benefit distribution.

The OAG asserted that the Commission should direct Xcel to allocate these costs based on an average of the energy and peak-demand allocators, to reflect that other classes benefit by discount recipients' peak load and energy requirements being reflected in these allocators. Consequently, the OAG recommended red-line modifications to the following Findings: 1079 and 1082.[143]

4. Staff Analysis

The Company's initial reason for changing the allocator of Economic Development Discount was in consensus with XLI's proposal in the Company's last rate case, that the base revenue allocator was more appropriate, since these discounts pertain to base revenues and not fuel or riders. The OAG's contention is principally that using the R02 allocator increases the Residential class's share of economic development costs without providing evidence that the class is receiving an increased share of the benefits. Although the increase due to the change is not significant, the OAG argued that it does not follow either cost causation or benefit accrual.

Xcel and XLI justification for the change seems credible, that these discounts pertain to base revenues and not fuel or riders, and as such, makes more sense to allocate them using a revenue allocator that does not include fuel costs.

Staff agrees with the ALJ's conclusion, that because the discount rates do not provide a discount on fuel costs, it would not be reasonable to use an allocator that incorporates fuel. As such, the Commission should approve Xcel's use of the R02 (Base Revenue) allocator.

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[141] ALI Report; Findings 1075 – 1082.

[142] OAG's Exception to ALJ Report; at 40.

[143] OAG's Exception to ALJ Report; at 42.

5. Decision Options for Classification and Allocation of Economic Development Discount Costs

4023. Approve Xcel's use of the R02 (Base Revenue) allocator to classify and allocate Economic Development Discount Costs. (Xcel, XLI, Department, ALJ)

OR

4024. Require Xcel to use the R01 (Total Revenue) allocator to classify and allocate Economic Development Discount Costs. (OAG)

III. DECISION OPTIONS

4001. Determine that each CCOSS model provides useful information and decline to adopt any specific model. (ALJ, Staff)

OR

4002. Determine that _____ CCOSS model is the most reasonable based on this record.

Classification of Production Costs

4003. Approve Xcel's proposal to classify and allocate production costs using the Stratification Method. (Xcel, DOC, OAG).

OR

4004. Order Xcel to classify and allocate production costs using the AED-4CP Method. (XLI)

D10S Allocator

4005. Approve Xcel's calculation of the D10S allocator based on its system peak coincident with the MISO system peak using historical data. (Xcel, Department)

OR

4006. Approve the OAG's alternative calculation of the D10S allocator. (OAG)

4007. Approve OAG's recommendation that the D10S allocator reflect usage at 12CP, rather than the MISO peak, in future Xcel rate cases. (OAG)

4008. Order Xcel to use the best available actual system usage at historical peaks to calculate the D10S allocator in future rate cases. (Staff)

Classification of Transmission Costs

4009. Approve Xcel's use of the 12 CP allocator to allocate demand-related transmission costs, for the 2025 and 2026 test year Cost studies. (Xcel, OAG, ALJ)

4010. Approve Xcel's proposal to allocate demand-related transmission costs using the D10S allocator in its future rate cases. (Xcel, XLI and Department)

OR

4011. Approve the OAG's proposal for use of the 12 CP to allocate demand-related transmission costs in Xcel's future rate cases. (OAG, ALJ)

4012. Do not adopt the ALJ's Finding of Fact 1025, which inaccurately describes the allocator.(Xcel)

Classification of Distribution Costs

4013. Approve Xcel's filing of the three Cost studies, using different methods to classify distribution system costs. (Xcel, Department, ALJ)

4014. Approve Xcel's classification and allocation of distribution costs using a hybrid of the Minimum Size Method and Zero Intercept Method. (Xcel)

OR

4015. Require Xcel to use the Basic Customer Method to classify and allocate distribution costs. (OAG)

OR

4016. Require Xcel to use the Peak-and-Average method to classify and allocate distribution costs. (OAG)

4017. Require Xcel to use only the results of one of the Minimum System Study to classify and allocate distribution costs. (XLI)

4018. Require Xcel to file an updated study calculating its demand adjustment applied to the Minimum System Method in its next rate case. (Department)

Decision Options for Classification and Allocation of AMI

4019. Allocate AMI meters and related costs to be classified as one-third each energy-, demand-, and customer-related. (OAG, ALJ)

Or

4020. Require Xcel to provide a study showing the costs of AMI meters compared to the costs of traditional meters, and to classify the difference between those costs as either demand- or energy-related in Xcel's next rate case. (Department, ALJ)

Classification of Other Production O&M

4021. Approve Xcel's classification of Other Production O&M costs that vary with energy usage

as energy-related. (Xcel, OAG, ALJ)

OR

4022. Require Xcel to classify labor-related production O&M as demand-related, with the remaining costs classified as energy-related. (XLI)

Classification and Allocation of Economic Development Discount Costs

4023. Approve Xcel's use of the R02 (Base Revenue) allocator to classify and allocate Economic Development Discount Costs. (Xcel, XLI, Department, ALJ)

OR

4024. Require Xcel to use the R01 (Total Revenue) allocator to classify and allocate Economic Development Discount Costs. (OAG)

IV. Appendix

References to the Record

Background
Min. R. 7825.4300(c)
ALJ Report, p. 173
Xcel, Barthol Direct, pp. 28-29

General
Docket No. E-017/GR-20-719, p. 44
ALJ Report, p. 159

Classification and Allocation of Production Costs – Stratification Method
Xcel, Barthol Direct, pp. 15-17, 20, 22
Xcel, Barthol Rebuttal, pp. 11, 13-14
XLI, Ly Direct, pp. 2-4, 7-8, 10-11, 13
XLI, Ly Surrebuttal, p. 2
DOC, Zajicek Direct, p. 42
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OAG, Scharer Direct, p. 33
OAG, Scharber Rebuttal, pp. 3, 30

Classification and Allocation of Production Costs – D10S Allocator
Xcel, Barthol Direct, pp. 18-20
Xcel, Barthol Rebuttal, p. 18
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Classification and Allocation of Transmission Costs
Xcel, Barthol Direct, pp. 22-26
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Classification and Allocation of Distribution Costs
Xcel, Barthol Direct, pp. 33-34, 37, 42, 45-48
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Xcel, Barthol Rebuttal, pp. 37-38
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Xcel, Barthol Direct, p. 10
OAG, Scharber Direct, pp. 31-32
XLI, Ly Direct, p. 21

Classification and Allocation of AMI
Xcel, Barthol Rebuttal, p. 28
Xcel, Exceptions, pp. 65-67
DOC, Zajicek Surrebuttal, p. 6
XLI, Ly Rebuttal, at 17
OAG, Exceptions, p. 40
ALJ Findings, 1069 and 1070