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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIG DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2024-0319

Jefferson City, Missouri
January 2025

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REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2024-0319

EXECUTIVE SUMMARY

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, and my business address is 200 Madison Street, Jefferson City, MO 65102.

Q. Are you the same Sarah L.K. Lange who provided direct class cost of service and rate design testimony in this matter, filed December 17, 2024?

A. Yes.

Q. What areas will you be addressing in this testimony?

A. I will respond to the Ameren Missouri Class Cost of Service ("CCoS") Study included in the testimony of Thomas Hickman, and the derivative studies and recommendations provided by MIEC[1] witnesses Brubaker and York, MECG[2] witness Maini, and Consumers Council Witness Palmer. I will respond to the revenue responsibility allocation and rate design recommendations of Ameren witness Bowden, and the intervenor witnesses. I will also respond to Dr. Bowden's requested changes to the time-based rate elements for non-residential customers, MECG witness Austin's request for Electric Vehicle Charging rates, and the various rate design requests made in direct testimony of Ameren Missouri and intervenors. I will also

[1] Missouri Industrial Energy Consumers.
[2] Missouri Energy Consumers Group.

address recommendations for rate modernization made by various parties, and provide a correction to my direct testimony concerning net metering billing.

MODIFICATION OF RATE STRUCTURES FOR COMPATIBILITY WITH NET METERING

Q. Have you become aware of an error and an omission in your recommended language to modify rate structures for compatibility with net metering?

A. Yes. My direct testimony reflected the Evergy time-period labels of "on-peak," "off-peak," and "super off-peak," rather than the Ameren Missouri time-period labels, "on-peak," "intermediate," and "off-peak." I also failed to include a cap on the amount of credit provided. The corrected language is set out below:

> For bill calculation purposes, all net kWh shall be billed at the intermediate rate, with the difference between the on-peak and intermediate rate applied as a surcharge to the net kWh consumed during the on-peak period, and the difference between the off-peak and intermediate rate applied as a credit to the net kWh consumed during the off-peak period. In no event shall the cash value of the credits calculated pursuant to this calculation be used to offset the customer charge or any rider, tax, or other charge.

CLASS COST OF SERVICE STUDIES

Q. Did parties other than Staff perform a CCoS Study reflecting that party's recommended revenue requirement?

A. Ameren Missouri filed a CCoS Study reflecting its direct case. MIEC, MECG, and CCM[3] filed derivative partial studies relying on Ameren Missouri's filed revenue requirement, and Ameren Missouri's CCoS Study. MECG and MIEC discuss minor modifications to a single allocator, and CCM discuss changes to distribution classification.

[3] Consumers Council of Missouri.

In testimony filed on December 3, 2024, MIEC witness Walters recommended a return on equity ("ROE") of 9.50%, as opposed to the 10.25 which is the basis of the Ameren Missouri CCoS Study. Mr. Walters' recommended rate of return ("ROR") is 7.1%, which he notes would reduce the Ameren Missouri revenue requirement by approximately $72.1 million.[4]

In testimony filed on December 3, 2024, MECG witness Meyer recommends increasing Ameren Missouri's revenues associated with the High Prairie windfarm by $10.9 million.

Using Ameren Missouri's study with the MIEC ROR and the MECG wind revenues reduces the alleged residential, Small General Service ("SGS"), and lighting "subsidies" by $27.8 million (8%) and $5.9 million (14.3%), and $0.88 million (5.5%), respectively.

(Dollar values in millions of dollars)

			Residential	SGS	LGS/SPS	LPS	Lighting
MECG Wind Revenue	Staff ROE Position	Increase $	$ 321,639	$ 36,370	$ 24,134	$ (5,328)	$ 15,292
MECG Wind Revenue	MIEC ROE Position	Increase $	$ 322,415	$ 36,530	$ 24,490	$ (5,246)	$ 15,321
MECG Wind Revenue	Ameren ROE Position	Increase $	$ 345,536	$ 41,292	$ 35,096	$ (2,795)	$ 16,169
MECG Wind Revenue	Staff ROE Position	Increase %	22.05%	11.00%	2.89%	-2.42%	36.30%
MECG Wind Revenue	MIEC ROE Position	Increase %	22.11%	11.05%	2.93%	-2.39%	36.36%
MECG Wind Revenue	Ameren ROE Position	Increase %	23.69%	12.49%	4.20%	-1.27%	38.38%
Ameren Wind Revenue	Staff ROE Position	Increase $	$ 326,342	$ 37,517	$ 27,920	$ (4,099)	$ 15,327
Ameren Wind Revenue	MIEC ROE Position	Increase $	$ 327,118	$ 37,677	$ 28,275	$ (4,017)	$ 15,356
Ameren Wind Revenue	Ameren ROE Position	Increase $	$ 350,239	$ 42,439	$ 38,882	$ (1,566)	$ 16,204
Ameren Wind Revenue	Staff ROE Position	Increase %	22.37%	11.35%	3.34%	-1.87%	36.38%
Ameren Wind Revenue	MIEC ROE Position	Increase %	22.43%	11.40%	3.38%	-1.83%	36.45%
Ameren Wind Revenue	Ameren ROE Position	Increase %	24.01%	12.84%	4.65%	-0.71%	38.46%
Difference from Ameren direct to MIEC/MECG positon $:			**$ 27,824**	**$ 5,909**	**$ 14,392**	**$ 3,680**	**$ 883**
Ameren Direct Under/Over Contribution %:			**7.09%**	**-2.54%**	**-8.90%**	**-12.62%**	**16.97%**
MECG Wind Under/Over Cotnrribution %:			**6.76%**	**-2.89%**	**-9.35%**	**-13.18%**	**16.89%**

*Under contributions are calculated as the amount of increase needed to equalize rates of return among classes, therefore under contributions appear as positive values and over contributions appear as negative values.

Q. How did you allocate the MECG wind revenue valuation in these calculations?

A. I allocated the additional wind revenue using class energy requirements, consistent with the Ameren Missouri study.

[4] Walters Direct, page 2-3. The ROR reflected in the Ameren Missouri study is 7.398%.

Q. Other testimonies in this case have generally provided CCoS study results as the percentage increase applicable to class revenues to provide a system average rate of return at the requested rate of return. Is this the most useful presentation?

A. Staff finds the presentation of the dollars and percentages of over or under-contribution at the current revenue level to be the most useful presentation of CCoS study results. Among the reasons for this preference is that it eliminates the differences in requested and recommended ROEs and capital structures from influencing study results, and it is more useful in determining the extent of any subsidy.

Q. Are you aware of any study demonstrating a subsidy in this case?

A. No. No study indicates that any studied class fails to produce sufficient revenue to cover expenses resulting in a negative rate of return from that class.

Production Allocation

Q. Does the Ameren Missouri study reasonably allocate production-related costs and expenses?

A. No. First, many of the Ameren Missouri solar farms are allocated as distribution plant. Second, the allocation of the costs, expenses, and revenues of renewable generation is internally inconsistent, not consistent with cost causation, and is unreasonable. Third, the allocation of wholesale energy expenses and revenues fails to acknowledge the existence of the MISO[5] integrated energy market, which is entering its 20th year of operation. Fourth, the peaks selected in the Ameren Missouri study and derivative studies are not reasonably related to the Ameren Missouri capacity requirements in the MISO market. Finally, cost responsibility is unreasonably shifted by the decision to combine the Large General Service ("LGS") and Small

[5] Midcontinent Independent System Operator, Inc.

Primary Service ("SPS") classes for purposes of finding the combined non-coincident peak ("NCP").

Production in Distribution

Q. In the last rate case, did the Commission order Ameren Missouri to take actions to address the allocation of solar facilities booked to distribution accounts?

A. Yes. At page 48 of the Report and Order in ER-2022-0337, the Commission included, "The Commission also directs Ameren Missouri to create subaccounts within distribution accounts and transmission accounts for recording infrastructure related to utility-owned generation." However, that was not completed in the accounting records allocated in this case by Ameren Missouri, and Mr. Hickman did not perform a manual correction.

Q. What is the effect of allocating solar facilities using Ameren Missouri's distribution allocators?

A. Allocating solar facilities using Ameren Missouri's distribution allocators shifts revenue responsibility to the residential and SGS classes, and away from the LGS, SPS, and LPS classes.

Renewable Allocations Causation of Renewable Energy Resource Revenue Requirements

Q. Has Ameren Missouri added facilities for purposes of generating renewable energy to comply with the Missouri Renewable Energy Standard statutory requirements?

A. Yes. Matt Michels' direct testimony in EA-2019-0181, filed May 15, 2019, explicitly states that RES[6] compliance drove the "need" for recent windfarm additions:

[6] Renewable Energy Standard.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to support Ameren Missouri's application for a Certificate of Convenience and Necessity ("CCN") for the Outlaw Wind Project (the "Project"), which is being built so that Ameren Missouri can meet its compliance obligations under the Missouri Renewable Energy Standard ("RES").

Q. Please summarize the conclusions of your direct testimony.

A. Beginning in 2021, Ameren Missouri must have Renewable Energy Credits ("RECs") representing at least 15% of its retail sales in order to satisfy its RES obligations. Missouri wind resources are an attractive option for meeting this need. The proposed Project represents a significant portion of the portfolio of resources that are needed to comply with the RES in a cost-effective manner. For these reasons, the Missouri Public Service Commission ("Commission") should approve the Company's application for a CCN for the Project.

II. THE NEED FOR RENEWABLE RESOURCES

Q. Please briefly describe the Missouri RES and its requirements.

A. The RES was passed by Missouri voters via a ballot initiative in 2008. The RES requires that Missouri's investor-owned utilities acquire renewable resources equal to increasing percentages of their respective retail sales. As noted, the requirement reaches a minimum of 15% of retail sales in 2021. The RES includes a 1.25 times multiplier for renewable energy generated within the state of Missouri to encourage in-state development of renewable resources so that 1 megawatt ("MW") of generation in Missouri results in 1.25 RECs for RES compliance purposes.

Q. What is Ameren Missouri's need for renewable resources starting in 2021?

A. To meet the 15% RES requirement, Ameren Missouri will need to retire a minimum of approximately 4.5 million RECs each year.

Q. Does Ameren Missouri already have renewable resources that can be used to meet some or all of this need?

A. It has some of the resources it needs. Ameren Missouri owns renewable resources, including hydroelectric, solar, and landfill gas resources. Ameren Missouri also has a contract (the term of which ends in August 2024) for 102 MW of wind energy from Horizon's Pioneer Prairie wind farm in northern Iowa. Together, these resources currently generate approximately 1.4 million RECs annually. In addition, the Company has also entered into agreements to purchase the High Prairie Wind Project and the Brickyard Hills Wind Project, which together are expected to generate roughly 2.4 million RECs annually. This leaves a remaining need of at least approximately 0.7 million RECs in 2021. Figure 1 below was included in Ameren Missouri's 2017 IRP, which was filed with the Commission in September 2017. It shows the RES REC requirement by year, RECs generated from Ameren Missouri's existing renewable energy resources, and additional RECs that will be needed to meet the RES requirements.

[Figure 1 omitted]

Q. What is Ameren Missouri's plan for meeting its remaining need for non-solar RECs?

A. **Ameren Missouri plans to meet its need for additional RECs through the construction and acquisition of a total of at least 700 MW of new wind generation by the end of 2020, including the 400 MW expected from the High**

> **Prairie Wind Project and the 157 MW expected from the Brickyard Hills Wind Project upon their completion.**
> Q. Does Ameren Missouri need the Project to satisfy any resource requirement other than the requirements of the RES?
> A. No. Ameren Missouri has sufficient generation resources to meet its resource adequacy obligations under the Midcontinent Independent System Operator, Inc. ("MISO") Module E tariff and to provide its customers with safe and reliable electric service at a reasonable cost. This is consistent with the analysis and findings in the Company's 2017 IRP. **But for the need to comply with the RES, Ameren Missouri would not pursue the Project.**[7]
> **[Emphasis added]**

Q. Have the Outlaw wind farm and the other resource additions Mr. Michels discussed been built?

A. The project designated as "Outlaw" is the Atchison wind farm, and has been built. Ameren Missouri canceled its plans to acquire Brickyard Hills.[8] The High Prairie project has been built, and the Report and Order included a finding of fact that "The wind generation project for which Ameren Missouri has been granted a CCN in this case is intended to comply with the renewable energy mandates of the law."[9] That Report and Order also approved the "Third Stipulation and Agreement," submitted by Ameren Missouri, Staff, Renew Missouri, MIEC, DE,[10] the Sierra Club, the NRDC,[11] and OPC.[12] That stipulation included, at page 2, that "[t]he Signatories agree the costs of this Project are Renewable Energy Standard compliance costs so long as the facility is certified by the Division of Energy as a renewable energy resource under 4 CSR 340-8.010." That certification has occurred.

Q. What is the reasonable allocation of the revenue requirement of the Atchison and High Prairie windfarms?

[7] Direct Testimony of Matt Michels, EA-2019-0181, pages 2-5.
[8] CCN issued in EA-2019-0021.
[9] Report and Order, effective December 22, 2018, in EA-2018-0202, page 5, citing to Wills Direct, page 3, Lines 8-22.
[10] Missouri Division of Energy.
[11] Natural Resources Defense Council.
[12] The Office of the Public Counsel.

A. Allocation on energy is the only reasonable approach for the revenue requirement associated with these facilities. The most reasonable allocation method would be on the basis of metered generation, which is used in calculating the RES requirements. However, Staff is not opposed to allocation based on usage at transmission or generation to improve consistency with the RESRAM,[13] FAC,[14] and the allocation of revenue from the sale of generated energy.

Q. What did Ameren Missouri testify constituted the need for the Huck Finn Solar project?

A. In EA-2022-0244, Lindsey Forsberg testified on behalf of Ameren Missouri, that the purpose of her direct testimony was "…to support Ameren Missouri's application for a Certificate of Convenience and Necessity ("CCN") for the Huck Finn Solar Project (the "Project"), which is being built to meet Ameren Missouri's compliance obligations under the Missouri Renewable Energy Standard ("RES")."[15]

Q. What did the Commission find with regard to the Huck Finn Solar project?

A. At page 4 of its "Order Approving Stipulation and Agreement and Granting Certificates of Convenience and Necessity," in EA-2022-0244, the sole finding related to need for the project was that "[i]n its recommendation, Staff states there is a need for the service, as the Project will enable Ameren Missouri to meet its Missouri Renewable Energy Standard ("RES"), which requires electric utilities to generate or purchase no less than 15% of its energy from renewable recourses, of which at least 2% must be from solar resources."[16]

[13] Renewable Energy Standard Rate Adjustment Mechanism.
[14] Fuel Adjustment Clause.
[15] Forsberg direct in EA-2022-0244 at page 3
[16] Order Approving Stipulation and Agreement and Granting Certificates of Convenience and Necessity, in EA-2022-0244Page 4.

Q. Did the Huck Finn Solar case include testimony concerning Ameren Missouri's need for additional RES compliance resources?

A. Yes. Ms. Forsberg testified that:

> The addition of the Huck Finn Solar Project is expected to fulfill the Company's remaining RES compliance needs over a ten-year planning horizon. However, as discussed above, the exact value of Ameren Missouri's retail load in future years is uncertain, and the exact generation output for the renewable energy resources that make up the Company's RES compliance portfolio will vary year over year. The size of the Huck Finn Solar Project is expected to provide a small buffer against this dual uncertainty in RES compliance planning. However, if load growth exceeds current expectations, or if resource output is not within expected ranges from one or more of the Company's RES compliance resources, additional resources may be needed in the near term to meet compliance requirements. Ameren Missouri will continue to evaluate its RES compliance portfolio annually and utilize spot market REC purchases as needed to ensure annual compliance is met.
>
> Beyond 2032, it is expected that increases in retail load combined with the loss of customer-owned solar RECs between 2029 and 2033 will create a need for additional compliance resources. Figure 1 illustrates Ameren Missouri's 20-year compliance position under expected or average resource output, including the addition of the Huck Finn Solar Project in late 2024.[17][Confidential Figure 1 omitted]

Q. What is the reasonable allocation of the revenue requirement of the Huck Finn Solar project?

A. The Huck Finn Solar project can only be reasonably allocated on energy. The most reasonable allocation method would be on the basis of metered generation, which is used in calculating the RES requirements. However, Staff is not opposed to allocation based on usage at transmission or generation to improve consistency with the RESRAM, FAC, and the allocation of revenue from the sale of generated energy.

[17] Forsberg direct in EA-2022-0244 at page 8

Q. Ameren Missouri sought CCNs for four solar projects in EA-2023-0286, filed June 16, 2023. What testimony did Ameren Missouri offer to support the need for these projects?

A. Ameren Missouri testified that the Cass County Solar, Huck Finn Solar, Bowling Green Solar, and Vandalia Solar projects were necessary to satisfy an "energy need," discussed by witnesses Ajay Arora, and Matt Michels. Also, the direct testimony of Mr. Wills in EA-2023-0286 at pages 7-8, discusses "the role that renewables play in supporting robust economic activity in the region, by helping to attract and retain customers that are ultimately large employers in the service territory and whose load contributes to affordability for all customers by providing additional sales over which to spread the Company's fixed costs of providing service."

The signatories' support for a CCN for the Cass County solar project was conditioned upon the successful auction of subscriptions to the project as a Renewable Solutions Program resource.[18]

Q. Whether the cost causation of these four solar projects is the RES or "energy needs," how should the costs of these four solar projects reasonably be allocated?

A. Both of these causation theories support allocation on the basis of class energy requirements. The most reasonable allocation method would be on the basis of metered generation, which is used in calculating the RES requirements. However, Staff is not opposed to allocation based on usage at transmission or generation to improve consistency with the RESRAM, FAC, and the allocation of revenue from the sale of generated energy.

[18] Stipulation and Agreement in EA-2023-0286, paragraphs 6 – 8 (page numbers not provided in Stipulation).

Q. How does the consideration of attracting and retaining large usage customers and the use of the Cass project (150 MW) in the RSP program impact cost allocations for these projects?

A. A reasonable analyst could conclude that the costs of these projects should be assigned directly to the classes of large energy users and RSP participants. However, Staff is not advocating for that result at this time.

Q. What is the causation for the Boomtown Solar Project?

A. In its Report and Order in at page 31, EA-2022-0245, effective April 22, 2023, the Commission found, inter alia, that the project was needed due to:

> 1. A need for winter capacity additions,[19]
> 2. Concern that waiting to add renewable resources could result in Ameren Missouri falling sort of meeting "energy needs," [20]
> 3. That other benefits of the project included "Offering its larger customers an option to purchase renewable energy is one way for Ameren Missouri to help prevent these customers from leaving, or seeking to expand outside, the Ameren Missouri service territory,"[21] and that "Real business investment decisions are being made based on renewable energy access, and states that can provide access to renewables are succeeding in some of the largest economic development opportunities in the country."[22]

In light of these considerations, the most reasonable allocation of the Boomtown Solar project revenue requirement is on the basis of energy; however, a reasonable analyst could conclude that the costs of these projects should be assigned directly to the classes of large energy users and RSP participants although Staff is not advocating for that result at this time.

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[19] Report and Order in EA-2022-0245, page 11.
[20] Report and Order in EA-2022-0245, page 12.
[21] Report and Order in EA-2022-0245, page 16.
[22] Report and Order in EA-2022-0245, page 16.

Q. How does the Ameren Missouri study allocate Production Tax Credits ("PTCs") and Investment Tax Credits ("ITCs")?

A. I'm not entirely sure. A reasonable study would allocate these tax benefits consistently with the allocation of capital costs for the underlying project.

Q. Do the Ameren Missouri study or any derivative studies allocate or assign RES compliance costs to account for the cost and/or value of RECs that are generated by facilities that are disproportionately allocated?

A. No.

Q. How disproportionate is the allocation?

A. An approximate calculation demonstrating normalized and annualized loads and generation is shown below:

Class	Ameren & Derivative Allocator	Usage in MWh @ Meter	Solar RES Requirement	Allocated Solar	Solar Adequacy / Deficit	RES Requirement	Allocated RECs	Adequacy / Deficit	% Deficit
Residential	51.03%	13,229,515.01	264,590	656,456	391,866	1,984,427	2,310,988	326,561	16.46%
SGS	11.26%	3,240,837.31	64,817	144,854	80,037	486,126	509,942	23,817	4.90%
LGS/SPS	29.56%	10,711,199.51	214,224	380,238	166,014	1,606,680	1,338,588	(268,092)	-16.69%
LPS	7.85%	3,726,207.30	74,524	101,018	26,494	558,931	355,623	(203,308)	-36.37%
Lighting	0.29%	36,987.44	740	3,742	3,002	5,548	13,173	7,624	137.42%
		30,944,747	618,895	1,286,307	667,412	4,641,712	4,528,315	(113,397)	-2.44%

Using the approach taken in the Ameren Missouri study and the derivative study, although the test period resources reviewed did not generate all required RECs for the load, the residential, SGS, and lighting classes are paying for the generation of RECs beyond their needs while the LGS, SPS, and LPS classes do not pay for adequate RECs for their needs.[23]

However, if the allocation of these resources is done on the basis of class energy, all classes participate essentially evenly in the deficit, shown below:

[23] Ameren Missouri may comply with the RES through the use of banked RECs from previous years.

Class	Energy Allocator @ Transmission Voltage	Usage in MWh @ Meter	Solar RES Requirement	Allocated Solar	Solar Adequacy / Deficit	RES Requirement	Allocated RECs	Adequacy / Deficit	% Deficit
Residential	43.11%	13,229,515	264,590	554,550	289,960	1,984,427	1,952,237	(32,191)	-1.62%
SGS	10.56%	3,240,837	64,817	135,848	71,031	486,126	478,240	(7,886)	-1.62%
LGS/SPS	34.56%	10,711,200	214,224	444,604	230,380	1,606,680	1,565,185	(41,495)	-2.58%
LPS	11.64%	3,726,207	74,524	149,754	75,230	558,931	527,195	(31,736)	-5.68%
Lighting	0.12%	36,987	740	1,550	811	5,548	5,458	(90)	-1.62%
		30,944,747	618,895	1,286,307	667,412	4,641,712	4,528,315	(113,397)	-2.44%

Q. If the RES is assessed on energy and the renewables are allocated on energy, why are the deficit percentages not uniform?

A. The RES is assessed on metered energy. Because of losses, an allocation factor calculated using usage at transmission voltage or generation voltage allocates more to classes served at secondary than does an allocation factor calculated using metered usage.

Renewable Allocations – Internal Inconsistency

Q. Setting aside the RES requirements and the causation of the resources described in the preceding section, is the allocation of the revenue requirement and revenues for renewable energy in the Ameren Missouri study and the derivative studies reasonable?

A. No. There are essentially no "fuel" costs or other costs that vary with generation for these resources. However, the Ameren Missouri study and its derivatives allocate the costs of these resources using a capacity allocator and allocate the value of the energy of these resources using the energy allocator.

Q. Is it reasonable that one class of customers pays the majority of the costs for a project to be built while another class of customers receives the benefits of that project's generation revenues?

A. No. Under the Ameren Missouri and derivative studies, the Residential, SGS, and Lighting classes pay for more of the cost of renewable projects than they receive the value of the energy generated, while the LGS, SPS, and LPS classes pay for less of the cost and receive the value of more of the energy generated.

Q. What is the difference in production cost allocations if renewable plant is allocated on the basis of energy while maintaining Ameren Missouri's allocation using the Average & Excess ("A&E") allocator for coal, non-renewable natural gas, and nuclear units?

A. Renewable resources are about 32% of Ameren Missouri's production ratebase, and about 22% of production-related depreciation expense.

The table below provides the allocators used in the Ameren Missouri study:

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Capacity Allocator	51.03%	11.26%	29.56%	7.85%	0.29%
Ameren Energy Allocator	43.15%	10.52%	34.73%	11.28%	0.32%

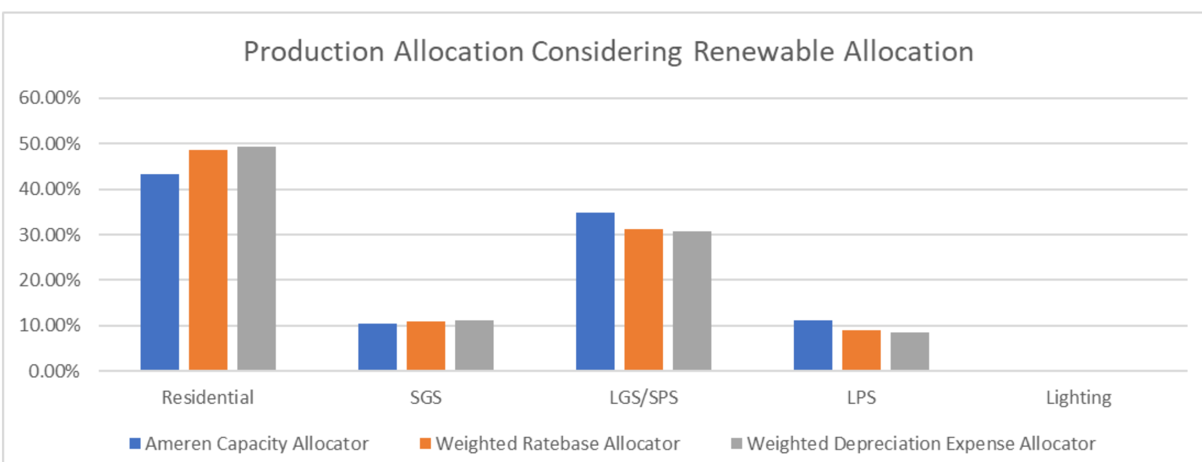
The calculation of the weighted ratebase allocator is provided below:

Production Ratebase	Residential	SGS	LGS/SPS	LPS	Lighting
Allocate with Ameren Capacity Allocator	$ 2,393,455,903	$ 528,139,654	$ 1,386,355,982	$ 368,313,826	$ 13,642,602
Allocate with Ameren Energy Allocator	$ 953,813,216	$ 232,558,109	$ 767,803,978	$ 249,327,465	$ 7,145,274
	$ 3,347,269,119	$ 760,697,763	$ 2,154,159,960	$ 617,641,292	$ 20,787,876
Weighted Ratebase Allocator	48.51%	11.02%	31.22%	8.95%	0.30%

The calculation of the weighted depreciation expense allocator is provided below:

Production Depreciation Expense	Residential	SGS	LGS/SPS	LPS	Lighting
Allocate with Ameren Capacity Allocator	$ 159,244,435	$ 35,138,855	$ 92,238,789	$ 24,505,121	$ 907,687
Allocate with Ameren Energy Allocator	$ 38,457,511	$ 9,376,685	$ 30,957,665	$ 10,052,821	$ 288,096
	$ 197,701,946	$ 44,515,540	$ 123,196,455	$ 34,557,943	$ 1,195,783
Weighted Depr. Expense Allocator	49.28%	11.10%	30.71%	8.61%	0.30%

A comparison of the allocators is provided below:



Q. Did you reallocate expenses related to operations and maintenance of production plant when you incorporated these allocators in to your review of the Ameren Missouri study results?

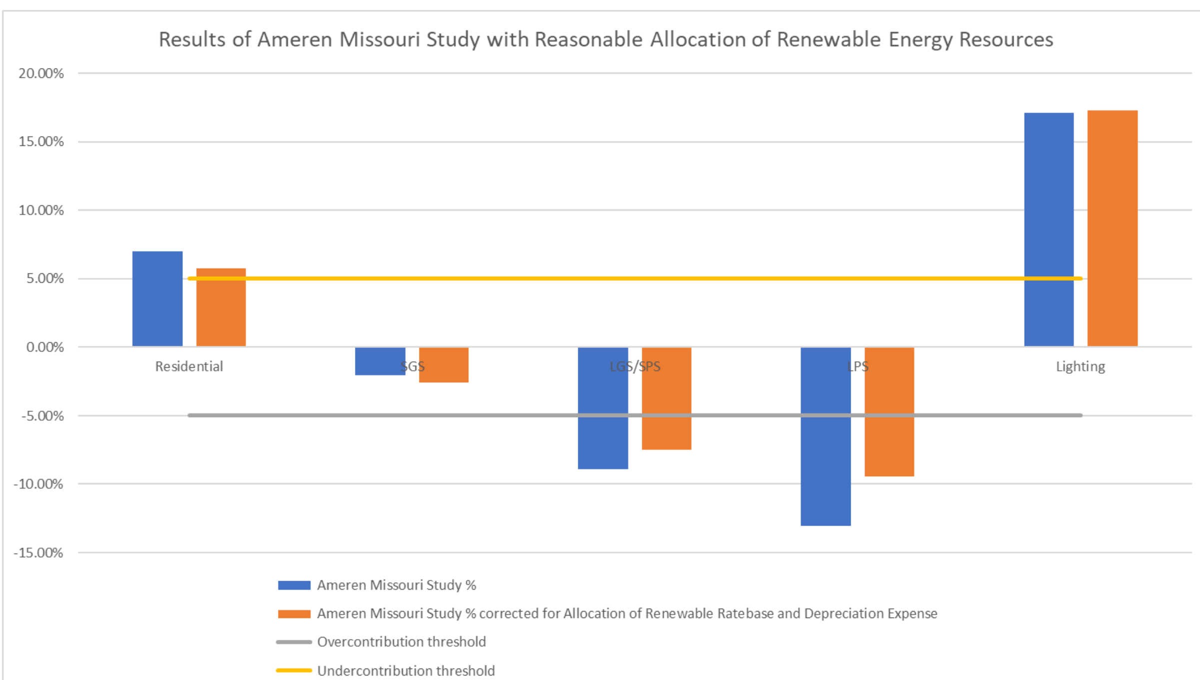
A. No. I used the version of my recreation of the Ameren Missouri study that addresses the Allocator 35 issue, discussed below; however, I did not modify the allocation of any expenses other than depreciation expense and Allocator 35.

Q. Could you provide the changes that correcting the allocation of renewable generation to an energy allocation produces to the results of the Ameren Missouri study?

A. Yes.

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for Allocation of Renewable Ratebase and Depreciation Expense	5.78%	-2.57%	-7.46%	-9.44%	17.32%

*Under contributions are calculated as the amount of increase needed to equalize rates of return among classes, therefore under contributions appear as positive values and over contributions appear as negative values.



Q. Is it reasonable to rely on any study which allocates RES compliance costs on a basis other than energy requirements, or to rely on any study which does not consistently allocate renewable energy costs, expenses, revenues, and associated tax benefits?

A. No. Either of these flaws, and particularly both, cause unreasonable CCoS study results.

Renewable Solutions Program, Community Solar Program, and Other Complications

Q. Would it be reasonable to consider the allocations of the revenue requirement of facilities used for the Renewable Solutions Program and the Community Solar Program to the customers participating in those programs?

A. Yes. However, this will be a complicated exercise which would involve both class and intraclass revenue requirements. Staff suggests that the parties make best efforts to evaluate the costs and revenues of these programs and facilities in the ongoing rate modernization workshop.

Q. Has the advent of these programs complicated performance of a CCoS study?

A. Yes. Recognizing the limited time afforded to Staff for performance of a CCoS study, participant programs such as the RSP and CSP, regulatory mechanisms such as Plant in Service Accounting ("PISA"), RESRAM, and various amortizations, and tax consequences such as production and investment tax credits, Accumulated Deferred Income Tax ("ADIT"), and Excess Deferred Income Tax("EDIT") have lent significant complexity to conduct of a CCoS study.

Q. Do the loads relied upon by the parties reflect load reductions due to demand response that are funded through Missouri Energy Efficiency Investment Act ("MEEIA")?

A. Yes. Due to this, customers within a class are being compensated for avoiding load, while the class itself is not being allocated the cost of load.

Q. What is the effect on CCoS study results of allocating renewable resources on the basis of capacity, allocating energy revenues on the basis of energy, and ignoring the RES for purposes of resource allocation in the CCoS?

A. Each of these decisions shifts costs to the Residential and SGS classes and away from the LGS, SPS, and LPS classes.

Wholesale Energy Expenses and Revenues

Q. Is it possible to know what the actual wholesale energy costs were for each studied class?

A. Absolutely. While a handful of different approaches can be taken to normalize and annualize this valuation in a rate case, and the real-time deviations of each class versus the projected load of each class can introduce further complexities, the actual cost of market energy in the Day Ahead market is a simple calculation of multiplying the Location Marginal Price ("LMP") for each interval by the class load for each interval.[24] The Commission has not considered these additional complexities, because the intervening parties simply ignore the multi-billion dollar wholesale energy transactions when performing (or adopting) a CCoS study.

Q. Did Ameren Missouri or the derivative studies consider wholesale energy prices in allocating the cost to serve load?

A. No. The Ameren Missouri study netted all fuel costs, energy costs, and wholesale energy revenues and allocated all of these on the basis of energy.

[24] For example, using the actual test period cost of energy and allocating it to the classes based on normalized loads and normalized LMPs will produce different results than multiplying normalized loads and normalized LMPs.

Q. How long has the MISO integrated energy market been in operation?

A. The MISO integrated energy market has been in operation for approximately 20 years. Ameren Missouri sells all of its generated energy (except that generated at the distribution level such as by community solar projects) into the integrated energy markets, and Ameren Missouri purchases all of the load requirements of its customers (except for that supplied by distribution-level solar, net metering customers, and qualified facilities generation) from the integrated energy markets. It is not reasonable to rely on any study that fails to acknowledge the cost and revenue causation of these market activities.

Q. What is the effect of ignoring the actual cost of load on the CCoS study results of Ameren Missouri and the derivative studies?

A. In isolation, this decision shifts revenue responsibility away from the Residential and SGS class and onto LGS, SPS, LPS, and Lighting. However, if a study is designed to ignore the capacity market, seasonal resource adequacy, reasonable allocation of renewable energy resource costs and revenues, and otherwise flatten the costs and revenues considered in a CCoS study, then it is probably more reasonable to rely on flat load prices than to include this detail in isolation.

Peak Selection and Capacity Requirements

Q. What determines Ameren Missouri's capacity requirements?

A. Ameren Missouri is required by MISO to meet resource adequacy requirements in each of four seasons. For background, the following description was provided by Ameren Missouri witness Andrew Meyer in his direct testimony in EA-2024-0237, beginning at page 10:

> In August 2022, FERC approved significant changes to the MISO capacity construct, deconstructing the annual approach into four seasonal planning windows to identify the unique reliability needs of each season and align resource availability with seasonal needs. Each season has a unique Planning Reserve Margin ("PRM") and unique Zonal Import & Export Limits. Additionally, the MISO accreditation rules for Capacity Resources changed from an annual Unforced Capacity ("UCAP") method to Seasonal Accredited Capacity ("SAC") method for thermal resources. The new seasonal construct, using accreditation values announced by MISO in late 2022, did not begin until its use in the PRA for the 2023-24 Planning Year.

Q. Did the Ameren Missouri study or any derivative study take these resource adequacy requirements into account?

A. No.

Q. Do intervenors explicitly reject the seasonal MISO capacity construct?

A. Yes. Mr. Brubaker, at page 18 of his direct testimony, includes the following exchange:

> Q. WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?
>
> A. The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that cause the utility to incur capacity costs.

However, Mr. Brubaker opines that "This analysis shows that summer peaks dominate the AMO system. (This same information is presented in tabular form on Schedule MEB-COS-2.) The system peak occurred in June, with a just slightly lower peak demand in August. The July peak was 97.9% of the annual peak. The fourth highest peak occurred in January. The peaks occurring in the other months were substantially lower. These lower loads simply are not representative of peak-making weather and use of these lower demands as part of the allocation factor could distort the allocations and under-allocate costs to the most temperature-sensitive loads."[25]

He continues:

> Q. WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?
>
> A. As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class's contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.[26]

Mr. Brubaker and Ms. York recite claims of this nature throughout their testimonies, but they are, bluntly, irrelevant to the circumstances of Ameren Missouri which has participated in MISO for decades, and has continuing authority to do so.[27]

Ms. Maini on behalf of MECG makes similar claims regarding peak selection in her direct testimony at pages 11-13.

Q. Can reasonable CCoS practitioners disagree about allocator selection given the facts pertinent to a utility?

A. Yes. However, whether or not the MISO seasonal construct exists and whether or not Ameren Missouri's load is subject to it, is not up for debate. The same is true for the

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[25] Brubaker direct page 18
[26] Brubaker direct pages 18-19
[27] At pages 21-22, Mr. Brubaker testifies that "a coincident peak allocation, using the demands during the peak months," would be appropriate for allocation of generation. Note, Staff's allocation of generation relies on the coincident peak allocators of the peak month for each of the four MISO seasons.

existence of the integrated energy markets and the billing of MISO transmission charges on the basis of load and 12 monthly peak usage.[28]

Q. Has the seasonal energy need been a subject of consequence in recent CCNs?

A. Yes. Although it is not yet constructed, Ameren Missouri included the following testimony in its application for a CCN for Castle Bluff simple cycle gas unit:

> Q. As discussed in Mr. Michels' testimony, the primary need for the Castle Bluff project is to address extreme winter weather events. But will it also be utilized in the MISO PRA?
>
> A. Yes, the Project will be a capacity resource that will be utilized in future PRAs. The Project will consist of four units, with a winter nameplate capacity rating of 204 megawatts each, for a total of 816 megawatts. Applying a winter class average unforced capacity percentage of 10.53%, produced by MISO for the 2024-25 PRA, the Project would have an accredited capacity of 730 megawatts that would count toward the PRMR.
>
> Q. The MISO PRA for 2024-25 resulted in Zone 5 pricing separating from the rest of the MISO zones, with noticeably higher clearing prices for Fall 2024 and Spring 2025. Will the Project help to solve the issues causing Zone 5 prices to spike?
>
> A. Yes, with the Project being located at the site of the former Meramec Energy Center, it will physically reside in Zone 5. As such, the Project will contribute to satisfying the LCR for the zone.
>
> Q. Why did Zone 5 prices separate to the high side in the 2024-25 PRA?
>
> A. In the 2024-25 PRA, Zone 5 failed to satisfy its LCR in the Fall and Spring, missing the requirement by 872.3 and 196.4 Zonal Resource Credits ("ZRCs"), respectively. In similar fashion to how Castle Bluff will help the Company satisfy its full PRMR in the future, an ancillary benefit of the Project will be its significant contribution to allowing Zone 5 to meet its LCR requirements.[29]

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[28] Incurence of transmission infrastructure is increasingly determined by regional loads and regional planning, not Ameren-Missouri's specific transmission requirements. Per the testimony of Ms. York on behalf of MIEC in her direct testimony at page 6, "As explained by Company witness Mr. Hickman, a 12 CP allocation of transmission costs is consistent with the way AMO incurs transmission costs from MISO. Thus, I am not opposed to the Company's allocation of transmission costs. However, given the system load characteristics discussed above, it could be reasonable to allocate transmission costs on a 4 CP basis."
[29] Andrew Meyer direct page 13 in EA-2024-0237

Q. What peaks are relevant to Ameren Missouri's resource requirements?

A. The most relevant peaks to consider would be Ameren Missouri's load net of distribution-level generation at the hour of MISO system peak in each of the four MISO Planning Resource Auction ("PRA") seasons, Winter, Spring, Summer, and Fall. Because of the difficulty of normalizing the MISO load as a whole, it would also be reasonable to consider the Ameren Missouri peak load at the time of retail peak in each of those four seasons, or related similar approaches.

Q. Did Ameren Missouri or any of the derivative studies rely on the Ameren Missouri coincident peak in each of the relevant seasons for purposes of capacity allocation?

A. No. Ameren Missouri relied on the four highest NCP for each studied class regardless of the month in which each peak occurred. With the exception of the lighting class, those peaks occurred in June, July, August, September, and January. MECG slightly modified this approach by relying on the NCP in each of the four months with the highest system demand, which were June, July, August, and January, in the load information that it used.

Q. Is use of the A&E allocator consistent with the existence of the MISO resource adequacy construct?

A. No. The A&E allocator requires use of an NCP; however, the MISO resource adequacy construct requires use of a CP.

Q. Do Ameren Missouri's capital costs of owning production facilities vary directly with energy consumed?

A. No.

Q. Does Ameren Missouri's cost of owning production facilities and maintaining resource adequacy vary due to annual energy usage?

A. Yes. Ameren Missouri's participation in the resource adequacy auction and market imbues variability to the expenses and revenues of generation ownership and serving load. If Ameren Missouri is long there is money to be made, and if Ameren Missouri is short there will be additional expense incurred. Old worldviews of strictly "fixed" and "variable" which were handy shorthand for complex concepts have become largely irrelevant to modern utility cost causation.

Non-Coincident Peak Selection

Q. Are customers in the LGS and SPS classes the same?

A. No. LGS customers rely on secondary distribution infrastructure, while SPS customers do not.

Q. How did Ameren Missouri combine the NCPs of these classes for purposes of the A&E calculation?

A. Ameren Missouri chose to add the hourly loads of these two classes together prior to finding NCPs for the combined classes, rather than to consistently find the NCPs for each class, calculate the A&E allocator, and then sum the allocators for ease of study presentation. This approach unreasonably reduces the allocation that is due to these classes under the A&E allocator. The parties to Ameren Missouri cases typically recommend that the same interclass revenue responsibility result be applied to these classes, because customers can make changes to move between the classes; however, that does not justify combining the class determinants to shift cost allocation away from the combined class.[30]

[30] MECG repeated this approach in its derivative study.

Q. Have you calculated a corrected allocator addressing the order of summation of class loads?

A. Yes. The corrected allocator is provided below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri A&E	51.0342%	11.2612%	29.5604%	7.8533%	0.2909%
Ameren Missouri A&E with Corrected LGS/SPS summation	50.7162%	11.1985%	29.8069%	7.8392%	0.4392%

Q. Have you calculated the Ameren Missouri study results with this correction?

A. Yes.

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for LGS/SPS allocator summation	6.76%	-2.28%	-8.53%	-13.12%	21.45%

Q. Have you calculated the Ameren Missouri study results with correction of the A&E allocator for summation of LGS and SPS class demands and with allocation of renewable resources on the basis of energy?

A. Yes. The calculation of the weighted capacity allocator is set out below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Corrected A&E Capacity Allocator	50.72%	11.20%	29.81%	7.84%	0.44%
Ameren Energy Allocator	43.15%	10.52%	34.73%	11.28%	0.32%

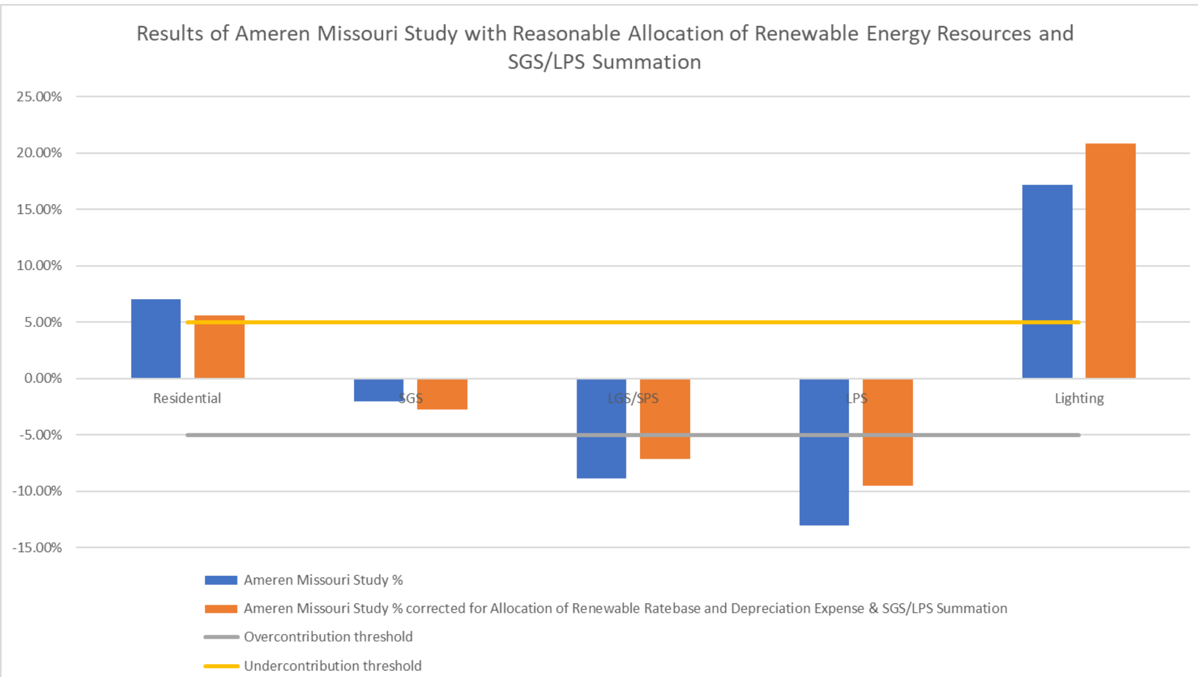
Production Ratebase	Residential	SGS	LGS/SPS	LPS	Lighting
Allocate with Ameren Capacity Allocator	$ 2,378,543,104	$ 525,199,344	$ 1,397,916,178	$ 367,651,265	$ 20,598,076
Allocate with Ameren Energy Allocator	$ 953,813,216	$ 232,558,109	$ 767,803,978	$ 249,327,465	$ 7,145,274
	$ 3,332,356,320	$ 757,757,453	$ 2,165,720,156	$ 616,978,730	$ 27,743,350
Weighted Ratebase Allocator	48.29%	10.98%	31.38%	8.94%	0.40%

Production Depreciation Expense	Residential	SGS	LGS/SPS	LPS	Lighting
Allocate with Ameren Capacity Allocator	$ 158,252,238	$ 34,943,227	$ 93,007,927	$ 24,461,039	$ 1,370,457
Allocate with Ameren Energy Allocator	$ 38,457,511	$ 9,376,685	$ 30,957,665	$ 10,052,821	$ 288,096
	$ 196,709,749	$ 44,319,912	$ 123,965,592	$ 34,513,860	$ 1,658,553
Weighted Depr. Expense Allocator	49.03%	11.05%	30.90%	8.60%	0.41%

	Residential	SGS	LGS/SPS	LPS	Lighting
Weighted Ratebase Allocator	48.29%	10.98%	31.38%	8.94%	0.40%
Weighted Depreciation Expense Allocator	49.03%	11.05%	30.90%	8.60%	0.41%

The resultant CCoS study results are set out below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for Allocation of Renewable Ratebase and Depreciation Expense & SGS/LPS Summation	5.56%	-2.75%	-7.17%	-9.51%	20.81%



Q. Could you clarify the modifications made to the Ameren Missouri CCoS study to produce the results immediately above?

A. Yes. The results immediately above reflect the Ameren Missouri CCoS study modified only:

1. To correct the use of Allocator 35,
2. To correct the summation of the A&E allocator calculation for the LGS and SPS classes, and
3. To allocate renewable resource capital costs and depreciation expense on the basis of class energy requirements, consistent with RES requirements and allocation of the revenue from sales of energy from these resources.

Distribution Allocation

Q. In its Report and Order in ER-2022-0337 at page 23, the Commission included the following in its Decision:

> The Commission finds none of the parties' CCOSSs suitable for setting rates that are just and reasonable in this rate case. The Commission finds Staff's concerns about Ameren Missouri's CCOSS credible. The Commission finds Staff's CCOSS insufficient for allocating class revenue responsibilities because Staff was unable to obtain the necessary information to complete more than an interim step toward its goal of rate modernization. MECG and MEIC's modifications to Ameren Missouri's CCOSS do not address the underlying problems with the CCOSS they modify.

The concerns the Commission had discussed throughout the order were:

1. "The 4NCP method does not include any considerations for renewable generation plant characteristics that are different from baseload generation. The 4NCP method also does not include any consideration for use of advanced metering infrastructure (AMI) data that can differentiate between class energy consumption during hours of the day."[31]
2. "Staff argues that the Average and Excess allocator is less reasonable for allocation of the revenue requirement associated with Ameren Missouri's production plant included in rate base since MISO's integrated marketplace was introduced. This is largely because Ameren Missouri's fuel costs vary with the demand for energy in a given hour of the regional load, and do not vary with the Ameren Missouri load relied on in Ameren Missouri's Average and Excess allocator analysis."[32]
3. "The 1992 NARUC manual, when addressing embedded cost of service studies like Ameren Missouri's minimum distribution study, states that classifying distribution plant using the minimum-size method "assumes that a minimum size distribution can be built to serve the minimum loading requirements of the customer." Ameren Missouri has approximately 648 primary voltage customers. Ameren Missouri's minimum distribution study for plant accounts 364-368 uses components that operate at primary voltages, but most of Ameren Missouri's customers take service at secondary voltage. So, Ameren Missouri's minimum size study is oversized for a majority of Ameren Missouri's customers."[33]

Did Ameren Missouri modify its minimum size study in the current case to address the Commission's decision that the study is "oversized for a majority of Ameren Missouri's customers?"

[31] Report and Order at page 14
[32] Report and Order at page 16
[33] Report and Order pages 15-16

A. No. Ameren Missouri continues to rely on a study of the primary distribution system. Further, as noted in my direct testimony in this case, the Ameren Missouri CCoS study does not yet incorporate assignment or allocation of customer-specific infrastructure or the other items ordered by the Commission at pages 48 and 49 of the Report and Order.

Q. Given these shortcomings, what view should be taken of Ameren Missouri and derivative CCoS study results?

A. The Ameren Missouri and derivative CCoS study results are not reliable for rate design purposes, and the results skew allocations toward the Residential and SGS classes, and away from the SPS and LPS classes. It is difficult to estimate the net directional impact on the LGS and Lighting classes.

Q. Have you attempted to correct these errors in the Ameren Missouri study?

A. No. Doing so would effectively duplicate the Staff study. I do discuss more basic errors in the Ameren Missouri and derivative studies.

Ameren Missouri Underground Classifier Error

Q. In response to the CCM Data Request ("DR") 7, Ameren Missouri identified a formula error in one of its CCoS input workpapers related to the customer-allocated portion of accounts 367 - Underground Conductors and Devices, and 366 – Underground Conduit. The corrected workpaper indicates a classifier of 27.1708% versus the classifier underlying the direct-filed Ameren study of 27.4004%. Did Ameren Missouri provide a study workpaper with the corrected classifier?

A. I cannot find that Ameren Missouri provided a corrected study workpaper. As noted by CCM witness Palmer, the Ameren Missouri CCoS study workpaper is difficult for a non-Ameren witness to operate. Staff understands that this is due to internal macros that calculate internal allocators. This is a common complication to CCoS study workpapers, but this complication was compounded by Ameren Missouri's decision to utilize the allocation of labor expense as an allocator of plant. Staff has duplicated the Ameren Missouri CCoS study in a new workpaper to model the impact of the corrected distribution classifier among other things.

Q. Were there other apparent errors in the Ameren Missouri study related to this classifier?

A. Yes. Ameren Missouri classified 29.299% of underground line expense as customer-allocated, rather than either the 27.4004% value in the original workpaper, or the 27.1708% value in the corrected workpaper.[34] Correcting the classifiers for Underground Line expenses, and the plant and reserves for Accounts 366 and 367 to 27.1708% produces the results indicated below:

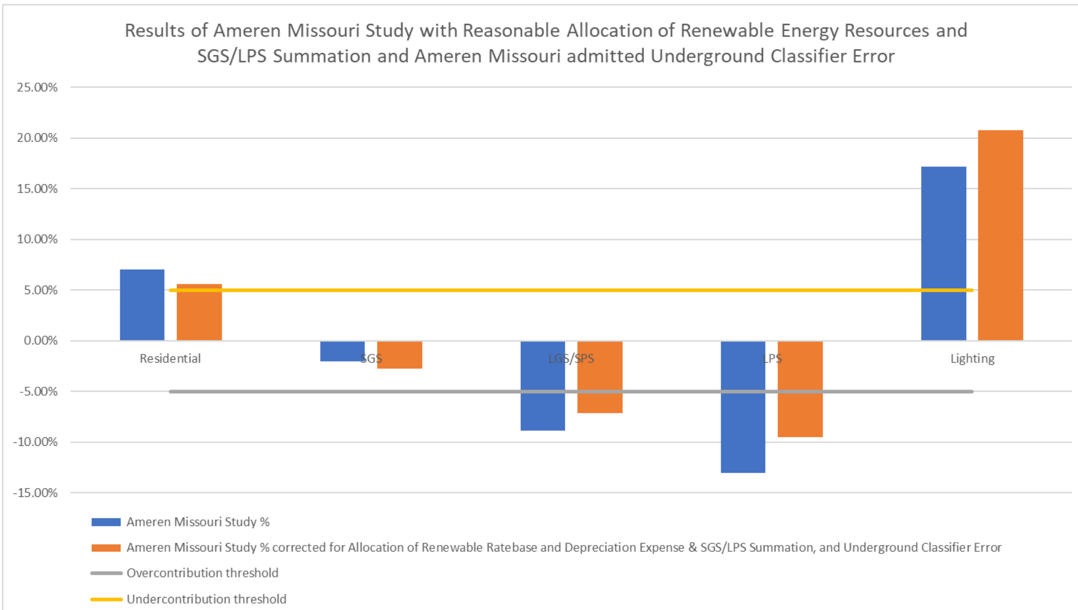
	Residential	SGS	LGS/SPS	LPS	Lighting
Increase $	$ 103,239	$ (8,406)	$ (74,227)	$ (27,725)	$ 7,119
Increase %	7.08%	-2.54%	-8.88%	-12.62%	16.90%
Increase $	$ 103,366	$ (8,412)	$ (74,368)	$ (27,737)	$ 7,150
Increase %	7.09%	-2.54%	-8.90%	-12.62%	16.97%
	$ 127	$ (6)	$ (140)	$ (12)	$ 31

Q. Did you calculate the results of this correction to the study in addition to the distribution study results you discussed above?

A. Yes.

[34] The derivation of this second error is not clear. It could be that Ameren Missouri failed to update a classifier from a prior draft study, or that Ameren Missouri unreasonably included services plant in the calculation of the expense allocator. Because secondary customers are responsible for the maintenance and repair of their own service lines, it would not be reasonable to include service lines in expense allocations, if that is the derivation of this second error related to distribution classification.

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for Allocation of Renewable Ratebase and Depreciation Expense & SGS/LPS Summation, and Underground Classifier	5.55%	-2.75%	-7.15%	-9.50%	20.73%



Handy Whitman

Q. Did Mr. Hickman base his minimum system study on the embedded costs of recorded assets?

A. No. Without explanation, Mr. Hickman chose to adjust the asset costs recorded to the Ameren Missouri continuing property record using the Handy Whitman index, which is an index to relate costs incurred in one year to costs incurred in other years.

Q. Is this reasonable in the context of embedded cost of service ratemaking?

A. No. This index may be used to estimate marginal costs, but it is not appropriate when reviewing embedded costs, and it is not appropriate in finding the hypothetical minimum size system costs for various accounts. Based on Staff's analysis of only the poles account, this artificially inflated the minimum size by 5.15%. I would expect similar results on other accounts.

Production in distribution and Taps Accounts

Q. Did Mr. Hickman account for the presence of distribution-voltage generation in the distribution accounts in allocating distribution plant?

A. No.

Q. Does Mr. Hickman acknowledge that the overhead distribution accounts include infrastructure that is functionally transmission or that is dedicated to specific high voltage customers?

A. Yes.[35] However, he did not allocate this plant accordingly, and the manner through which the Ameren CCoS Study incorporates the minimum system study results (as a percentage as opposed to a dollar value) resulted in 67.8421% of the Poles account and 48.806% of this high voltage infrastructure being allocated to the classes on the basis of customer counts, which is fundamentally unreasonable.

Reasonableness of Ameren Missouri Minimum System Study

Q. Is the Ameren Missouri minimum system classification and further allocations reasonably performed and consistent with the National Association of Regulated Utility Commission ("NARUC")?

A. No. Ameren Missouri chose to perform what it describes as a minimum distribution system study. However, the approach Ameren Missouri has taken is not consistent with the rationale underpinning a minimum distribution system study.

Q. What is the rationale underpinning a minimum distribution system study?

[35] Information provided in response to DR 0600.

A. At pages 90-91, regarding embedded cost of service studies, the NARUC manual states:

> Classifying distribution plant with the minimum-size method **assumes that a minimum size distribution can be *built to serve the minimum loading requirements of the customer*.** The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). **[Emphasis added.]**

Q. In what ways was Ameren Missouri's distribution classification and allocations inconsistent with the NARUC Manual or otherwise unreasonable?[36]

A. Several:

1. Ameren Missouri chose to rely on a classification method that is inherently inconsistent with its current design and booking of its distribution system.
2. Ameren Missouri did not perform its minimum distribution system study consistent with NARUC's guidance.
    a. Ameren Missouri classifies devices as customer-related.
    b. Ameren Missouri failed to account for the demand-serving capability of the selected "minimum"-size infrastructure.
3. Ameren Missouri failed to identify or allocate customer-specific substations and other infrastructure.
4. Ameren Missouri did not adjust its approach to account for these shortcomings, such as by netting customer-allocated values from its voltage-classified amounts, or weighting customer counts by demand or by limiting customer counts to network endpoints.

Q. How is the minimum-size classification method inherently inconsistent with the current design and booking of Ameren Missouri's distribution system?

[36] There may be reasonable deviation from the NARUC Manual, particularly in areas where there have been changes in cost causation or regulatory framework over the last 30 years.

A. The minimum-size classification method inherently assumes that each account contains infrastructure that is sized to serve the smallest customers at the lowest loads possible. Most Ameren Missouri customers take service at secondary voltage, at 120 or 240 volts, with a demand of 20 kW or less.

At page 95 of the NARUC Manual:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.
>
> When allocating distribution costs determined by the minimum-size method, some cost analysists will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Discussion of a marginal cost study at page 138 of the NARUC Manual provides further context for these issues:

> The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a **hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW)**, yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics. **[Emphasis added.]**

When applying this approach, it is necessary to take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by the company or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand.

Q. Does Ameren Missouri currently own or operate a networked overhead secondary distribution system?

A. Essentially, no. By Ameren Missouri's own admission less than 3% of the assets recorded to the overhead conductors and device Account 365 operate at secondary voltage.[37] Secondary voltage components are largely recorded in the services accounts.

Q. Please describe Ameren Missouri's "minimum" distribution system, as studied by Mr. Hickman.

A. Ameren Missouri's minimum distribution system relied upon by Mr. Hickman for classification of Accounts 364-368 operates at primary voltage.

Q. What guidance is included in NARUC for classifying devices recorded in Accounts 365 and 367 as customer related under a minimum-size study?

A. Page 91 the NARUC Manual provides the methodologies for determining the minimum size of distribution plant for use in calculating the customer-classified portion of the minimum-size method. The entirety of the entries for Accounts 365 and 367 are set out below:

> 2. Account 365 – Overhead Conductors and Devices
>
> - Determine minimum size conductor currently being installed.
>
> - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. **Balance of plant account is demand component.** (Note: two conductors in minimum system.)
>
> 3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices
>
> - Determine minimum size cable currently being installed.
>
> - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, based on ratio of cable account.

[37] "A.F. Dist Study" tab of Hickman CCoS Study workpaper.

> - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. **Balance of plant account is demand component. [Emphasis added.]**

Significant context can be established from the discussion of applications of the minimum-intercept method, using the text quoted below from pages 93-94:

> 2. Account 365 – Overhead Conductors and Devices
>
> - **If accounts are divided between primary and secondary voltages**, develop a customer component separately for each. The total investment assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.
>
> - **When developing the customer component, consider only the investment in conductors, and not in devices such as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component,** based on the conductor assignment.
>
> > - Determine the feet, investment and average installed book cost per foot for distribution conductors by size and type.
> >
> > - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
> >
> > - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)
> >
> > - Balance of conductor investment is assigned to demand.
> >
> > - **Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor ratio.**
>
> 3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices
>
> > - The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

> - The conductor sizes and types for the customer component derivation are restricted to I/c able. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
>
> - Determine the feet, investment and average installed book cost per foot for I/c cables by size and type of cable.
>
> - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
>
> - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
>
> - Balance of cable investment is assigned to demand.
>
> - Total dollars in Account 366 and 367 are assigned to customer and demand components based on conductor investment ratio. **[Emphasis added.]**

While there is discussion of the classification of devices in Account 365 pursuant to the minimum intercept method, under the discussion of Account 365 classification using the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 365 are classified as demand-related. This is in contrast to the decision of Ameren Missouri to classify $594,445,713 of plant related to lightening arrestors, switches, and reclosers, as "customer-related".[38]

For the underground accounts under the minimum intercept method, not all devices are classified as demand-related, however they are neither classified as customer-related, rather, they are reflected on the ratio of minimum-intercept dollars associated with cables to total cable dollars in Account 366. Again, in contrast in the description of the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component,"

[38] This language also clarifies that Account 365 (Overhead Conductors and Devices) is assumed to include both primary and secondary voltage infrastructure. Concerning the underground accounts, there is again clarity that the accounts are assumed to include both primary and secondary conductors, although the Ameren Missouri selected "minimum" conductor for each is a primary voltage conductor which is oversized for secondary purposes.

unequivocally stating that all devices in Account 366 are classified as demand-related. For the minimum size method, the ratio of minimum-size cable dollars in Account 366 to total dollars in Account 366 that is the basis for the classification of Account 367 dollars.

Q. How did Ameren Missouri fail to account for the demand-serving capability of the selected "minimum"-size infrastructure?

A. Not only did Ameren Missouri improperly scale its voltage classification when classifying customer costs (discussed and addressed below), but Ameren Missouri also failed to follow the guidance provided at page 95 of the NARUC Manual:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.**
>
> When allocating distribution costs determined by the minimum-size method, some cost analysis will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those **customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs**.
>
> Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus the customer cost of a particular piece of equipment has no demand cost in it whatsoever. **[Emphasis added.]**

Q. Did Ameren Missouri identify or allocate customer-specific substations and other infrastructure consistent with NARUC guidance?

A. No. At pages 90-91, regarding embedded cost of service studies, the NARUC manual states:

> Classifying distribution plant with the minimum-size method **assumes that a minimum size distribution can be *built to serve the minimum loading requirements of the customer*.** The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). **[Emphasis added.]**

Discussing marginal costs studies, the minimum-size method, at page 136 the NARUC manual states:

> Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, **for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them. As noted above in "Transmission," distribution costs of equipment dedicated to individual customers can be directly assigned to them, thus reducing the common distribution costs assignable to the remainder of the class. [Emphasis added.]**

The portion of the discussion quoted above informs this language, found at page 87 of the NARUC Manual:

> Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

Q. Did Ameren Missouri make any attempt to identify or allocate customer-specific substations and other infrastructure?

A. No.

Q. Does this deviation from reasonable classification of the distribution system impact only CCoS?

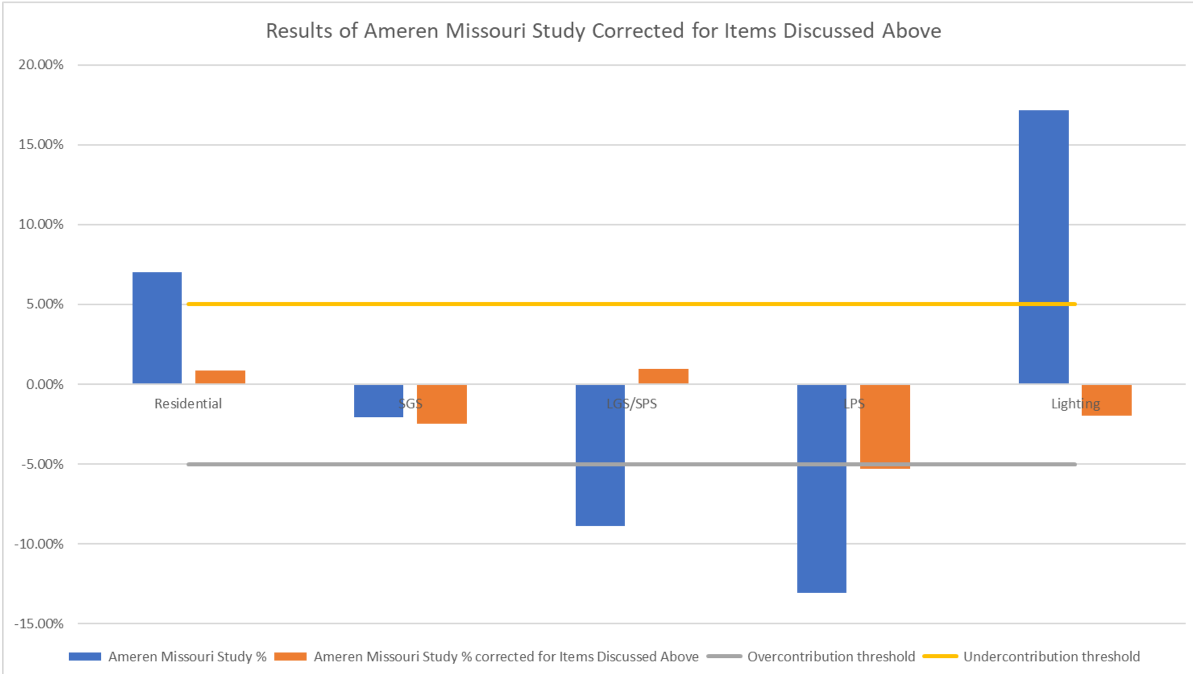
A. No. Due to this critical failure, the Ameren Missouri study is not reliable for valuing reasonable credits under Rider B, nor for reliance on estimating the revenue to be reasonably collected from various elements of classes' rate structures.

Adjusted Ameren Missouri Study Results

Q. CCM witness Palmer discussed an inability to apply her basic customer classification to the Ameren Missouri CCoS study. Can you provide the results of the Ameren study with the modifications you discussed to production allocation and with a basic customer classification of accounts 364-368?

A Yes.

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for Items Discussed Above	0.86%	-2.45%	0.95%	-5.29%	-1.98%



Q. What do these results indicate?

A. These results indicate that a small revenue responsibility reallocation between LPS and Lighting could be reasonable, however these results should be tempered by the known shortcoming regarding customer-specific infrastructure allocation, the failure to reflect wholesale energy prices for class loads, and the use of the A&E allocator which is not consistent with the realities of modern resource planning. Each of these factors would tend to under-allocate costs to the LPS class, and over-allocate costs to the Lighting class.

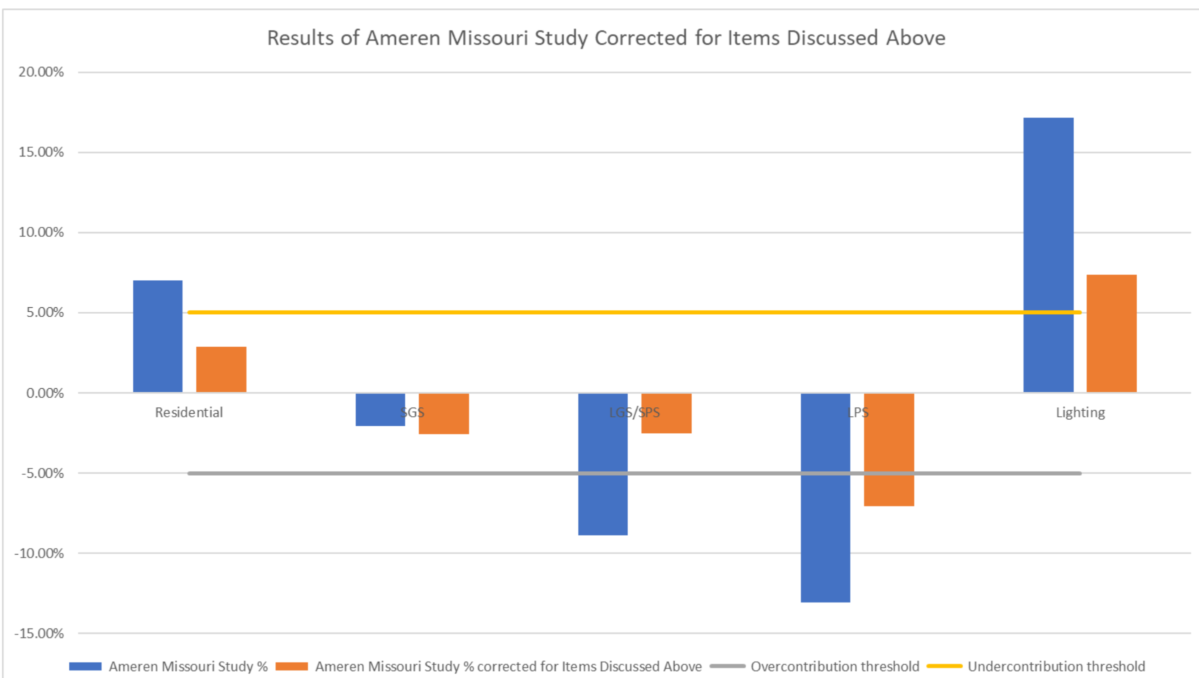
Q. Is use of this approach reasonable?

A. In this case, given the ongoing development of improved distribution allocation studies, this approach can be taken as something of a surrogate for a well-conducted study that is reflective of either (1) zero-intercept for all account or (2) minimum size system with appropriate minimum-selection and consideration given to the load-carrying abilities of the minimum unit selected, where adjustments have been made for customer specific infrastructure, the Taps accounts, and the other major flaws in the company study. In other words, with regard to this case – Ms. Palmer's approach is no less reasonable that than taken by Mr. Hickman, and the actual result probably lies somewhere in the middle.

Q. Can you provide the corrected Ameren Missouri study results using the Customer-classifications discussed in the Staff CCoS direct for accounts 364-368?

A. Generally, however it would be very difficult to incorporate the concerns with the Taps accounts or the inclusion of production plant in the distribution accounts. Also, recall that I was unable to address the level of customer specific infrastructure at this time due to the data availability issues ordered to be addressed in the last Ameren Missouri rate case.

	Residential	SGS	LGS/SPS	LPS	Lighting
Ameren Missouri Study %	7.03%	-2.05%	-8.89%	-13.04%	17.14%
Ameren Missouri Study % corrected for Items Discussed Above	2.87%	-2.59%	-2.49%	-7.08%	7.34%



Q. What do these results indicate?

A. These results indicate that a small revenue responsibility reallocation between LPS and Lighting could be reasonable, however these results should be tempered by the known shortcoming regarding customer-specific infrastructure allocation, the failure to reflect wholesale energy prices for class loads, and the use of the A&E allocator which is not consistent with the realities of modern resource planning. Each of these factors would tend to under-allocate costs to the LPS class, and over-allocate costs to the Lighting class.

Q. What impact on the above results occurs if the MECG wind revenue is incorporated?

A. Incorporating additional wind revenue would reduce the revenue requirements of all classes, reducing the indicated under-contributions, and increasing the indicated over-contributions.

Other Allocators and Issues

Allocator 35

Q. What is Allocation Factor 35?

A. Allocation Factor 35 is "PRODUCTION, T&D, & CUSTOMER EXP." This is a multilevel internally calculated allocator in the Ameren Missouri CCoS. It is calculated by dividing each class's allocated labor expenses related to production, transmission, distribution, and other accounts.

Q. How is Allocation Factor 35 used?

A. Allocation Factor 35 is used to directly allocate $2,249,551,000 of gross rate base ($1,367,478,000 of net rate base), the depreciation expense associated with this plant, 45%

of $611,655,000 related to PISA, and it is also used to directly allocate $357,435,000 in expense.

Q. If you correct or otherwise modify any allocation of production, transmission, or distribution plant allocation, does Allocation Factor 35 change?

A. It should, if macros internal to the Ameren Missouri spreadsheet update correctly. However, if someone not running the spreadsheet from an Ameren Missouri computer system updates an allocator, as Ms. Palmer would have done, manual updating of Allocator 35 and other allocators is necessary to fully implement those changes.

Q. Is it reasonable to use an allocator based on composite labor expenses as opposed to composite net rate base for allocation of general plant, intangible plant, and the capital components of over-collected amortizations?

A. No. It is not reasonable to use a composite expense allocator to allocate rate base. If the decision is made to allocate general plant and similar items using already allocated class responsibilities, it is much less unreasonable to use the allocation of net plant for those items, not the allocation of labor expense. Ameren Missouri also uses Allocator 35 for allocation of $77,663,000 of offsets to ratebase related to pensions and OPEBS. For this limited rate base account, use of a composite labor allocator is not blatantly unreasonable.

Q. Is it reasonable to use an allocator based on composite labor expenses for allocation of a significant portion of PISA ratebase?

A. No. There is no relationship between $15,093,372 of PISA rate base related to General Plant, and labor expenses.

Q. Is it reasonable to use an allocator based on composite labor expenses for allocation of $286,516,000 in non-labor expense?

A. Generally, no. This allocator is used for General Plant depreciation expense, miscellaneous "other", expense, and for payroll taxes. Use for payroll taxes is reasonable. Use for general plant depreciation expense is unreasonable as discussed. Use for "other," is inherently unreasonable, as the non-labor allocation of allocated expenses is more appropriate than the labor-related allocation of allocated expenses.

Q. Are there other allocator choices in the Ameren Missouri study that appear to be mistakes or inadvertent?

A. Yes. While Staff disagrees with many allocator choices, the following items are presumably mistakes and not intentional choices by Ameren Missouri

1. Allocation of Transmission 26A – labeled as allocated with allocator 3, formula actually pulls to allocator 11. Staff does not disagree with allocation using energy, but the allocator is labeled wrong for anyone reviewing the file.
2. AF 29 is indicated for allocation of direct lighting plant, but the formula does not use that allocator Staff does not disagree with the direct assignment, but the allocator is labeled wrong for anyone reviewing the file.
3. AF 31 is an internal allocator, and if classifies all lighting as demand-related, which is not reasonable and over-allocates to lighting.

Causation of PISA Revenue Requirement

Q. What is the causation of PISA balances and amortizations?

A. The causation of these amounts in the Ameren Missouri revenue requirement are Missouri statutes and Ameren Missouri management decisions.

Q. Is Ameren Missouri's allocation of the PISA amounts reasonable?

A. No. Even if it were reasonable to allocate the PISA amounts on the basis of the allocation of the underlying plant, Ameren Missouri does not reflect the appropriate underlying plant. For example, a review of PISA projects indicates that distribution spend is not uniform, and are primarily if not exclusively related to infrastructure operating at voltages above secondary. However, the PISA distribution allocation relies on the plant allocation of all distribution plant, which includes Ameren Missouri's unreasonable minimum system approach, and includes all distribution plant balances including service lines, meters, and lighting.

Order of Operations

Q. At pages 27-29 Dr. Bowden sets out proposed order of operations for implementing a rate increase, do you agree with his recommendations?

A. Generally, yes. However, Dr. Bowden chose the following process regarding the revenues that a given class contributes for optional renewable programs,

> The allocation of Community Solar Generation is not prescribed by law but follows the same proportional to normal base rate revenues for one simple reason. The cost associated with the Community Solar assets are included in the overall revenue requirement and are therefore implicitly included in the base rates of all customers' classes. Therefore, it is just and reasonable to allocate the associated benefits, the offsetting Community Solar Generation revenue, proportionally to all classes.

It is more reasonable to follow Staff's approach wherein within the CCoS the revenue from the Solar Generation Rate under the Community Solar Program is removed from rate revenue and treated as other revenue offsetting the cost of corresponding generation assets. In many instances these approaches will produce parallel or near-parallel results at the level of such revenues which are included in this case, but differing results could occur depending on specific wording of a given Commission Report and Order. For this reason, Staff recommends the Commission explicitly specify the approach taken to this issue in the Report and Order, and recommends Staff's method be used.

<u>INTERCLASS REVENUE RESPONSIBILITY SHIFTS</u>

Q. Dr. Bowden at page 30 requests that the SPS and LPS classes receive a below average increase, and that the residential classes receive an above average increase. Are these results reasonable?

A. No. A study which reasonably allocates costs, expenses, and revenues does not support these shifts in revenue responsibility, and these shifts exacerbates the issues found by Staff's study. Further, given the general alignment of the LGS and SPS rate schedules, and the ability of customers to move between them, these rate schedules are typically adjusted evenly to avoid encouraging rate switching and cost-shifting between rate cases. As shown above, when basic errors in the Ameren Missouri and derivative studies are addressed, no changes to interclass revenue requirements are supported by the study.

Note, Staff's CCoS study indicates that shifts to the LGS/SPS and LPS classes are appropriate in this case. However, if the revenue requirement ultimately ordered by the Commission significantly differs in magnitude or composition from that studied by Staff, it would not be unreasonable to order an equal percent increase to all classes' revenue responsibilities.

Q. Mr. Brubaker relies on the "Change required in percentage" calculations from Ameren Missouri's CCoS studies[39] in his requested interclass revenue responsibility shift recommendation to "move each class one-third of the way toward its cost of service."[40] Does he adjust this recommendation for the revenue requirement recommendations of his employee, MIEC witness Walters who recommended a ROE of 9.50%, as opposed to the 10.25% which is the basis of the Ameren Missouri CCoS Study?[41]

A. No. Mr. Walters' recommended ROR is 7.1%, which he notes would reduce the Ameren Missouri revenue requirement by approximately $72.1 million. This revenue

[39] Brubaker direct Table 2, page 26.
[40] Brubaker direct, page 28.
[41] Ms. York, also on behalf of MIEC, testifies to 33% and 25% adjustments, or larger, at pages 10-14 of her direct testimony.

requirement reduction would primarily reduce the revenue requirements for classes which consume relatively less energy – Residential, SGS, and Lighting.

		Residential	SGS	LGS/SPS	LPS	Lighting
Ameren ROE Position	Increase $	$ 350,239	$ 42,439	$ 38,882	$ (1,566)	$ 16,204
MIEC ROE Positon	Increase $	$ 327,118	$ 37,677	$ 28,275	$ (4,017)	$ 15,356
Ameren ROE Position	Increase %	24.01%	12.84%	4.65%	-0.71%	38.46%
MIEC ROE Positon	Increase %	22.43%	11.40%	3.38%	-1.83%	36.45%
Ameren ROE Position	Brubaker Recommended Increase	$ 116,746	$ 14,146	$ 12,961	$ (522)	$ 5,401
MIEC ROE Positon	Brubaker Recommended Increase	$ 109,039	$ 12,559	$ 9,425	$ (1,339)	$ 5,119
	Difference (In Millions of Dollars)	$ 7,707	$ 1,588	$ 3,536	$ 817	$ 283
	Difference (In % of Class Revenues)	0.53%	0.48%	0.42%	0.37%	0.67%

Q. If the Commission orders approximately half of Ameren Missouri's requested increase, what does us tell us about Ameren Missouri's CCoS Study results?

A. It tells us that the Commission-determined revenue requirement is significantly different than the revenue requirement that underlies the recommendations of the parties in this case.

Q. Ms. Maini modified the A&E allocator in the Ameren Missouri CCoS. Did she adjust the wind revenue calculation as recommended by her fellow MECG witness, Greg Meyer?

A. No, she excluded this adjustment, which would reduce the revenue requirements of all classes and the percentage increase indicated by her study results. Ms. Maini recommends a 25% revenue neutral shift based on either her derivative study results or the Ameren Missouri study results.[42]

MEEIA Interaction

Q. At pages 23-24 of his direct testimony, Mr. Brubaker testifies that "cost-based" rates will assist in the development of effective energy efficiency programs in that

[42] Maini direct, page 24.

> A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is based on an under-priced rate, the customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

Could you summarize the MEEIA budgets for Ameren Missouri's recently-approved MEEIA cycle 4 plan?

A. Yes. Budgets of up to $67.5 million were authorized for residential programs, and budgets of up to $57.5 million were authorized for business programs.[43]

Income Eligible	$	20,000,000
Residential	$	20,000,000
Residential Demand Response	$	27,500,000
Business	$	20,000,000
Business Demand Response	$	37,500,000

Q. What are those budgets on a per-customer basis?

A. The residential MEEIA budget works out to about $61.71 per residential customer. The business MEEIA budget works out to about $366.84 per commercial and industrial customer.

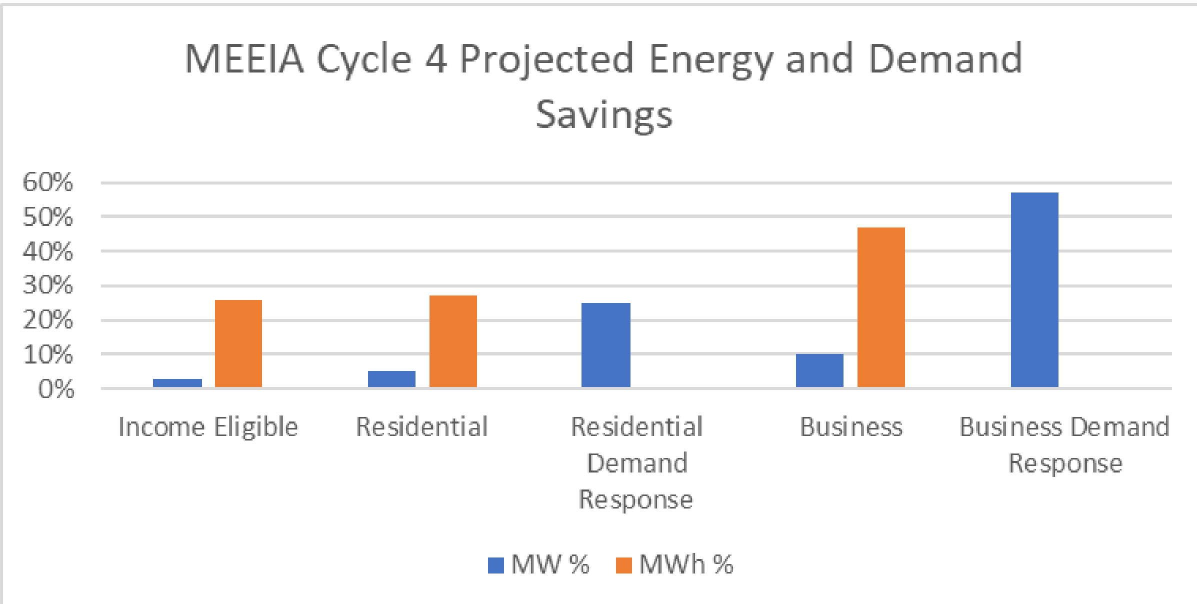
Q. Mr. Brubaker testifies that:

> This is a significant commitment of dollars and a large amount of the cost is for programs associated with residential customers. Cost-based rates for residential customers will provide higher rewards to customers who implement these programs. Failure to fully price the residential rates, and to reflect the cost of EE programs in the residential rate, will diminish the likelihood that these programs will be successful.[44]

Q. How does Mr. Brubaker's testimony reflect to the MW and MWh values attached to the MEEIA cycle 4 stipulation?

[43] See, Non-Unanimous Stipulation and Agreement Regarding the Implementation of Certain MEEIA 4 Programs through Plan Year 2027, Motion for Expedited Treatment, and Request for Variance, in file EO-2023-0136, at page 3.
[44] Brubaker direct page 24.

A. Over half of the projected MW savings (180 MW of 316 MW total) are projected to come from business demand response. Nearly half (60.753 MWh of 129,508 MWh total) are projected to come from business efficiency programs.



Q. Does this mean cost recovery should be unreasonably shifted to business customers to increase the likelihood that these programs will be successful?

A. No. However, the facts of Ameren Missouri's MEEIA plan are directly counter to the offer Mr. Brubaker is making, that higher residential rates will support MEEIA success.

Q. Do cost-based rates support energy efficiency?

A. Yes. However, the role of rate design in supporting customer reduction of energy usage is paramount. High demand charges and hours-use rate structures mute bill savings due to avoided energy consumption. Well-designed time-based rates that reasonably reflect the market cost of energy and appropriately-designed fixed charges support energy efficiency and participation in demand response programs. These considerations underlie the ongoing rate modernization work.

RATE DESIGN

Residential

Q. Does Staff support increasing the residential customer charge?

A. No. The Ameren Missouri study did not reasonably classify and allocate the costs that Ameren Missouri relies upon in its recommendation concerning the residential customer charge.

Non-Residential

Q. Would you restate Staff's position on non-residential rate design?

A. Yes. Ameren Missouri, Staff, and other stakeholders have taken part in discussions concerning rate modernization and cost causation. As noted in the "Notice Regarding Status of Issues" filed in ER-2022-0337 on June 14, 2024:

> Ameren Missouri and Staff have discussed how Ameren Missouri anticipates restructuring its non-residential rates by removing Rider B in a rate case subsequent to ER-2024-0319 and implementing charges within applicable rate classes to reflect the voltage of service received by customers. Ameren Missouri and Staff have further discussed how the end result of this restructuring would likely include discrete rate components for customers served at (1) transmission voltages, (2) subtransmission voltages, and (3) primary voltages. Given these discussions, Ameren Missouri and Staff agree that implementing such restructuring in a rate case subsequent to ER-2024-0319, with the goals of the restructuring to include alignment of revenue responsibility and cost causation while considering customer impacts in the timing and implementation of a restructuring, would reasonably address the Rider B sub-issue. which the Commission directed be addressed in the Commission's above-referenced Report and Order.

In light of these ongoing discussions and data acquisition process, Staff recommends that changes to rate structures and rate designs in this case be limited. Staff generally recommends equal percentage increases to each rate element within each rate class, as the information necessary to refine intraclass revenue allocations is not available at this time, and transition to modernized rate structures is anticipated. However, Staff recommends eliminating additional customer charges that are applicable to time-based rates.[45] Also, consistent with the last order and the pending study, Staff recommends that Rider B charges on Sheet 75 be held constant.

Q. Did any of the intervenor rate design recommendations include discussion or consideration of the wholesale cost of energy as a variable cost to be fully recovered through energy charges?

A. No. This was not addressed by any intervenor testimony, although it is the single largest expense incurred by the utility, it is purely variable, and it is directly variable with energy consumed.

Large Power Service ("LPS")

Q. At page 14 Ms. York testifies that:

> Based on the Company's CCOSS, the demand-related revenue requirement for Rate 11M would be about $170.3 million, but the Company's proposed rate design would only recover about $109.6 million through demand charges. Thus, AMO's proposed demand rates would under-recover demand-related costs by approximately $61 million, or 36%. As a result, it would be reasonable to increase the demand rates to be more in line with cost of service, and to apply a corresponding reduction to the energy rates.

Do you agree with this conclusion?

A. No, for several reasons. First, the Ameren Missouri study did not reasonably allocate production costs nor distribution costs. Secondly, the customer NCP – which is the determinant for the LPS demand charge – is not the determinant for MISO resource adequacy requirements nor even for stand-alone utility resource planning. Finally, ongoing productive

[45] Ameren Missouri also requests to eliminate these charges intended historically to recover the costs of additional metering infrastructure. With advanced metering, additional infrastructure is no longer required to support time-based rates.

work is occurring in rate modernization and changes to rate structures and rate design variation should be paused pending completion of that work.

Incidentally, this rate design change recommendation is counter to the testimony of Mr. Brubaker encouraging rate design as a tool to support deployment of energy efficiency and demand response programs.

Q. What is the MECG position on LPS demand charges?

A. Ms. Maini testifies in her direct testimony at page 28 that LPS rate design, "appropriately recovers a substantive portion from demand charges and is more functionally aligned with the COSS results. Given the current rate design charges, I do not oppose an equal percent increase to the demand, customer and energy charges."

Large General Service ("LGS") and Small Primary Service ("SPS")

Q. What is Ms. Maini's recommendation on behalf of MECG for the intraclass implementation of any increase ordered in this case?

A. Ms. Maini, on behalf of MECG, testifies that she is "concerned that the demand charges are relatively low, which results in substantive over recovery from energy charges and under recovery from the demand charges as compared to the COSS results. According to the unbundled COSS results, 79% of the costs for the LGS and SPS classes are demand related. However, under current rates, only 14% is recovered from demand charges and 84% of the revenue requirements are recovered from energy charges. This mismatch sends economically inefficient and faulty pricing signals."[46] She recommends:

[46] Maini direct, page 25, see also page 27.

1. Increase the customer charges, on and off peak adjusters as proposed by the Company.
2. Increase the summer and winter demand charges by 150%.
3. Increase energy charges to recover the remaining revenue requirement by an equal percentage.[47]

Q. Does Staff agree with this recommendation?

A. Staff does not agree with disproportionately increasing the demand charges (parts 2 and 3). The customer NCP on which demand charges are based is not a reasonable measure of a customer's causation of production, transmission, or distribution capacity. Work is underway in the rate modernization docket to better align cost causation with revenue recovery, and changes to rate design of this nature should wait until that work is completed to implement modernized rate structures.[48]

Electric Vehicle Charging Rates

Q. Mr. Austin, on behalf of MECG, requests that the Commission order Ameren Missouri to "create alternative optional LGS ("LGS-EV") and SP ("SP-EV") rates for EV charging customers with load sizes that would qualify to take service on LGS or SP rates,"[49] that eliminate the billing demand charge.[50] Is this concept consistent with Ms. Maini's testimony, also on behalf of MECG, that the demand charges in the LGS and SPS rate schedules are not sufficiently large. Her testimony is that she is "concerned that the demand charges are relatively low, which results in substantive over recovery from energy charges and under recovery from the demand charges as compared to the COSS results. According to the unbundled COSS results, 79% of the costs for the LGS and SPS classes are demand related. However, under current rates, only 14% is recovered from demand charges and 84% of the

[47] Maini Direct, pages 26 and 27.
[48] The time-based differential is discussed below.
[49] Austin Direct page 5.
[50] Austin Direct, page 7.

revenue requirements are recovered from energy charges. This mismatch sends economically inefficient and faulty pricing signals."[51]

A. No. These positions are fundamentally inconsistent, and both are oversimplified.

Q. Are the end-use rates proposed by Mr. Austin reasonable?

A. No. First, end-use rates are not reasonable and are unduly discriminatory and therefore unlawful. Second, hours-use rates are no longer appropriate with the advent of AMI metering and any EV rates which may be considered should be time-based. Third, the absence of any billing demand charge for a customer of the size and sophistication that these rates would apply to is fully unreasonable; and finally, progress is being made in the rate modernization docket and rates which are both cost-based and compatible with incenting/not disincenting efficient EV charging are the expected result.

Q. If implemented, what would the impact of this proposal be on the level of accretive earnings assumed to justify ratepayer funding of the Ameren Missouri Charge Ahead portfolio of subsidies to EV-charging customers?

A. This proposal would substantially reduce the accretive earnings assumed in justifying the Charge Ahead portfolio.

Q. Is this proposal cost-based?

A. No.

Q. Is it likely that any customer with a high demand and low load factor, such as welding shops, smelters, grain dryers, millers and other customers currently served on the SGS,

[51] Maini direct, page 25, see also page 27.

LGS, SPS, and LPS rate schedules would prefer to avoid the demand charges that Mr. Austin references?

A. Any customer with a low load factor or a high demand contributes more revenue per kWh than customers with a high load factor or a low demand under the current Ameren Missouri rate designs for these schedules. These customers may or may not cause more costs than one another.

Q. Is it reasonable to introduce specialty end-use rates?

A. No. The solution is not the creation of a multitude of specialty end-use rates, rather the solution is rate schedule modernization as described in my direct testimony, which would align cost causation with revenue responsibility based on the actual time of energy consumption and the level of infrastructure required for customers. With the full deployment of AMI meters, it is not reasonable to rely on assumptions about use patterns to develop rate structures around a given end-use. Rather, rate structures should reasonably align the cost causation of providing service to a customer with a given usage pattern with that customer's revenue responsibility, regardless of whether that energy is used to charge an electric vehicle battery, to run refrigeration units, to operate a computer server, or any other purpose.

Time-Based Differential

Q. At page 33, Dr. Bowden states that the company requests that the Commission order "Revenue neutral adjustments to time-of-day rate adjustments in the 3M, 4M, and 11M classes. These adjustments were motivated by the findings of a rate impact study conducted in the Company's NRRD working docket." Are the time-of-day adjustments proposed by Ameren Missouri optimal?

A. No. However, optimizing these adjustments is contingent on final ordered rate design. Given that the rate modernization path appears to be headed toward removing these adjustments in favor of significant changes to the overall rate structures of the non-residential classes, so long as the overall resulting rate design is not unreasonable, Staff is not opposed to use of Ameren Missouri's requested adjustments.

Q. Do you agree with these recommended changes?

A. I conditionally agree with these requested changes. The time-of-day rate adjustments must be considered in concert with related blocked energy charge to ensure that energy is not sold, on average, at a loss for a given time of day and season of the year. Staff has reviewed the results of the combination of blocked energy charges and time-of-day adjustments for the LGS and LPS and determined that these results are not unreasonable, however if adjustments to the blocked energy charges are not a uniform increase, it is possible that unreasonable results could occur from the proposed time-of-day adjustments.

RATE MODERNIZATION

Q. At page 28, Ms. Maini testifies, "I understand that non-residential rate design is being investigated in another docket as noted by Company witness Mr. Nicholas Bowden on page 32 of his direct testimony. I recommend that the Company provide a progress report as well as a timeline by when it intends to propose alternative or optional rate design proposals applicable to non- residential classes." Has MECG been included in this docket?

A. Yes.

Q. Are you opposed to Ameren Missouri providing a "progress report," and "timeline?"

A. Not necessarily, but I would also be concerned that time that could be used for actual work in the docket not be overly diverted to administrative concerns.

MISCELLANEOUS TARIFF CORRECTIONS

Q. Is Staff opposed to Mr. Harding's recommendations to address a typographical error on sheet 145.1, or to update the name of the rate plan on Sheet 158.3?

A. No.

CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service	)))	Case No. ER-2024-0319

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Rebuttal Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of January 2025.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin
Notary Public