Exhibit No.:	
Issue(s):	*Class Cost of Service and Rate Design*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2024-0319*
Date Testimony Prepared:	*December 17, 2024*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRIAL ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2024-0319

Jefferson City, Missouri
December 2024

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SARAH L.K. LANGE

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DIRECT TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a Ameren Missouri

CASE NO. ER-2024-0319

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. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission ("Commission") as an Economist for the Tariff/Rate Design Department, in the Industry Analysis Division.

Q. Please describe your educational and work background.

A. Please see Schedule SLKL-d1.

Q. What is the purpose of your direct testimony?

A. I will present the results of Staff's class cost of service ("CCoS") study, and provide Staff's recommended implementation of effectuating an increase of Ameren Missouri's currently tariffed rates to collect a total of $3,273,176,205 from its customers, an increase of $402,243,605 (14%) from its current retail revenues of $2,870,932,600.[1]

I will also provide a recommendation concerning the availability of highly-differentiated time-based rates for residential net metering customers, as ordered in the

[1] Staff's CCoS study is generally based on Staff's Accounting Schedules and supporting workpapers filed December 3, 2023. However, a minor error has come to Staff's attention. An estimate of the correction of this error is that at a rate of return of 7.09%, Staff recommends an increase of $402,243,605 to the current retail revenues of approximately $2,870,932,600, an increase of approximately 14%.

Commission's May 15, 2024, Report and Order ("R&O") in File No. ET-2024-0182, at pages 24 – 25.

Q. Could you provide a summary of the results of the CCoS Study and recommended interclass revenue responsibility?

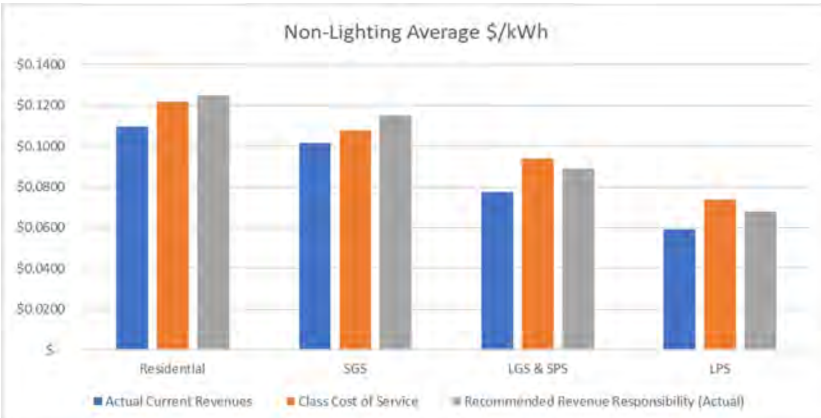
A. Yes. As shown in Table 1, the Large General Service ("LGS"), Small Primary Service ("SPS"), and Large Primary Service ("LPS") classes are under-contributing to the total company cost of service while the Lighting, Small General Service ("SGS"), and Residential classes are overcontributing to the current system average return, with the Lighting class overcontributing to the full cost of service. Staff recommends reallocating a portion of revenue responsibility from the SGS and Lighting classes to the LGS, SPS, and LPS classes, such that the LGS and Lighting customers would receive a below system-average increase and the LGS, SPS, and LPS customers would receive an above system-average increase.[2]

Table 1

	Residential	SGS	LGS & SPS	LPS	Lighting	System Average/
Actual Current Revenues	$ 1,447,291,019	$ 329,249,326	$ 830,584,205	$ 220,665,241	$ 41,999,473	$ 2,869,789,264
Current Revenues for Study	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419	$ 2,869,789,264
Class Cost of Service	$ 1,610,709,058	$ 348,737,574	$ 1,005,765,051	$ 274,973,400	$ 31,847,787	$ 3,272,032,870
Study Difference ($)	$ 168,554,375	$ 20,656,732	$ 175,119,820	$ 47,915,312	$ (10,002,633)	$ 402,243,606
Difference as % of Studied Rev.	11.69%	6.30%	21.08%	21.10%	-23.90%	14.02%
Return Provided on Allocated Ratebase (Study revenues)	**4.67%**	**5.66%**	**2.78%**	**2.37%**	**13.33%**	**4.15%**
Under/Over Contribution %	**2.55%**	**6.69%**	**-6.67%**	**-7.94%**	**35.16%**	**0.00%**
Interclass Revenue	$ -	$ (2,772,909)	$ 4,896,511	$ 1,338,468	$ (3,462,070)	$ -
Recommended Revenue	$ 1,644,294,090	$ 371,293,339	$ 951,969,013	$ 260,222,121	$ 44,254,308	$ 3,272,032,870
% Increase (Actual)	13.97%	13.12%	14.61%	15.03%	5.72%	14.02%
% Increase (Studied)	14.02%	13.17%	14.61%	14.61%	5.74%	14.02%

[2] At a class level, studied revenues vary from current revenues due to the reallocation of the benefit of the Economic Development Incentive from the LGS, SPS, and LPS classes to all classes proportionate to class revenue. Additionally, the revenues depicted in Table 1 include an adjustment related to treatment of Community Solar revenues.

The graphs below illustrate the current revenue, class cost of service results, and recommended revenue responsibility, on an average $/kWh basis:[3]



Q. Could you summarize your rate design recommendations in this case?

A. In light of the on-going rate modernization process, Staff recommends that increases in revenue responsibility be applied as an equal percentage adjustment to all rate elements within each class,[4] with the following exceptions.

- No changes to the current residential customer charge of $9.00,
- Staff does not recommend any changes be made at this time to Rider B rates.
- Remove additional metering charges for time-differentiated options on non-residential rate schedules,
- Staff also recommends updating residential tariff language in general to reflect the completion of AMI metering roll-out and the status of the Evening-Morning Savers rate plan as the default residential rate plan.

Q. Could you summarize the composition of Ameren Missouri's cost of service?

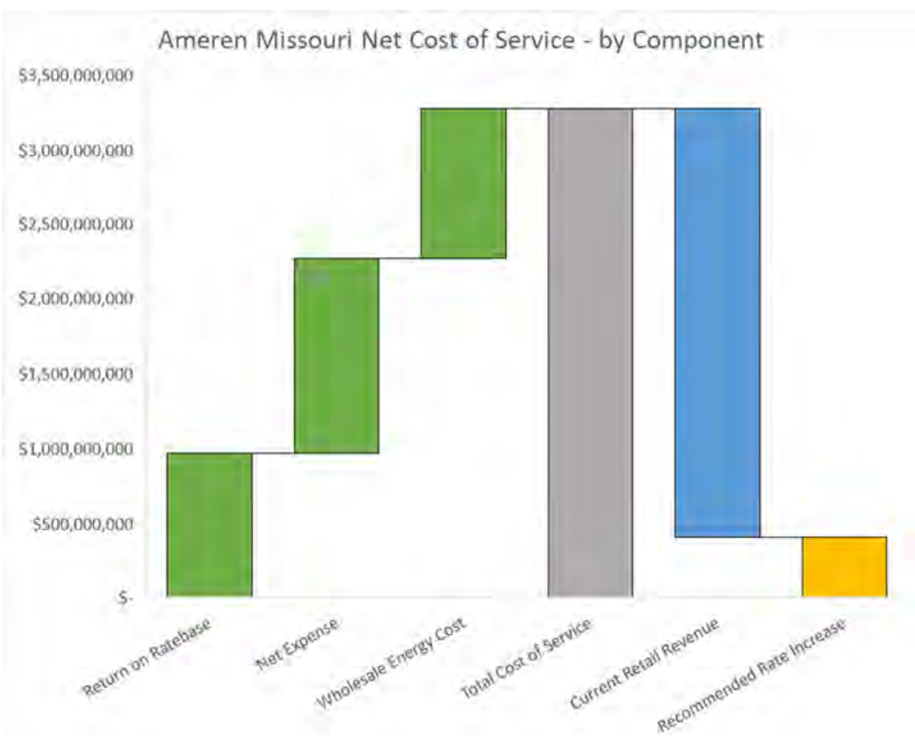
[3] Due to the inclusion of significant amounts of lighting infrastructure, when calculated on a $/kWh basis, the revenue responsibility of the lighting class is significantly higher than customers in other classes of service.
[4] Applying the recommended residential class increase of 13.97% would result in a residential customer charge of $10.26, an increase of $1.26 from the current rate of $9.00 per customer per month.

A. Yes. Table 2 provides a summary of the net expense component of each major function,[5] and a summary of the cost of capital component of each major function, at the midpoint of Staff's recommended rate of return range:

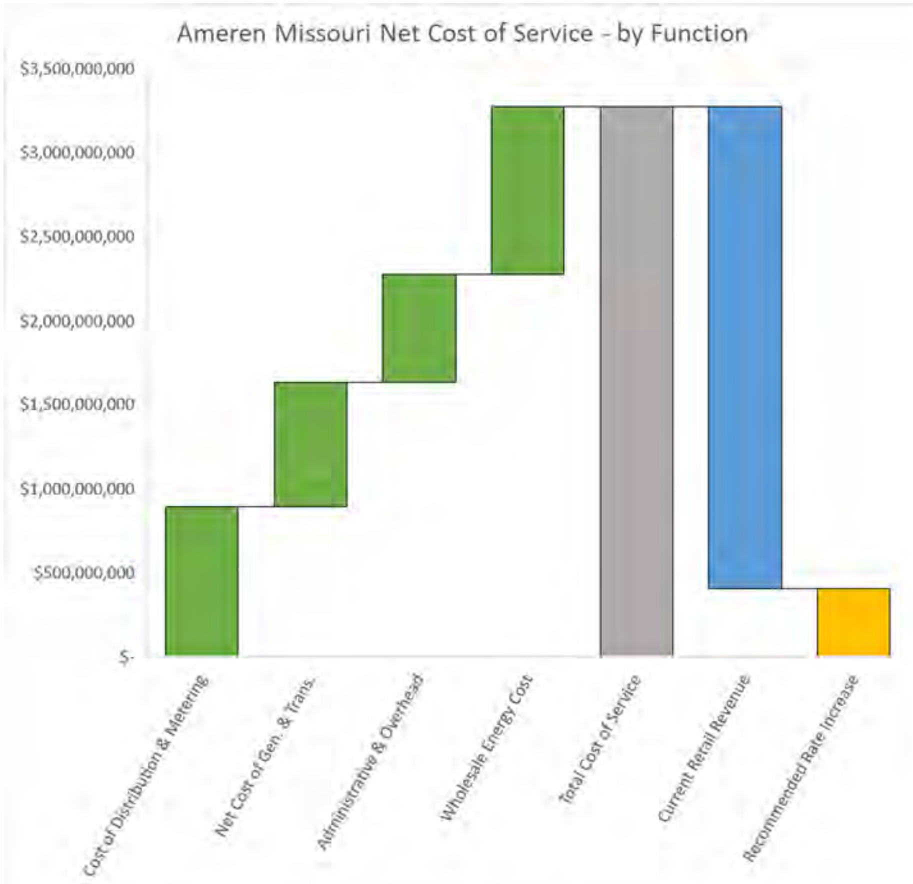
Table 2

Distribution/ Meter/ Customer Net Expense	$	555,724,346
Total Administrative/ Overhead Net Expense	$	511,610,860
Wholesale Energy Cost	$	1,001,326,330
Other Market Production & Transmission Expense	$	234,545,642
Distribution/ Meter/ Customer Midpoint Return	$	336,906,794
Total Administrative/ Overhead Midpoint Return	$	131,256,998
Market Production & Transmission Midpoint Return	$	500,661,902
Total Cost of Service	**$**	**3,272,032,870**
Current Retail Revenue	$	(2,869,789,264)
Recommended Rate Increase	**$**	**402,243,606**

The relative size of each of these components and functional revenue requirements, as compared to current revenues, are provided in the graphs below:



[5] A glossary of terms used throughout this testimony is attached as Schedule SLKL-d2.



CLASS COST OF SERVICE STUDY

Q. What is the purpose of a CCoS study?

A. A CCoS study is a comparison of the revenue groups of customers provide against the total cost of providing service for a year, as assigned and allocated among those customers. For purposes of analyzing CCoS study results, the results are generally expressed by subtracting expenses from revenues, and calculating the rate of return provided by the remaining revenues. The summary results of Staff's CCoS are provided below in Table 3.

Table 3

	Total	Residential	SGS	LGS & SPS	LPS	Lighting
Total Net Expense	$ 2,303,011,090	$ 1,116,045,357	$ 246,096,500	$ 717,421,895	$ 202,953,484	$ 20,493,854
Retail Revenue for Study	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
Revenue for Return	$ 566,778,173	$ 326,109,326	$ 81,984,343	$ 113,223,335	$ 24,104,604	$ 21,356,566
Total Net Ratebase	$ 13,671,300,501	$ 6,978,889,684	$ 1,448,096,421	$ 4,068,046,772	$ 1,016,082,340	$ 160,185,284
Return at Current Revenues	4.15%	4.67%	5.66%	2.78%	2.37%	13.33%
Required Return at Current	$ 566,778,173	$ 289,327,438	$ 60,034,482	$ 168,651,118	$ 42,124,251	$ 6,640,884
Under/Over Contribution $	$ -	$ 36,781,888	$ 21,949,861	$ (55,427,783)	$ (18,019,647)	$ 14,715,682
Under/Over Contribution %	**0.00%**	**2.55%**	**6.69%**	**-6.67%**	**-7.94%**	**35.16%**

A CCoS study filed in direct testimony will reflect the direct case of a given party, therefore any changes in total revenue requirement that occur during the pendency of a case, including the true-up, if applicable, will not be reflected in a CCoS study. Due to the timing of this case, the Boomtown, Huck Finn, and Cass County solar facilities are not included in Staff's direct case, although those facilities are currently anticipated to be included in the case's true-up. Estimates for the net revenue requirement impact of these facilities are included in Staff's CCoS study.

Q. What is Staff's general approach to implementing revenue responsibility shifts and the precision of CCoS results?

A. In general, Staff will not recommend any class receive a reduction in a general rate proceeding with a positive net revenue requirement; and Staff will not recommend adjustment to study results unless those results indicate one or more classes' percent change to bring class rate revenue to the studied cost of service exceeds 5% in one direction and another class or classes' indicated change exceeds 5% in the opposite direction.

In this case, revenue neutral adjustments to revenue responsibility are appropriate to address the overcontributions of the SGS and Lighting classes, and the undercontributions of the LGS, SPS, and LPS classes.

Q. Should a CCoS study's results be the only factor in applying a rate increase to a utility's charges for service?

A. No. Policy considerations, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, and meeting of incremental costs, are also relevant factors in revenue responsibility allocation, rate structure, and rate design. The precision of a CCoS study is also a factor. In addition to the limitation that a CCoS study filed in direct testimony will reflect the direct case of a given party and will not reflect a

Commission-ordered revenue requirement, the availability of data is also a significant limitation to the precision and reliability of a CCoS study.

At this time, plans are underway for comprehensive restructuring of Ameren Missouri's rate schedules. These plans include study of Ameren Missouri's distribution system, as ordered by the Commission in ER-2022-0337. The Commission included several requirements to, among other issues, improve the reliability of CCoS studies and facilitate rate modernization. Those requirements include:

- Accounting changes related to voltage support infrastructure in transmission accounts;[6]
- Accounting changes related to generation assets recorded in distribution or transmission accounts;[7]
- Conduct of a study of customer-specific infrastructure;[8]
- Retention of data related to reactive demand requirements;[9]
- Retention of rate base and expense of radial transmission circuits;[10]
- Study of integrating distributed generation technologies and time-differentiated rate structures;[11]
- Study of the underlying costs of Riders B and C values; [12] and

[6] "To that end, the Commission directs Ameren Missouri to record transmission assets related to maintenance of voltage support due to the retirement of large synchronous generators be recorded to new subaccounts." R&O page 48, Case No. ER-2022-0337.

[7] "The Commission also directs Ameren Missouri to create subaccounts within distribution accounts and transmission accounts for recording infrastructure related to utility-owned generation." R&O page 48, Case No. ER-2022-0337.

[8] "So that sufficient information and data is available for analysis, The Commission finds it reasonable to direct Ameren Missouri to conduct and provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage, in its next general rate case." R&O page 48, Case No. ER-2022-0337.

[9] "Additionally, the Commission finds it reasonable to direct Ameren Missouri to retain customer and rate schedule characteristics related to draws of reactive demand." R&O page 48, Case No. ER-2022-0337.

[10] "Ameren Missouri is also directed to provide data concerning the level of rate base and expense associated with radial transmission facilities, including substation components by customer, for its next rate case." R&O pages 48-49, Case No. ER-2022-0337.

[11] "Renew Missouri's requests that the Commission direct Ameren Missouri to conduct a study on integrating distributed generation technologies and TOU rate plans is reasonable. In view of the forgoing, the Commission will direct Ameren Missouri to conduct such a study." R&O page 38, Case No. ER-2022-0337.

[12] "Likewise the Commission does not find it appropriate to adjust the Rider C factor or alter the Rider B values due to absent sufficient information to do so. All of these issues involve the non-residential classes. The Commission finds these sub-issues appropriate to address in the non-residential working docket ordered in File No. ER-2021-0240." R&O page 43, Case No. ER-2022-0337.

- Study of the structure and design of rates to support electric vehicle charging.[13]

Q. Is any of the information described above available at this time?

A. Generally, no. However, while Ameren Missouri has not made the accounting changes ordered related to generation assets recorded in distribution or transmission accounts, it has provided information related to this issue to Staff in response to data requests,[14] which has been incorporated into Staff's CCoS study. Further, Ameren Missouri has recently provided draft data related to items 3, 5, and 7.[15]

Ameren Missouri's direct workpapers in this case include significantly more detail than has been provided to Staff in recent cases concerning the utilization of poles at various voltages, and information has been provided with regard to inclusion of customer-specific infrastructure in the substation accounts and in certain poles and conductor subaccounts.

As noted in the "Notice Regarding Status of Issues" filed in ER-2022-0337 on June 14, 2024 (Attached as Schedule SLKL-d3), Staff and Ameren Missouri, as well as additional stakeholders, have met and had several discussions concerning rate modernization and the ordered provisions discussed above. As a part of these broader rate design discussions, 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.

[13] "The Commission also finds it appropriate for MECG's proposed optional EV charging rate to be examined in the non-residential working docket. The Commission has concerns about allowing a special rate that, is potentially, not based upon causation." R&O page 43, Case No. ER-2022-0337.
[14] It is Staff's understanding that at this time there is not investment related to voltage support.
[15] Ameren Missouri provided the draft data on November, 21, 2024, and participated in a productive call on December 3, 2024. However, corrections and additional information are necessary to incorporate the information into a CCoS study or rate structure and rate design recommendations.

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-2022-0337, 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.[16]

Q. Has Staff been able to perform a CCoS study in this case that is reliable for ratemaking purposes?

A. Largely, yes. However, Staff's study does not fully recognize the demand-carrying capability of the customer-allocated distribution components,[17] nor does Staff's study fully recognize the customer-specific infrastructure required by customers served at voltages above secondary.[18] Further, given the limited data available, Staff's study does not attempt to refine allocations of distribution costs and components to the extent necessary to review the reasonableness of intraclass revenue responsibility as reflected in rate design. Given the productive ongoing rate modernization discussions and the anticipated refinement of distribution-related information, Staff recommends the Commission focus in this case on improving the interclass revenue responsibility allocation. Staff further notes that based on its

[16] *See* Schedule SLKL-d3 "Notice Regarding Status of Issues" filed in ER-2022-0337 on June 14, 2024, page 2.
[17] "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." NARUC Manual, page 95.
[18] With regard to facilities operating at transmission voltage, the NARUC Manual at page 83 states, "The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system." With regard to facilities operating at distribution voltages, the NARUC Manual at pages 87 and 89 states "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."

experience and the review of the preliminary distribution data, that additional data will likely exacerbate its CCoS findings in this case – namely, more accurately classifying and allocating customer-specific data is expected to cause the Lighting, SGS, and Residential classes to show additional overcontribution, and to cause the LPS, SPS, and LGS classes to show further undercontribution.

Revenues

Q. On a normalized and annualized basis, what revenues are currently generated by each class from current tariffed rates?

A. The currently tariffed rates subject to increase in this case produce revenues of $2,869,789,264. This amount includes an imputation of revenue related to paperless billing, and moves $1,143,335 of revenue from the Solar Generation portion of the Community Solar rates paid by Residential and SGS customers to treatment as "other revenue," incorporated into the net expense calculation in Staff's CCoS Study.

	Residential	SGS	LGS & SPS	LPS	Lighting	Total
Revenues from Kim Cox Workpaper	$ 1,447,972,232	$ 329,248,608	$ 830,579,960	$ 220,665,216	$ 41,998,847	$ 2,870,464,863
Impute Paperless Bill Revenue	$ 408,560	$ 54,280	$ 4,245	$ 25	$ 626	$ 467,736
Remove Solar Generation Revenue	$ (1,089,773)	$ (53,563)				$ (1,143,335)
Actual Rate Revenue	$ 1,447,291,019	$ 329,249,326	$ 830,584,205	$ 220,665,241	$ 41,999,473	$ 2,869,789,264

Q. Are further adjustments made to revenue for purposes of the Staff CCoS study?

A. Yes. Economic Development Incentives ("EDI") in the amount of $10,220,959 are provided to LGS, SPS, and LPS customers. Pursuant to statute, the values of these discounts are credited back to the LGS, SPS, and LPS classes, then redistributed as a reduction in revenue to all classes. This results in the LGS, SPS, and LPS classes being treated as producing more revenues than actually produced, and other classes treated as producing less revenue than actually produced, for CCoS purposes.

	Residential	SGS	LGS & SPS	LPS	Lighting	Total
Actual Rate Revenue	$ 1,447,291,019	$ 329,249,326	$ 830,584,205	$ 220,665,241	$ 41,999,473	$ 2,869,789,264
Reverse EDI Adjustment			$ 3,019,428	$ 7,201,531		$ 10,220,959
Non EDI Rate Revenue	$ 1,447,291,019	$ 329,249,326	$ 833,603,633	$ 227,866,772	$ 41,999,473	$ 2,880,010,223
Redistribute EDI Responsibility	$ (5,136,337)	$ (1,168,483)	$ (2,958,402)	$ (808,684)	$ (149,053)	$ (10,220,959)
Class Revenue for Study Purposes	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419	$ 2,869,789,264

Functionalized Cost of Service Results

Q. Could you provide a greater detail of the functionalized cost of service?

A. Yes, the results are summarized below:

	Production Type 1	Production Type 2	Transmission	Net MP&T	Distribution/ Meter/ Customer
Net Ratebase	$ 4,689,907,967	$ 2,210,648,043	$ 1,815,566,470	$ 5,036,605	$ 5,851,270,520
NonLabor Expense & Dep. Exp. with True-up Plug	$ 1,547,000,738	$ 148,236,776	$ 77,383,248	$ 171,261,540	$ 376,443,514
Labor Expense	$ 175,898,620	$ 4,392,038	$ 2,901,406	$ 25,518,396	$ 87,757,305
Other Revenues	$ 666,233,965	$ 66,753,819	$ 216,557	$ 235,459,395	$ -

	Administrative/ Overhead	Reallocate on Retail Revenue	Income Tax Ratebase	Reallocate on Payroll	Reallocate on Net Ratebase
Net Ratebase	$ 2,290,866,389	$ 2,664,730	$ (3,023,636,164)	$ (123,309,812)	$ (50,480,705)
NonLabor Expense & Dep. Exp. with True-up Plug	$ 388,426,557	$ 21,702,965	$ 6,030,906	$ (32,207,979)	$ 194,374,280
Labor Expense	$ 78,132,192	$ 1,638,556	$ -	$ 19,198,264	$ -
Other Revenues	$ 1,719,264	$ -	$ -	$ -	$ -

After the indicated reallocations, the following functionalized revenue requirements were found:

	Market Production & Transmission	Distribution Meter & Customer	Total Adminstrative & Overhead
Net Ratebase	$ 7,063,514,413	$ 4,753,199,683	$ 1,851,819,947
Midpoint Return	$ 500,661,902	$ 336,906,794	$ 131,256,998
NonLabor Expense & Dep. Exp. with True-up Plug	$ 2,029,578,838	$ 438,440,308	$ 430,633,399
Labor Expense	$ 219,406,879	$ 92,254,871	$ 83,775,026
Other Revenues	$ 968,663,735	$ -	$ 1,719,264
Income Taxes	$ (44,450,010)	$ 25,029,167	$ (1,078,302)
Total Cost of Service	$ 1,736,533,873	$ 892,631,139	$ 642,867,857

Market, Production, and Transmission Function

Wholesale Energy Cost

Q. What is market energy?

A. Ameren Missouri participates in the Midcontinent Independent System Operator ("MISO") integrated market, which consists of 197 members and 500+ market participants spread over 15 US states and Canada. Each day generators owned by its market participants, including Ameren Missouri, are bid into the market, and MISO chooses which ones to dispatch to serve its system-wide load on a least-cost basis. Generally all energy produced by Ameren Missouri is sold into this market, and all energy to serve its load is purchased from the market. Among several markets for energy and ancillary services, MISO operates a Day Ahead ("DA") market into which each participating load serving entity projects its load's requirements for the next day, and each resource submits the prices and terms at which it is willing to generate energy.[19] Most of Ameren Missouri's purchases of energy for its load, and sales of energy from Ameren Missouri-owned generation, are transacted in the DA market. The DA market is simulated in fuel and production cost modeling performed by both Staff and Ameren Missouri that is reflected in each party's calculated cost of service.[20]

Q. What was the cost of market energy for each class and voltage during the test year?

A. Provided below is the amount of energy required to serve each class at each voltage level based on the hourly loads provided by Ameren Missouri in response to Staff DR 0529, as well as the cost of that energy using the actual MISO DA prices for the Ameren Missouri load zone. The final row calculates the percentage of the total cost of DA

[19] Also called the "Day 2" market.
[20] Additional energy is transacted in the Real Time and ancillary services markets.

energy that is attributable to each class's actual load during the test year as updated. The cost of energy on a per-kWh basis at transmission voltage, and at each class's metered voltage is also provided:

	Residential	SGS	LGS	SPS	LPS Primary	LPS Sub-Trans.	LPS Trans.	Lighting
Energy at Transmission Voltage	13,686,701,823	3,403,992,002	7,701,023,948	3,613,534,877	1,589,421,831	1,784,082,205	330,349,124	133,446,087
Cost of Energy at Tranmssion Voltage	$ 470,388,279	$ 112,639,219	$ 245,952,846	$ 111,253,645	$ 47,897,973	$ 53,819,420	$ 9,501,141	$ 3,523,864
$/ kWh at Transmission Voltage	$ 0.03437	$ 0.03309	$ 0.03194	$ 0.03079	$ 0.01293	$ 0.02394	$ 0.00067	$ 0.00020
$/kWh at Meterd Voltage	$ 0.03629	$ 0.03494	$ 0.03373	$ 0.03153	$ 0.01324	$ 0.01301	$ 0.01284	$ 0.00022
Percent of Market Energy Cost	**44.59%**	**10.68%**	**23.31%**	**10.55%**	**4.54%**	**5.10%**	**0.90%**	**0.33%**

Q. How did you use this information in your CCoS Study?

A. For purposes of inclusion in the Staff Accounting Schedules and Cost of Service calculation, Staff's fuel and production cost modeling calculates the net expense or revenue that resulted in each hour of simulated market transactions of energy market purchases and sales.[21] Staff's fuel and production cost model relies on normalized hourly energy prices and normalized hourly energy requirements at the system level. Because normalized hourly loads are not available at the class and voltage level, Staff's CCoS Study uses the percentage of the actual cost of DA energy during the test year as updated to allocate the value of energy purchases to serve load calculated in Staff's fuel and production cost modeling.

Cost of generation resource ownership and operation

Q. What costs does Ameren Missouri incur in owning and operating generation resources?

[21] This accounting treatment is consistent with FERC requirements. For financial reporting purposes, FERC requires that utilities such as Ameren Missouri report the value of the net amount of energy transacted in a given interval, as opposed to the actual value of both the energy sold and the energy purchased. The portion of energy requirement that coincides with utility generation is sometimes referred to as "native load."

A. Ameren Missouri incurs capital costs, depreciation expense, operation and maintenance expenses, including property taxes, and fuel expenses associated with ownership and operation of its generation resources.

Q. What is resource adequacy?

A. Resource adequacy is the concept that a load-serving entity must own or contract for enough generation capacity to meet the load of that load-serving entity at the time of the system peak hour. For load serving entities that participate in the MISO integrated energy market, there are four such hours each year, one in each season.

Q. Is resource adequacy Ameren Missouri's sole motivation in its decisions to build generation resources?

A. No. Ameren Missouri has indicated an "energy need,"[22] desires of certain customers for renewable energy,[23] and Missouri's Renewable Energy Standard as motivations for recent generation resource construction decisions.

Q. How did Staff allocate Ameren Missouri's generation resource net cost of service?

[22] Report and Order in EA-2022-0245 concerning the Boomtown solar facility, stating at page 12 "Waiting to add renewable resources could result in Ameren Missouri falling short of meeting energy needs or requiring the rapid deployment of less beneficial resources, particularly if viable renewable energy projects are limited, transmission constraints cause delays or higher costs, or financing rates are higher in the future when transitioning from fossil-fuel generation," and "Analysis by Ameren Missouri of its peak days for each summer and winter month from 2019 through 2021 showed that, without the coal-fired Meramec Energy Center (retired at the end of 2022) and Rush Island Energy Center (scheduled for retirement by the end of 2025), the Company would have had to purchase more energy than it generated to serve its native load." See direct testimony of Ajay K. Arora at pages 17 – 22 in File No. EA-2023-0286, and direct testimony of Steven Wills at pages 8 and 19 in File No. EA-2023-0286. File EA-2023-0286 concerned the Cass, Split Rail, Vandalia, and Bowling Green solar projects.

[23] Report and Order in EA-2022-0245 concerning the Boomtown solar facility, stating at page 31 "Demand for clean, reliable, and affordable energy is an increasingly important factor in determining where businesses locate new jobs and investment. Missouri is competing with other states for new jobs and investment from businesses that have large energy demand and a need for renewable energy resources. Customer preferences for renewable energy and corporate sustainability goals by Missouri's large employers for their energy needs should not be dismissed." Also see direct testimony of Steven Wills at pages 20 – 22 in File No. EA-2023-0286.

A. Staff determined that it was most reasonable to subfunctionalize generation assets by operating characteristics.[24] Staff subfunctionalized generation assets as "Type 1," those assets which have significant variable costs of operation which are avoidable if the unit is offline and are fully dispatchable with limited exceptions. Staff subfunctionalized generation assets as "Type 2" those assets with no or minimal variable costs of operation, where asset dispatch is often limited by weather conditions or other factors beyond control of utility, many eligible for compliance with Missouri's Renewable Energy Standard.[25]

Staff allocated all rate base, expenses, and revenues associated with Type 1 assets using the NARUC Manual's "All Peak Hours Approach," described at page 47 of the NARUC Manual.[26] Staff selected four peaks consistent with the four MISO resource adequacy seasons.

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[24] Historically, the classification of production cost of service to "energy" and "demand" causation was typically a step in a class cost of service study. However, this simplification is not a good representation of the cost causation of Ameren Missouri's production cost of service and revenues. Prior to the development of robust integrated energy markets, an electric utility would build its generation fleet to efficiently meet the needs of its customers over time. Meaning, a utility would build baseload, intermediate, and peaking generation in configurations that management determined to be appropriate for its current and anticipated load, with a relatively small amount of excess capacity or energy, or a relatively small shortfall of capacity or energy, which would be balanced among neighboring utilities.

Baseload generation such as nuclear plants or large coal plants are relatively cheap to operate, but very expensive to build. Baseload plants generate energy very efficiently at a given point on the heat rate curve, but are less efficient at the upper and lower bounds of the operating range. While these units could be ramped up and down on a daily basis, they cannot be and require days or weeks to turn off and on. Intermediate plants could include small coal or oil plants, or combined cycle natural gas plants. These plants could be turned on for a peak season, typically summer, but would have roughly the same range of intra-day variability as larger baseload plants. Peaking plants, such as small natural gas or oil reciprocating or combustion units, and small to large natural gas combustion turbines, can power off and on in minutes. These plants tend to be relatively inexpensive to construct, but very expensive to operate on a per MWh basis, subject to the fluctuations of the natural gas market and pipeline capacity availability. While legacy baseload units remain in operation at Callaway (nuclear), Labadie (coal), and Sioux (coal), Ameren Missouri has retired several of its coal generation assets in recent years, and the units at Labadie and Sioux operate at a lower utilization factor than historically. Also, in recent years, Ameren Missouri has added significant amounts of wind and solar generation.

[25] Cass County, Boomtown, and Huck Finn solar projects are included as a "plug" for true-up. Production Tax credits associated with Huck Finn and revenue associated with the Renewable Solutions Program are also included.

[26] Section 393.1620 RSMo requires that "[i]n determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual." The National Association of Regulatory Utility Commissioners ("NARUC") cost allocation manual from 1992 describes over 18 different production cost allocation methods, many of which have multiple variations. ("NARUC Manual") The

However, for purposes of calculating the class-level peaks, Staff removed the generation provided by each class' allocation of Type 2 assets from that class' peak demand.

Staff allocated all rate base, expenses, and revenues associated with Type 2 assets using the partial energy weighting method described at page 49 of the NARUC Manual.[27] This approach allocates the production plant costs to the classes on the basis of the energy loads, but does not classify the costs as "energy-related," in that these costs are not expected to vary with the level of generation produced or consumed.

Q. How did Staff recognize the capacity values of Type 2 assets?

A. The capacity values of Type 2 assets are fully reflected in Staff's allocation of Type 1 assets in that Type 1 assets were allocated, on the basis of each class's contributions to the identified MISO seasonal peak hours net of the generation produced in each of those peak hours by each class's share of Type 2 assets.

Q. What portions of Type 2 Resources are allocated to each class?

A. The energy requirements of each class at transmission voltage, and the percentage of each class's share of total energy are provided below. The percentage of each class's share of total energy is the Type 2 Resource allocator.

	Residential	**SGS**	**LGS & SPS**	**LPS**	**Lighting**
kWh at Transmission Voltage:	13,970,367,846	3,422,324,200	11,200,593,291	3,772,651,746	39,058,732
Energy Share (Type 2 Resource Allocator):	**43.11%**	**10.56%**	**34.56%**	**11.64%**	**0.12%**

Commission rarely (if ever) orders approval of a specific allocation method because the appropriate method will vary from case to case based on the utility's characteristics and available data.

[27] This treatment is most reasonable in general, but also particularly in light of the operation of the Fuel and Purchase Power Adjustment Clause.

Q. How much energy was generated by Type 2 Resources during the Peak Hour for each MISO resource adequacy season?

A. Including the true-up plants, the size of the peak, the hour of the peak, and the MW of Type 2 generation occurring during each peak is provided below:

Season	Peak Hour Usage	Hour of Peak	Type 2 Generation During Peak Hour
Summer	6,220,382	6/25/24 14:00	931
Fall	5,189,088	9/4/23 15:00	942
Winter	5,715,620	1/17/24 6:00	407
Spring	4,851,706	5/21/24 16:00	825

Q. How did the Generation of Type 2 Resources during peak hours offset the usage of each class during those peak hours?

A. Provided below are the class loads during each peak hour, in MW:

Season	Peak Hour Usage	Residential	SGS	LGS & SPS	LPS	Lighting
Summer	6,220,382	3,130.70	689.25	1,908.05	492.39	-
Fall	5,189,088	2,757.98	510.93	1,516.10	404.08	-
Winter	5,715,620	3,129.31	569.70	1,604.89	382.36	29.36
Spring	4,851,706	2,307.09	500.47	1,574.15	470.00	-

These loads are then offset by the Type 2 generation allocation for each class during each peak hour, which recognizes the capacity contributions of the Type 2 assets, in MW:

Type 2 Capacity Contribution at Seasonal Peak					
	Residential	SGS	LGS & SPS	LPS	Lighting
Summer	401.29	98.30	321.73	108.37	1.12
Fall	406.00	99.46	325.50	109.64	1.14
Winter	175.40	42.97	140.62	47.37	0.49
Spring	355.49	87.08	285.01	96.00	0.99

The resulting net load during each MISO resource adequacy seasonal peak are shown below, which are then used to allocate the costs, expenses, and revenues, of Type 1 assets:

Type 1 Capacity Requirement at Seasonal Peak					
	Residential	**SGS**	**LGS & SPS**	**LPS**	**Lighting**
Summer	2,729.41	590.95	1,586.32	384.02	(1.12)
Fall	2,351.98	411.48	1,190.59	294.44	(1.14)
Winter	2,953.91	526.73	1,464.27	334.99	28.87
Spring	1,951.60	413.38	1,289.14	374.00	(0.99)
	9,986.90	1,942.54	5,530.32	1,387.46	25.62
Type 1 Resource Allocator:	**52.92%**	**10.29%**	**29.30%**	**7.35%**	**0.14%**

Q. What are the revenue requirements for each type of resource?

A. As seen in the chart below, the cost of owning and operating Type 1 assets, net of the value for the energy generated and sold into the DA market, is approximately $394 million. The cost of owning and operating Type 2 assets, net of the value for the energy generated and sold into the DA market, is approximately $46 million.

	Type 1 Assets	**Type 2 Assets**
Capital Costs at Midpoint Return	$ 268,020,682	$ 127,835,099
Net Cost to Generate	$ 1,796,428,204	$ 108,535,229
Capacity Sales	$ 666,233,965	$ 69,537,933
Value of Generation	$ 1,004,665,227	$ 120,648,033
Net Revenue Requirement	**$ 393,549,694**	**$ 46,184,362**
Apprx. Capacity	7,880	776
RR $/MW	$ 49,945	$ 59,517
Generation	31,183,885	3,934,850
RR $/MWh	$ 12.62	$ 11.74

The net cost to generate includes production tax credits, Renewable Solutions Program revenues, and Community Solar Program revenues. The net cost to generate for each resource type is also net of the revenue associated with capacity sales.

Q. Using the allocators described above, how are the revenue requirements of these assets allocated to the classes?

A. The resulting revenue responsibility allocations are provided below:

	Residential	SGS	LGS & SPS	LPS	Lighting
Production Type 1	$ 208,253,977	$ 40,507,185	$ 115,322,131	$ 28,932,218	$ 534,183
Production Type 2	$ 19,910,896.65	$ 4,877,577	$ 15,963,349	$ 5,376,872	$ 55,667

Q. What is the wholesale cost of energy for each class?

A. The wholesale cost of energy for Ameren Missouri, as normalized and annualized, is approximately $1 billion. The class responsibilities are provided below:

	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Wholesale Energy	$ 446,379,595	$ 106,890,097	$ 338,974,621	$ 105,541,924	$ 3,344,005

Transmission Net Revenue Requirement

Q. What other revenue requirement components are included in the Market, Production, and Transmission function?

A. The costs and revenues of transmission ownership and transmission activities are included. These amounts are generally allocated to the classes using a 12-CP allocator, consistent with MISO billing of most transmission schedules, including Network Integrated Transmission Service ("NITS"). However, MISO Schedule 26a is billed based on a utility's load relative to total MISO load, so a portion of transmission revenue requirement was allocated using the energy allocator.[28] These allocations, as well as the allocations described above, are summarized below:

	Residential	SGS	LGS & SPS	LPS	Lighting
Production Type 1	$ 208,253,977	$ 40,507,185	$ 115,322,131	$ 28,932,218	$ 534,183
Production Type 2	$ 19,910,896.65	$ 4,877,577	$ 15,963,349	$ 5,376,872	$ 55,667
Transmission	$ 105,381,821	$ 22,872,828	$ 67,181,759	$ 17,675,731	$ 353,627
Allocate on kWh	$ 36,425,343	$ 8,923,125	$ 29,203,630	$ 9,836,544	$ 101,839
Cost of Wholesale Energy	$ 446,379,595	$ 106,890,097	$ 338,974,621	$ 105,541,924	$ 3,344,005
Total MP & T	$ 816,351,632	$ 184,070,812	$ 566,645,490	$ 167,363,288	$ 4,389,321
Class MP & T %	46.95%	10.59%	32.59%	9.63%	0.25%

[28] MISO Schedule 26a charges fund the Multivalue Projects ("MVP").

Classification and Allocation of distribution-related cost of service and revenues

Q. What is the cost of service associated with distribution, metering, and the cost of billing a customer?

A. The net cost of service for the Distribution, Meter, & Customer function is provided below:

	Distribution Meter & Customer	
Net Ratebase	$	4,753,199,683
Midpoint Return	$	336,906,794
NonLabor Expense & Dep. Exp. with True-up Plug	$	438,440,308
Labor Expense	$	92,254,871
Other Revenues	$	-
Income Taxes	$	25,029,167
Total Cost of Service	$	892,631,139

Adjustments to Continuing Property Record Data and Distribution Account Functionalization

Q. Did Staff rely on the Ameren Missouri continuing property record ("CPR") for its distribution classifications?

A. Yes. The classifications described below relied on the CPR Ameren Missouri provided as its "most current," in response to DR 0143, on August 2, 2024.

Q. In response to Staff DR 0384, Ameren Missouri indicated that fencing that was recorded to Account 364 (Poles) is not currently being used to the benefit of ratepayers and should be retired for accounting purposes. (Attached as SLKL-d4). In response to Staff DR 0385, Ameren Missouri indicated that the CPR included "abnormalities" in how asset additions and retirements were recorded. (Attached as SLKL-d5). Have you incorporated the information provided in these data request responses to the CPR information prior to analyzing the asset information for purposes of classification and allocation?

A. Yes.

Q. In response to Staff DR 0158, Ameren Missouri indicated that the assets used for distributed generation that had been recorded in distribution plant accounts at the time of the last rate case were still reflected in those accounts at this time.[29] Have you used the information provided in response to this data request to calculate a gross plant cost and distribution expense amount to functionalize as production-related?

A. Yes. Provided below are the gross plant amounts that are functionalized as production-related for each indicated account, and the percent of depreciation expense for that account that is functionalized as production-related:

Distribution Assets Interconnecting Generation Assets	**Count**		**Value**	**% of Account**
Poles - Account 364	114	$	288,302	0.0169%
Overhead Conductor and Devices - Account 365	7,109	$	655,670	0.0341%
Underground Conduit - Account 366	322	$	10,347	0.0013%
Underground Conductor and Devices - Account 367	1,861	$	104,253	0.0096%
Uncerground Services - Account 369.2	1	$	2	0.0000%
Street Lighting and Signals - Account 373	162	$	1,751.65	0.0007%
Grand Total	9,569	$	1,060,325	

Q. Did you calculate depreciation reserve associated with each asset?

A. No. Because the assets that are functionally production-related are of very recent vintage, it would overstate the associated reserve to assume that a proportionate share of the account's reserve is functionally production-related.[30]

[29] No.: MPSC 0158: Has Ameren Missouri segregated plant used for distributed generation from traditional distribution plant recorded in accounts 360-370? If so, please identify the plant moved, the account it was moved to or subaccount created, and the date(s) the associated entries were recorded.

RESPONSE Prepared By: Paul Mertens Title: Manager Plant Accounting Date: 8/8/2024
Ameren Missouri has recorded and segregated all work related to interconnecting to solar facilities. A listing of assets constructed, by facility and individual work order number sorted by depreciation group, is attached. These assets will continue to be depreciated within the same grouping, although in our accounting records these assets will be shown as location property rather than mass property. The transfer of the assets listed from mass to location property will occur prior to the true up date.

[30] At most, three years of depreciation expense have accrued against some of these assets, with many being one year or less.

Q. How did Staff functionalize, classify, and allocate the Poles – Taps and Overhead Conductor and Device – Taps subaccounts?

A. Staff reviewed Ameren Missouri's response to Staff DR 0600, which indicated the purposes of the location-specific subaccounts within the Poles – Taps subaccount. This response indicated that $26 million of the assets recorded to Poles – Taps were used for transmission purposes, or were distribution tie lines operating at 138 kV and 161 kV.[31] Staff allocated these assets to the classes using the 12-CP allocator, which is consistent with Transmission infrastructure allocation.

The DR 0600 response indicated that $14.9 million of the assets recorded to Poles – Taps were taps to provide service to single customers, which are classified as high-voltage customer-related, as the lines operate at 138 kV. Staff allocated these costs to the LPS class, which includes the customers taking service at transmission voltage.

$1.9 million of the assets recorded to Poles – Taps were described by Ameren Missouri in DR 0600 as "Assets should be classified in [accounts] 364000 and 365000 and will be transferred to mass location," and an additional $21,555 were not captured in Ameren Missouri's response to DR 0600. Staff incorporated that additional $1,979,031 into its demand allocation of the main Poles account. Comparable amounts and purposes were identified for the Overhead Conductor and Devices accounts:

Taps Subaccount Asset Type	Account 364	Account 365	Allocation
Transmission-related	$ 26,184,838	$ 17,559,508	12 CP at Transmission Voltage
Transmission-customer classified	$ 14,923,319	$ 10,019,901	Assign to LPS
Move	$ 1,957,476	$ 733,312	Allocate consistent with 364/365 composite demand
Unaccounted for	$ 21,555	$ 55,684	Allocate consistent with 364/365 composite demand

Consistent allocations were made for depreciation reserves and depreciation expenses.

Q. How did Staff reconcile any differences between the CPR totals for an account and the account balance reflected in Staff's Accounting Schedules?

[31] These amounts are retained within the distribution function for purposes of the functional revenue requirements reported in this testimony.

A. Staff carried over exact amounts such as those described above, and the customer-related amounts as calculated. Given the general NARUC instructions to allocate the balance of accounts using demand allocators, Staff calculated a single demand allocator for each account as a composite of the more detailed demand allocations described below. This composite allocator was applied to each account balance in the Accounting Schedules, net of the amounts carried over.

Substation Accounts

Q. How did Staff classify and allocate the distribution substations Accounts 360 - Land and Land Rights, 361 - Structures and Improvements, and 362 - Station Equipment?

A. In response to Staff DR 0601, Ameren Missouri provided information concerning substation usage, which indicated that approximately $10 million of assets are recorded to the substation accounts that are used by single customers. Staff classified these amounts as customer-related for the LPS class.[32]

Staff classified the remainder of these accounts as demand-related.[33]

Staff allocated the demand-related portions of these accounts, as seen below, using the 12-CP demand allocator, as measured at Transmission voltage.[34]

	Demand at Transmission
Residential	49.3671%
SGS	10.7150%
LGS/SPS	31.4719%
LPS Combined	8.2804%
Lighting	0.1657%

[32] NARUC Manual at pages 87 and 89, "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."
[33] NARUC Manual at page 90, "Distribution substations costs (which include Accounts 360-Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served."
[34] NARUC Manual at page 97, "The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities."

Poles Account

Q. How did Staff classify Account 364 (Poles)?

A. To find the customer-classified portion of account 364, Staff relied on the representation of Thomas Hickman that a 40' wood pole is the current minimum design standard of Ameren Missouri's distribution system.[35] Accordingly, Staff reviewed the CPR assets and identified whether a given pole was more than, less than, or equal to 40'. For 40' poles, Staff identified those assets which were 40' wood poles, and which were other 40' poles.

Staff then found the average embedded cost for poles less than 40', poles more than 40', and for 40' wood poles. Staff graphed these values in an attempt to establish a minimum-intercept value, however, the resulting cost of -$4,265 was not reasonable, indicating the presence of anomalous data.[36] Staff unsuccessfully attempted to refine the data by using only the most recent years, using individual rather than average heights and costs, and combinations of those approaches.

The minimum system classification and allocation using 40' wood poles is set out below, where poles shorter than 40' are included at actual costs, and poles 40' and taller are included at the 40' wood pole cost:

Minimum System	Number of Poles	$/Pole	Adjusted Dollars
<40' at CPR Cost	429,858	$ 501	$ 215,310,785
40'+ at 40' WP $	469,681	$ 1,394	$ 654,513,458
	899,539	$ 967	**$ 869,824,244**

[35] Indicated in Ameren Missouri's workpapers.
[36] NARUC Manual, page 95, "The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases; because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted."

		Minimum System Allocated Pole Responsibilities		
Poles	**Min Sys $**	Poles <40'	40' Wood Poles	Poles 40'+
Residential	$ 759,778,103	375,474.35	256,763	153,496
SGS	$ 100,942,300	49,884.62	34,113	20,393
LGS/SPS	$ 7,893,943	3,901.10	2,668	1,595
LPS Combined	$ 46,541	23.00	16	9
Lighting	$ 1,163,356	574.92	393	235

Staff is aware that some subset of the assets recorded to the Poles account is more properly classified as the customer-specific infrastructure of one or more large customers, however, information to classify either the specific assets or a representative asset cost is not available in this rate case.[37]

Q. Why did Staff use the 40’ wood pole for the minimum system unit?

A. Staff does not consider the 40’ wood pole to be the proper minimum system unit, however, to minimize the differences between study approaches in this case, Staff has generally used the units identified by Mr. Hickman. For additional context, use of the 35’ wood pole which comprises 30% of Ameren Missouri’s installed poles, results in a minimum-system customer classification of $526,578,970. Use of a 30’ wood pole, comprising 16% of Ameren Missouri’s installed poles, results in a minimum-system customer classification of $354,050,512. Mr. Hickman’s pole workpaper indicates that 50% of the poles carrying secondary voltage are 30’, and 38% of secondary-only poles are 35’. Only 8% of the poles that carry secondary voltage only are 40’.[38] As Ameren Missouri states in its response to Staff DR 0145, “of the 301,509 records represented within 40 Foot Wood Poles, 139,114 (~46.14%)

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[37] NARUC Manual at pages 87 and 89, “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.”

[38] As noted in the NARUC Manual, page 95, “The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: ‘Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?’ The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.”

contain exclusively Primary voltage equipment, 7,879 (~2.61%) contain exclusively Secondary voltage equipment, and 2,982 (~0.99%) contain exclusively Sub Transmission equipment."

Q. Should the number of customers in a class or some other factor be used for allocation of the customer-classified costs?

A. Because the 40' pole is effectively a primary-system component, the most reasonable determinant for allocation of customer-classified costs would be the number of customers served at primary or greater voltage, and the number of line transformers that drop primary voltage to secondary voltage.[39] However, that information was not available, so in this case, Staff relied on the number of customers in a class.

Q. How did Staff subclassify the demand-related costs in Account 364?

A. To avoid allocating the costs for the secondary and primary systems to customers served at subtransmission voltage, and to avoid allocating the costs for the secondary system to customers served at primary voltage, I subclassified the assets in the distribution accounts by voltage. To do so, Staff relied on a workpaper provided by Mr. Hickman which included various pole asset names and the number of each of those assets associated with conductors of various voltages and combinations of voltages.[40] Using this information, I found the number of poles at each voltage and voltage combination for 40' wood poles, poles less than 40' and poles more than 40' and other 40' poles (collectively, "Poles 40'+"): [41]

[39] For example, if there is a single line transformer serving 5 customers in a subdivision, 30 customers in an apartment complex, or 10 customers in a stripmall, then the quantity of poles is not varying by the addition or subtraction of one of those customers, rather it is varying by the existence and location of a line transformer.

[40] In response to Staff DR 0319, Ameren Missouri indicated that the information in this workpaper was "from Pole Inspection records and represents a complete population of responses over a period of time. Pole inspections occur in such a way that every pole is inspected as part of a groundline inspection once every 12 years."

[41] Staff notes that the results that 11% of poles are exclusively secondary and that 32% of poles include secondary is surprising in light of Ameren Missouri representations in various dockets that there are relatively few miles of secondary overhead circuits to justify retention of information concerning mileage of secondary facilities, including as noted in response to Staff DR 0152 in this case. Staff is also concerned that this count of poles at secondary could include poles exclusively used for lighting, which should not be borne by all secondary customers.

	Secondary	Primary	Subtransmission	Sec. & Pri.	Sec. & Sun.	Sec., Pri., & Sub	Pri. & Sub.
Poles <40'	85,741	112,070	2,065	96,465	51	130	809
40' Wood Poles	7,879	139,114	2,982	148,820	108	546	2,060
Poles 40'+	1,084	50,384	29,492	39,588	992	19,761	34,323
Total:	94,704	301,568	34,539	284,873	1,151	20,437	37,192

For poles attributed to more than one voltage, I evenly split the pole counts among the indicated voltages. Also, I adjusted the count of poles in each range to reflect the quantity of poles recorded to the CPR. This resulted in the following counts of poles by height, by voltage:

	Secondary	Primary	Subtransmission
Poles <40'	134,042	160,750	2,538
40' Wood Poles	82,525	214,736	4,248
Poles 40'+	27,961	93,927	53,737

Secondary-voltage poles were allocated as follows, using the 4-NCP Summer at Secondary allocator:

Demand at Secondary		Poles <40'	40' Wood Poles	Poles 40'+
		193,788	80,457	27,978
Residential	60.42%	117,085	48,611	16,904
SGS	13.49%	26,151	10,857	3,775
LGS/SPS	25.54%	49,493	20,549	7,145
LPS Combined	0.00%	-	-	-
Lighting	0.55%	1,059	440	153

Primary-voltage poles were allocated as follows, using the 12-NCP at Primary allocator:

Demand at Primary		Poles <40'	40' Wood Poles	Poles 40'+
		232,400	209,355	93,982
Residential	51.14%	118,851	107,065	48,063
SGS	12.00%	27,880	25,115	11,275
LGS/SPS	32.68%	75,938	68,408	30,709
LPS Combined	3.64%	8,462	7,623	3,422
Lighting	0.55%	1,270	1,144	513

Subtransmission-voltage poles were allocated as follows, using the 12-CP at High Voltage allocator:

Demand at Subtrans.		Poles <40'	40' Wood Poles	Poles 40'+
		3,670	4,142	53,768
Residential	49.66%	1,822	2,057	26,702
SGS	10.78%	396	446	5,796
LGS/SPS	31.66%	1,162	1,311	17,023
LPS Combined	7.73%	284	320	4,158
Lighting	0.17%	6	7	90

Ameren Missouri's response to DR 0570.1 in Case No. ER-2022-0337 indicated that lighting poles would not trigger designating a pole as secondary.

Q. The NARUC Manual at page 95 states:

> 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 analysts 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.

Did Staff attempt to address this issue?

A. Staff attempted to address this issue with the data available. In general, the Residential and SGS classes were allocated more of each pole size through the minimum-system allocation than indicated by demand responsibility. For each size pole, Staff reviewed the minimum system poles, and whether or not a class' demand requirement was satisfied by the customer-classified allocation:

Min. Sys. Poles <40'		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	375,474	$ 188,070,661	237,758	$ 119,090,099	(137,716)	$ (68,980,561)	$ 188,070,661	
SGS	49,885	$ 24,986,618	54,426	$ 27,261,541	4,542	$ 2,274,923	$ 24,986,618	
LGS/SPS	3,901	$ 1,954,017	126,593	$ 63,409,025	122,692	$ 61,455,008		$ 65,363,041
LPS Combined	23	$ 11,521	8,746	$ 4,380,558	8,723	$ 4,369,038		$ 4,392,079
Lighting	575	$ 287,970	2,335	$ 1,169,562	1,760	$ 881,592		$ 1,457,532
	429,858	$ 215,310,785	429,858	$ 215,310,785	0	$ 0		

Min. Sys. 40' Wood Poles		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	256,763	$ 357,806,932	157,733	$ 219,805,231	(99,030)	$ (138,001,701)	$ 357,806,932	
SGS	34,113	$ 47,537,373	36,419	$ 50,750,867	2,306	$ 3,213,495	$ 47,537,373	
LGS/SPS	2,668	$ 3,717,543	90,268	$ 125,790,522	87,600	$ 122,072,980		$ 129,508,065
LPS Combined	16	$ 21,918	7,943	$ 11,068,741	7,927	$ 11,046,823		$ 11,090,659
Lighting	393	$ 547,866	1,590	$ 2,216,270	1,197	$ 1,668,404		$ 2,764,137
	293,953	$ 409,631,632	293,953	$ 409,631,632	0	$ (0)		

Min. Sys. Poles 40'+		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	153,496	$ 213,900,510	91,669	$ 305,765,004	(61,827)	$ 91,864,494	$ 213,900,510	
SGS	20,393	$ 28,418,310	20,846	$ 69,531,523	453	$ 41,113,213	$ 28,418,310	
LGS/SPS	1,595	$ 2,222,384	54,878	$ 183,046,128	53,283	$ 180,823,745		$ 185,268,512
LPS Combined	9	$ 13,103	7,580	$ 25,283,560	7,571	$ 25,270,457		$ 25,296,663
Lighting	235	$ 327,520	756	$ 2,521,544	521	$ 2,194,024		$ 2,849,064
	175,728	$ 244,881,826	175,728	$ 586,147,759	0	$ 341,265,933		

Note, for 40'+ poles the minimum system cost is that of a 40' pole, while the demand cost is that of the average pole 40'+ pole.

This exercise did not allocate the full account balance, as additional plant in the form of crossarms, non-unitized plant, anchors, and other miscellaneous amounts are recorded. This additional cost was allocated using the already-allocated demand totals, which reflect the weighted cost of demand for service to each class at each applicable voltage.

Q. Please summarize the allocation of the Poles account. [42]

A. The allocation is summarized in the table below:

Poles	Customer-Classified Allocation	Transmission Customer-Classified	Demand Allocation	Total	Composite Demand
Residential	$ 759,778,103	$ -	$ 174,565,960	$ 934,344,063	23.37%
SGS	$ 100,942,300	$ -	$ 39,953,052	$ 140,895,352	5.35%
LGS/SPS	$ 7,893,943	$ -	$ 473,045,151	$ 480,939,093	63.34%
LPS Combined	$ 46,541	$ 14,923,319	$ 51,762,809	$ 66,732,669	6.93%
Lighting	$ 1,163,356	$ -	$ 7,507,020	$ 8,670,377	1.01%
	$ 869,824,244	$ 14,923,319	$ 746,833,992	$ 1,631,581,554	
	Customer Counts	Customer Assigned	Composite		

Q. All else being equal, what direction of inaccuracy does this classification and allocation approach tend to have on the accuracy of CCoS study results?

A. The inability to segregate poles that are customer-specific infrastructure of a large customer other than the two taps lines identified in response to DR 0600, the selection of a 40’ pole as a minimum-size unit, and the use of customer counts rather than customer counts at primary voltage (represented for secondary customers as primary-to-secondary line transformers) would tend to understate the revenue-responsibilities of the LPS and SPS classes, and overstate the revenue responsibilities of the LGS, SGS, Residential, and Lighting classes. The inclusion of lighting fixtures as an indicator of poles for service at secondary voltage would tend to understate revenue responsibility to the Lighting class, and overstate revenue responsibility to all other classes.

[42] Transmission Customer-Classified amounts were calculated in review of the Poles – Taps subaccounts.

Overhead Conductors and Devices Account

Q. How did Staff subfunctionalize Account 365 (Overhead Conductors and Devices)?

A. Staff first subfunctionalized the account by identifying assets as Wires, Cables, Capacitors, Fusing, Switches, and Lightening Arrestors.

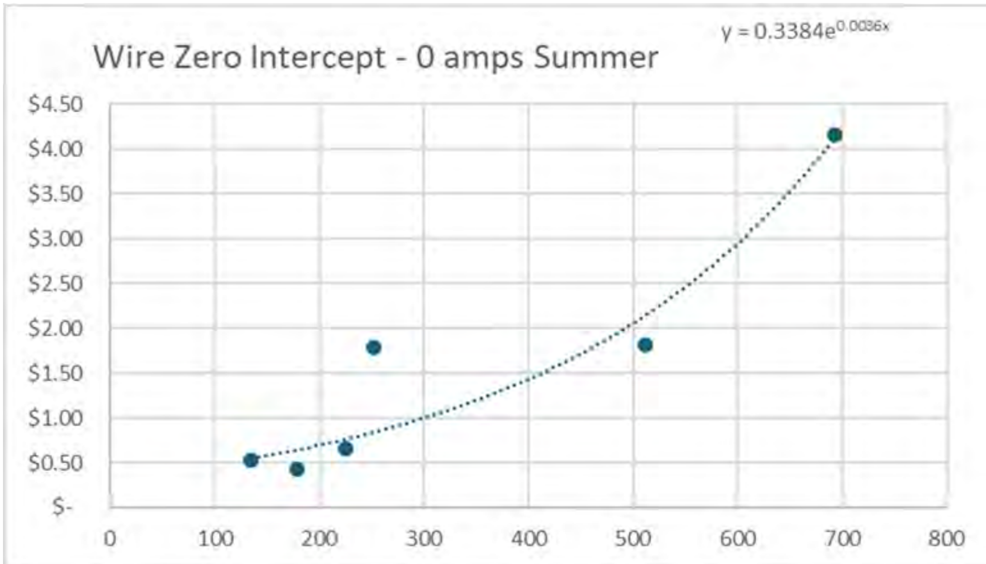
Q. How did Staff classify Cables, Capacitors, Fusing, Switches, and Lightening Arrestors?

A. For each of these subfunctions, I found the minimum cost installed unit with reasonable quantity installed for Cable, Capacitor, Fusing, Lightening Arrestors, and Switches. Because the operating ranges of Lightening Arrestors were plainly indicated in the retirement unit name, I attempted a minimum-intercept study, however, it resulted in a V shaped curve. For Fusing, 236 units existed that were priced less than selected minimum unit, these were priced out at actual price, for all other quantities, the per-unit cost of the minimum unit was multiplied by the number of units.

Q. How did Staff classify Wire?

A. I relied on Mr. Hickman's representation that the Ameren Missouri overhead system requires 270,846,365' of double conductor. I then removed the double-conductor length associated with the length of cable, resulting in a minimum system size for Wire of 267,084,035'.[43] I then calculated a zero-intercept value of $0.3384 calculated based on summer ampacity ratings of wire for which information was available (DR 0251 in File ER-2022-0337).

[43] Per response to DR 0251, in File ER-2022-0337, cables do not require a separate neutral.



Q. What are the customer-classified costs for this account?

A. The customer-classified costs, by subfunction, are provided below:[44]

	Minimum Unit	$/Unit	Count less than	Balance less than	Customer-Classified $
Cable	CABLE,3-350MCM	$ 0.58			$ 1,091,024
Capacitor	CAPACITOR,CELL,BELOW 75 KVAR	$ 493.91			$ 6,731,930
Fusing	MOUNTING,FUSE,INCLUDES FUSE & CLIPS	$ 2,415.49	236	$ 2,341	$ 30,966,456
LA	ARRESTER,LIGHTNING,10,001V-22,000V	$ 95.75			$ 28,012,363
Switch	SWITCH,50-249 AMP,7.5KV OR LESS	$ 152.68			$ 66,532,520
Wire	Zero Intercept Wire	$ 90,381,237			$ 90,381,237
					$ 223,715,530

Note, through subfunctionalizing devices, Staff's classification is more detailed than required by the NARUC Manual. This subclassification resulted in more customer-classified costs for Switches and Lightening Arrestors than if Staff had used the conductor classifier for these devices.[45] A comparison of these approaches is provided below:

$	133,334,292	<subfunctions
$	97,997,578	<use Wire allocator
$	35,336,714	36% difference

[44] Staff is aware that some subset of the assets recorded to the Overhead Conductors and Devices account is more properly classified as the customer-specific infrastructure of one or more large customers, however, information to classify either the specific assets or a representative asset cost is not available in this rate case.

[45] NARUC Manual at 93, "Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio."

Staff did include $96 million of "other" plant, including assets associated with unitization and retirement delays, for treatment with Wire.

Q. How did Staff subfunctionalize the Overhead Conductor & Device account by voltage?

A. Staff relied on the mileage of overhead conductors reported by Ameren Missouri in response to DR 0152.

	Overhead
Secondary Conductors	0%
Primary Conductors	84%
Subtransmission Conductors	16%

Staff netted the customer classified costs from the primary system costs.[46]

	Minimum Unit	Customer-Classified $	Primary Less Cust. Class. $	Sub Transmission $
Cable	CABLE,3-350MCM	$ 1,091,024	$ 7,896,591.56	$ 2,820,890
Capacitor	CAPACITOR,CELL,BELOW 75 KVAR	$ 6,731,930	$ 40,011,456	$ 15,728,728
Fusing	MOUNTING,FUSE,INCLUDES FUSE & CLIPS	$ 30,966,456	$ 177,355,170	$ 71,062,561
LA	ARRESTER,LIGHTNING,10,001V-22,000V	$ 28,012,363	$ 48,641,734	$ 42,766,140
Switch	SWITCH,50-249 AMP,7.5KV OR LESS	$ 66,532,520	$ 299,876,123	$ 137,055,968
Wire	Zero Intercept Wire	$ 90,381,237	$ 643,507,927	$ 231,634,442
		$ 223,715,530	$ 1,217,289,001	$ 501,068,729

Q. Did Staff attempt to rely on the minimum cost unit identified by Mr. Hickman, "WIRE,1/0,ALUMINUM"?

A. Yes, however there is more wire priced under the average embedded cost of "WIRE,1/0,ALUMINUM" than there are feet in the minimum system.

Q. What are the allocations of the subfunctions and total account?

[46] NARUC Manual at page 93. "Balance of conductor investment is assigned to demand."

A. Staff allocated the primary and subtransmission costs consistent with the demand allocators discussed for the Poles account. There were no identified secondary costs to allocate.

Underground Conductors & Devices	Customer-Classified Allocation	Net Primary Demand Allocation	Subtransmission Demand Allocation	Total	Composite Demand
Residential	$ 290,752,325	$ 467,357,965	$ 191,597,808	$ 949,708,098	50.70%
SGS	$ 38,628,658	$ 109,632,560	$ 41,585,766	$ 189,846,984	11.64%
LGS/SPS	$ 3,020,859	$ 298,613,246	$ 122,145,145	$ 423,779,250	32.37%
LPS Combined	$ 17,810	$ 33,274,392	$ 29,836,093	$ 63,128,296	4.86%
Lighting	$ 445,194	$ 4,992,591	$ 642,940	$ 6,080,725	0.43%
	$ 332,864,845	$ 913,870,755	$ 385,807,751	$ 1,632,543,352	
	Customer Counts	NCP 12 at Primary	CP 12 at HV		

Q. All else being equal, what direction of inaccuracy does this classification and allocation approach tend to have on the accuracy of CCoS study results?

A. Data was not available to account for the demand-carrying capabilities of Cables, Capacitors, Fusing, Lightening Arrestors, and Switches. The inability to segregate conductors and devices that are customer-specific infrastructure of a large customer and the use of customer counts rather than customer counts at primary voltage (represented for secondary customers as primary-to-secondary line transformers) would tend to understate the revenue-responsibilities of the LPS and SPS classes, and overstate the revenue responsibilities of the LGS, SGS, Residential, and Lighting classes. The lack of information to subfunctionalize non-conductors by voltage would tend to understate the revenue-responsibilities of the Residential, SGS, LGS, and Lighting classes, and overstate the revenue responsibilities of the LPS and SPS classes.

Underground Conduit and Underground Conductors & Devices Accounts

Q. How did Staff subfunctionalize Account 367 (Underground Conductors and Devices)?

A. Staff first subfunctionalized the account by identifying assets as Cables, Wires, Other Cables/Wires (such as control wires and fiber optics), Capacitors, Switches, Lightening Arrestors, and "Other," which include retirements and delayed unitizations.

Q. How did Staff calculate the customer-classified portion of each of these subfunctions?

A. I found the minimum cost installed unit with reasonable quantity installed for Wires, Other Cables/Wires, Capacitors, Switches, and Lightening Arrestors.

Q. How did Staff calculate the customer-classified portion of Cables?

A. I relied on Mr. Hickman's representation that the Ameren Missouri underground system requires 43,731,072' of cables. I then removed the length of half of the wire recorded to the account, resulting in a minimum system size for cable of 43,701,233'.[47] There were 3,425,270' of cable recorded to the account at a lower cost per foot than "CABLE,5KV,1-2,RUBBER,CONC NEUT," which was the unit Mr. Hickman identified as the minimum unit.[48] I calculated the weighted cost of the system pricing the remaining cable requirement at the cost per foot of "CABLE,5KV,1-2,RUBBER,CONC NEUT," to find a weighted-average cost per foot of the minimum system.

	Quantity	Balance	$/Unit Min	Customer-Classified
Cable	43,731,072	$ 1,041,486,038	$ 7.21	$ 315,133,765
Wire	59,679	$ 311,195	$ 0.86	$ 51,056
Other Cable/Wire	80,858	$ 596,036	$ 4.87	$ 393,465
Capacitor	12	$ 423,499	$ 9,289.79	$ 111,477
Switch	2,322	$ 88,678,330	$ 5,007.74	$ 11,627,972
LA	13,220	$ 6,042,599	$ 419.60	$ 5,547,110
Other	12,338	$ 162,140,809		
		$ 1,299,678,506		$ 332,864,845

[47] Per response to DR 0251, in File ER-2022-0337, wire requires separate neutral when used as a conductor.
[48] As indicated by the voltage rating contained in the unit name, this unit supports the primary system and exceeds the demand requirements of customers served at secondary.

Note, through subfunctionalizing devices, Staff's classification is more detailed than required by the NARUC Manual. This subclassification resulted in more customer-classified costs for Other Cables/Wires and Lightening Arrestors than had Staff used the conductor classifier for these devices.[49] A comparison of these approaches is provided below:

$	17,731,081	<subfunctions
$	29,063,396	<use Cable allocator
$	(11,332,315)	-39% difference

Staff did include $162 million of "other" plant, including assets associated with unitization and retirement delays, for treatment with Cable.

Q. How did Staff subfunctionalize the Overhead Conductor & Device account by voltage?

A. Staff relied on the mileage of overhead conductors reported by Ameren Missouri in response to DR 0152.

	Underground
Secondary Conductors	0%
Primary Conductors	96%
Subtransmission Conductors	4%

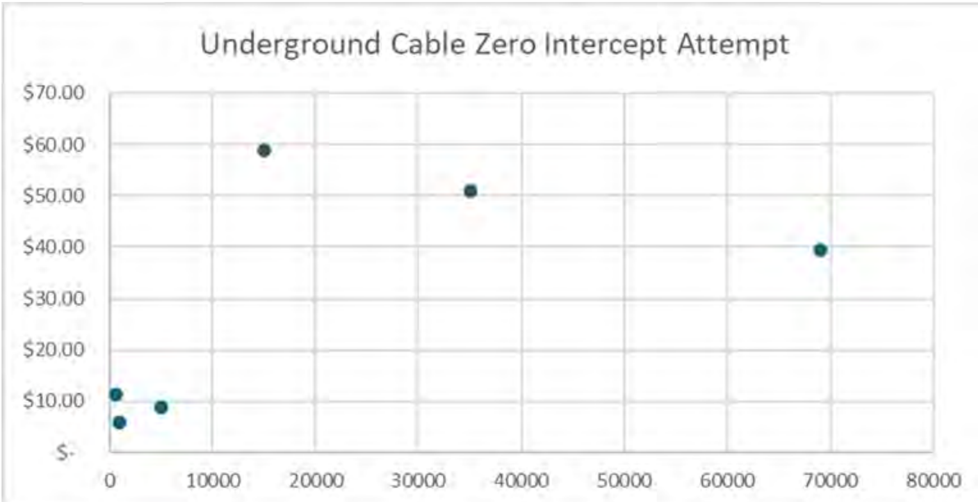
Staff netted the customer classified costs from the primary system costs.[50]

	Quantity	Balance	$/Unit Min	Customer-Classified	Primary Less Cust. Class. $	Sub Transmission $
Cable	43,731,072	$ 1,041,486,038	$ 7.21	$ 315,133,765	$ 839,462,878	$ 364,163,969
Wire	59,679	$ 311,195	$ 0.86	$ 51,056	$ 247,462.32	$ 63,733
Other Cable/Wire	80,858	$ 596,036	$ 4.87	$ 393,465	$ 178,291.02	$ 417,745
Capacitor	12	$ 423,499	$ 9,290	$ 111,477	$ 294,769.70	$ 128,729
Switch	2,322	$ 88,678,330	$ 5,008	$ 11,627,972	$ 73,438,011.97	$ 15,240,318
LA	13,220	$ 6,042,599	$ 420	$ 5,547,110	$ 249,341.84	$ 5,793,257
Other	12,338	$ 162,140,809				
		$ 1,299,678,506		$ 332,864,845	$ 913,870,755	$ 385,807,751

[49] NARUC Manual at 93, "Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio."
[50] NARUC Manual at page 93. "Balance of conductor investment is assigned to demand."

Q. Did Staff attempt a zero-intercept study?

A. Yes. It did not produce results for reasonable extrapolation:



Q. What are the allocations of the subfunctions and total account?

A. Staff allocated the primary and subtransmission costs consistent with the demand allocators discussed for the Poles account. There were no identified secondary costs to allocate.

Underground Conductors & Devices	Customer-Classified Allocation	Net Primary Demand Allocation	Subtransmisison Demand Allocation	Total	Composite Demand
Residential	$ 290,752,325	$ 467,357,965	$ 191,597,808	$ 949,708,098	50.70%
SGS	$ 38,628,658	$ 109,632,560	$ 41,585,766	$ 189,846,984	11.64%
LGS/SPS	$ 3,020,859	$ 298,613,246	$ 122,145,145	$ 423,779,250	32.37%
LPS Combined	$ 17,810	$ 33,274,392	$ 29,836,093	$ 63,128,296	4.86%
Lighting	$ 445,194	$ 4,992,591	$ 642,940	$ 6,080,725	0.43%
	$ 332,864,845	$ 913,870,755	$ 385,807,751	$ 1,632,543,352	
	Customer Counts	NCP 12 at Primary	CP 12 at HV		

Q. How did Staff subfunctionalize Account 366 (Underground Conduit)?

A. Staff first subfunctionalized the account by identifying assets as Conduit, Manholes, and "Other," which include retirements and delayed unitizations.

Q. How did Staff calculate the customer-classified portion of each of these subfunctions?

A. I found the minimum cost installed unit for Conduit and Manholes.

	Quantity	Balance	$/Unit Min	Customer-Classified
Conduit	39,137,752	$ 451,479,112	$ 2.37	$ 92,749,754
Manhole	1,821,504	$ 146,171,757	$ 9.32	$ 16,967,770
Other	69,988	$ 190,222,990	$ 9.88	
		$ 787,873,858		$ 109,717,524

Q. How did Staff subfunctionalize the Conduit account by voltage?

A. Staff relied on the mileage of underground conductors reported by Ameren Missouri in response to DR 0152. Staff did include $190 million of "other" plant, including assets associated with unitization and retirement delays, for treatment with Conduit.

Staff netted the customer classified costs from the primary system costs.[51]

	Quantity	Balance	$/Unit Min	Customer-Classified	Primary Less Cust. Class. $	Sub Transmission $
Conduit	39,137,752	$ 451,479,112	$ 2.37	$ 92,749,754	$ 522,812,365.12	$ 118,889,737
Manhole	1,821,504	$ 146,171,757	$ 9.32	$ 16,967,770	$ 123,249,623.57	$ 22,922,133
Other	69,988	$ 190,222,990	$ 9.88			
		$ 787,873,858		$ 109,717,524	$ 646,061,989	$ 141,811,870

Q. What are the allocations of the subfunctions and total account?

A. Staff allocated the primary and subtransmission costs consistent with the demand allocators discussed for the Poles account. There were no identified secondary costs to allocate.

Conduit	Customer-Classified Allocation	Net Primary Demand Allocation	Subtransmisison Demand Allocation	Total	Composite Demand
Residential	$ 95,836,570	$ 330,399,255	$ 70,425,862	$ 496,661,687	50.87%
SGS	$ 12,732,617	$ 77,504,865	$ 15,285,735	$ 105,523,218	11.78%
LGS/SPS	$ 995,723	$ 211,104,980	$ 44,897,054	$ 256,997,757	32.49%
LPS Combined	$ 5,871	$ 23,523,370	$ 10,966,892	$ 34,496,133	4.38%
Lighting	$ 146,743	$ 3,529,518	$ 236,326	$ 3,912,587	0.48%
	$ 109,717,524	$ 646,061,989	$ 141,811,870	$ 897,591,382	
	Customer Counts	NCP 12 at Primary	CP 12 at HV		

[51] NARUC Manual at page 93. "Balance of conductor investment is assigned to demand."

Q. All else being equal, what direction of inaccuracy does this classification and allocation approach tend to have on the accuracy of CCoS study results?

A. Data was not available to account for the demand-carrying capabilities of assets. The inability to segregate assets that are customer-specific infrastructure of a large customer and the use of customer counts rather than customer counts at primary voltage (represented for secondary customers as primary-to-secondary line transformers) would tend to understate the revenue-responsibilities of the LPS and SPS classes, and overstate the revenue responsibilities of the LGS, SGS, Residential, and Lighting classes.

Line Transformer Account

Q. How did you classify and allocate Account 368 (Line Transformers)?

A. Relying on Mr. Hickman's representation that "TRANSFORMER,0025KVA,1PH,7200V" is the minimum unit, I calculated the customer-classification pricing the 64,000 transformers that were less expensive than TRANSFORMER,0025KVA,1PH,7200V at the embedded costs of those transformers, and the remaining 260,000 transformers at the price of TRANSFORMER,0025KVA,1PH,7200V.

		Count	Balance	$/Transformer
	Transformers less expensive than Hickman Min:	64,686	$ 39,273,899	$ 607.15
Minimum Unit per Hickman >	TRANSFORMER,0025KVA,1PH,7200V	259,126	$ 243,464,028	$ 939.56

The resulting amount is allocated to the LGS, SGS, Residential, and Lighting classes based on customer counts.

Line Transformers	Customer-Classified Allocation	Secondary Demand Allocation	Total	Composite Demand
Residential	$ 225,864,481	$ 43,569,019	$ 269,433,500	70.04%
SGS	$ 30,007,814	$ 8,178,579	$ 38,186,393	13.15%
LGS/SPS	$ 26,519,792	$ 10,277,657	$ 36,797,449	16.52%
LPS Combined	$ -	$ -	$ -	0.00%
Lighting	$ 345,839	$ 182,730	$ 528,569	0.29%
	$ 282,737,926	$ 62,207,985	$ 344,945,911	
	Customers @ Secondary	Sigma Demand @ Secondary %		

The remaining plant balance is allocated to the same classes on the basis of estimated customer NCP demand at secondary.

Services Accounts

Q. How did you classify and allocate Account 369.1, Overhead Services?

A. Relying on Mr. Hickman's representation that "CABLE,TRI,2-2&1-2 BARE MSGR,AL" is the minimum unit, I calculated the customer classification pricing the cable that was less expensive than the CABLE,TRI,2-2&1-2 BARE MSGR,AL at the embedded cost of that cable, and the remaining feet of cable at the price of CABLE,TRI,2-2&1-2 BARE MSGR,AL.

		Feet	Balance	$/Foot
	Cable less expensive than Hickman Min:	50,970,722	$ 104,260,390	$ 2.05
Minimum Unit per Hickman >	CABLE,TRI,2-2&1-2 BARE MSGR,AL	25,420,545	$ 145,815,391	$ 5.74

I also found the minimum average unit cost Wires and Switches, and multiplied the total quantity of each by that cost.

Overhead Services	Quantity	Balance	$/Unit Min	Customer-Classified	Demand Allocation
Wire	22,118,949	$ 1,275,158	$ 0.04	$ 900,003	$ 375,155
Cable	76,391,267	$ 255,299,396	$ 3.27	$ 250,075,781	$ 5,223,615
Switch	19	$ 20,733	$ 287.34	$ 5,459	$ 15,274
Retirement/Unitization	481	$ 6,964,261			$ 6,964,261
		$ 263,559,548		$ 250,981,243	$ 12,578,304

The resulting customer-classified counts were allocated to the LGS, SGS, Residential, and Lighting classes based on customer counts. The remaining plant balance is allocated to the same classes on the basis of estimated customer NCP demand at secondary.

Overhead Services	Customer-Classified Allocation	Secondary Demand Allocation	Total	Composite Demand
Residential	$ 200,495,735	$ 8,809,550	$ 209,305,285	70.04%
SGS	$ 26,637,383	$ 1,653,689	$ 28,291,072	13.15%
LGS/SPS	$ 23,541,130	$ 2,078,117	$ 25,619,248	16.52%
LPS Combined	$ -	$ -	$ -	0.00%
Lighting	$ 306,995	$ 36,948	$ 343,943	0.29%
	$ 250,981,243	$ 12,578,304	$ 263,559,548	
	Customers @ Secondary	Sigma Demand @ Secondary %		

Q. How did you classify and allocate Account 369.2, Underground Services?

A. Relying on Mr. Hickman's representation that "CABLE,600V,2-3/0 X 1-1/0,AL" is the minimum unit, I calculated the customer classification pricing the feet of cable that were less expensive than the CABLE,600V,2-3/0 X 1-1/0,AL at the embedded cost of that cable, and the remaining feet of cable at the price of CABLE,600V,2-3/0 X 1-1/0,AL.

		Feet	Balance	$/Foot
	Cable less expensive than Hickman Min:	4,459,065	$ 11,002,936	$ 2.47
Minimum Unit per Hickman >	CABLE,600V,2-3/0 X 1-1/0,AL	35,490,256	$ 168,049,618	$ 4.74

I also found the minimum average unit cost Wires and Switches, and multiplied the total quantity of each by that cost.

Underground Services	Quantity	Balance	$/Unit Min	Customer-Classified	Demand Allocation
Wire	100	$ 898	$ 0.04	$ 4	$ 894
Cable	39,949,321	$ 195,053,702	$ 4.48	$ 179,052,554	$ 16,001,149
Switch	1,803	$ 2,554,911	$ 287.34	$ 518,065	$ 2,036,846
Other	312,742	$ 2,281,836			$ 2,281,836
Retirement/Unitization	707	$ 8,067,917			$ 8,067,917
		$ 207,959,265		$ 179,570,623	$ 28,388,643

The resulting customer-classified counts were allocated to the LGS, SGS, Residential, and Lighting classes based on customer counts. The remaining plant balance is allocated to the same classes on the basis of estimated customer NCP demand at secondary.

Underground Services	Customer-Classified Allocation	Secondary Demand Allocation	Total	Composite Demand
Residential	$ 143,449,540	$ 19,882,742	$ 163,332,282	70.04%
SGS	$ 19,058,363	$ 3,732,298	$ 22,790,661	13.15%
LGS/SPS	$ 16,843,073	$ 4,690,213	$ 21,533,286	16.52%
LPS Combined	$ -	$ -	$ -	0.00%
Lighting	$ 219,647	$ 83,389	$ 303,036	0.29%
	$ 179,570,623	$ 28,388,643	$ 207,959,265	
	Customers @ Secondary	Sigma Demand @ Secondary %		

Meters Accounts

Q. Mr. Hickman's workpapers included a meter study and calculated allocation. Did you use this information?

A. Yes. Pending expected refinements in the rate modernization workshops, I relied on Mr. Hickman's meter allocator for purposes of this case.

Distribution and Metering Expenses

Q. How were distribution and metering expenses allocated to the classes in Staff's CCoS study?

A. Depreciation expense was allocated consistent with the allocation of plant. For other expenses, because additional detail is not available, many accounts are allocated using the gross allocation of distribution net plant.

Account		Allocation
580	Supervision & Engineering - DE	12 CP
581	Load Dispatching - DE	12 CP
582	Station Expenses - DE	12 CP
583.1	Overhead Line Expenses - DE	Weighted Overhead
583.2	Install, Remove & Replace Line Transformers - Overhead	Line Transformers
584.1	Underground Line Expenses - DE	Weighted Underground
584.2	Install, Remove & Replace Line Transformers - Underground	Line Transformers
585	Street Lighting & Signal System Expenses - DE	Lighting Assignment
586	Meters - DE	Meter Allocator
587	Customer Install - DE	Gross Allocation of Distribution Plant
588	Miscellaneous - DE	Gross Allocation of Distribution Plant
589	Rents - DE	Gross Allocation of Distribution Plant
590	S&E Maintenance - DE	12 CP
591	Structures Maintenance - DE	12 CP
592	Station Equipment Maintenance - DE	12 CP
593	Overhead Lines Maintenance - DE	Weighted Overhead
594	Underground Lines Maintenance - DE	Weighted Underground
595	Line Transformers Maintenance - DE	Line Transformers
596	Street Light & Signals Maintenance - DE	Lighting Assignment
597	Meters Maintenance - DE	Meter Allocator
598	Misc. Plant Maintenance - DE	Gross Allocation of Distribution Plant
901	Supervision - CAE	Gross Allocation of Distribution Plant
902	Meter Reading Expenses - CAE	Customer Counts
903	Customer Records & Collection Expenses - CAE	Customer Counts
905	Misc. Customer Accounts Expense	Customer Counts
403	Depreciation Expense, Dep. Exp.	Gross Allocation of Distribution Plant

Q. How was the total function allocated to the classes in Staff's CCoS study?

A. The allocation is provided below:

	Residential	SGS	LGS/SPS	LPS Combined	Lighting
Net Plant	56.18%	10.82%	25.89%	4.00%	3.12%
Net Expense	58.88%	10.86%	23.72%	3.68%	2.86%
Labor	$ 53,879,700	$ 9,708,296	$ 18,312,742	$ 3,138,884	$ 2,717,683
Non Labor	$ 70,908,913	$ 12,122,633	$ 23,340,891	$ 3,368,710	$ 2,297,035
Depreciation	$ 148,552,520	$ 28,597,198	$ 68,447,070	$ 10,567,040	$ 8,241,504
Midpoint Return	$ 375,353,346	$ 72,257,635	$ 172,947,836	$ 26,700,144	$ 20,824,124
Functional CoS	$ 648,694,479	$ 122,685,763	$ 283,048,539	$ 43,774,777	$ 34,080,346
Functional RR %	57.29%	10.84%	25.00%	3.87%	3.01%

Other Costs and Expenses

Q. How are items like property taxes, employee benefits, and income taxes treated in Staff's CCoS study?

A. Staff relied on temporary subfunctions "Income Tax Ratebase," "Reallocate on Payroll," and "Reallocate on Net Ratebase," to capture these items in the Accounting schedules for redistribution to the other functions. The revenue requirement composition of each is provided below:

	Income Tax Ratebase	Reallocate on Payroll	Reallocate on Net Ratebase
Net Ratebase	$ (3,023,636,164)	$ (123,309,812)	$ (50,480,705)
NonLabor Expense & Dep. Exp. with True-up Plug	$ 6,030,906	$ (32,207,979)	$ 194,374,280
Labor Expense	$ -	$ 19,198,264	$ -
Other Revenues	$ -	$ -	$ -

Administrative and Overhead Function

Q. What is the cost causation of the costs, expenses, and revenues functionalized as Administrative and Overhead in the Staff CCoS study?

Q. The Commission assessment is directly related to class level revenue, so it is reasonably allocated to the classes using each class's share of revenue. The net ratebase element of sales and use taxes were also allocated on class revenue. Other costs in the administrative and overhead category lack causation that relates to any determinant of any class. The revenue requirement of each is indicated below:

	Administrative/ Overhead	Reallocate on Retail Revenue
Net Expense	$ 488,269,339	$ 23,341,521
Midpoint Return	$ 131,068,122	$ 188,876
	$ 619,337,460	$ 23,530,397

Q. How does Staff recommend that the non-revenue-related administrative and overhead costs be allocated to the classes?

A. Staff recommends these costs be allocated to the classes on the basis of energy sales, as the basic product of an electric utility. However, for validation of its CCoS results, Staff also calculated the return of each class where administrative and overhead costs are allocated to the classes on each class's share of net rate bases, and where administrative and overhead expenses are allocated to the classes on each class's share of net expenses. The allocations and the overall results of each study are provided below:

Energy Sales Allocation of Administrative and Overhead Costs and Expenses - Recommended Study						
	Total	Residential	SGS	LGS & SPS	LPS	Lighting
Non A&O Net Expense	$ 1,791,400,231	$ 893,813,984	$ 191,861,428	$ 541,898,435	$ 144,261,447	$ 19,564,936
Reallocate on Retail Revenue	$ 23,341,521	$ 11,729,810	$ 2,668,456	$ 6,756,079	$ 1,846,784	$ 340,392
Administrative & Overhead	$ 488,269,339	$ 210,501,563	$ 51,566,616	$ 168,767,381	$ 56,845,253	$ 588,526
Total Net Expense	$ 2,303,011,090	$ 1,116,045,357	$ 246,096,500	$ 717,421,895	$ 202,953,484	$ 20,493,854
Retail Revenue for Study Purposes	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
Revenue for Return	$ 566,778,173	$ 326,109,326	$ 81,984,343	$ 113,223,335	$ 24,104,604	$ 21,356,566
Non A&O Net Ratebase	$ 11,819,480,554	$ 6,180,347,000	$ 1,252,500,641	$ 3,428,126,022	$ 800,589,311	$ 157,917,581
Reallocate on Retail Revenue	$ 2,664,730	$ 1,339,106	$ 304,638	$ 771,292	$ 210,834	$ 38,860
Administrative & Overhead	$ 1,849,155,217	$ 797,203,577	$ 195,291,142	$ 639,149,458	$ 215,282,196	$ 2,228,843
Total Net Ratebase	$ 13,671,300,501	$ 6,978,889,684	$ 1,448,096,421	$ 4,068,046,772	$ 1,016,082,340	$ 160,185,284
Return at Current Revenues	4.15%	4.67%	5.66%	2.78%	2.37%	13.33%

Net Expense and Net Rate Base Allocation of Administrative and Overhead Costs and Expenses - Comparison Study						
	Total	Residential	SGS	LGS & SPS	LPS	Lighting
Non A&O Net Expense	$ 1,791,400,231	$ 893,813,984	$ 191,861,428	$ 541,898,435	$ 144,261,447	$ 19,564,936
Reallocate on Retail Revenue	$ 23,341,521	$ 11,729,810	$ 2,668,456	$ 6,756,079	$ 1,846,784	$ 340,392
Administrative & Overhead	$ 488,269,339	$ 243,643,080	$ 52,339,666	$ 147,619,449	$ 39,311,472	$ 5,355,672
Total Net Expense	$ 2,303,011,090	$ 1,149,186,874	$ 246,869,551	$ 696,273,963	$ 185,419,704	$ 25,261,000
Retail Revenue for Study Purposes	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
Revenue for Return	$ 566,778,173	$ 292,967,809	$ 81,211,292	$ 134,371,268	$ 41,638,384	$ 16,589,420
Non A&O Net Ratebase	$ 11,819,480,554	$ 6,180,347,000	$ 1,252,500,641	$ 3,428,126,022	$ 800,589,311	$ 157,917,581
Reallocate on Retail Revenue	$ 2,664,730	$ 1,339,106	$ 304,638	$ 771,292	$ 210,834	$ 38,860
Administrative & Overhead	$ 1,849,155,217	$ 966,905,484	$ 195,956,940	$ 536,329,338	$ 125,256,773	$ 24,706,681
Total Net Ratebase	$ 13,671,300,501	$ 7,148,591,591	$ 1,448,762,219	$ 3,965,226,652	$ 926,056,917	$ 182,663,122
Return at Current Revenues	4.15%	4.10%	5.61%	3.39%	4.50%	9.08%

In each study, the SGS and Lighting classes are found to overcontribute, and the LGS, SPS, and LPS classes are found to undercontribute. The Residential class slightly overcontributes when Administrative and Overhead expenses and costs are allocated on energy, and slightly undercontributes when Administrative and Overhead expenses and costs are allocated on net expense and net rate base, respectively.

Revenue Responsibility and Interclass Recommendation

Q. Should CCoS results be the only factor in setting rate class revenue requirements?

A. No. CCoS studies serve as a guide to setting rate class revenue requirements and should not be solely relied upon for establishing each class' revenue requirement because they are not precise, and are not updated for changes from the studied revenue requirement and billing determinants to the ordered revenue requirement and billing determinants.[52]

Policy considerations, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices are also taken into account in Staff's recommendation of Ameren Missouri's class revenue recovery through rate design. Staff endeavors to provide methods to promote revenue stability and efficiency when implementing any Commission-ordered overall change in customer revenue responsibility in rates. Staff must also balance this, to the extent possible, with retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.

[52] CCoS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless that study is updated, or unless the Commission approves that exact set of accounting schedules as well as the direct-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCoS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case.

Q. How should the revenue responsibility for the cost of service ordered in this case be recovered from the customer classes?[53]

A. Staff's CCoS Study indicates that the LPS, LGS, and SPS classes are under-contributing to the total company cost of service while the Lighting, SGS, and Residential classes are overcontributing to the current system average return, with the Lighting class overcontributing to the full cost of service. Staff recommends reallocating approximately $2.6 million of revenue responsibility from the SGS class, and approximately $3.5 million from the Lighting class, to LPS and LGS & SPS customers, in the amounts of approximately $1.3 million, and $4.8 million, respectively.

The full study results, this interclass revenue responsibility shift recommendation, and the results are presented below:

Net Expense	Cost of Wholesale Energy	$ 1,001,326,330	$ 446,467,025	$ 106,911,033	$ 339,041,015	$ 105,562,596	$ 3,344,660
Net Expense	Net MP&T (excluding Wholesale Energy)	$ 234,349,555	$ 120,112,890	$ 24,579,674	$ 71,048,861	$ 18,257,721	$ 350,408
Net Expense	Distribution/Customer	$ 555,724,346	$ 327,234,068	$ 60,370,721	$ 131,808,560	$ 20,441,130	$ 15,869,867
Net Expense	Reallocate on Retail Revenue	$ 23,341,521	$ 11,729,810	$ 2,668,456	$ 6,756,079	$ 1,846,784	$ 340,392
Net Expense	Administrative & Overhead	$ 488,269,339	$ 210,501,563	$ 51,566,616	$ 168,767,381	$ 56,845,253	$ 588,526
	Total Net Expense	$ 2,303,011,090	$ 1,116,045,357	$ 246,096,500	$ 717,421,895	$ 202,953,484	$ 20,493,854
	Retail Revenue for Study Purposes	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
	Revenue for Return	$ 566,778,173	$ 326,109,326	$ 81,984,343	$ 113,223,335	$ 24,104,604	$ 21,356,566
			48%	11%	31%	9%	1%
Net Ratebase	MP&T	$ 7,066,280,871	$ 3,509,826,751	$ 738,410,437	$ 2,197,656,913	$ 610,626,239	$ 9,760,531
Net Ratebase	Distribution/Customer	$ 4,753,199,683	$ 2,670,520,249	$ 514,090,204	$ 1,230,469,109	$ 189,963,072	$ 148,157,050
Net Ratebase	Reallocate on Retail Revenue	$ 2,664,730	$ 1,339,106	$ 304,638	$ 771,292	$ 210,834	$ 38,860
Net Ratebase	Administrative & Overhead	$ 1,849,155,217	$ 797,203,577	$ 195,291,142	$ 639,149,458	$ 215,282,196	$ 2,228,843
	Total Net Ratebase	$ 13,671,300,501	$ 6,978,889,684	$ 1,448,096,421	$ 4,068,046,772	$ 1,016,082,340	$ 160,185,284
			51%	11%	30%	7%	1%
	Return at Current Revenues	**4.15%**	**4.67%**	**5.66%**	**2.78%**	**2.37%**	**13.33%**
	Required Return at Current System Average	$ 566,778,173	$ 289,327,438	$ 60,034,482	$ 168,651,118	$ 42,124,251	$ 6,640,884
	Under/Over Contribution $	**$ -**	**$ 36,781,888**	**$ 21,949,861**	**$ (55,427,783)**	**$ (18,019,647)**	**$ 14,715,682**
	Under/Over Contribution %		**2.55%**	**6.69%**	**-6.67%**	**-7.94%**	**35.16%**
	5% threshold		$ 72,107,734	$ 16,404,042	$ 41,532,262	$ 11,352,904	$ 2,092,521
	Overrecovery			$ (5,545,818)			$ (12,623,161)
	Interclass Adjustment			$ (2,772,909)	$ 4,896,511	$ 1,338,468	$ (3,462,070)
System Average Return	MP&T	$ 500,857,988	$ 248,776,520	$ 52,338,532	$ 155,769,922	$ 43,281,188	$ 691,826
System Average Return	Distribution/Customer	$ 336,906,794	$ 189,286,475	$ 36,438,714	$ 87,215,650	$ 13,464,583	$ 10,501,372
System Average Return	Administrative & Overhead	$ 131,256,998	$ 56,600,705	$ 13,863,829	$ 45,357,583	$ 15,274,146	$ 160,735
	Class Cost of Service	**$ 3,272,032,870**	**$ 1,610,709,058**	**$ 348,737,574**	**$ 1,005,765,051**	**$ 274,973,400**	**$ 31,847,787**
	Class Cost of Service Minus Current Revenue	**$ 402,243,606**	**$ 168,554,375**	**$ 20,656,732**	**$ 175,119,820**	**$ 47,915,312**	**$ (10,002,633)**
	Increase to Equalize Rate of Return	**14.02%**	**10.46%**	**5.92%**	**17.41%**	**17.43%**	**-31.41%**
	Current Retail Revenues	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
	Interclass Revenue Responsibility Adj.	$ -	$ -	$ (2,772,909)	$ 4,896,510.65	$ 1,338,468.34	$ (3,462,070)
	Equal Percentage Increase	$ 402,243,606	$ 202,139,407	$ 45,985,405	$ 116,427,271	$ 31,825,565	$ 5,865,958
	Total Increase	$ 402,243,606	$ 202,139,407	$ 43,212,496	$ 121,323,782	$ 33,164,033	$ 2,403,888
	New Revenue Responsibility for Study Purposes	$ 3,272,032,870	$ 1,644,294,090	$ 371,293,339	$ 951,969,013	$ 260,222,121	$ 44,254,308
	% Increase for Study Purposes	14.02%	14.02%	13.17%	14.61%	14.61%	5.74%
	Return at New Revenues	**7.09%**	**7.57%**	**8.65%**	**5.77%**	**5.64%**	**14.83%**
	Actual Class Revenues	$ 2,869,789,264	$ 1,447,291,019	$ 329,249,326	$ 830,584,205	$ 220,665,241	$ 41,999,473
	% Increase of Actual Revenues	**14.02%**	**13.97%**	**13.12%**	**14.61%**	**15.03%**	**5.72%**

[53] The allocation of revenue responsibility among customer classes is also referred to as ***interclass revenue responsibility***, while the pricing of elements of a given class's rate structure can be referred to as ***intraclass revenue responsibility***, or also as ***rate design***.

Rate Design

Residential

Q. Should language regarding the transition of customers to AMI meters and the establishment of the Evening-Morning Savers rate schedule be cleaned up?

A. Yes. Staff recommends that prior to the filing of surrebuttal testimony that Ameren Missouri engage with Staff and other interested parties to clean up this language. Staff does not anticipate that any substantive changes will be necessary, but recommends that the clean-up be completed prior to the closing of testimony so that if any issues do come up they can be resolved in a timely manner.

Q. How should any rate increase in this case be implemented?

A. Staff recommends application of an equal percentage increase to all rate elements including the Evening-Morning Savers summer and winter on-peak adders, but excluding the residential customers charge. Staff recommends this charge remain at its current rate of $9.00 per customer per month.

Residential Customer Charge Cost Causation

Q. What is the net rate base associated with the residential class' portion of the meter, service line, and line transformer accounts?

A. There is $1,054,486,967 net rate base associated with the residential allocation of accounts, which results in $74,742,036 of capital costs at Staff's midpoint rate of return.

Q. What are the expenses associated with the residential allocation of these same accounts?

A. The annualized expense allocation is $15,734,679, plus $16,778,158 in depreciation expense.

Q. Does each customer require a line transformer?

A. No. This is an area where additional work is being done in the rate modernization context to better align cost with cost causation.

Q. Have you calculated the monthly customer charge based on embedded costs with and without inclusion of line transformers?

A. Yes.

	With Line Transformers		Without Line Transformers	
Midpoint Return	$	74,571,393	$	41,438,074
Expense	$	15,734,679	$	8,014,811
Depreciation	$	16,778,158	$	6,794,077
	$	107,084,231	$	56,246,962
Charge count		13,125,180		13,125,180
Per Customer per Month	**$**	**8.16**	**$**	**4.29**

Q. Have you reviewed the incremental costs attributable to a new residential customer?

A. Yes, Staff has prepared two estimates. Each estimate relies on the company CPR for vintage 2023 and 2024 distribution plant additions. The first review is based on the low-cost retirement units from these vintages, and the calculation includes a meter and a line transformer were required for each customer, and 50' of service line. The service line costs are based on an even split of overhead and underground connections. Using an aggressive 20-year depreciation rate, and a 10% plug for the costs of equity, debt, and property taxes results in an estimated first year cost of service of $17.36/month.[54]

Component	Retirement Unit	Recent Vintage Average Cost		Quantity	Gross Plant	
Meter	METER,AMI,6S20,120/480V,S4X	$	115.57	1	$	115.57
Line Transformer	TRANSFORMER,1KVA,1PH,7620V	$	943.67	1	$	943.67
Underground Service Line	CABLE,TRI,335.6MCM	$	10.09	25	$	252.31
Overhead Service Line	CABLE,TRI,4/0	$	3.09	25	$	77.13
				Gross Plant:	$	1,388.67
				Years:		20
	^Staff review of units and illustrative #			Depreciation Expense:	$	69.43
			10%	Return:	$	138.87
				Annual Capital RR:	$	208.30
				Monthly Capital RR:	$	17.36

[54] Given AMI metering and online billing, I did not include incremental costs for meter reading, billing, or postage.

A second incremental cost estimate was performed using the minimum unit identified by Mr. Hickman for line transformers and both types of service lines. For this second estimate the number of line transformers divided by the number of non-lighting customers at secondary was used for the amount of a transformer applicable to a single customer, and the number of feet of each service type divided by the number of non-lighting customers at secondary. All other inputs were the same:

Component	Retirement Unit	Recent Vintage Average Cost	Quantity	Gross Plant	Quantity in Service
Meter	METER,AMI,6S20,120/480V,S4X	$ 115.57	1	$ 115.57	
Line Transformer	TRANSFORMER,0025KVA,1PH,7200	$ 1,878.45	0.24	$ 444.80	323,812
Underground Service Line	CABLE,TRI,2-2&1-2 BARE MSGR,AL	$ 6.93	29.21	$ 202.58	39,949,321
Overhead Service Line	CABLE,600V,2-3/0 X 1-1/0,AL	$ 11.60	55.86	$ 647.84	76,391,267
Non-lighting customers @ Secondary	1,367,504		Gross Plant:	$ 1,410.79	
			Years:	20	
	^Minimum Unit and #/Customer		Depreciation Expense:	$ 70.54	
		10%	Return:	$ 141.08	
			Annual Capital RR:	$ 211.62	
			Monthly Capital RR:	$ 17.63	

This resulted in a first-year cost of service of $17.63/month.

Both estimates are likely to overstate the cost of an incremental residential customer in that larger transformers and fewer customers per transformer are likely to be expected for LGS and SGS customers, and many residential customers may be served from a single transformer and a single service drop.

Modification of Rate Structures for Compatibility with Net Metering

Q. What changes does Staff recommend related the availability of highly differentiated time-based rates for residential net metering customers?[55]

[55] The Commission's May 15, 2024 Report and Order in File No. ET-2024-0182, concerning the Solar Subscription Rider tariffs of Evergy Missouri Metro and Evergy Missouri West included the following language at pages 24 – 25: "What are the appropriate billing provisions for SSP participants? The next question before the Commission is how billing should be accomplished. For this small group of customers, the Commission is persuaded by Evergy that Staff's proposed billing methodology is too complex for the limited rates that these customers have access to. Since the Commission is not expanding access to the other TOU rates at this time, it finds that the potential cost and delay would not be reasonable for these 750 customers who have voluntarily paid a premium for the benefits of this program. However, the Commission appreciates Staff bringing forward what it

A. If the Commission determines that it is reasonable, Staff recommends that Ameren Missouri's tariff incorporate the following language,

> For bill calculation purposes, all net kWh shall be billed at the off-peak rate, with the difference between the on-peak and off-peak rate applied as a surcharge to the net kWh consumed during the on-peak period, and the difference between the super off-peak and off-peak rate applied as a credit to the net kWh consumed during the super off-peak period.

Q. Are the net bills that would result from this treatment reflective of the alignment of cost causation and revenue responsibility?

A. No, they are not. However, they are consistent with Section 386.890, RSMo.

Q. What is the statutory guidance on billing net metered customers?

A. Relevant provisions of Section 386.890, RSMo are excerpted below:

> 2.(5) "Net metering", using metering equipment sufficient to measure the difference between the electrical energy supplied to a customer-generator by a retail electric supplier and the electrical energy supplied by the customer-generator to the retail electric supplier over the applicable billing period;
>
> ***
>
> 3. (2) Offer to the customer-generator a tariff or contract that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator; and
>
> ***
>
> 5. Consistent with the provisions in this section, the net electrical energy measurement shall be calculated in the following manner:
>
> (1) **For a customer-generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period in accordance with normal metering practices for customers in the same rate class,** either by employing a single, bidirectional meter that measures the amount of electrical energy produced

believes to be and what Evergy admits is a logical and reasonable approach to allowing customers to get full benefit from TOU rates. The Commission expects Evergy to be looking ahead to its next rate cases and revising its tariffs in ways that provide all of its customers, including the SSP participants, the opportunity to participate fully in the TOU rate schedules."

> and consumed, or by employing multiple meters that separately measure the customer-generator's consumption and production of electricity;
>
> (2) **If the electricity supplied by the supplier exceeds the electricity generated by the customer-generator during a billing period, the customer-generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;**
>
> (3) **If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier during a billing period**, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with subsection 3 of this section **and shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated during the billing period**, with this credit applied to the following billing period;
>
> (4) Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve months after their issuance or when the customer-generator disconnects service or terminates the net metering relationship with the supplier [Emphasis added.].

Q. Do approaches that explicitly net usage within a time period comply with this statute?

A. No.

SGS, LGS, SPS, and LPS Rate Schedules

Q. Have Ameren Missouri, Staff, and other stakeholders taken part in discussions concerning rate modernization and cost causation?

A. Yes. As noted in the “Notice Regarding Status of Issues” filed in ER-2022-0337 on June 14, 2024 (Attached as Schedule SLKL-d3), 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.

Q. In light of these ongoing discussions and data acquisition process, is Staff limiting its rate structure and rate design recommendation in this case?

A. Yes. In this case, 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.[56] Also, consistent with the last order and the pending study, Staff recommends that Rider B charges on Sheet 75 be held constant.[57]

Lighting

Q. How does Staff recommend any rate increase be implemented in lighting rates?

A. Staff recommends an equal percentage increase to each rate.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

[56] Legacy Optional Time of day rate with increased customer charge for SGS –Sheet 55; Additional customer charge for Time of Day adjustments ($21.08) are found on LGS – Sheet 56, SPS – Sheet 57, and LPS – Sheet 61.
[57] "Likewise the Commission does not find it appropriate to adjust the Rider C factor or alter the Rider B values due to absent sufficient information to do so. All of these issues involve the non-residential classes. The Commission finds these sub-issues appropriate to address in the non-residential working docket ordered in File No. ER-2021-0240." R&O page 43, Case No. ER-2024-0319.

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	)	
	)	ss.
COUNTY OF COLE	)	

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 *Direct 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 16th day of December 2024.

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

Sarah L.K. Lange

I received my J.D. from the University of Missouri, Columbia, in 2007, and am licensed to practice law in the State of Missouri. I received my B.S. in Historic Preservation from Southeast Missouri State University, and took courses in architecture and literature at Drury University. Since beginning my employment with the MoPSC I have taken courses in economics through Columbia College and courses in energy transmission through Bismarck State College, and have attended various trainings and seminars, indicated below.

I began my employment with the Commission in May 2006 as an intern in what was then known as the General Counsel's Office. I was hired as a Legal Counsel in September 2007, and was promoted to Associate Counsel in 2009, and Senior Counsel in 2011. During that time my duties consisted of leading major rate case litigation and settlement, and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints.

In July 2013 I was hired as a Regulatory Economist III in what is now known as the Tariff / Rate Design Department. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and regulatory adjustment mechanisms and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation. I have also participated before the Commission under the name Sarah L. Kliethermes.

Presentations

Midwest Energy Policy Series – Impact of ToU Rates on Energy Efficiency (August 14, 2020)

Billing Determinants Lunch and Learn (March 27, 2019)

Support for Low Income and Income Eligible Customers, Cost-Reflective Tariff Training, in cooperation with U.S.A.I.D. and NARUC, Addis Ababa, Ethiopia (February 23-26, 2016)

Fundamentals of Ratemaking at the MoPSC (October 8, 2014)

Ratemaking Basics (Sept. 14, 2012)

Participant in Missouri's Comprehensive Statewide Energy Plan working group on Energy Pricing and Rate Setting Processes.

Relevant Trainings and Seminars

Regional Training on Integrated Distribution System Planning for Midwest/MISO Region (October 13-15, 2020)

"Fundamentals of Utility Law" Scott Hempling lecture series (January – April, 2019)

Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30, 2014)

MISO Markets & Settlements training for OMS and ERSC Commissioners & Staff (January 27–28, 2014)

Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)

PSC Transmission Training (May 14 – 16, 2013)

Grid School (March 4–7, 2013)

Specialized Technical Training - Electric Transmission (April 18–19, 2012)

The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)

Mid-American Regulatory Conference Annual Meeting (June 5–8, 2011)

Renewable Energy Finance Forum (Sept. 29–Oct 3, 2010)

Utility Basics (Oct. 14–19, 2007)

Testimony and Staff Memoranda

Company	Case No.
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2024-0319
Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2024-0189
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's and Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Solar Subscription Rider Tariff Filings	ET-2024-0182
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West The Staff of the Missouri Public Service Commission, Complainant, v Evergy Metro, Inc. d/b/a Evergy Missouri Metro's and Evergy Missouri West, Inc. d/b/a Evergy Missouri West	EC-2024-0092
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of the Joint Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of Tariff Revisions to TOU Program	ET-2024-0061
Union Electric Company d/b/a Ameren Missouri In the Matter of the Petition of Union Electric Company d/b/a Ameren Missouri for a Financing Order Authorizing the Issue of Securitized Utility Tariff Bonds for Energy Transition Costs related to Rush Island Energy Center	EF-2024-0021
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Requests for Customer Account Data Production from Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West	E0-2024-0002
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request to Revise Its Solar Subscription Rider	EO-2023-0423 EO-2023-0424
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism	EO-2023-0369 EO-2023-0370
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	ER-2023-0136

Company	**Case No.**
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Certificates of Convenience and Necessity for Solar Facilities	EA-2023-0286
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2022-0337
NextEra Energy Transmission Southwest, LLC In the Matter of the Application of NextEra Energy Transmission Southwest, LLC for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 345 kV Transmission Line and associated facilities in Barton and Jasper Counties, Missouri	EA-2022-0234
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2022-0179
Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West for a Financing Order Authorizing the Financing of Extraordinary Storm Costs Through an Issuance of Securitized Utility Tariff Bonds	EF-2022-0155
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Convenience and Necessity Under Section 393.170 RSMo Relating to Transmission Investments in Southeast Missouri	EA-2022-0099
The Empire District Electric Company d/b/a Liberty In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	ER-2021-0312
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2021-0240

Company	Case No.
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 138 kV Transmission Line and associated facilities in Perry and Cape Girardeau Counties, Missouri	EA-2021-0087
Evergy Affiliates In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of a Transportation Electrification Portfolio	ET-2021-0151
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2021-0108
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren for Approval of its Surge Protection Program	ET-2021-0082
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren Missouri to Implement the Delivery Charge Adjustment for the 1st Accumulation Period beginning September 1, 2019 and ending August 31, 2020	GT-2021-0055
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs Approval of a Transportation Electrification Portfolio for Electric Customers in its Missouri Service Area	ET-2020-0390
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs to Increase Its Revenues for Electric Service	ER-2019-0374
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service	ER-2019-0335
KCP&L Greater Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company Request for Authority to Implement Rate Adjustments Required by 4 CSR 240-20.090(8) And the Company's Approved Fuel and Purchased Power Cost Recovery Mechanism	ER-2019-0413
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Natural Gas Service	GR-2019-0077
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri Revised Tariff Sheets	ET-2019-0149
The Empire District Electric Company In the Matter of The Empire District Electric Company's Revised Economic Development Rider Tariff Sheets	ET-2019-0029

Company	Case No.
The Empire District Electric Company In the Matter of a Proceeding Under Section 393.137 (SB 564) to Adjust the Electric Rates of The Empire District Electric Company	ER-2018-0366
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Construct a Wind Generation Facility	EA-2018-0202
Kansas City Power & Light Company KCP&L Greater Missouri Operations Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2018-0145 ER-2018-0146
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program	ET-2018-0132
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff	ET-2018-0063
Laclede Gas Company Laclede Gas Company d/b/a Missouri Gas Energy In the Matter of Laclede Gas Company's Request to Increase Its Revenue for Gas Service, In the Matter of Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenue for Gas Service.	GR-2017-0215 GR-2017-0216
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0316
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0167
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Annual RESRAM Tariff Filing	ET-2017-0097
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2016-0358
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2016-0325
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	ER-2016-0285

Company	**Case No.**
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Subscriber Solar Program and File Associated Tariff	EA-2016-0207
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2016-0179
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0156
Empire District Electric Company In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0023
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri to the Iowa Border and an Associated Substation Near Kirksville, Missouri	EA-2015-0146
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line in Marion County, Missouri and an Associated Switching Station Near Palmyra, Missouri	EA-2015-0145
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	EO-2015-0055
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2014-0370
Empire District Electric Company In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	ER-2014-0351
Union Electric Company d/b/a Ameren Missouri City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0316
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2014-0258

Company	**Case No.**
Union Electric Company d/b/a Ameren Missouri Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0224
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2014-0207
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Application for Authority to Establish a Renewable Energy Standard Rate Adjustment Mechanism	EO-2014-0151
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Filing for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism	EO-2014-0095
Veolia Energy Kansas City, Inc. In the Matter of Veolia Energy Kansas City, Inc. for Authority to File Tariffs to Increase Rates	HR-2014-0066

SIMPLIFIED GLOSSARY

Cost of Service – The total amount required to own and operate a utility for one year, often expressed as

CoS = Rate Base x Cost of Capital + Expenses – Other Revenues

Note, some materials and analysists will use "Cost of Service" and "Revenue Requirement" synonymously, and some will use the term "Revenue Requirement" to refer to the Cost of Service minus current retail revenues.

Class Cost of Service – The portion of a utility's cost of service allocated to a group of similar customers

Function – The cost of service associated with a utility business segment, such as generation or distribution

Classification – The grouping or dividing of costs or expenses by how those costs or expenses will be allocated

Allocation – Attributing portions of the Cost of Service to the Classes studied in a Class Cost of Service Study

Coincident Peak - The highest amount of energy used in a defined interval, during a defined time period, across a utility or a class of customers. Or the amount of energy a customer or class of customers is using during the interval when the utility or class uses the most energy.

Noncoincident Peak – The highest amount of energy used in a defined interval, during a defined time period, for a specified customer or group of customers, regardless of when other customers or groups of customers use energy.

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.	**)))**	**File No. ER-2022-0337**

<u>NOTICE REGARDING STATUS OF ISSUES</u>

COME NOW Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") and Staff of the Missouri Public Service Commission ("Staff"), and provide this *Notice Regarding Status of Issues* to the Missouri Public Service Commission ("Commission") stating as follows:

1. On June 14, 2023, the Commission issued its *Report and Order* in this case. The *Report and Order* determined that an issue regarding Rider B and regarding the Company's Continuing Property Record ("CPR") should be addressed outside this case.

2. Specifically, the *Report and Order* stated the following regarding Rider B:

> … the Commission does not find it appropriate to … alter the Rider B values due to absent sufficient information to do so. All of these issues involve the non-residential classes. The Commission finds these sub-issues appropriate to address in the non-residential working docket ordered in File No. ER-2021-0240. Because Ameren Missouri filed this case before the Commission established a working docket via separate order, the Commission will issue an order opening a non-residential working docket within 30 days of the effective date of this order[.]

Report and Order, p. 43.

3. And with respect to the CPR, the *Report and Order* stated the following:

> Ameren Missouri proposes the Commission order the Company, Staff, Public Counsel and any other interested stakeholders, which may include other regulated utilities, to meet and discuss the mass property retirement process further. Staff's witness indicated that Staff would be open to discussions about mass property and assets. The Commission finds Ameren Missouri's proposed solution reasonable. Ameren Missouri shall meet with Staff, Public Counsel, and other interested stakeholders to resolve Staff's concerns with how mass property assets are recorded in the Company's CPR. Staff shall inform the Commission of any resolution by appropriate pleading.

Report and Order, p. 60.

4. Ameren Missouri has led three workshops so far in EW-2024-0031, which the Commission opened after issuance of the *Report and Order*. As a part of these broader rate design discussions, 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*.

5. With respect to the CPR, two meetings have been held to discuss resolution of Staff's concerns and additional meetings are contemplated over the next several months to continue efforts to resolve those concerns. The Staff and Company agree that these issues merit further discussion and analysis that the Staff and the Company expect will not lead to resolution and implementation of the CPR-related issues until subsequent to ER-2024-0319. It is anticipated that such discussions will include discussion about the scope of possible changes relating to recording mass property assets in the CPR and about the timeline for implementing such changes to efficiently and effectively resolve this issue which the Commission directed be addressed in the Commission's above-referenced *Report and Order*.

WHEREFORE, Ameren Missouri and Staff provide this *Notice Regarding Status of Issues*.

Respectfully submitted,

/s/ Jennifer L. Hernandez
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ATTORNEYS FOR UNION ELECTRIC COMPANY d/b/a AMEREN MISSOURI

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been emailed to the parties of record on this 14th day of June 2024.

/s/ James B. Lowery
James B. Lowery

No.: MPSC 0384

Please explain how fencing recorded to the Poles account, 364, is typically installed. For example, are miles of circuits fenced? Are tower bases fenced? Is fencing associated with substations improperly recorded to Account 364?

RESPONSE Prepared By: David Gilligan Title: Manager, Plant Accounting (ASC) Date: 08/22/2024

It is not part of our current standards to have fencing for 364-Poles and Structures and we are not aware of fencing that is actively being utilized for the 364-Poles and Structures. The assets identified as fencing recorded in account 364 in the amount of $68,519.57 will be retired from our records.

No.: MPSC 0384REV

RESPONSE Prepared By: David Gilligan Title: Manager, Plant Accounting (ASC) Date: August 29, 2024

The last time fencing was capitalized into account 364 was in 1985. It is not part of our current standards to have fencing for 364-Poles and Structures. After further analysis, we are not specifically aware of fencing that is actively being utilized for the 364-Poles and Structures. The assets identified as fencing recorded in account 364 in the amount of $68,519.57 will be retired from our records prior to the true-up date in this case.

No.: MPSC 0385

(a) Please provide any available information or context for the significant increases in the costs of 40’ wood poles recorded in the year 2023 relative to other years. (b) Please provide any available information or context for the significant increases in the costs of anchors recorded to account 374 in the years 2022, 2019, and 2008, with reference to Asset IDs 44105966, 37602707, and 7583639. Please provide any available information or context for the significant decreases in the costs of anchors recorded to account 374 in the years 2008 and 2021, with reference to Asset IDs 7624186, 7624615, 40086417, 6081019.

RESPONSE Prepared By: David Gilligan Title: Manager, Plant Accounting (ASC) Date: 08/19/2024

a) During the annual blanket work order unitization process in January 2024, the team identified abnormalities in the results for work order 0A018. The material costs on the project incurred in November and December 2023 included materials installed, such as the 40' wood poles, but also returns/stock adjustments of material, 50' wood poles as an example. The net assignment of the costs for work order 0A018 matched the $5.5M that was expected, but the costs assigned to the individual retirement units and associated distribution utility accounts were inflated for both the additions (positive) and returns/adjustments (negative). The team identified this in January 2024 and proceeded to make adjustments to begin correcting the retirement units and distribution utility accounts to reduce the impact on depreciation expense. A final adjustment will be made in Q3 2024 to correct the remaining impacted retirement units and utility accounts. The attached excel spreadsheet shows the detail for the retirement units impacted and associated adjustment. This adjustment will correct the amounts across the distribution utility accounts and provide a more reasonable average cost for the retirement units involved. The average cost for 40' wood poles will show approximately $7400/unit for vintage year 2023, which is reasonable based on past experience. As a result of this abnormality, depreciation expense has been overstated by approximately $55,000 total from January to July 2024.

b) The average costs of the anchors recorded in account 364 mentioned above are attributed to normal operations. As construction projects are completed, costs assigned to individual assets can fluctuate for various factors including circumstances specific to individual construction jobs, timing of labor dollars, as well as inventory and cost adjustments recorded to the work orders. The average cost by vintage year in total are in alignment with past experience.