Exhibit No. 138

Staff – Exhibit 138
Sarah L. K. Lange
Surrebuttal Testimony
File No. ER-2022-0337

Exhibit No.:	
Issue(s):	*Class Cost of Service, Rate Design*
Witness:	*Sarah L.K. Lange*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2022-0337

Jefferson City, Missouri
March 2023

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EXECUTIVE SUMMARY

Q. Please state your name and business address.

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

Q. Are you the same Sarah L.K. Lange who provided direct class cost of service (CCOS) and rate design testimony in this matter, and rebuttal testimony in this matter?

A. Yes.

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

A. In this testimony I will respond to Mr. Wills concerning time of use rate design and deployment, including his request to bill future customers to recoup deemed bill savings from proposed EV charging rate plans, and rate modernization in general. I will also respond to the Class Cost of Service, Revenue Allocation, and Rate Design rebuttal testimonies of Tom Hickman, Steve Chriss, Maurice Brubaker, and Jackie Hutchinson. I also indicate apparent contradictions in the testimonies of Mitch Lansford and Tom Hickman with respect to the retention of basic property records and the reliability and age of data relied upon bv Mr. Hickman.

Summary of Recommendations

Q. Have you modified any of your prior recommendations due to information provided in the rebuttal testimonies of witnesses in this matter?

A. Yes. Discussed in more detail below, Mr. Wills identifies a depreciation expense dispute as causative of a small increase in Staff's calculation of the residential customer charge if resolved in favor of the Ameren Missouri position. If the depreciation expense issue is resolved in favor of the Ameren Missouri position, I support a $0.50 increase in the residential customer charge.

Q. If your direct-filed CCOS Study were modified to (1) eliminate use of the RA Allocator, and to rely on a 1 CP allocator instead, and (2) to remove your customer-specific allocation of distribution accounts 364-367, and (3) to rely on Mr. Hickman's unsupported voltage classification of accounts 364-367, would your study results support the interclass allocations requested by Mr. Chriss and Mr. Brubaker?

A. No. If all of these changes were made the results would support an equal percent adjustment to all classes. The approaches on these issues taken in my direct-filed CCOS is the most reasonable approach to take for a CCOS Study in this case given the data the Company has been able or willing to make available; however Mr. Chriss, Mr. Brubaker, and Mr. Hickman take issue with these items in particular. However, my review indicates that even if these changes were made, the shifts Mr. Chriss and Mr. Brubaker request would not be supported by the modified study results. Recognizing the inherent imprecision of CCOS Studies, Staff has recommended revenue responsibility shifts only when one or more classes are studied as undercontributing by 5 or more percent while one or more classes are overcontributing by 5 or more percent.

The results of these comparative studies are summarized below, where undercontributions in excess of 5% are indicated with green highlighting, and where overcontributions in excess of 5% are indicated in red highlighting:

	Residential	SGS	LGS	SPS	LPS	Lighting	Shifts Warranted?
Bottom Bound	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
Staff Direct	7.2%	2.4%	-6.1%	-13.5%	-15.6%	42.7%	Yes, increases to LGS, SPS, & LPS
1CP Instead of RA	-0.4%	10.2%	0.3%	-8.1%	-7.8%	52.8%	Yes, increases to SPS, & LPS
364-367 Ameren Voltage, No Customer-Specific	2.6%	-0.5%	-8.1%	3.3%	-1.1%	38.3%	Yes, increase to LGS
1CP and Distribution Modifications	-4.4%	6.9%	-2.0%	11.1%	9.7%	47.8%	No.
Upper Bound	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	

RESIDENTIAL RATE DESIGN

Residential Time of Use Rate Plans

Q. Mr. Wills discussed the residential rate plan ToU process at pages 4 – 10 of his rebuttal testimony. His major concerns with Staff's recommendation to default all AMI customers to the Evening/Morning Saver rate plan one month after AMI installation appear to boil down to two concerns (1) that customers who affirmatively selected the Anytime rate plan during the last couple of years will be upset to be defaulted to the Evening/Morning Saver rate plan, and (2) that one month of time is insufficient for development of sufficient billing history for a customer to evaluate the risks of service under one of the more highly-differentiated rate plans. What are your responses to these concerns?

A. Staff is open to a provision of temporary grandfather status to those who already opted out, or who opt out prior to ToU rates for 6 months after the rate case, to be phased out the next rate case after AMI deployment is complete. However, with regard to the "evening/morning savers," rate plan, the risk he alleges of customers being unable to respond to price signals is significantly overstated. Note, Staff's recommendation here is consistent with what the Commission just ordered for Evergy.

With regard to Mr. Wills's concern that a month is insufficient for a customer to opt into a higher differential plan, Staff agrees. Staff is particularly concerned with customers opting into the "Ultimate" saver plan with its demand charge component. Staff recommends that bill comparisons for the Smart and Ultimate plans be presented only after a year, or upon specific request of a customer. This concern is compounded if the Commission allows the customer charges on these plans to be discounted relative to other residential plans.

Residential Customer Charges

Q. In his rebuttal testimony on page 16 Mr. Wills testifies that "Interestingly, where Staff can identify similar costs – including costs related to the accounts that I just referenced such as poles, but where the costs are "customer-specific," meaning the pole or similar asset only serve one individual customer, Staff includes those costs as customer-related for the classes where that identification has been made. But the fact that some or all of the costs of those items are also attributable to the need to simply connect customers to the grid is not unique to those customers and customer classes where the customer-specific assets are readily identifiable." How do you respond?

A. Mr. Wills failed to note that I included the services accounts 369.1 and 369.2. These accounts include the customer-specific assets used to connect customers to the grid when those customers are served at a secondary voltage.

Q. What is the difference between the property recorded to services accounts and the property you estimated as "customer specific" in accounts 364 – Poles, 365 – Overhead conductors, and 366 – Underground conduit.?

A. Essentially nothing, which is why I treated them the same in my CCOS Study.

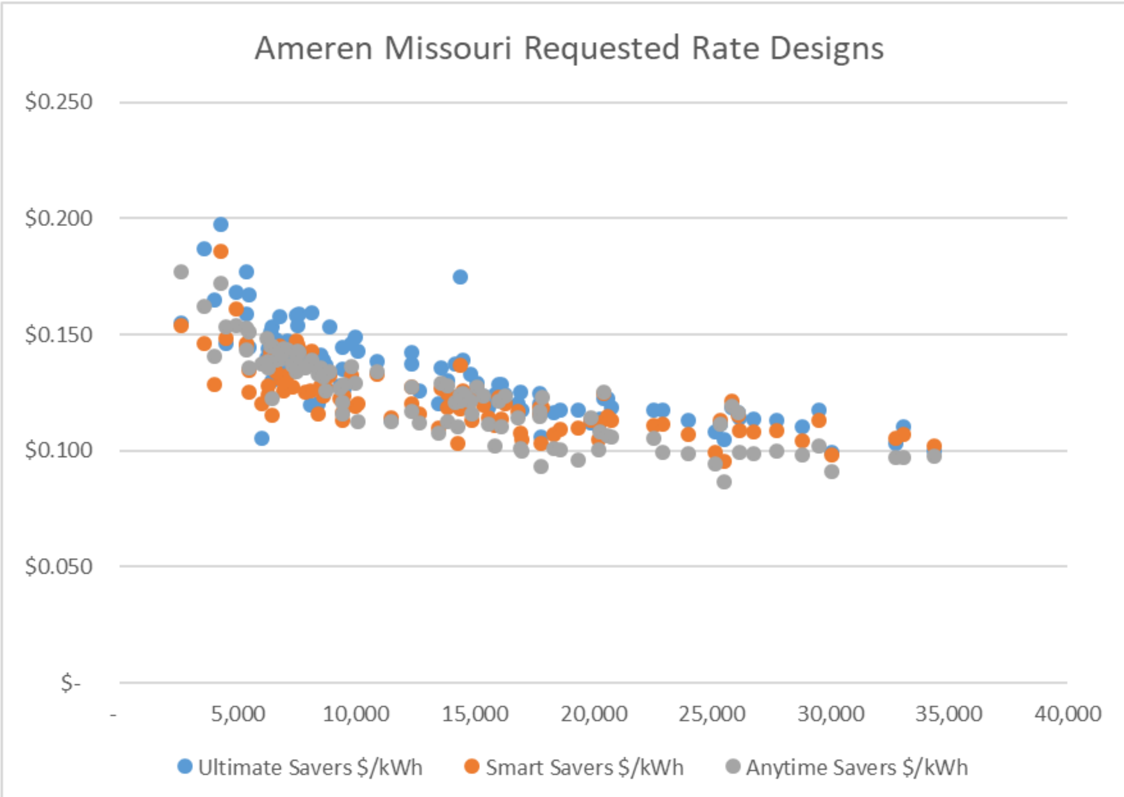
Q. In his rebuttal testimony on page 19 Mr. Wills states "As far as Ms. Hutchinson's suggestion that fixed charges should be kept low in order to provide customers with an enhanced ability to control their bills, the Company's proposal in this case already accommodates this recommendation. Recall that the advanced TOU rates, which are designed with customers who want to control their bill in mind, are proposed to have no or little increase in the customer charge." Is this reasonable?

A. No. This is the exact harm Staff is concerned about in recommending that a year should be used to provide customer comparisons on highly differentiated rates. Staff reviewed the demand charges that would be incurred for the 99 residential sample customers if they took service on the Ultimate Savers plan. The customer with the lowest annual demand charge calculation would be billed $99.01 in demand charges, for an average of $4.52 per month. The average demand charge calculated was $33.00 per month, averaging $21.98 for non-summer months and $55.06 for summer months. This plan is incredibly risky for ratepayers under the rate design proposed by Ameren Missouri in this case, and is possibly the worst suggestion for rate payers looking to limit their electric bill.

Q. Have you compared whether the energy rate savings for customers would mitigate the bill risk for customers on the Ultimate Saver's plan versus the Anytime Savers plan?

A. Yes. I have plotted the annual average bills below, on a per kWh basis which includes energy charges, customer charges, and demand charges as applicable:

continued on next page



Q. Have you calculated for the sample customers whether the Ultimate Savers would be an annual bill increase or decrease relative to the Anytime Savers plan?

A. Yes. Sixteen customers experienced a decrease, with an average value of 6%, while 83 customers experienced an increase, with an average size of 11%. The largest increase experienced was 41%, and the biggest decrease experienced was 23%.

Q. Is the Smart Savers plan a good solution to address Ms. Hutchinson's concerns?

A. No. Forty-five customers would experience a decrease, with an average value of 5%, and 54 customer would experience an increase with an average size of 5%. The largest increase experienced was 14%, and the biggest decrease was 14%. Please note, these values are based on annual bill impacts, and month to month variations can be much more significant.

Q. Do month to month bill variations improve or lessen the reasonableness of these rate plans to address Ms. Hutchinson's concern?

A. Month to month variations increase the concern. Customers would need to review at a minimum a year of their usage data to determine the sort of impact a highly differentiated rate plan will have on their energy budget.

Q. At pages 17-18 of his rebuttal testimony, Mr. Wills testifies "Second, Staff appears to have excluded the expenses in account 903 – Customer Records and Collection Expenses from its Residential customer charge study. These costs, as the account name clearly implies, are driven by customer count, not usage levels, and should be allocated as such."[1] The USOA for account 903 states "903 Customer records and collection expenses. This account shall include the cost of labor, materials used and expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints." It lists specific items. Do these items vary directly with the addition of a new customer, or the discontinuance of service of an existing customer?

A. Some items are listed which could vary with the addition of a new customer, or the discontinuance of service of an existing customer; however, Ameren's CCOS "A.F. 13" was calculated based on "Charge Offs" and "LPCs" per class. These costs are not driven by customer counts, and do not vary directly with the addition of a new customer, or the discontinuance of service of an existing customer. Rather, charge offs and late payment charges

[1] At page 18 Mr Wills testifies "Staff's customer charge analysis from the Company's last electric rate case, File No. ER-2021-0240, identified expense from account 903 in its customer charge study. Staff has not articulated a rationale for excluding these costs in this case. The Company has a pending data request to seek clarification of Staff's rationale on this point. But inclusion of the account 903 costs would increase Staff's suggested monthly cost per customer by $2.47." Staff's response to this Data Request is attached as schedule SLKL-s3, workpaper omitted.

vary with customer payment behaviors, levels of debt that vary with sizes of customer bills, and ultimately, utility management decisions.

Q. Staff's Data Request No. 0562 requested a breakdown of the values recorded to Account 903 to review the extent to which those costs would be expected to vary with the addition of a new customer, or the discontinuance of service of an existing customer. What was Ameren Missouri's response?

A. Ameren Missouri's response was that "The Company does not keep, nor is it required to maintain, records in a manner that allows it to identify these costs in the manner requested and no analysis of these costs in the requested manner exists."

Q. Is it reasonable to include Account 903 in the estimation of a reasonable customer charge value based on the data available in this case?

A. No. It is possible that for some utilities at sometimes postage or other expenses that may vary with the addition of a new customer, or the discontinuance of service of an existing customer, constitute a substantial portion of the Account 903 balance. The information Ameren Missouri has made available in this case indicates that postage (particularly postage related to customer billing) does not constitute any appreciable portion of the Account 903 balance.

Q. Mr. Wills testifies that the value of a dispute on depreciation rates between the Staff and the company would result in an increase to Staff's calculated customer charge amount if the dispute is resolved as requested by Ameren Missouri. What is your response?

A. I do not object to a $0.50 increase in all residential customer charges if Ameren Missouri's depreciation rates are ordered by the Commission.

INTERCLASS REVENUE RESPONSIBILITIES

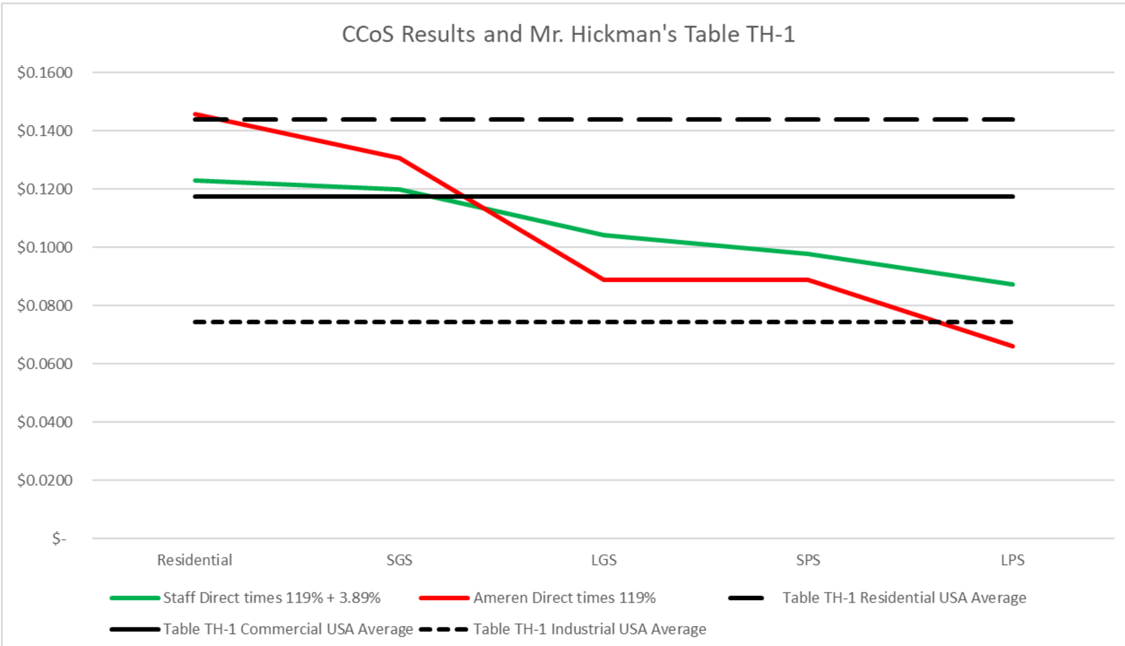
Precision of CCOS Studies

Q What is Mr. Hickman's rebuttal Table TH-1?

A. Mr. Hickman testifies that the Edison Electric Institute collects sales and revenues data from a large number of Investor-Owned Utilities ("IOUs") twice per year and publishes data related to the Average Realization Rates experienced by Residential, Commercial, and Industrial customers. He represents that Table TH-1 is the results of the national average "average $/kWh" and the Ameren Missouri "average $/kWh" results from the most recent report. He includes a "total" column indicating that the Ameren Missouri average $/kWh are 19% lower than the USA Average average $/kWh. He states his conclusion at page 4 that "This comparison is helpful because it does not look at a single utility, area, market, or data point. It is the average across IOUs throughout the country. At this high level, it indicates that the Company's CCOS results are much more reasonable than Staff's."

Q. Have you compared the USA Average results to the Ameren Missouri and Staff CCOS Study results scaled to the national average as presented by Mr. Hickman?

A. Yes. The illustration below provides a comparison of the USA Average results from Mr. Hickman's rebuttal Table TH-1 to (1) the Ameren Missouri study results, scaled up 119% consistent with Mr. Hickman's assertion of the degree to which Ameren Missouri's realized average $/kWh differs from the national average, and (2) to my direct-filed CCOS results scaled up 119% plus 3.89%, reflecting the difference in Staff and Ameren Missouri calculated total cost of service. All values are presented as average $/kWh:



Q. What conclusions should be drawn from this illustration?

A. The Staff study results are below the national average for residential customers, and slightly out of the national average range for the mixed commercial and industrial customers in the SGS class. Staff's results for customers in the mixed commercial and industrial customers in the LGS, SPS, and LPS classes are within the national average range, and trend down across those classes with LPS customers' studied costs of service much closer to the industrial average, and LGS customers closer to the commercial average.

The Ameren Missouri results are above the national average for residential customers, and for the mixed industrial and commercial LPS class, Ameren Missouri's results are below the national average for industrial customers. The Ameren Missouri results for the mixed commercial and industrial customers in the SGS class are above the national average for commercial customers, and far above the national average for industrial customers. Ameren

Missouri's results for its combined LGS/SPS customers are within the range of the national average results for commercial and industrial customers.

Q. Do you agree with Mr. Hickman's assessment that the information in Table TH-1 supports a conclusion that the Ameren Missouri results are more reasonable than the Staff results?

A. No. This illustration supports the conclusion that Staff's study is largely in line with the USA Average and that Ameren Missouri's results are relatively inconsistent with the USA Average.

Q. Does Ameren Missouri have classes that serve Commercial Customers separate from Classes that serve Industrial Customers?

A. No. SGS customers include small retail business, small offices, and light manufacturing, and service locations. LPS customers include factories, data centers, and large office. LGS and SPS range in between, including significant amounts of big box retail, offices, retail complexes, and manufacturing.

Q. Is it your opinion that this illustration demonstrates that either study is inherently unreasonable?

A. Absolutely not. Reliance on EEI data is no substitute for a utility-specific cost study. Such information could never appropriately reflect the customer make-up and rate design considerations of a given studied utility, let alone the underlying revenue requirement. As an example, a rate design that recovers more from customer and demand-based charges than from energy charges may result in higher "Commercial" average $/kWh and a lower "Industrial" average $/kWh.

Q. Would you expect the residential results presented by EEI to trend higher or lower than those appropriately found for a Missouri utility?

A. While Mr. Hickman's workpapers provided these results as a hard value with no underlying calculation, my expectation is that feed-in tariffs, the impact of net metering, and various public policy programs to support energy efficiency and universal access to electricity that occur in other jurisdictions in excess of the level to which these programs exist in Missouri would trend the USA Average residential average $/kWh higher than that reasonably calculated for a Missouri utility.

Q. Can reasonable CCOS studies produce different results?

A. Yes. While it happens that the Ameren study is not reasonable, it is entirely possible for CCOS studies to produce very different results because CCOS Studies are not precise and should only be used as a guide. At page 2 Mr. Hickman states "There are only two complete CCOS provided in the direct round of testimony in this case, one by the Company and one by Staff. The results of these two studies tell incredibly different stories. The Company's results indicate that Residential and Small General Service ("SGS") customers are providing well below target returns and Large Primary Service ("LPS") customers are providing above target returns. Staff's results indicate almost the opposite, showing Residential and SGS customers close to target and Large General Service ("LGS"), Small Primary Service ("SPS"), and LPS customers are paying below target. These directional differences and the magnitude of difference expressed cannot lead someone to conclude that both studies are reasonable." However, Staff and Ameren Missouri based their studies on different revenue requirements reflecting different levels of expenses and rate base which could drive significant differences in otherwise reasonable studies.

Q. If not based on the fact that your results differ from Ameren Missouri's, and that Ameren Missouri's results are less consistent with Mr. Hickman's representation of national averages than yours, then on what do you base your conclusion that Ameren Missouri's study results are unreasonable?

A. The most blatant flaw in the Ameren Missouri study is the reliance on an unreasonable classification of the distribution system, followed by Ameren Missouri's decision to allocate the revenue responsibility for no/low variable cost resources to classes on the basis of a demand allocator, while allocating the revenues produced from those facilities on the basis of energy.

Q. On page 3 of his rebuttal testimony, Mr. Hickman presupposes that customer interest groups will oppose a study that does not produce the results that are most favorable to them. Is this a reasonable prediction? Is this a useful prediction?

A. Staff agrees that it is likely that customers will likely support results that favor the class in which they are served, and that groups representing the interests of groups of customers will likely support the results that they deem to most favor the customers whose interest they represent. Staff unequivocally has no interest in the results of a CCoS with regard to favoring or disfavoring a given class or customers. However, Ameren Missouri does have an interest in the results of a CCOS. Ameren Missouri would prefer to see revenue diverted to areas of growth (residential customer charges) and away from areas of loss, (large customers). The revenue requirement in a given rate case is calculated for a fixed operational year, including billing determinants, but neither costs nor determinants are static in reality. Simply put, over time Ameren Missouri has tended to have increasing numbers of residential customers, and decreasing sales of kWh of energy to industrial customers, so when Ameren Missouri chooses how it wants to divide its revenue requirement by its billing determinants, it only makes sense that it would choose to recover more profit from a growth area, and less from a shrinking sales base of industrial and large commercial energy sales. Of note, in the recent Evergy rate increase requests, Ms. Bulkley who is Ameren Missouri's rate of return witness in this case filed testimony on behalf of Evergy on the same subject. In that case Ms. Bulkley testified in preference of higher residential customer charges.[2]

Criticisms of Staff's Allocation of Production Revenue Requirement

Q. On page 15 Mr. Hickman's rebuttal testimony he indicates that he has misunderstood Staff's allocation of the production revenue requirement, stating, "I think trying to assign the value of a production asset as exclusively energy or demand is problematic." Did Staff assign the value of a production asset as exclusively energy or demand?

A. No, Staff's approach explicitly recognized the capacity value of those resources allocated on the basis of energy. Staff's approach was set out in detail in my direct testimony on pages 20-23. To summarize that testimony, Staff's approach first subfunctionalized those resources with no or low variable cost as "Type 2," with remaining resources subfunctionalized as "Type 1."[3] The revenue requirement for Type 2 assets was allocated to all classes on the basis of that class's energy requirements. This is reasonable as an effective conversion of the annual revenue requirement to an average cost of energy, but also because many of these resources have been acquired to satisfy Ameren Missouri's requirements under the Missouri Renewable Energy Standard, which is based entirely on energy usage.[4]

[2] See Bulkley direct in File Nos. ER-2022-0129 and ER-2022-0130, beginning at page 63.
[3] Mr. Hickman conflates Type 1 and Type 2 assets in his rebuttal testimony.
[4] Because the preponderance of these resources are not fully dispatchable, this approach is not inconsistent with the approach Mr. Hickman assumed that I took.

Next, in the step apparently overlooked by Mr. Hickman, Staff prorated the generation in each hour from no/low variable cost resources to each class, and subtracted that amount from each class's hourly load in each hour. This produces a value for each hour for each class of that class's demand that is not met by no/low variable cost resources, which fully recognizes the capacity value of these Type 2 assets. For allocation of the revenue responsibility of the remaining production assets (which I denominated "Type 1"), Staff created an allocator reflecting the level of this unmet demand in each hour designated as an RA hour by MISO.

Q. On pages 15-16 of his rebuttal testimony, Mr. Hickman testifies "Consider new load being added to the Company's system. That load would come with both energy requirements and capacity requirements. If the production system was not sufficient to provide for this new load, Staff's approach implies that the Company would build one asset (a "Type 1" asset) to serve the energy of that customer and a second asset (a "Type 2" asset) to serve the demand of that customer. This is illogical." Is that what your approach implies?

A. No. Under Staff's approach, if the production system did not generate sufficient RECs to satisfy the RES obligations associated with the new load, Staff assumes Ameren Missouri would seek to meet those RES obligations. If Ameren Missouri met those RES obligations through the purchase or construction of generating resources, under the Staff approach the revenue requirement of those resources would be allocated to all customers on the basis of class energy consumption. If the production system with the new generation was insufficient to meet Ameren Missouri's capacity obligations under applicable federal law, rule, and tariff, Staff's approach assumes that Ameren Missouri would seek to procure additional capacity to meet the level of requirement that remains after the acquisition of the RES-related resource. This capacity could be acquired through a variety of means, ranging from a bilateral capacity-only contract, to market transactions in MISO, to a purchased-power agreement for some or all of the capabilities of a resource owned by another entity, to construction of a variety of types of generating resources.

Staff's approach to the allocation of the production revenue requirement in this case was selected in part to overcome the anachronistic belief that Ameren Missouri acquires production assets for the sole purpose of serving its retail load.[5] In reality, Ameren Missouri purchased "fire sale" CTs which were recognized in its rate base in the mid 2000's, and since then has expanded its fleet only with renewable generation.[6] Quite simply, while Ameren Missouri has increased its production fleet to meet RES requirements, Ameren Missouri has not increased its capacity to serve new load in at least decades.

Q. Mr. Chriss at page 6 of his rebuttal testifies:

> My general understanding is Staff proposes to first bifurcate the Company's generation assets into dispatchable and non-dispatchable groupings. Staff then proposes to further subdivide costs according to "variable revenue requirement components" and "stable revenue requirement components."[2] Finally, Staff proposes to allocate the dispatchable generation portion based on the All Peak Hours Approach from the NARUC Manual and appears to propose to allocate the non-dispatchable portion using an Average and Excess methodology, while not referencing the methodology by name in their testimony.[3]
> 12 See Direct Testimony of Sarah L.K. Lange, page 20, line 6, to page 22, line 15.

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[5] At page 7 Mr. Chriss criticizes reliance on the RA as based on a brand new MISO policy, and criticizes that "no other jurisdiction has ever used this specific methodology – this is wholly a creation of Staff, with no industry precedent, external validation, or peer regulatory review." Staff respectfully suggests that a new approach to a new reality is better than reliance on an approach for a reality that no longer exists.

[6] While Ameren Missouri was able to increase its capacity factor at Taum Sauk in its rebuild of the facility following its disastrous destruction, the literal capacity value was not affected. The Commission's Finding of Fact #5, Report and Order page 5 in File No. EA-2018-0202, concerning the High Prairie wind project stated, "The wind generation project for which Ameren Missouri has been granted a CCN in this case is intended to comply with the renewable energy mandates of the law." File No. EA-2019-0181 was resolved by a Stipulation and Agreement that included a provision at page 2 that "The Signatories agree the costs of this Project are Renewable Energy Standard compliance costs so long as the facility is certified by DE as a renewable energy resource under 4 CSR 340-8.010." Not only were these facilities not constructed to meet system peak capacity, these facilities were constructed to meet a statutory requirement that is based on the amount of annual energy sold at retail.

> [2] Staff does not specifically define "stable," which in my experience is not a term used in the ratemaking process, nor does it appear to delineate between costs incurred and revenue requirements. For the purposes of this docket MECG assumes Staff means "fixed costs"
>
> [3] Staff references page 49 of the NARUC Manual, and Average and Excess is the only methodology presented on that page.

Why did you use the term "stable," and did you mean "fixed costs," as suggested by Mr. Chriss?

A. I deliberately chose a term which I hoped lack common usage in the ratemaking process to clarify confusion implicated by use of terms like "fixed costs," and "variable costs." A utility's gross cost of service varies over time, and virtually no element is truly "fixed," but some elements are more stable than others.[7] A utility can significantly increase or decrease rate base associated with an asset between rate cases through depreciation, interim net salvage, repairs and maintenance, capital investment, and disposal of assets. Similarly, while costs like fuel and operation costs and expenses are variable, it is incredibly important to be cognizant that those costs and expenses vary with market dispatch of the asset, and that these costs and expenses DO NOT vary with Ameren Missouri's actual retail load.[8]

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[7] This phenomena is discussed, in part, by Mr. Hickman in his response to Mr. Brubaker's O&M argument, presented at pages 18-19 of Hickman rebuttal, stating, in pertinent part, "Mr. Brubaker highlights the fact that maintenance on coal and nuclear generation units is scheduled based on the passage of time. I think focusing on how maintenance is scheduled misses the bigger point of how much non-labor material is used during each maintenance period, and what causes the need for maintenance in the first place. The fact that maintenance occurs is a significant driver of labor costs, and the Company has classified the labor portion as fixed. The extent of maintenance performed is variable in nature and can vary significantly with the amount of time and extent to which a plant has run. Further, the need for this regularly scheduled maintenance is related to utilization of the unit – the wear and tear that occurs as energy is generated, making the energy-related allocator consistent with cost causation. In our production operations, there are components of non-labor O&M expense, which are actually budgeted based on anticipated plant generation. Our engineers have identified a number of specific examples where this is the case, including but not limited to: conveyers, coal mills, chemicals, and the limestone in scrubbers."

[8] At page 5 Chriss defined "Fixed costs are defined as costs that do not vary with the level of output and must be paid even if there is no output." While this is true in the abstract, it is imperative in the regulatory context that all utility costs vary over time, and that the relevant output to Ameren Missouri's generation is the MISO market demand for energy, not Ameren Missouri's retail load, and certainly not the energy requirement of a given Ameren Missouri customer class or customer.

Further, a given asset can have identical revenue requirement impact but be structured as purely fixed or purely variable. A good example of this is wind generation. Consider utility "A" with a PPA with a wind farm at a cost of $25 per MW hour, and utility "B" which owns a wind farm at an annual revenue requirement of $25 per MW hour. Under an anachronistic approach as advocated by Mr. Chriss, Mr. Brubaker, and Mr. Hickman, the Utility A windfarm revenue requirement would be considered variable, and the value of its output would be considered variable, and therefore would be allocated predominately to high load factor classes, on the basis of energy. However, the Utility B windfarm revenue requirement would be considered fixed and therefore allocated primarily to the low load factor classes on the basis of demand, while the value of its output is considered variable and allocated primarily to the high load factor classes on the basis of energy. However, in a given rate case, the revenue requirement of Utility B's windfarm is reducible to a $/MWh value on the basis of its normalized output, and the revenue requirement of Utility's A's windfarm could be expressed as a fixed annual value on the basis of its normalized output.

Q. In their rebuttal testimonies, Mr. Brubaker at page 4 and Mr. Chriss at page 7 criticize the use of the RA hours and the NARUC All Peak Hours approach for Type 1 production assets. Do you agree with their criticisms?

A. No. Given the significant change in the MISO integrated energy market, I continue to find my use of the RA hours net of Type 2 generation to be the most reasonable allocator for Type 1 generation under the NARUC All Peak Hours. However, I have prepared a 1 CP allocator based on each class's contribution to summer peak load net of the Type 2 generation supplied in the system peak hour as the use of a 1 CP allocator in this manner is not unreasonable. The results are summarized in the indicated section below.

Criticisms of Staff's Distribution-System Classification and Allocation

Q. Can you summarize the criticisms of your allocation of revenue responsibility presented by Mr. Hickman, Mr. Chriss, and Mr. Brubaker?

A. Yes. In general, these criticisms fell into the following categories:

> 1. Dissatisfaction with classification of customer-specific infrastructure recorded to accounts 364-367 analogous to the services for customers served at secondary recorded to account 369 subaccounts;
>
> 2. Dissatisfaction with declining to rely on Mr. Hickman's unsupported voltage classifications;
>
> 3. Dissatisfaction and apparent misunderstanding of allocation of the distribution network on the basis of each class's contribution to the system requirements in each hour, and proportionate to each hour's utilization of the distribution system;
>
> 4. General dissatisfaction with the results.

Customer-Specific Infrastructure in Accounts 364-367

Q. Did Mr. Hickman or any other witness present evidence calculating an alternative estimate of customer-specific infrastructure in distribution accounts 364-367, or disputing your calculations?

A. No.

Q. Does classification of customer-specific infrastructure within the distribution accounts 364-367 penalize any customers or group of customers?

A. No. While the USOA creates an account for the customer specific infrastructure associated with smaller customers, the customer specific infrastructure for larger customers is included in accounts 364-367, consistent with the treatment of these accounts described in the 1992 NARUC Manual. As detailed in my rebuttal testimony, my classification of these accounts simply puts customers served at a voltage other than secondary on equal footing with customers served at secondary.

Q. At pages 11-12 Mr. Brubaker testifies, "Staff has double-counted costs or has simply over-allocated or assigned the amount of costs associated with the distribution system to the LPS class, which uses hardly any of the distribution system." Does the LPS class hardly use any of the distribution system?

A. No. While there are not as many customers in the LPS class as in other customer classes, the infrastructure required by these customers is much more expensive than the infrastructure required by customers served at lower voltages with lower noncoincident demands. Also, customers in the LPS class are geographically diverse.

Q. Is there any evidence in this case as to the relative scale of the differences in cost of the customer-specific infrastructure associated with customers in different classes?

A. Yes. Mr. Hickman provides a hardcoded valuation of customer advances and deposits, by class. While there are differences in the line extension policies for residential customers, a useful touchpoint is that the current LPS customer advance per customer value is about 380 times bigger than the current SGS customer advance per customer value, as indicated below:

	Residential	SGS	LGS & SPS	LPS	Lighting
Hickman Valuation:	$ 6,526,709	$ 5,356,763	$ 6,451,838	$ 943,386	$ 83,395
# of Customers:	1,079,892	136,459	11,343	63	55322
$/Customer:	$ 6.04	$ 39.26	$ 568.79	$ 14,974.39	$ 1.51

Q. Since Ameren Missouri maintains records of the customer advances by class, wouldn't it be reasonable to expect Ameren Missouri to maintain records of customer extension costs by class?

A. Yes. It would be reasonable for Ameren Missouri to maintain records of customer extension costs by class, and these customer extension costs are generally the costs

Staff identifies as customer-specific infrastructure. However, the missing piece is Ameren Missouri making these records available in a usable form, and a correlation between the costs provided and the manner in which Ameren Missouri records those assets. For example, Staff is unable to determine whether a given conductor, device, pole, or conduit is recorded to a service account, a line transformer account, or some or all of the accounts 364-367.

Q. If customers are providing advances to offset some or all of the costs of customer-specific infrastructure, why is it necessary to allocate the cost of customer-specific infrastructure to the classes?

A. The company's books and records record customer advances for construction separate from the recording of an asset. As a simple example, if a customer in LGS required a pole be set, and paid a $500 advance that fully offset the installed costs of that pole, that pole would be allocated to all classes (predominately to SGS and Residential, under the Hickman approach) while the $500 advance would be allocated entirely to LGS. Thus, the LGS class would have an overall lower revenue requirement because a customer needed and paid the costs of a new pole.

Q. Ameren Missouri committed at paragraph 8 of the October 4, 2018 Stipulation and Agreement in ET-2018-0132 that "Ameren Missouri agrees to record customer contribution values by voltage and service classification. Prior to beginning to record these values, the Company shall circulate the form for Staff and OPC comment and agreement. This information shall be retained by Ameren Missouri and made available to Staff and OPC in future cases involving class cost of service study and/or rate design issues." Staff requested information related to this commitment in Staff's Data Request No. 0470.2 in ER-2019-0335, which Ameren Missouri represented it was unable to provide. Also in that Data Request attached as

Schedule SLKL-s1, Ameren Missouri indicated a connection between the customer and accounting systems was expected to be operational by the beginning of 2021. Has Ameren Missouri provided information in this case consistent with an internal ability to query and aggregate project information based on premise number?

A. No.

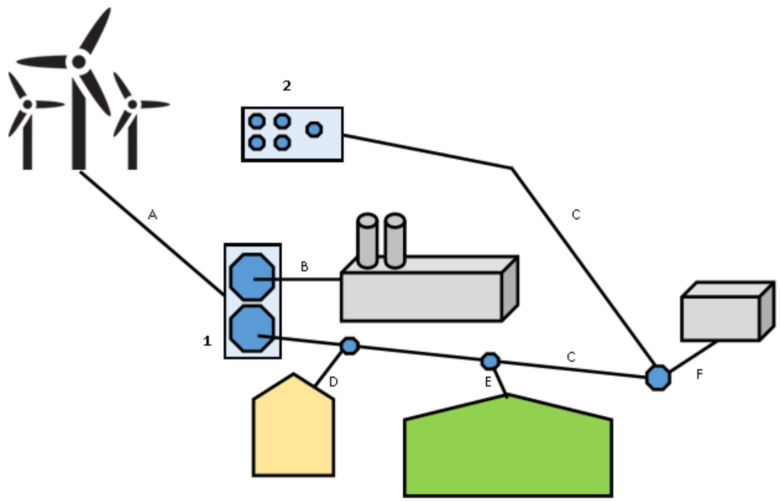
Q. At page 10, Mr. Hickmann testifies that "A significant number of circuits that operate radially on the Company's system have normally open tie switches. This fact was noted in data request responses to Staff, which were quoted by Staff witness Sarah Lange in direct testimony, at Schedule SLKL-d3 Page 7. The point is that such a circuit is not just benefitting the one customer." Does Staff invite further discussion on this point?

A. Yes. Staff relied on this information for its customer-specific infrastructure calculation only because Ameren Missouri did not make Staff's initially requested information available. One important consideration on Mr. Hickman's concern stated here, however, is that Ameren Missouri does offer a redundant supply service, tariffed as the "Rider RDC, Reserve Distribution Capacity Rider," at sheet number 84 et seq.. For customers on this service, there are actually two or more sets of customer-specific infrastructure included in Ameren Missouri's revenue requirement.

Q. On pages 7-8 of his rebuttal testimony, Mr. Hickman tries to analogize a customer-specific primary radial circuit serving a single large customer to a primary radial circuit serving a residential neighborhood. Is this an apt analogy?

A. No, the proper analogy would be to compare a customer-specific primary radial circuit serving a single large customer to a customer's service line. The primary service classes are entirely insulated from the costs of service lines, which are recorded to the Account 369 subaccounts.

A very simple example transmission and distribution system is illustrated below:



Line A represents a transmission line. Line A ties a generator to Substation 1.

Substation 1 interfaces the transmission system to the primary distribution system.

Line B is a primary distribution line operating at 12.4 kV, and has an endpoint at the facility of a customer served on the Large Primary Service rate schedule, and an endpoint at a transformer dedicated to the customer, and would be known as a radial line because it does not tie back in with other lines or substations.

Line C is a primary distribution line operating at 12.4 kV and has an endpoint at Substation 1 and another endpoint at Substation 2. In addition to supplying Substation 2, it serves three customers.

Line D is a service line for a customer served on the Residential service rate schedule. It operates at 120 Volts, and has an endpoint at a transformer that interfaces Line C's 12,400 Volt operation with the customer's 120 Volt meter.

Line E is a service line for a customer served on the Large General Service rate schedule. It operates at 600 Volts, and has an endpoint at a transformer that interfaces Line C's 12,400 Volt operation with the customer's 600 Volt meter.

Line F is a primary distribution line operating at 4.1 kV, and has an endpoint at the facility of a customer served on the Large Primary Service rate schedule, and an endpoint at a transformer dedicated to the customer, and would be known as a radial line because it does not tie back in with other lines or substations.

Ameren Missouri would record the assets associated with each line as follows:

Line A	Transmission accounts
Line B	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices
Line C	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices
Line D	369.1 Overhead Services or 369.2 Underground Services
Line E	369.1 Overhead Services or 369.2 Underground Services
Line F	364 Poles, Towers, & Fixtures and 365 Overhead Conductors & Devices – OR – 366 Underground Conduit and 367, Underground Conductors & Devices

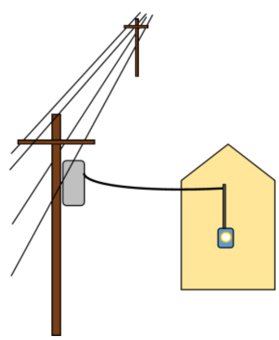
Ameren Missouri would record the assets associated with each transformer as follows:

Transformer to Line B	362 Station Equipment
Transformer to Line C	362 Station Equipment
Transformer to Line D	368 Line Transformers
Transformer to Line E	368 Line Transformers
Transformer to Line F	370 Meters

In some instances, the customer served by Line B may own the transformer used in its power supply, rather than Ameren Missouri. In that case, the customer would receive a Rider B credit to reduce a customer's bill when that customer does not rely on utility-owned customer-specific substation equipment.[9]

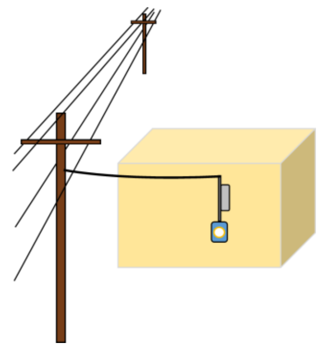
A series of examples are provided below to illustrate how assets providing similar uses are recorded differently depending on whether the ultimate customer takes service at a primary voltage or at a secondary voltage. With certain exceptions described below, Staff is not alleging that Ameren Missouri's accounting of recording the assets dedicated to the service of primary customers to Accounts 360, 361, 362, 364, 365, 366, and 367 is improper. However, it is important to be aware of the placement of these assets in these accounts in determining the appropriate allocation of these accounts within a CCoS study.

Example A: The drawing below represents a 12.47kV primary overhead line, a line transformer, a service drop, and a meter installation, all associated with a Single Family home.

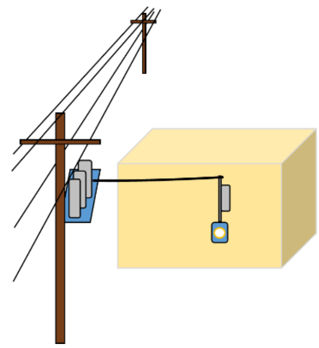


Example B: The drawing below represents a 12.47kV primary overhead line, a 12.47kV overhead cable providing service to a customer, and a meter installation including a potential transformer, all associated with a Small Primary Service customer.

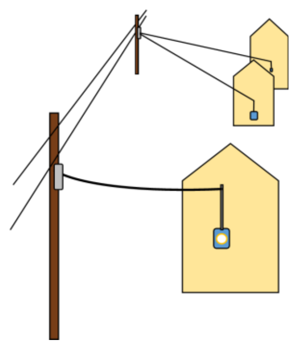
[9] The remaining assets associated with both substations would be primarily recorded to Account 362, Station Equipment, with underlying real estate and structures recorded to Account 360, Land Rights, and Account 361, Structures & Improvements.



Example C: The drawing below represents a 69kV primary overhead line, a small substation, a 34kV overhead cable providing service to a customer, and a meter installation including a potential transformer, all associated with a Large Primary Service customer.



Example D: The drawing below represents a 12.47kV primary overhead line, two line transformers, three service drops, and three meter installations, all associated with Three Single Family homes.



The poles and conductors associated with the primary overhead lines would be recorded in FERC Account 364, Poles, Towers & Fixtures and FERC Account 362, Station Equipment, respectively.[10] In addition, the plant required to serve the customers in each example would be recorded to the accounts indicated below:

Account Number	Account Description	Example A - Single Family home	Example B - Small Primary Service customer	Example C - Large Primary Service customer	Example D - Three Single Family homes
360	Land/Land Rights			Small substation	
361	Structures & Improvements			Small substation	
362	Station Equipment			Small substation	
364	Poles, Towers, & Fixtures				
365	Overhead Conductors & Devices		Cable providing service	Cable providing service	
368	Line Transformers	Line Transformer			Two line transformers
369.1	Services - Overhead	Service Cable			Three service cables
370	Meters	Meter	Metering Transformer and Meter	Metering Transformer and Meter	Three meters

Q. On page 9 of his rebuttal testimony, Mr. Hickman testifies that "if the radial circuit example where a large customer is connected directly to a substation and exclusively uses that portion of the distribution system (customer-specific, in Staff's eyes), why should that customer's contribution to system requirements in each hour be the basis for allocating any other assets? That customer's needs of the distribution system are fully met, in this example, by assets that were already assigned to their class. It is wholly inappropriate to make no attempt at removing their contribution to the allocator used for the remainder of distribution system assets." Is this fair?

A. Staff's understanding is that the LPS, SPS, and LGS customers are geographically diverse. While Staff welcomes further information on this subject, it is Staff's understanding that the distribution system functions at many voltages, with substations operating at many different voltages. Consider a customer served at 12 kV primary voltage from hypothetical substation "C." Substation C is receiving a feed from Substation "B," which operates at 34 kV voltage. That feed and Substation B are properly allocable to the 12 kV

[10] An overhead system is depicted here, but the recording of assets associated with the underground system is similar, with entries made to comparable underground accounts.

customer. Substation B is receiving a feed from Substation "A," which operates at 69 kV voltage, and Substation B also has a redundant feed to Substation "Z," which also operates at 34 kV. Substation A, Substation Z, and the related feeds are properly allocable to the 12 kV customer.

Q. On page 6 of his rebuttal testimony, Mr. Hickman's states that "The largest components of investment in distribution accounts are poles, wires and cables (jointly referred to as conductors), and line transformers." Is this an accurate statement?

A. No. Mr. Hickman neglects to include devices such as lightning arrestors, switches, and reclosers in this listing. Per Mr. Hickman's response to Data Request No. 0564, devices comprise 48% of Account 365, and 7% of Account 367, and account for a higher percentage of the referenced accounts than does transformers, as indicated below.

Conductors	$	1,687,934,754	37%	of Accounts 364, 365, 367, 368
Poles	$	1,029,815,360	23%	of Accounts 364, 365, 367, 368
Switches, Devices, and Lightening Arrestors	$	813,474,814	18%	of Accounts 364, 365, 367, 368
Transformers	$	530,304,839	12%	of Accounts 364, 365, 367, 368

Of this $813 million, Mr. Hickman allocates $594.5 million to the classes on the basis of customer count.

continued on next page

Mr. Hickman's workpaper, with percentages added, is reproduced below:

Lightning arrestors	288,080	88,999,982
Switches and reclosers	435,107	$ 505,445,731
Total Ameren Missouri Overhead Miles	25,626	
Feet in a Mile	5,280	
Total Overhead Feet	135,305,280	
Minimum System Number of Conductors	2	
Minimum System in Feet	270,610,560	18%
Minimum Feet @ Weighted Cost	260,512,012.64	17%
Lightning Arrestors, Switches, and Reclosers	594,445,712.75	40%
Total Minimum Costs	854,957,725	57%
Total Account Costs (Excluding Non-Unitized and Misc)	1,491,739,083	100%

Q. What is the relevance of this with regard to the Smart Energy Plan and Ameren Missouri's planned distribution spending?

A. For every dollar spent on smart gird project devices in the past and in the future, a minimum of 61 cents is allocated to Residential customers, no matter what level of demand or usage the class contributes in the future. Without looking at one bit of usage data, or class peak information, Ameren Missouri allocates 61% of each dollar spent on devices to residential customers. Another 9% is allocated to SGS customers. Before Ameren Missouri begins to consider demand in its allocation process for a new device, 70% of its cost is allocated to small customers.

Q. Have you prepared a version of the Staff CCOS Study that removes your classification of customer-specific infrastructure from each distribution account?

A. Yes. I have. The results are provided in the indicated section below.

Unavailability of Reasonable Voltage Classification Data

Q. On page 5-6 Mr. Hickman's testimony states that "Staff indicates that changes such as how the distribution system is networked and how smart meters can communicate with switches to reduce the duration of an outage in some cases justifies this incredibly dramatic shift in proposed cost responsibility." Is use of smart meters the basis of Staff's classification of the distribution system in this case?

A. No. The testimony Mr. Hickman appears to rely on for this statement is found at page 15 of my direct testimony.[11] It is immediately followed by this exchange

> Q. Even if the grid were not as fully integrated at this point in time as described above, is it reasonable to attempt to classify accounts 364-368 by voltage in this case?
>
> A. No. Staff has become aware of significant shortcomings in Ameren Missouri's CPR, which is the data set used for such classifications. Further, while in past cases Staff has largely deferred to Ameren Missouri's classifications, Staff is unable to verify or corroborate the information Ameren Missouri relied upon to perform its classifications. Information that could be used to corroborate this information would include miles of circuits (including secondary) operating at various voltages, and average cost or materials per line mile.

Q. In his rebuttal of Staff's classification of accounts 364-368, did Mr. Hickman provide miles of circuits operating at various voltages, and average cost or materials per line mile?

A. No, he did not.

Q. In his rebuttal testimony on page 9, Mr. Brubaker testifies, "Knowing the exact cost (and depreciated value) of a specific 34 kV line running from Point A to Point B as compared to the average cost per mile of all 34 kV lines is not particularly meaningful when rates are set on the basis of general categories of customers and voltage level. Customers taking service at 34 kV are allocated a share of the costs of 34 kV and higher voltage equipment. Rates

[11] Staff Data Request No. 0564 inquired "Please provide all support for Mr. Hickman's testimony that 'Staff indicates that changes such as how the distribution system is networked and how smart meters can communicate with switches to reduce the duration of an outage in some cases justifies this incredibly dramatic shift in proposed cost responsibility.'" Mr. Hickman's response was "The support for this statement is contained within the direct testimony of Staff Witness Sarah Lange and the rebuttal testimony of Company Witness Tom Hickman."

are designed to serve all 34 kV customers as a class, without regard to their specific geographic location, or the age of the facilities specifically providing service. In other words, unless rates were to be set separately for each individual customer, the added information would be of no value." What is the average cost of a 34 kV line?

A. Neither Staff, nor Mr. Brubaker, nor Ameren Missouri know the average cost of Ameren Missouri's 34 kV lines. In addition to the data requests described in earlier testimonies, given Mr. Brubaker's testimony on this matter, Staff submitted Data Request No. 0563, "What is the average cost per mile of all 34 kV lines?" In response, Ameren Missouri supplied the objection that "The Company objects to Data Request No. 0563 because it seeks information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence, and is overly broad and unduly burdensome, and further objects to said Data Request to the extent it seeks to require the Company to engage in research, to compile data, and to perform analyses rather than seeking the discovery of facts or existing documents or information, which is beyond the proper scope of discovery." This is confirmation that Ameren Missouri doesn't know the cost of its 34 kV system, and an apparent admission that Ameren Missouri does not consider the cost of the 34 kV system to be relevant to the question of how to reasonably allocate the cost of the 34 kV system among the customer classes for purposes of a CCOS Study in this case.

Q. In his rebuttal testimony on pages 11-12 Mr. Hickman testifies "In much the same way that Staff has tried – albeit in a biased manner – to isolate the costs of assets that serve only one customer from other customers that do not utilize that asset, separation of the costs by different voltage levels isolates costs of distribution assets at certain voltage levels that could never be involved in providing service to customers at higher voltage levels. And it is done in a balanced manner based on a thorough study of the utilization of different assets and asset classes by the voltage levels of the system that does not unfairly disadvantage one group of customers over another, unlike Staff's customer-specific cost analysis does as I discussed above." – where is this "thorough study"?

A. No such study has been submitted by Ameren Missouri in this case, or any case Staff is aware of since approximately 1996.

Q. In his rebuttal testimony on pages 20-21 Mr. Hickman testifies "Staff has repeatedly requested plant accounting information by voltage. For good reason, voltage is not an attribute typically contemplated by utility plant accounting." Does Mr. Hickman acknowledge that voltage-related information is available internally?

A. Yes, at pages 21-22 of his rebuttal testimony Mr. Hickman testifies "Relative to poles, the Company does recurring inspections of poles and records the results of those inspections. These inspections occur over periods of years, such that the information is never perfectly current. An attribute noted during these inspections is whether the pole has primary equipment, secondary equipment, or both." However Mr. Hickman at pages 21 testifies "The Company cannot produce a version of accounting records with voltage information attached." Rather than to correlate its accounting records with its available voltage information, Mr. Hickman chooses to rely on an inaccurately-scaled vaguely-referenced study to classify the Ameren Missouri distribution system for his CCOS Study.

Q. Do you have reason to question the accuracy of Mr. Hickman's testimony regarding the thoroughness of this study and the underlying records?

A. Yes. Mr. Lansford, on behalf of Ameren Missouri testifies that Ameren Missouri does not keep records concerning its poles. At page 9-10 of his rebuttal testimony, Mr. Lansford testifies that

> …if an accountant were to agree with Mr. Cunigan, a recordkeeping system would be necessary where each of the Company's approximately 900,000 poles (for example) would have to be identified by location, vintage year, and perhaps other parameters. Then a service worker would have to consult that recordkeeping system when a pole is removed and definitively know the exact vintage year of the pole removed from that location and update the CPR accordingly.

Mr. Hickman's allusions that Ameren Missouri maintains highly detailed records on the characteristics of each pole somewhere but not in the CPR is inconsistent with Mr. Lansford's testimony that a record of the characteristics of each pole would need to be created in order to maintain accurate vintage and retirement information in the CPR. Specifically, in response to Data Request No. 0565, attached as Schedule SLKL-s2, Mr. Hickman states that Ameren Missouri possesses records of the vintage year and location of each of the Company's approximately 900,000 poles.

Q. Did you obtain greater detail on the reliability of Mr. Hickman's "thorough study"?

A. Yes. In Ameren Missouri's response to Data Request No. 0565 Mr. Hickman states that the study was completed using data obtained prior to 2009, which is no longer available.

Q. While not endorsing in any manner the reasonableness of Mr. Hickman's distribution voltage classifications, have you prepared a version of the Staff CCOS Study that incorporates these classifications?

A. Yes. I have. The results in conjunction with the Ameren Missouri distribution demand allocators for each account are provided in the indicated section below.

Allocation of Distribution Network on Proportionately-Weighted Hourly Demand

Q. In his rebuttal testimony on page 9, Mr. Hickman testifies that "Staff allocated most of the cost associated with Accounts 364 through 367 'proportionate to each class's contribution to the system requirements in each hour, and proportionate to each hour's utilization of the distribution system.' This allocation method creates allocators that are nearly identical to those used to allocate costs on an energy (kWh) basis." Is this allocator nearly identical to an allocation on the basis of energy?

A. In this case, it worked out that the allocators are very similar. However, this is not always going to be the case, and the method I relied on is a reasonable allocation of the network distribution facilities.

Q. Have you prepared a version of the Staff CCOS Study that relies on NCP class demands at each classified voltage level?

A. Yes. I have. For these purposes I used Mr. Hickman's classification by voltage for the distribution accounts, although there is no evidence to support his classification. The results are provided in the indicated section below.

Results of Comparative CCOS Studies

Q. What are the results of modifying the Staff direct-filed CCOS Study to utilize a 1CP allocator for Type 1 generation resources' revenue requirements and revenues?

continued on next page

A. Those results would indicate above system-average increases are appropriate for the SPS and LPS classes, and are provided below:

1 CP ONLY							
	Residential	**SGS**	**LGS**	**SPS**	**LPS**	**Lighting**	**Total**
Net Rate Base	$ 5,077,996,226	$ 1,081,058,673	$ 2,193,338,237	$ 1,063,069,511	$ 902,138,695	$ 142,393,691	$ 10,459,995,033
Total Expense	$ 1,968,789,148	$ 203,696,721	$ 317,668,343	$ 74,039,461	$ 8,199,782	$ (3,617,811)	$ 2,568,775,644
Other Revenue	$ 903,074,015	$ (4,616,726)	$ (103,091,270)	$ (120,320,012)	$ (159,022,249)	$ (21,401,403)	$ 494,622,354
Net Expense:	$ 1,065,715,133	$ 208,313,448	$ 420,759,613	$ 194,359,473	$ 167,222,031	$ 17,783,592	$ 2,074,153,290
System Average Return on Rate Base:	$ 348,452,101	$ 74,182,246	$ 150,506,870	$ 72,947,830	$ 61,904,757	$ 9,771,055	$ 717,764,859
Pre-Allowance Revenue Requirement:	$ 1,414,167,235	$ 282,495,694	$ 571,266,482	$ 267,307,303	$ 229,126,788	$ 27,554,647	$ 2,791,918,149
Allowance for Known & Measurable Changes	$ 64,632,174	$ 12,910,998	$ 26,108,789	$ 12,216,838	$ 10,471,861	$ 1,259,340	$ 127,600,000
Rate Revenue:	$ 1,372,438,719	$ 303,286,530	$ 558,350,473	$ 239,386,090	$ 205,776,421	$ 41,023,694	$ 2,720,261,926
Revenue Available for RoR:	$ 242,091,411	$ 82,062,084	$ 111,482,071	$ 32,809,778	$ 28,082,529	$ 21,980,762	$ 518,508,636
RoR Provided at Current Revenues:	4.77%	7.59%	5.08%	3.09%	3.11%	15.44%	**4.96%**
Revenue Requirement at Current Average RoR:	$ 1,382,066,824	$ 274,813,215	$ 555,593,580	$ 259,273,346	$ 222,413,483	$ 26,101,478	$ 2,720,261,926
(Under)/Over Contribution $ at Current Average RoR:	$ (9,628,106)	$ 28,473,315	$ 2,756,894	$ (19,887,257)	$ (16,637,062)	$ 14,922,216	$ -
(Under)/Over Contribution % at Current Average RoR:	-0.70%	10.36%	0.50%	-7.67%	-7.48%	57.17%	0.00%
Revenue Requirement at System Average RoR:	$ 1,478,799,408	$ 295,406,692	$ 597,375,272	$ 279,524,141	$ 239,598,649	$ 28,813,987	$ 2,919,518,149
(Under)/Over Contribution $ at System Average RoR:	$ (106,360,690)	$ 7,879,838	$ (39,024,799)	$ (40,138,052)	$ (33,822,228)	$ 12,209,707	$ (199,256,223)
(Under)/Over Contribution % at System Average RoR:	-7.19%	2.67%	-6.53%	-14.36%	-14.12%	42.37%	-6.82%
Revenues at System Average Increase:	$ 1,472,968,360	$ 325,501,938	$ 599,249,037	$ 256,920,860	$ 220,849,319	$ 44,028,635	$ 2,919,518,149
(Under)/Over Contribution $ with System Average Increase:	$ (5,831,049)	$ 30,095,246	$ 1,873,765	$ (22,603,281)	$ (18,749,329)	$ 15,214,648	$ -
(Under)/Over Contribution % with System Average Increase:	-0.39%	10.19%	0.31%	-8.09%	-7.83%	52.80%	0.00%
% change to Achieve System Average RoR:	7.75%	-2.60%	6.99%	16.77%	16.44%	-29.76%	7.32%

Q. What are the results of modifying the Staff direct-filed CCOS Study to ignore the presence of customer-specific infrastructure in the distribution accounts, and to rely on the company's voltage classifications and allocators for the distribution accounts?

A. Those results would indicate above system-average increases are appropriate for the LGS class, and are provided below:

continued on next page

NO CUSTOMER-SPECIFIC & COMPANY VOLTAGE CLASSIFICATION							
	Residential	SGS	LGS	SPS	LPS	Lighting	Total
Net Rate Base	$ 5,100,566,572	$ 1,189,416,068	$ 2,383,834,768	$ 866,411,070	$ 764,357,140	$ 153,496,867	$ 10,458,082,484
Total Expense	$ 1,467,687,833	$ 326,299,403	$ 535,772,543	$ 134,790,437	$ 96,486,993	$ 7,545,644	$ 2,568,582,851
Other Revenue	$ 444,309,747	$ 95,206,176	$ 75,608,963	$ (43,666,258)	$ (64,510,043)	$ (12,353,189)	$ 494,595,396
Net Expense:	$ 1,023,378,086	$ 231,093,227	$ 460,163,580	$ 178,456,694	$ 160,997,035	$ 19,898,833	$ 2,073,987,455
System Average Return on Rate Base:	$ 350,000,878	$ 81,617,731	$ 163,578,742	$ 59,453,128	$ 52,450,187	$ 10,532,955	$ 717,633,620
Pre-Allowance Revenue Requirement:	$ 1,373,378,964	$ 312,710,958	$ 623,742,322	$ 237,909,822	$ 213,447,222	$ 30,431,788	$ 2,791,621,075
Allowance for Known & Measurable Changes	$ 62,774,693	$ 14,293,458	$ 28,510,145	$ 10,874,432	$ 9,756,290	$ 1,390,983	$ 127,600,000
Rate Revenue:	$ 1,372,438,719	$ 303,286,530	$ 558,350,473	$ 239,386,090	$ 205,776,421	$ 41,023,694	$ 2,720,261,926
Revenue Available for RoR:	$ 286,285,940	$ 57,899,845	$ 69,676,749	$ 50,054,963	$ 35,023,095	$ 19,733,879	$ 518,674,471
RoR Provided at Current Revenues:	5.61%	4.87%	2.92%	5.78%	4.58%	12.86%	**4.96%**
Revenue Requirement at Current Average RoR:	$ 1,339,118,241	$ 304,376,442	$ 606,901,348	$ 232,301,270	$ 208,662,047	$ 28,902,579	$ 2,720,261,926
(Under)/Over Contribution $ at Current Average RoR:	$ 33,320,478	$ (1,089,913)	$ (48,550,875)	$ 7,084,820	$ (2,885,626)	$ 12,121,116	$ -
(Under)/Over Contribution % at Current Average RoR:	2.49%	-0.36%	-8.00%	3.05%	-1.38%	41.94%	0.00%
Revenue Requirement at System Average RoR:	$ 1,436,153,657	$ 327,004,415	$ 652,252,466	$ 248,784,254	$ 223,203,512	$ 31,822,770	$ 2,919,221,075
(Under)/Over Contribution $ at System Average RoR:	$ (63,714,938)	$ (23,717,886)	$ (93,901,993)	$ (9,398,164)	$ (17,427,092)	$ 9,200,924	$ (198,959,149)
(Under)/Over Contribution % at System Average RoR:	-4.44%	-7.25%	-14.40%	-3.78%	-7.81%	28.91%	-6.82%
Revenues at System Average Increase:	$ 1,472,818,479	$ 325,468,817	$ 599,188,061	$ 256,894,717	$ 220,826,847	$ 44,024,155	$ 2,919,221,075
(Under)/Over Contribution $ with System Average Increase:	$ 36,664,822	$ (1,535,599)	$ (53,064,405)	$ 8,110,463	$ (2,376,665)	$ 12,201,385	$ -
(Under)/Over Contribution % with System Average Increase:	2.55%	-0.47%	-8.14%	3.26%	-1.06%	38.34%	0.00%
% change to Achieve System Average RoR:	4.64%	7.82%	16.82%	3.93%	8.47%	-22.43%	7.31%

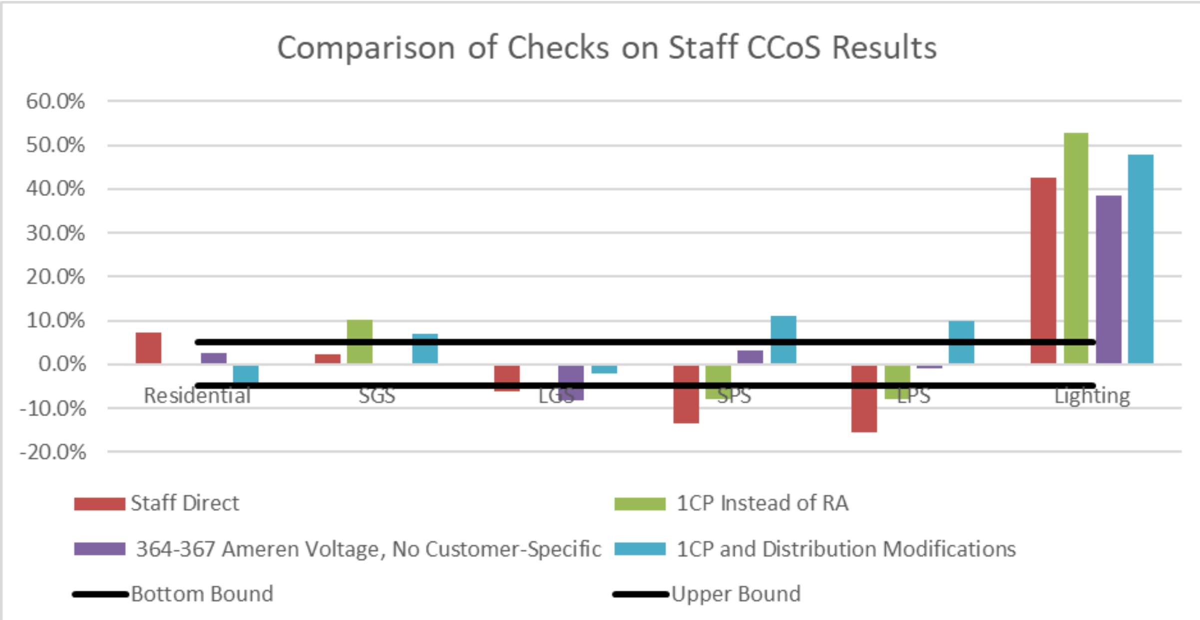
Q. What are the results of combining both modifications?

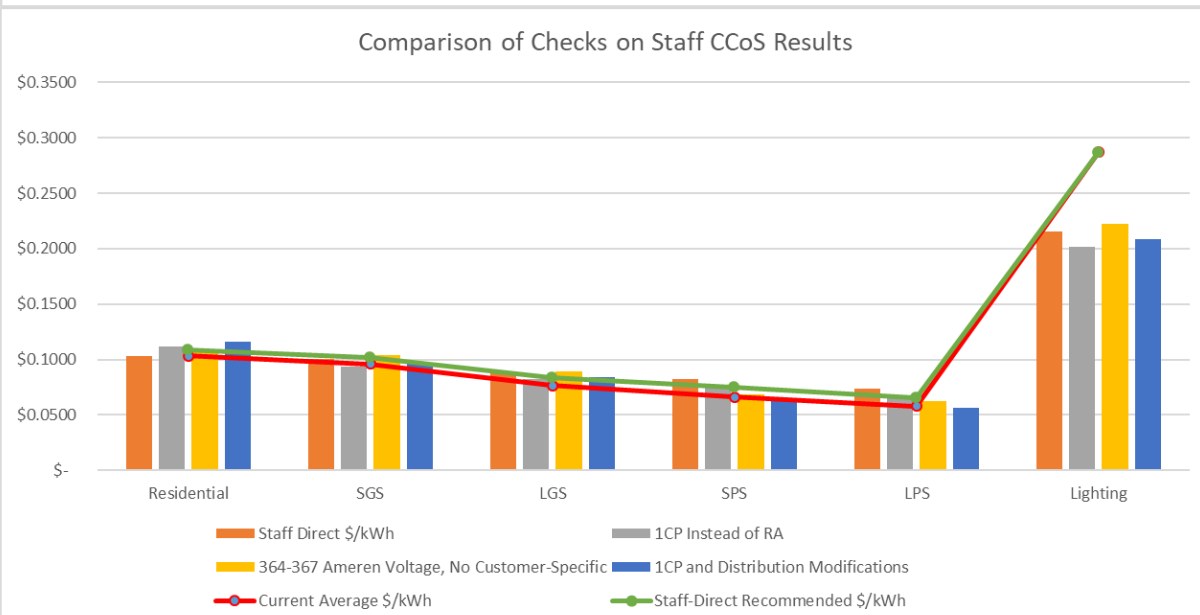
A. Those results would indicate that no revenue neutral shifts are necessary, and are provided below:

1 CP & NO CUSTOMER-SPECIFIC & COMPANY VOLTAGE CLASSIFICATION							
	Residential	SGS	LGS	SPS	LPS	Lighting	Total
Net Rate Base	$ 5,398,140,641	$ 1,125,484,818	$ 2,268,586,105	$ 816,249,825	$ 701,918,338	$ 147,702,757	$ 10,458,082,484
Total Expense	$ 2,008,566,232	$ 210,096,295	$ 326,293,563	$ 43,616,048	$ (17,003,405)	$ (2,985,882)	$ 2,568,582,851
Other Revenue	$ 905,428,299	$ (3,861,210)	$ (102,979,503)	$ (121,395,748)	$ (161,264,743)	$ (21,331,698)	$ 494,595,396
Net Expense:	$ 1,103,137,933	$ 213,957,504	$ 429,273,067	$ 165,011,796	$ 144,261,338	$ 18,345,817	$ 2,073,987,455
System Average Return on Rate	$ 370,420,411	$ 77,230,768	$ 155,670,379	$ 56,011,063	$ 48,165,636	$ 10,135,363	$ 717,633,620
Pre-Allowance Revenue	$ 1,473,558,344	$ 291,188,273	$ 584,943,445	$ 221,022,859	$ 192,426,975	$ 28,481,180	$ 2,791,621,075
Allowance for Known &	$ 67,353,713	$ 13,309,694	$ 26,736,717	$ 10,102,559	$ 8,795,492	$ 1,301,824	$ 127,600,000
Rate Revenue:	$ 1,372,438,719	$ 303,286,530	$ 558,350,473	$ 239,386,090	$ 205,776,421	$ 41,023,694	$ 2,720,261,926
Revenue Available for RoR:	$ 201,947,072	$ 76,019,331	$ 102,340,689	$ 64,271,735	$ 52,719,590	$ 21,376,054	$ 518,674,471
RoR Provided at Current Revenues:	3.74%	6.75%	4.51%	7.87%	7.51%	14.47%	4.96%
Revenue Requirement at Current	$ 1,438,215,461	$ 283,086,250	$ 568,521,585	$ 215,596,723	$ 187,868,865	$ 26,973,042	$ 2,720,261,926
(Under)/Over Contribution $ at	$ (65,776,743)	$ 20,200,280	$ (10,171,112)	$ 23,789,367	$ 17,907,556	$ 14,050,653	$ -
(Under)/Over Contribution % at	-4.57%	7.14%	-1.79%	11.03%	9.53%	52.09%	0.00%
Revenue Requirement at System	$ 1,540,912,057	$ 304,497,967	$ 611,680,163	$ 231,125,418	$ 201,222,467	$ 29,783,004	$ 2,919,221,075
(Under)/Over Contribution $ at	$ (168,473,339)	$ (1,211,437)	$ (53,329,689)	$ 8,260,672	$ 4,553,953	$ 11,240,691	$ (198,959,149)
(Under)/Over Contribution % at	-10.93%	-0.40%	-8.72%	3.57%	2.26%	37.74%	-6.82%
Revenues at System Average	$ 1,472,818,479	$ 325,468,817	$ 599,188,061	$ 256,894,717	$ 220,826,847	$ 44,024,155	$ 2,919,221,075
(Under)/Over Contribution $ with System Average Increase:	$ (68,093,578)	$ 20,970,849	$ (12,492,102)	$ 25,769,299	$ 19,604,380	$ 14,241,151	$ -
(Under)/Over Contribution % with System Average Increase:	-4.42%	6.89%	-2.04%	11.15%	9.74%	47.82%	0.00%
% change to Achieve System	12.28%	0.40%	9.55%	-3.45%	-2.21%	-27.40%	7.31%

Q. Could you illustrate these relative results?

A. Yes, an illustration is provided below:





Q. Could you provide a summary of these results as an average $/kWh by class?

A. Yes.

	Residential	SGS	LGS	SPS	LPS	Lighting
Current Average $/kWh	$ 0.1033	$ 0.0961	$ 0.0766	$ 0.0662	$ 0.0578	$ 0.2870
Staff Direct $/kWh	$ 0.1034	$ 0.1008	$ 0.0875	$ 0.0821	$ 0.0734	$ 0.2158
1CP Instead of RA	$ 0.1113	$ 0.0936	$ 0.0820	$ 0.0772	$ 0.0673	$ 0.2016
364-367 Ameren Voltage, No Customer-Specific	$ 0.1081	$ 0.1036	$ 0.0895	$ 0.0688	$ 0.0627	$ 0.2226
1CP and Distribution Modifications	$ 0.1160	$ 0.0965	$ 0.0839	$ 0.0639	$ 0.0565	$ 0.2083
Staff-Direct Recommended $/kWh	$ 0.1089	$ 0.1013	$ 0.0836	$ 0.0747	$ 0.0652	$ 0.2870

Q. Could you provide a summary of the indicated results as the percent change to current revenues required to equalize the rates of return of the studied classes?

A. Yes. Those results and the indicated shifts are summarized below:

	Residential	SGS	LGS	SPS	LPS	Lighting	Shifts Warranted?
Bottom Bound	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	-5.0%	
Staff Direct	7.2%	2.4%	-6.1%	-13.5%	-15.6%	42.7%	Yes, increases to LGS, SPS, & LPS
1CP Instead of RA	-0.4%	10.2%	0.3%	-8.1%	-7.8%	52.8%	Yes, increases to SPS, & LPS
364-367 Ameren Voltage, No Customer-Specific	2.6%	-0.5%	-8.1%	3.3%	-1.1%	38.3%	Yes, increase to LGS
1CP and Distribution Modifications	-4.4%	6.9%	-2.0%	11.1%	9.7%	47.8%	No.
Upper Bound	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	

LGS, SPS, AND LPS RATE DESIGN

Rate Modernization

Q. In his rebuttal testimony on page 11 Mr. Wills testifies that "The Residential rate changes were ordered in March 2020, but could not be fully implemented until May 2021," in support of his claim that changes to bill customers the recommended ToU overlay will require extensive leave time. Does this testimony omit significant context?

A. Yes. On 10/6/2020 Ameren Missouri filed an application seeking authority to temporarily delay certain TOU rates being offered to or becoming default rates for residential customers for up to five months and to temporarily delay the provision of TOU rate-related communication tools for up to five months, including:

> Making adjustments to Ameren Missouri's systems and processes to allow the migration of all of Ameren Missouri's more than 1 million residential customers to TOU billing has turned out to be more difficult and time-consuming than the Company thought it would be when the First Agreement was signed. Despite Ameren Missouri's best efforts, the

> timeframes set out in the First Agreement for the Daytime/Overnight default rate implementation, the optional three-part rate with demand charge and TOU energy charges implementation, a communication to customers within six months of their AMI being installed to educate customers on what their bill would have been in prior billing periods under available rate options, and the on-line rate comparison tool cannot be met. As detailed further below, the barriers to meeting the original timeframes are the additional technical and process scope of the project beyond that which was originally identified, the need for additional testing/quality assurance measures to ensure that the integrity of the Company's billing system is preserved, **the virtual training needed for field personnel and across the customer-interacting departments, the difficulty of coordinating key vendors' timeframes, and other COVID-19 pandemic impacts**.[12] [Emphasis added].

At page 17, the Application cites COVID 19 as the reason for delay in training for billing department employees, “To ensure the best remote training experience under the COVID-19 pandemic work circumstances, training is more compartmentalized and broken up in smaller delivery times over more days creating a longer timeline for training delivery. Additionally, multiple training resources are needed to complete the virtual training — one trainer to deliver the material and another trainer to ensure user retention and field virtual questions and any system issues. This additional resource need for virtual training lengthens the Company's training delivery timeline due to resource availability.” At page 18 the Application states “e. COVID-19 Impacts: The extended changes to Ameren Missouri's work environment to support co-worker health and safety under the COVID-19 pandemic impacted the Company's efficiencies when developing technological requirements through BPD sessions and collaboration. Testing on the billing system remotely has also triggered numerous performance issues so that testing remotely has been less efficient than testing on-site. This has been an extenuating circumstance adding to the testing timeline.”

[12] See Application in EE-2021-0103 at pages 4-5.

In response to Staff's Data Request No. 0002 in EE-2021-0130, "Please refer to the Application in this matter, at page 20, stating "Furthermore, since two of the TOU rate options will be slightly delayed, it only makes sense for the rates communication tools (communication to customers within six months of their AMI being installed to educate customers on what their bill would have been in prior billing periods under available rate options and the on-line rate comparison tool) about those rate options and the other already available rate options to be synced up and slightly delayed." Please specify which of the two TOU Rate options will be delayed. Please clarify how of the three non-demand rate ToU options deployment of one is more complicated than the other two? Please clarify whether programming of TOU options or whether deployment of a change in the default rate are the driver of this request – or whether some other issue is the driver of this request." Mr. Wills, on behalf of Ameren Missouri responded:

> The two rate options that will be delayed are R-DAYNIGHT (branded Evening/Morning Savers), which is the new default rate for residential customers with an AMI meter, and R-TOUUS (branded Ultimate Savers), which is the new three part rate with Time of Use energy charges and a demand charge. The primary driver of the requested delay in this case is not programming the billing system to be able to generate a bill on the new rates, but rather the system and business process impacts that will result from the default rate conversion process, customer education needed to support that transition, and the rapid conversion of most customers to interval billing to support TOU. Those impacts include but are not limited to: creation of shadow bill capability (IT), develop customer communication/mailings (Customer Experience), develop rate analysis/switching tools for the customer (IT), rate switching processes and training for Company's Contact Center employees (Customer Experience), conversion of most AMI customers to interval billing (IT), modifying bill print to support interval billing (vendor IT), and substantial testing to make sure the new functionality does not negatively impact existing systems and processes.
>
> The R-DAYNIGHT rate is not significantly more complex to bill than R-TOU (branded Smart Savers) or R-TOU2 (branded Overnight Savers). However, R-TOU and R-TOU2 were proposed by the Company in its

> direct testimony filed in July 2019 in File No. ER-2019-0335. As such, programming was underway for these rates well in advance of the settlement reached in that case, which gave rise to the R-DAYNIGHT rate option. The Company had begun to plan for these rates to be available upon conclusion of the rate review approximately a year in advance of the time when customers would first be allowed to elect those rates. The advance work done to prepare billing systems for those rates was not able to be performed for the R-DAYNIGHT rate because that rate simply was not contemplated at the time the Company developed its case.

Q. Has Ameren Missouri undertaken any "advance work" to prepare to implement any future rate modernization efforts?

A. Ameren Missouri's response to Data Request No. 0566 indicated that as of February 27, 2023, Ameren Missouri has not undertaken any advance work begun, in progress, or completed to prepare billing systems for rate plans for non-residential customers that differ from the rate structures currently authorized.

Q. In his rebuttal testimony on page 11 Mr. Chriss states "My understanding is that Staff proposes that the Commission maintain the current relationship between LGS and SP charges and apply any rate change on a uniform percentage with the exception of the reactive kVar charges. See Direct Testimony of Sarah L.K. Lange, page 39, line 12 to line 16." Is this accurate?

A. No. I recommended different interclass revenue responsibility levels for the LGS and SPS classes.

Q. Mr. Wills on page 10-11 of his rebuttal testimony testifies that it is unreasonable to begin rate modernization for non-residential customers in this case, but rather that the tariffs should wait for a full overhaul in a future rate case. Is this reasonable?

A. No. Staff's proposed overlay is so modest it will cause less bill impact for most customers than the proposal of MECG. Disproportionate rate adjustments like that proposed by MECG are not uncommon. Staff welcomed input on time period selection. Staff's proposal makes customers aware of the issue and develops determinants prior to a massive overhaul as envisioned by Wills.

Q. Mr. Hickman at page 20 of his rebuttal testimony opines that Staff's requests for the basic data related to distribution costs that I have discussed is both "increasingly granular" and that it lacks "clear definition or scope." For purposes of a rate modernization workshop, what is the information that is necessary for determining the cost causation of various contemplated charge elements?

A. Based on existing data shortfalls, Staff suggests the following information be provided prior to any meetings or workshops associated with rate modernization:

1. Company to provide a study estimating costs of customer-specific infrastructure by class and by (1) HV, (2) Primary, (3) "average" LGS customer, (4) "average" SGS customer, (5) "average" residential customer. Residential may be broken down further by customers served at 3 phase, customers using in excess of 30kW in any hour, customers in apartments vs detached, etc.
    i. In distribution accounts 364-367 in total, and
    ii. In substation accounts in total.
    iii. Two sets of estimates of each to be developed
        i. One set of estimates based on historic costs, supported by workpapers,
        ii. One set of estimates based on current installation costs, informed by ongoing line extension requests or similar data, supported by workpapers.
2. Company to provide data concerning the level of rate base and expense associated with radial transmission facilities including substation components, by customer.
3. Company to provide a study to identify assets in distribution accounts that exist to support company-owned distributed generation.
4. Company to provide a study of the costs associated with service under "Rider RDC, Reserve Distribution Capacity Rider."

5. Company to provide a study estimating costs by mile of (1) HV, (2) Primary, (3) relatively high voltage secondary, (4) relatively low voltage secondary separately for overhead and underground,
    i. In distribution accounts 364-367 in total, and
    ii. In substation accounts in total.
    iii. Two sets of estimates of each to be developed
        i. One set of estimates based on historic costs, supported by workpapers,
        ii. One set of estimates based on current installation costs, informed by ongoing line extension requests or similar data, supported by workpapers.
    iv. Miles by voltage and overhead/underground to be provided, with indication of whether or not customer-specific facilities are included.
6. Company to provide a study of the level of net metered generation supplied by each class, and to specifically identify the extent to which hourly load data provided for weather normalization, class allocations, etc reflects netting from net metered generation.
7. Company to provide a breakdown of the values recorded to Account 903 to review the extent to which those costs would be expected to vary with the addition of a new customer, or the discontinuance of service of an existing customer.

Mr. Wills' Request to Bill Future Customers to Recoup Deemed Bill Savings from Proposed EV Charging Rate Plans

Q. At pages 25 – 26 Mr Wills testifies concerning Mr. Chriss' EV rate schedule request,

> Finally, there is another issue I can see with the implementation of this new optional rate. Either we would have to restrict the rate to only customers with significant EV charging applications, which would require additional administrative procedures to verify the eligibility of the customer for the optional rate, or we would potentially risk having every low load factor customer in these rate classes adopt the optional rate and reduce their bill as a "free rider" on the EV rate. That would create the potential for revenue erosion for the Company that would impact our opportunity to achieve the revenues needed to cover our revenue requirement and, ultimately, would raise rates for all customers. If the rate were adopted, I would recommend that rate switching into the new EV rate should be covered by the rate switching revenue tracker that I proposed in my direct testimony in this case.

Is there a risk of customers shifting to this rate (if available) to avoid demand charges?

A. Yes. If promulgated, it is imperative that any rate plan as proposed by Mr. Chriss be reserved exclusively to EV charging use (with attendant lighting) and that it be time-based rather than designed as proposed by Mr. Chriss.

Q. Is Mr. Wills' Request to Bill Future Customers to Recoup Bill Savings from Proposed EV Charging Rate Plans reasonable?

A. Absolutely not. Not only should other rate payers not bear the bills avoided by EV charging customers, but the premise of calculating the tracker balance for these customers is even more problematic than the incredibly problematic residential tracker request.

Q. If an existing customer adds EV charging, would Ameren Missouri's revenues go up?

A. Yes. When Ameren Missouri's rates are set in this proceeding they will be based on the current billing determinants for each class. When a customer adds EV charging Ameren will sell more units (particularly of demand) than were reflected in setting those rates, and all else being equal, Ameren Missouri will collect more revenue. Mr. Wills' proposal would be to allow certain customers to avoid paying a higher bill, but to charge all customers in the future for that higher bill not paid. This is egregious.

<u>CONCLUSION</u>

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service	)))	Case No. ER-2022-0337

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Surrebuttal 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 13th day of March 2023.

Dianna L. Vaught
Notary Public

DIANNA L VAUGHT
Notary Public - Notary Seal
STATE OF MISSOURI
Cole County
My Commission Expires: July 18, 2023
Commission #: 15207377

Ameren Missouri's
Response to MPSC Data Request - MPSC
ER-2019-0335
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service.

No.: MPSC 0470.2

Please reference paragraph 8 of the October 4, 2018 Stipulation and Agreement in ET-2018-0132. Please reference the Company's response to DR 470 in this docket, ER-2019-0335. Please describe all efforts the Company has undertaken to record customer contribution values by voltage and service classification. Please describe all efforts the Company has undertaken to circulate the form of such data retention for Staff and OPC comment. Please identify the date by which the Company will undertake record customer contribution values by voltage and service classification. Data Request submitted by Sarah Lange (sarah.lange@psc.mo.gov).

RESPONSE

Prepared By: Michael Harding
Title: Manager, Rates & Analysis
Date: 12-06-2019

The Company worked collaboratively with MSPC Staff before and during the ET-2018-0132 to develop changes to the Distribution Extension tariff language and calculator to estimate Extension Allowance using the Marginal Cost methodology. The sheet utilized by the division engineers to estimate the Extension Allowance has incorporated a field input for both voltage and service classification. The tariffs and calculator used to make the calculation had been circulated back and forth between the parties in the case in addition to the final version of the calculator being included in the working papers in the case.

Currently, the spreadsheet with the Marginal Cost calculator is attached by the engineer performing the analysis to the project in an Ameren software system called DOJM. The engineer manually inputs the Extension Allowance amount. DOJM itself does not have the class or voltage information with the project information, however upon further investigation we were able use the premise number in DOJM to cross reference against the premise number in CSS software system that does have the voltage and rate class information. This information has been attached to this DR along with additional information available in DOJM associated with each project.

Ameren Missouri does have plans to replace the ~25 year old DOJM system in the beginning of 2021, this new software should provide the ability to more quickly query and aggregate project information all in one place, eliminating the need to cross reference two separate systems based on the premise number.

Ameren Missouri's
Response to MPSC Data Request - MPSC
ER-2022-0337
In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service

No.: MPSC 0565

(1) Mr. Hickman at pages 21-22 of his rebuttal testimony testifies “Relative to poles, the Company does recurring inspections of poles and records the results of those inspections. These inspections occur over periods of years, such that the information is never perfectly current. An attribute noted during these inspections is whether the pole has primary equipment, secondary equipment, or both.” Please describe the format in which these records are retained. (2) Please describe the extent to which these records were relied upon by Mr. Hickman in his classification of poles, including identification of the years of inspection reports utilized. (3) Mr. Hickman at pages 21 testifies “The Company cannot produce a version of accounting records with voltage information attached.” Please produce a version of operational voltage records with accounting information attached for assets recorded to distribution accounts 360-368. (4) Please confirm whether Ameren Missouri possesses records of the vintage year and location of each of the Company's approximately 900,000 poles. (5) Please confirm whether Ameren Missouri possesses a record keeping system regarding the vintage year and location of each of the Company's approximately 900,000 poles. Requested by Sarah Lange (sarah.lange@psc.mo.gov <mailto:sarah.lange@psc.mo.gov>)

RESPONSE

Prepared By: Tom Hickman
Title: Regulatory Rate Consultant
Date: 2/24/2023

1. The records referenced in my testimony are maintained in a database. A separate field exists for Secondary, Primary, and High Voltage (Sub Transmission). Each field is populated with a positive or negative response, positive in the event any equipment at that level of voltage is present on the pole, negative in the event no equipment at that level of voltage is present on the pole. There is no specification of the precise voltage of such equipment.

2. An earlier version of these records were relied upon in the development of the 2009 Vandas study (based on prior conversations with the individuals directly involved in the study, who have since retired), which is relied upon in the classification of poles I made in this case. My reliance on such earlier records was indirect, and the records specifically underlying that study are no longer available.

3. Company accounting records and company operational records containing voltage cannot be related. As such, the Company can provide neither accounting records with voltage attached or voltage records with accounting attached.

4. Yes. Ameren possesses such records.

5. Yes and no. Both data points exist in separate systems, but one singular system does not contain both. Our accounting records are the record keeping system that contains vintage year information. Specific location of property is not contained in our accounting records, but there is a separate operational record keeping system that contains the location associated with each pole.

Response to Data Request 524 for ER-2022-0337

In the CCoS Report in ER-2021-0240, page 49 includes:

Metering & Billing Revenue Requirements (Customer Charges)
The approximate revenue requirements associated with metering and billing each class, as well as an approximation of a reasonable customer charge, are provided in the table below:

	Residential	SGS	LGS/SPS	LPS	Lighting
Meter Reading	$ 10,807,787	$ 1,466,077	$ 230,463	$ 2,518	$ 14,655
Customer Records and Collection	$ 39,628,631	$ 5,615,564	$ 415,909	$ 2,355	$ 2,003,386
Line Transformers	$ 20,465,905	$ 3,528,370	$ 3,595,944	$ -	$ 669,876
Services	$ 8,726,009	$ 1,510,874	$ 1,519,668	$ 60,948	$ -
Meters	$ 22,757,481	$ 6,543,807	$ 5,228,827	$ 326,060	$ 415,102
Customer Charge portion:	$ 102,385,813	$ 18,664,691	$ 10,990,811	$ 391,881	$ 3,103,020
Customer Count:	1,076,972	152,612	11,303	64	54,445
Customer Charge:	$ 7.92	$ 10.19	$ 81.03	$ 510.26	$ 4.75

With the exception of the LPS class, the current customer charges equal or exceed the CCoS Study-determined customer charge by class. Staff recommends retaining existing customer charges, except that the LPS customer charge should be increased to approximately $515.00 from its current charge of $323.82.

The purpose of the study in the ER-2021-0240 case was to review whether to raise the existing charge, not "calculating the appropriate customer charge;" specifically, the testimony states that it provides "an approximation of a reasonable customer charge."

If Account 903 is included in this case, it produces the results below:

	Residential	SGS	LGS	SPS	LPS	Lighting
Net Rate Base	$ 407,476,245	$ 141,109,693	$ 108,698,541	$ 270,757,931	$ 102,444,701	$ 139,522,126
Depreciation Expense	$ 27,581,932	$ 7,770,581	$ 5,010,841	$ 13,285,563	$ 5,052,116	$ 5,729,304
NonLabor Expense	$ 28,548,497	$ 4,550,334	$ 4,655,944	$ 5,386,828	$ 2,431,206	$ 2,242,202
Labor Expense	$ 28,916,104	$ 4,574,639	$ 4,399,385	$ 2,326,585	$ 1,275,919	$ 3,036,587
RoR	$ 27,961,020	$ 9,682,947	$ 7,458,894	$ 18,579,409	$ 7,029,755	$ 9,574,008
Approx. Income Tax	$ 2,914,086	$ 1,009,153	$ 777,363	$ 1,936,338	$ 732,638	$ 997,799
Functionalized RR:	$ 115,921,639	$ 27,587,655	$ 22,302,426	$ 41,514,724	$ 16,521,634	$ 21,579,900
# of Customers:	1,079,892	136,459	10,673	670	63	55322
# of Charges:	12,958,704	1,637,514	128,076	8,040	756	663,864
$/Customer/Month:	$ 8.95	$ 16.85	$ 174.13	$ 5,163.52	$ 21,854.01	$ 32.51
Gross up for Other/Misc.	$ 10.16	$ 19.13	$ 197.70	$ 5,862.36	$ 24,811.75	$ 36.91

Staff did not include Account 903 in its customer charge calculation in this case, as Staff sought to more accurately implement the Basic Customer Method approach, which seeks to include only those costs and expenses that vary directly in proportion to the number of customers served. Also see Excel document attached to this data request response. Response provided by Sarah Lange.