| | |
|---|---|
| *Exhibit No.:* | |
| *Issue(s):* | *Rate Design* |
| | *Class Cost of Service* |
| *Witness:* | *Sarah L.K. Lange* |
| *Sponsoring Party:* | *MoPSC Staff* |
| *Type of Exhibit:* | *Rebuttal Testimony* |
| *Case No.:* | *ER-2021-0240* |
| *Date Testimony Prepared:* | *October 15, 2021* |

# MISSOURI PUBLIC SERVICE COMMISSION

## INDUSTRY ANALYSIS DIVISION

## TARIFF/RATE DESIGN DEPARTMENT

# REBUTTAL TESTIMONY

# OF

# SARAH L.K. LANGE

## UNION ELECTRIC COMPANY
## d/b/a Ameren Missouri

## CASE NO. ER-2021-0240

***Jefferson City, Missouri***
***October 2021***

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Q. Please state your name.

A. My name is Sarah Lange.

Q. Are you the same Sarah Lange that contributed to Staff's CCoS and Rate Design Report?

A. Yes.

Q. Do you have any changes or updates to make to that the sections you authored?

A. Yes. At page 56 of the Staff Report I stated that "the RESRAM and FAC recovery for February 2021 will each begin February 1 of 2022, which is likely to be at or near the time of the Commission's Report and Order in the rate case, and potentially between the issuance of the Order and the compliance tariffs." The FAC Recovery Period covering February 2021 began October 1, 2021.

Q. What is the purpose of your rebuttal testimony, and how is it organized?

A. I will first identify how the Ameren Missouri's CCoS study does not indicate that it is appropriate to make revenue neutral shifts in revenue responsibility outside of the lighting classes in this case, even if it is reliable enough for evidentiary use in this case. I will then address the rate design recommendations of Mr. Chriss on behalf of Midwest Energy Consumers Group ("MECG") and Mr. Brubaker on behalf of Midwest Industrial Energy Consumers ("MIEC") and address some of the more blatantly misleading characterizations in these testimonies for the reference of Commissioners. I will identify flaws in the Ameren Missouri CCoS study that undermine its evidentiary reliability, and indicate the direction of the impact of the flaws to facilitate its consideration, if necessary. Finally, I will identify reasonable improvements to the form of the data retained by Ameren Missouri to mitigate the poor study quality in future cases.

## **CLASS COST OF SERVICE AND REVENUE RESPONSIBILITIES**

Q. What are the results of Ameren Missouri's class cost of service study?

A. Ameren Missouri's study indicates that all classes other than Customer Owned lighting are providing revenues that exceed allocated expenses, and are contributing towards rate of return. Staff reviewed the level of over or under-contribution of each class to Ameren Missouri's revenue requirement as a percent of rate revenue to determine whether any classes were contributing outside of the +/- 5% range Staff has typically relied on for recommended revenue neutral shifts to class revenue responsibility. While the Customer Owned Lighting class was found to be outside of this threshold at a 10% under-contribution, no other class was outside of this range which would trigger a shift recommendation.

| | Residential | SGS | LGS/SPS | LPS | Co. Owned Lighting | Cust. Owned Lighting |
|---|---|---|---|---|---|---|
| Allocated Revenues: | $ 190,455,332 | $ 41,396,996 | $ 135,073,308 | $ 41,824,724 | $ 1,757,517 | $ 551,535 |
| Total Expenses: | $ 1,289,839,375 | $ 258,628,745 | $ 673,615,489 | $ 183,519,424 | $ 24,287,640 | $ 4,180,205 |
| Rate Revenue: | $ 1,273,043,176 | $ 274,322,474 | $ 727,565,247 | $ 188,575,861 | $ 35,639,800 | $ 2,848,591 |
| Available Return: | $ 173,659,133 | $ 57,090,725 | $ 189,023,066 | $ 46,881,161 | $ 13,109,677 | $ (780,079) |
| Rate Base: | $ 5,601,035,696 | $ 1,108,885,033 | $ 2,571,566,786 | $ 609,212,234 | $ 145,390,336 | $ 17,085,077 |
| Return as Percent of Net Ratebase: | 3.10% | 5.15% | 7.35% | 7.70% | 9.02% | -4.57% |
| Required Return at System Average RoR: | $ 391,792,447 | $ 77,566,508 | $ 179,881,097 | $ 42,614,396 | $ 10,170,054 | $ 1,195,101 |
| Required Return plus Expenses net of Other Revenue: | $ 1,491,176,490 | $ 294,798,257 | $ 718,423,277 | $ 184,309,095 | $ 32,700,177 | $ 4,823,771 |
| % Change to Rate Revenues to Achieve System Average RoR: | 17.13% | 7.46% | -1.26% | -2.26% | -8.25% | 69.34% |
| kWh: | 14,454,221,713 | 3,278,305,271 | 11,488,103,967 | 3,689,239,273 | 85,330,142 | 45,767,767 |
| Start $/kWh: | $ 0.0881 | $ 0.0837 | $ 0.0633 | $ 0.0511 | $ 0.4177 | $ 0.0622 |
| End $/kWh: | $ 0.1032 | $ 0.0899 | $ 0.0625 | $ 0.0500 | $ 0.3832 | $ 0.1054 |
| Class Increase at System Average Increase: | $ 114,093,750 | $ 24,585,560 | $ 65,206,466 | $ 16,900,705 | $ 3,194,140 | $ 255,299 |
| Available Return with System Average Increase: | $ 287,752,883 | $ 81,676,285 | $ 254,229,533 | $ 63,781,866 | $ 16,303,817 | $ (524,781) |
| % Over/Under Contribution @ System Average: | 1.86% | -0.37% | -2.89% | -3.47% | -4.22% | 10.07% |

Q. Which other parties performed Class Cost of Service Studies?

A. None but Staff. MIEC relies on Ameren Missouri's study with slight modifications. MECG's workpapers are somewhat unclear as to whether they directly relied on Ameren Missouri's study or made slight modifications related to production allocation. Other parties make policy-based recommendations.

**MECG AND MIEC TESTIMONIES**

Q. What rate design recommendations are made by MIEC witness, Mr. Maurice Brubaker?

A. In his direct testimony at page 4, Mr. Brubaker states, "For purposes of implementing the final rates in this case, all of the charges in the Large Primary Service Rate, except for the Low-Income Pilot Program Charge, should receive the same percentage change."

Q. Mr. Brubaker includes statements such as "There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified as demand-related. Regardless of how production plant investment is classified, the associated capital costs (which include return on investment, depreciation, fixed O&M expenses, taxes and insurance) are fixed; that is, they do not vary with the amount of kWhs generated and sold. These fixed costs are determined by the amount of capacity (i.e., kW) that the utility must install to satisfy its obligation-to-serve requirement. On the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of fuel expense – is closely related to the amount of energy (number of kWhs) that customers use. Therefore, fuel expense is an energy-related cost."[1] Is this testimony relevant to Ameren Missouri in the year 2021?

[1] See Brubaker testimony at page 4.

A. No. A relevant discussion is found in the handbook "Electric Cost Allocation for a New Era," ("RAP Manual") by Jim Lazar, Paul Chernick and William Marcus, edited by Mark LeBel, (attached as Schedule SLKL-r1.) at page 17:

> The key texts and most of the analytical principles currently used for cost allocation were developed between the 1960s and early 1990s. Since that time, the electric system in the United States has been undergoing another period of dramatic change. That includes a wide range of interrelated advancements in technology, policy and economics:
>
> • Major advances in data collection and analytical capabilities.
>
> • Restructuring of the industry in many parts of the country, including new wholesale electricity markets, new retail markets and new market participants.
>
> • New consumer interests and technologies that can be deployed **behind the meter**, including clean **distributed generation**, **energy efficiency**, **demand response**, storage and other energy management technologies.
>
> • Dramatic shifts in the relative cost of technologies and fuels, including massive declines in the price of **variable renewable resources** like wind and solar and sharp declines in the cost of energy storage technologies.
>
> • The potential for beneficial electrification of end uses that currently run directly on fossil fuels — for example, electric vehicles in place of vehicles with internal combustion engines.
>
> Many, if not all, of these changes have quantifiable elements that can and should be incorporated directly into the regulatory process, including cost allocation. The increased development of renewable energy and the proliferation of more sophisticated meters provide two examples. Figure 3 illustrates the dramatic increase in wind and solar generation in the United States in the last decade, based on data from the U.S. Energy Information Administration. Traditional cost allocation techniques classify all utility costs as **energy-related**, **demand-related** or **customer related**. These categories were always simplifications, but they must be reevaluated given new developments. Some legacy cost allocation methods would have treated wind and solar generation entirely as a demand-related cost simply because they are capital investments without any variable **fuel costs**. However, wind and solar generation does not necessarily provide firm **capacity** at peak times as envisioned by the legacy frameworks, and it displaces the need for fuel supply, so it doesn't fit as a demand-related cost.
>
> ****
>
> In the end, cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder. In most situations,

cost allocation is a zero-sum process where lower costs for any one group of customers lead to higher costs for another group. However, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

In that spirit, we would like to highlight the following current best practices discussed at more length in the later chapters of this manual. To begin, there are best practices that apply to both embedded and marginal cost of service studies:

• Treat as customer-related only those costs that actually vary with the number of customers, generally known as the basic customer method.

• Apportion all shared generation, transmission and distribution assets and the associated operating expenses on measures of usage, both energy- and demand-based.

• Ensure broad sharing of overhead investments and administrative and general (A&G) costs, based on usage metrics.

• Eliminate any distinction between "fixed" costs and "variable" costs, as capital investments (including new technology and data acquisition) are increasingly substitutes for fuel and other short-run variable operating costs.

• Where future costs are expected to vary significantly from current costs, make the cost trajectory an important consideration in the apportionment of costs.

Second, there are current best practices specific to embedded cost of service studies:

• Classify and allocate generation capacity costs using a time-differentiated method, such as the probability-of dispatch or base-intermediate-peak (BIP) methods, or classify capacity costs between energy and demand using the equivalent peaker method.

• Allocate demand-related costs for generation using a broad peak measure, such as the highest 100 hours or the loss-of-energy expectation.

• Classify and allocate the costs of transmission based on its purpose, with any demand-related costs allocated based on broad peak periods for regional networks and narrower ones for local networks.

• Classify distribution costs using the basic customer method, and divide the vast majority of costs between demand-related and energy-related using an energy weighted method, such as the average-and-peak method that many natural gas utilities use.

• Allocate demand-related distribution costs using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for diversity in customer usage.

• Ensure that customer connection and service costs appropriately reflect differences between customer classes by using either specific cost studies for each element or a weighted customer approach.

• Functionalize and classify AMI and billing systems according to their multiple benefits across different elements and aspects of the electric system.

Further, at page 21, the RAP Manual includes the following "All shared distribution costs should be apportioned based on the time periods when customers utilize these facilities. The system is needed to provide service in every hour, and in most cases a significant portion of the distribution system cost should be assigned volumetrically to all hours across the year."

Q. At page 41 Mr. Brubaker states "Moving 50% of the way toward cost of service requires a Residential class revenue-neutral adjustment of only 3.9% (as compared to the 7.8% increase required to move all the way to cost of service) is relatively moderate…." What cost of service is he discussing moving towards?

A. Mr. Brubaker is discussing the revenue responsibility changes to cause the Residential class to contribute equally to the rate of return proposed by Ameren Missouri in its direct filing.

Q. Does MIEC recommend the Commission approve the revenue requirement or cost of service requested by Ameren Missouri?

A. No. MIEC witness Greg Meyer recommends reduction of Ameren Missouri's requested revenue requirement by "at least $56 million," at page 4 of his direct testimony.

Q. What rate design recommendations are made by MECG witness, Mr. Steve Chriss?

A. In his direct testimony at page 46, Mr. Chriss states,

> For the purposes of this docket, at the Company's proposed revenue requirement for the LGS and SP classes, MECG recommends that the Commission:
>
> 1) Accept Ameren's proposed customer charges and on-peak and off-peak adjusters for both LGS and SP, and Ameren's proposed Rider B credits and reactive charge for SP;
>
> 2) Increase the summer and winter demand charges for LGS and SP by three times the percent class increases; and
>
> 3) Apply the remaining proposed increase on an equal percentage basis to the summer and winter energy charges.

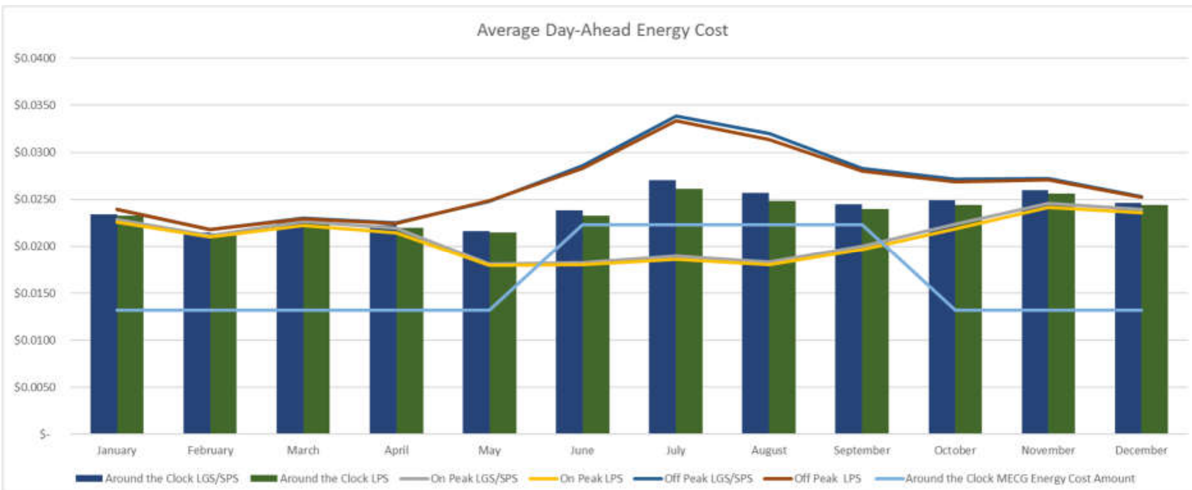
He goes on to state "If the Commission awards an increase for these classes that is lower than that proposed by the Company, then the Commission can then take larger steps to address the over-recovery of demand-related costs through energy charges and associated intra-class subsidies. Specifically, the Commission should set the demand charges per MECG's recommendation above and apply the approved reduction the class revenue requirement by reducing all base rate energy charges on an equal percentage basis."

Q. At page 38 Mr. Chriss provides his estimates of cost-based energy charges for LGS of $0.02228/kWh for the summer period and $0.01316/kWh for the winter period for energy charges. Are these values reasonable?

A. No, these values would not recover the marginal cost of energy.

Q. What are the marginal costs of energy for LGS, SPS, and LPS customers?

A. The energy rate required to recover only the cost of market energy for LGS and SPS customers is a year-round average of $0.0275/kWh and $0.0255/kWh for the LGS and SPS rate schedules, respectively. The average Day-Ahead energy costs for the combined LGS and SPS class and for the LPS class, both as a consumption-weighted around-the-clock average and as the Rider I time-period energy costs,[2] are provided below:




Q. How does Mr. Chriss explain the difference between the cost to obtain energy at wholesale to serve retail load and the amounts he recommends ideally be recovered through the energy charge?

A. Mr. Chriss' direct testimony does not address this.

Q. Mr. Chriss advocates for an increase in the percentage of LGS and SPS revenues that are recovered from demand charges. How are demand charges collected from customers within the LGS and SPS tariffs?

A. The relevant LGS Provisions are:

[2] For purposes of this graph, weekends and holidays are included with the relevant time period. Note, these amounts do not include Real Time market charges, Ancillary Service charges, or other charges that are assessed on measures of load.

a. Total Billing Demand The monthly Total Billing Demand shall be the maximum metered demand during the current month or, where elected by customer, the billing demand determined in accordance with Rider I, Off-Peak Demand Provisions, but in no event less than 100 kW.

b. Base Billing Demand The monthly Base Billing Demand, used only to apportion kilowatt-hours during the Company's winter billing season, shall be the Total Billing Demand during customer's immediately preceding May, October or maximum summer billing month, or customer's current winter month's Total Billing Demand, whichever is less.

The relevant SPS provisions are:

a. Total Billing Demand The monthly Billing Demand shall be the maximum demand established during peak hours or 50% of the maximum demand established during off-peak hours, whichever is greater, but in no event less than 100 kW. Peak hours and off-peak hours are defined as follows: Peak hours: 10:00 A.M. to 10:00 P.M., Monday through Friday. Off-peak hours: All other hours including the entire 24 hours of the following days: New Year's Day, Independence Day, Thanksgiving Friday, Good Friday, Labor Day, Christmas Eve Day, Memorial Day, Thanksgiving Day, Christmas Day, All times stated above apply to the local effective time.

b. Base Billing Demand The monthly Base Billing Demand, used only to apportion kilowatt-hours during the Company's winter billing season, shall be the Total Billing Demand during customer's immediately preceding May, October or maximum summer billing month, or customer's current winter month's Total Billing Demand, whichever is less.

In other words, LGS customers who have not elected to participate in Rider I are billed based on their monthly non-coincident peak ("NCP"), and the remaining LGS customers and SPS customers are billed based on the greater of their on-peak monthly NCP or 50% of their off-peak NCP. Additionally, the monthly NCP drives hours-use energy charge recovery.

Q. What is a customer's monthly NCP?

A. In simple terms, a monthly NCP is the highest demand a customer experienced during a month. This demand is measured typically as the highest usage experienced during a 15 minute interval.

Q. Is a customer's monthly NCP indicative of that customer's causation of generation, transmission, or distribution infrastructure or expenses?

A. Not really. Other than the very local distribution facilities that must be sized to accommodate that customer's peak load, it would be only coincidental if a given customer's NCP aligned with the drivers of generation, transmission, or distribution infrastructure.

Q. What is the relevance of a customer's NCP demand to the cost of Ameren Missouri's generation capacity or MISO IM resource adequacy?

A. A customer's NCP demand is not relevant to Ameren Missouri's generation capacity or MISO resource adequacy. The usage of a customer in the interval associated with the system peak known as that customer's coincident peak is the only determinant relevant to Ameren Missouri's MISO resource adequacy or generation capacity requirements. There may have been a time where customer usage was so uniform that it could reasonably be assumed that a customer's NCP demand would coincide with system peak, but that is certainly not the case today. Therefore, it is no more reasonable to recover the costs associated with system peak demands via a customer's NCP demand than it is to recover those costs via a customer's energy consumption, and it is potentially less reasonable to do so.

Q. Mr. Chriss on pages 35 – 36 states "All of the Company's production demand (capacity), transmission, and distribution demand costs should be recovered through demand charges. These costs are fixed and incurred to serve customer kW demands on the system regardless of how many kWh are consumed. Optimally the costs for each of the three functions would be recovered through its own unbundled demand charge (or charges if time or seasonal differentiation is appropriate) to best recover costs in a manner that reflects how those costs are incurred and allocated." Are these statements accurate?

A. No. First, no cost is truly "fixed" in a utility's revenue requirement. Some costs and expenses vary with the amount of energy consumed, or the number of customers served, or the amount of wholesale energy generated for sale, and some costs and expenses are relatively stable. I do agree that best practice would be to better reflect unbundled cost causation in rates, to the extent customer understandability is retained or enhanced. However, an NCP demand charge is not an ideal recovery mechanism for the costs discussed by Mr. Chriss.

Q. Mr. Chriss recommends movement toward time-based rate structures; is this consistent with Staff's recommendations in this case and related dockets?

A. Yes. However, his suggestion of moving additional revenue recovery away from energy charges and into the NCP demand charges is counter-productive to that goal, and has the potential to exacerbate customer confusion and lack of bill predictability preparing for that transition. Staff is optimistic that the next Ameren Missouri rate case will present an opportunity to fully redesign the non-residential rate structures to a modern rate structure as described in Staff's Report on Distributed Energy Resources, in File No. EW-2017-0245. Neither the NCP nor the hours use design are optimal for aligning cost causation and revenue recovery, however, they are what customers are used to. Mr. Chriss's recommended shift to increased NCP recovery isn't any better than the current design at aligning cost causation. The proper direction to take in this case is to minimize customer impact from rate design to minimize rate switching and customer confusion, both of which could complicate the imminent roll-out of a better rate structure in the next rate case.

Q. Are Mr. Chriss's opinions on production capacity planning applicable to Ameren Missouri's generation fleet as constituted in this case?[3]

A. No. The recent additions to the Ameren Missouri wind fleet were made to enable production of REC certificates to comply with the Renewable Energy Standard, and the legacy fleet existed to satisfy peaks established prior to the departure of a significant industrial load that has left its system. The Commission's order in File No. EA-2018-0202 found that "The wind generation project for which Ameren Missouri has been granted a CCN in this case is intended to comply with the renewable energy mandates of the law."[4] File No. EA-2019-0181 was resolved by a Stipulation and Agreement that included a provision 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."[5] Not only were these facilities not constructed to meet system peak capacity, these facilities were

[3] See page 11 "Q. IS IT YOUR UNDERSTANDING THAT PRODUCTION PLANT CAPACITY IS SIZED TO MEET THE MAXIMUM DEMAND IMPOSED ON THE SYSTEM BY THE COMPANY'S CUSTOMERS? A. Yes. It is my understanding that the timing and size of a utility's production plant capacity additions are generally made to meet the maximum demand placed on the utility's system by all customer classes, also known as its coincident peak ("CP"). All of a utility's generation units are needed to meet that demand, and removing any of the units from that stack will limit the utility's ability to do so."

[4] Finding of Fact #5, Report and Order page 5. This case concerned the High Prairie wind project.

[5] Nonunanimous Stipulation and Agreement at page 2.

constructed to meet a statutory requirement that is based on the amount of annual energy sold at retail.

Q. Mr. Chriss's Schedule 8 purports to provide a method to allocate the difference between Staff's revenue requirement and Ameren Missouri's revenue requirement to the results of Ameren Missouri's CCoS Study. Is this reasonable?

A. No. Of the approximately $77 million in differences Mr. Chriss identifies between Staff's Revenue Requirement and Ameren Missouri's revenue requirement, approximately $27 million is related to rate of return. Rate of return revenue responsibility is allocated to customer classes as the product of the rate of return studied and the net rate base allocated or assigned to each class. Applying Staff's recommended rate of return within the Ameren Missouri study, reduces the class revenue responsibilities as provided in the table below:

| | Total Missouri | Residential | Small Gen Serv | Large G.S./ Sm Primary | Large Primary | Lighting |
|---|---|---|---|---|---|---|
| Net Rate Base | $ 10,053,175,162 | $ 5,601,035,696 | $ 1,108,885,033 | $ 2,571,566,786 | $ 609,212,234 | $ 162,475,413 |
| Ameren Rate of Return | $ 703,219,603 | $ 391,792,447 | $ 77,566,508 | $ 179,881,097 | $ 42,614,396 | $ 11,365,155 |
| Staff Rate of Return | $ 676,076,030 | $ 376,669,651 | $ 74,572,519 | $ 172,937,866 | $ 40,969,523 | $ 10,926,472 |
| $ Difference | $ (27,143,573) | $ (15,122,796) | $ (2,993,990) | $ (6,943,230) | $ (1,644,873) | $ (438,684) |
| % of Difference | 100.0% | 55.7% | 11.0% | 25.6% | 6.1% | 1.6% |

Mr. Chriss is advocating to use a high rate of return to target the Residential class for above-average increases, but using a lower rate of return to distribute the below-average increases. This is not reasonable.

Q. Have you adjusted the Ameren CCoS to provide the level of over and under-contribution at the Staff-Recommended RoR?

A. Yes. The under/overcontributions remain within the bounds suggesting no revenue-neutral shifts are necessary, and the % of class revenue results to exactly match the class cost of service are closer to zero than in Ameren Missouri's study:

| | Residential | SGS | LGS/SPS | LPS | Co. Owned Lighting | Cust. Owned Lighting |
|---|---|---|---|---|---|---|
| Allocated Revenues: | $ 190,455,332 | $ 41,396,996 | $ 135,073,308 | $ 41,824,724 | $ 1,757,517 | $ 551,535 |
| Total Expenses: | $ 1,289,839,375 | $ 258,628,745 | $ 673,615,489 | $ 183,519,424 | $ 24,287,640 | $ 4,180,205 |
| Rate Revenue: | $ 1,273,043,176 | $ 274,322,474 | $ 727,565,247 | $ 188,575,861 | $ 35,639,800 | $ 2,848,591 |
| Available Return: | $ 173,659,133 | $ 57,090,725 | $ 189,023,066 | $ 46,881,161 | $ 13,109,677 | $ (780,079) |
| Rate Base: | $ 5,601,035,696 | $ 1,108,885,033 | $ 2,571,566,786 | $ 609,212,234 | $ 145,390,336 | $ 17,085,077 |
| Return as Percent of Net Ratebase: | 3.10% | 5.15% | 7.35% | 7.70% | 9.02% | -4.57% |
| Required Return at Staff-Recommended RoR: | $ 376,669,651 | $ 74,572,519 | $ 172,937,866 | $ 40,969,523 | $ 9,777,500 | $ 1,148,971 |
| Required Return plus Expenses net of Other Revenue: | $ 1,476,053,694 | $ 291,804,267 | $ 711,480,047 | $ 182,664,222 | $ 32,307,623 | $ 4,777,641 |
| % Change to Rate Revenues to Achieve System Average RoR: | 15.95% | 6.37% | -2.21% | -3.13% | -9.35% | 67.72% |
| kWh: | 14,454,221,713 | 3,278,305,271 | 11,488,103,967 | 3,689,239,273 | 85,330,142 | 45,767,767 |
| Start $/kWh: | $ 0.0881 | $ 0.0837 | $ 0.0633 | $ 0.0511 | $ 0.4177 | $ 0.0622 |
| End $/kWh: | $ 0.1021 | $ 0.0890 | $ 0.0619 | $ 0.0495 | $ 0.3786 | $ 0.1044 |
| Class Increase at System Average Increase: | $ 114,093,750 | $ 24,585,560 | $ 65,206,466 | $ 16,900,705 | $ 3,194,140 | $ 255,299 |
| Available Return with System Average Increase: | $ 287,752,883 | $ 81,676,285 | $ 254,229,533 | $ 63,781,866 | $ 16,303,817 | $ (524,781) |
| % Over/Under Contribution @ System Average: | 1.59% | -0.64% | -3.16% | -3.74% | -4.49% | 9.80% |
| Difference between available and system average RoR: | $ 203,010,518 | $ 17,481,794 | $ (16,085,200) | $ (5,911,638) | $ (3,332,177) | $ 1,929,051 |
| % of Class Revenues: | 15.9% | 6.4% | -2.2% | -3.1% | -9.3% | 67.7% |

Note, these results do not address the remaining differences between Staff and Ameren Missouri's revenue requirements and CCoS studies, and do not account for the changes in required taxes associated with the changes in ROR.

Q. On page 8 Mr. Chriss provides a table of what he states "show[s] that rates for the LGS and SP[S] classes have been set well in excess of cost of service since the 2007 rate case." What does the table show?

A. Mr. Chriss's table provides what appears to be the changes Ameren Missouri identified in its CCoS Study in its direct filing in each indicated case to the current revenues of the combined LGS and SPS classes to exactly match the combined LGS and SPS revenue requirement in each case. The table shows Ameren Missouri's position in various rate cases, and nothing more.

Q MECG asserts that "analysis for FERC Form 1 data shows that between 2008 and 2020, and not inclusive of the increases proposed in the instant docket, Ameren's reported revenue per kWh sold to LGS customers has increased from $0.0563/kWh to $0.0772/kWh, an increase of 37.1 percent."[6] Is the result of dividing the total dollars of revenue provided by customers on a given rate schedule by the kWh sold to customers on that rate schedule ten years ago relevant to any question before the Commission in this proceeding?

A. No. It may be informative for the Commission to review information related to shifts in revenue responsibility between various customers on various rate schedules over time, particularly as it relates to avoiding unnecessary rate switching or causing rate shock. However, this metric is particularly unhelpful for considerations of class cost of service and rate design, because it fails to account for the changing customer base (1) due to changes in customer characteristics and (2) due to changes in the total numbers of customers receiving service whether due to rate switching or due to customer growth/loss.

Q. In what ways does the metric of class-average revenue per kWh provide a misleading signal concerning the bills experienced by customers within a class?

A. To illustrate the misleading signal provided by this metric, in the following examples we will review the changes to the "LGS Average $/kWh" produced by varying customers and customer characteristics of a very small hypothetical class.

| **Example 1** | Annual Bill | kWh | $/kWh | **Example 2a** | Annual Bill | kWh | $/kWh |
|---|---|---|---|---|---|---|---|
| LGS Customer 1 | $ 3,500 | 50,000 | $ 0.070 | **LGS Customer 1** | **$ 7,000** | **100,000** | **$ 0.070** |
| LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 | LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 |
| LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 | LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Customer 4 | $ 2,000 | 50,000 | $ 0.040 | LGS Customer 4 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Average $/kWh | $ 11,000 | 200,000 | **$ 0.055** | LGS Average $/kWh | $ 14,500 | 250,000 | **$ 0.058** |

[6] Chriss direct, page 6.

In Example 1, the class-average revenue per kWh produced is $0.055 per kWh. In Example 2a, we see that Customer 1 has doubled usage. While the other customers' bills have not changed, the LGS Average $/kWh has increased to $0.058. This result is reproduced below in Example 2b, by the addition of another customer, LGS Customer 5.

| Example 2b | Annual Bill | kWh | $/kWh |
|---|---|---|---|
| LGS Customer 1 | $ 3,500 | 50,000 | $ 0.070 |
| LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 |
| LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Customer 4 | $ 2,000 | 50,000 | $ 0.040 |
| **LGS Customer 5** | **$ 3,500** | **50,000** | **$ 0.070** |
| LGS Average $/kWh | $ 14,500 | 250,000 | **$ 0.058** |

| Example 2c | Annual Bill | kWh | $/kWh |
|---|---|---|---|
| **LGS Customer 1** | **$ -** | **-** | **$ 0.070** |
| LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 |
| LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Customer 4 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Average $/kWh | $ 7,500 | 150,000 | **$ 0.050** |

As in Example 1, in Example 2b, no other customer's bill has changed, but the class-average revenue per kWh has increased by 5.45%. However, as illustrated in Example 2c, above, the loss of Customer 1 results in a decrease of 9.1% to the class-average revenue per kWh.

Q. Is it likely that these changes in customer counts and customer characteristics would result in changes in the costs allocated or assigned to the LGS class in the next rate case?

A. Yes. However, those potential changes would not impact the bills paid by Customer 2, 3, and 4 until the rate schedule under which they are billed is changed. If the rates are appropriately designed, and all else remained equal, it is likely that the bill changes experienced by Customers 2, 3, and 4 would be minimal and reflect only the minor change in the company's overall sales.

Q. Can changes to rate design in rate cases result in some customers paying higher bills while other customers on the same rate schedule pay lower bills?

A. Yes. As illustrated in Example 3 below, not only can customers within a class experience vastly different impacts from a rate case due to changes in rate design, but customers can experience such impacts without change to the resulting class-average revenue per kWh.

| Example 1 | Annual Bill | kWh | $/kWh | Example 3 | Annual Bill | kWh | $/kWh |
|---|---|---|---|---|---|---|---|
| LGS Customer 1 | $ 3,500 | 50,000 | $ 0.070 | **LGS Customer 1** | **$ 3,850** | **50,000** | **$ 0.077** |
| LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 | LGS Customer 2 | $ 3,500 | 50,000 | $ 0.070 |
| LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 | LGS Customer 3 | $ 2,000 | 50,000 | $ 0.040 |
| LGS Customer 4 | $ 2,000 | 50,000 | $ 0.040 | **LGS Customer 4** | **$ 1,650** | **50,000** | **$ 0.033** |
| LGS Average $/kWh | $ 11,000 | 200,000 | **$ 0.055** | LGS Average $/kWh | $ 11,000 | 200,000 | **$ 0.055** |

In Example 3, Customer 1's bill was increased by 10%, Customer 4's bill was decreased by 17.5%, and the metric of class-average revenue per kWh remained unchanged.

Q. Is there a more reasonable means of reviewing the impact of the last 12 years of Ameren Missouri rate cases on customers?[7]

A. While no metric is perfect, it is probably most useful to review the bills or average $/kWh that would be experienced by a given customer with that customer's characteristics held constant over time. Given the size of Ameren Missouri's customer base and classes, it is impossible to accurately summarize these impacts for all potential customers. Further, it is possible that a customer would change rate schedules over this time due to changes in the rate designs of the relative schedules.

To facilitate these comparisons, Staff created a set of Customer Profiles, and priced out the bills for those customers from the final rates promulgated from each rate case since Case No. ER-2007-0002. For example, the bills produced by the studied Residential Profiles are provided below:

| | ER-2007-0002 | ER-2008-0318 | ER-2010-0036 | ER-2011-0028 | ER-2012-0166 | ER-2014-0258 | ER-2016-0179 | Temp. Tax Reduction | ER-2019-0335 |
|---|---|---|---|---|---|---|---|---|---|
| Residential Flat | $ 817 | $ 882 | $ 988 | $ 1,079 | $ 1,156 | $ 1,219 | $ 1,260 | $ 1,186 | $ 1,202 |
| 1,500 ft Home w/ Space Heat | $ 1,015 | $ 1,098 | $ 1,230 | $ 1,346 | $ 1,443 | $ 1,525 | $ 1,577 | $ 1,480 | $ 1,505 |
| Large Home AC only | $ 1,161 | $ 1,257 | $ 1,408 | $ 1,542 | $ 1,653 | $ 1,748 | $ 1,808 | $ 1,699 | $ 1,734 |
| Small Apt w/ Space Heat | $ 840 | $ 907 | $ 1,016 | $ 1,110 | $ 1,188 | $ 1,254 | $ 1,299 | $ 1,224 | $ 1,247 |

[7] MEEIA, RESRAM, and FAC charges are not reflected in the bills and average rates discussed throughout this testimony.

To facilitate comparisons across customers of very different sizes, Staff divided the total bills described above by the kWh of each customer. This produces an experienced average $/kWh that can be displayed on a graph with a readable scale when comparing the bill one may experience with a small apartment to the bill one may experience when participating in substantial industrial manufacturing.

The experienced average $/kWh by Customer Profile are provided below, as well as an indication of the % change experienced from the final rates promulgated in Case No. ER-2007-0002 to the tariffed rates in effect today. Percent changes in excess of 35% are highlighted in red, and percent changes lower than 25% are highlighted in green.

| | ER-2007-0002 | ER-2008-0318 | ER-2010-0036 | ER-2011-0028 | ER-2012-0166 | ER-2014-0258 | ER-2016-0179 | Temp. Tax Reduction | ER-2019-0335 | % Change |
|---|---|---|---|---|---|---|---|---|---|---|
| Residential Flat | $ 0.068 | $ 0.073 | $ 0.082 | $ 0.090 | $ 0.096 | $ 0.102 | $ 0.105 | $ 0.099 | $ 0.100 | 47.2% |
| 1,500 ft Home w/ Space Heat | $ 0.065 | $ 0.070 | $ 0.079 | $ 0.086 | $ 0.093 | $ 0.098 | $ 0.101 | $ 0.095 | $ 0.097 | 48.3% |
| Large Home AC only | $ 0.066 | $ 0.071 | $ 0.080 | $ 0.088 | $ 0.094 | $ 0.099 | $ 0.103 | $ 0.097 | $ 0.099 | 49.4% |
| Small Apt w/ Space Heat | $ 0.070 | $ 0.076 | $ 0.085 | $ 0.092 | $ 0.099 | $ 0.104 | $ 0.108 | $ 0.102 | $ 0.104 | 48.6% |
| SGS Flat | $ 0.067 | $ 0.072 | $ 0.081 | $ 0.085 | $ 0.091 | $ 0.095 | $ 0.099 | $ 0.093 | $ 0.092 | 37.2% |
| SGS 24 Hour Retail | $ 0.063 | $ 0.068 | $ 0.076 | $ 0.080 | $ 0.085 | $ 0.089 | $ 0.092 | $ 0.087 | $ 0.086 | 37.0% |
| SGS Office Use with HVAC | $ 0.065 | $ 0.070 | $ 0.079 | $ 0.083 | $ 0.089 | $ 0.093 | $ 0.096 | $ 0.091 | $ 0.090 | 37.1% |
| SGS 2nd Metered Residential | $ 0.084 | $ 0.090 | $ 0.102 | $ 0.106 | $ 0.113 | $ 0.118 | $ 0.124 | $ 0.118 | $ 0.115 | 37.8% |
| Small LGS Low Load Factor Winter Peak | $ 0.065 | $ 0.065 | $ 0.070 | $ 0.077 | $ 0.081 | $ 0.090 | $ 0.093 | $ 0.089 | $ 0.087 | 33.6% |
| Small LGS High Load Factor Winter Peak | $ 0.044 | $ 0.044 | $ 0.047 | $ 0.052 | $ 0.055 | $ 0.061 | $ 0.063 | $ 0.058 | $ 0.058 | 30.9% |
| Small LGS Low Load Factor Flat Usage | $ 0.068 | $ 0.068 | $ 0.073 | $ 0.080 | $ 0.084 | $ 0.094 | $ 0.097 | $ 0.093 | $ 0.091 | 33.5% |
| Small LGS High Load Factor Flat Usage | $ 0.044 | $ 0.044 | $ 0.047 | $ 0.052 | $ 0.055 | $ 0.061 | $ 0.063 | $ 0.058 | $ 0.058 | 30.9% |
| Large LGS Low Load Factor Winter Peak | $ 0.069 | $ 0.069 | $ 0.074 | $ 0.082 | $ 0.086 | $ 0.096 | $ 0.099 | $ 0.094 | $ 0.092 | 32.8% |
| Large LGS High Load Factor Winter Peak | $ 0.043 | $ 0.043 | $ 0.047 | $ 0.051 | $ 0.054 | $ 0.060 | $ 0.062 | $ 0.057 | $ 0.057 | 30.7% |
| Large LGS Low Load Factor Flat Usage | $ 0.065 | $ 0.065 | $ 0.070 | $ 0.077 | $ 0.081 | $ 0.091 | $ 0.094 | $ 0.089 | $ 0.087 | 33.2% |
| Large LGS High Load Factor Flat Usage | $ 0.043 | $ 0.043 | $ 0.047 | $ 0.051 | $ 0.054 | $ 0.060 | $ 0.062 | $ 0.057 | $ 0.057 | 30.7% |
| Small SPS Low Load Factor Winter Peak | $ 0.067 | $ 0.072 | $ 0.079 | $ 0.083 | $ 0.089 | $ 0.093 | $ 0.097 | $ 0.093 | $ 0.083 | 24.0% |
| Small SPS High Load Factor Winter Peak | $ 0.044 | $ 0.047 | $ 0.052 | $ 0.054 | $ 0.058 | $ 0.061 | $ 0.063 | $ 0.058 | $ 0.056 | 28.4% |
| Small SPS Low Load Factor Flat Usage | $ 0.070 | $ 0.075 | $ 0.082 | $ 0.086 | $ 0.093 | $ 0.097 | $ 0.101 | $ 0.097 | $ 0.087 | 24.3% |
| Small SPS High Load Factor Flat Usage | $ 0.044 | $ 0.047 | $ 0.052 | $ 0.054 | $ 0.058 | $ 0.061 | $ 0.063 | $ 0.058 | $ 0.056 | 28.5% |
| Large SPS Low Load Factor Winter Peak | $ 0.065 | $ 0.070 | $ 0.077 | $ 0.081 | $ 0.087 | $ 0.091 | $ 0.094 | $ 0.090 | $ 0.079 | 20.7% |
| Large SPS High Load Factor Winter Peak | $ 0.042 | $ 0.045 | $ 0.049 | $ 0.051 | $ 0.055 | $ 0.058 | $ 0.060 | $ 0.055 | $ 0.053 | 27.4% |
| Large SPS Low Load Factor Flat Usage | $ 0.062 | $ 0.067 | $ 0.073 | $ 0.076 | $ 0.082 | $ 0.086 | $ 0.090 | $ 0.085 | $ 0.075 | 21.1% |
| Large SPS High Load Factor Flat Usage | $ 0.042 | $ 0.045 | $ 0.049 | $ 0.051 | $ 0.055 | $ 0.058 | $ 0.060 | $ 0.055 | $ 0.053 | 27.4% |
| Small LPS Low Load Factor Winter Peak | $ 0.057 | $ 0.062 | $ 0.069 | $ 0.072 | $ 0.077 | $ 0.081 | $ 0.081 | $ 0.081 | $ 0.076 | 33.8% |
| Small LPS High Load Factor Winter Peak | $ 0.022 | $ 0.023 | $ 0.026 | $ 0.028 | $ 0.030 | $ 0.031 | $ 0.031 | $ 0.029 | $ 0.029 | 34.6% |
| Small LPS Low Load Factor Flat Usage | $ 0.059 | $ 0.063 | $ 0.071 | $ 0.075 | $ 0.080 | $ 0.084 | $ 0.084 | $ 0.083 | $ 0.079 | 33.8% |
| Small LPS High Load Factor Flat Usage | $ 0.022 | $ 0.024 | $ 0.027 | $ 0.028 | $ 0.030 | $ 0.031 | $ 0.031 | $ 0.029 | $ 0.030 | 34.6% |
| Large LPS Low Load Factor Winter Peak | $ 0.057 | $ 0.061 | $ 0.069 | $ 0.072 | $ 0.077 | $ 0.081 | $ 0.081 | $ 0.081 | $ 0.076 | 33.6% |
| Large LPS High Load Factor Winter Peak | $ 0.022 | $ 0.023 | $ 0.026 | $ 0.027 | $ 0.029 | $ 0.031 | $ 0.031 | $ 0.028 | $ 0.029 | 34.5% |
| Large LPS Low Load Factor Flat Usage | $ 0.059 | $ 0.063 | $ 0.071 | $ 0.074 | $ 0.079 | $ 0.083 | $ 0.083 | $ 0.083 | $ 0.078 | 33.6% |
| Large LPS High Load Factor Flat Usage | $ 0.022 | $ 0.024 | $ 0.026 | $ 0.028 | $ 0.030 | $ 0.031 | $ 0.031 | $ 0.029 | $ 0.029 | 34.4% |

Q. What immediate conclusions can one draw from this information?

A. Across the LGS, SPS, and LPS classes, customers have experienced increases in the range of 21% -35%, with a simple average increase across all profiles in those classes of 30%. Across the Residential and SGS classes, customers have experienced increases in the range of 47%-49%, with a simple average increase across all profiles in those classes of 48%.

Q. Is it fair to say that residential customers have experienced a 48% increase while industrial and large commercial customers have experienced a 30% increase?

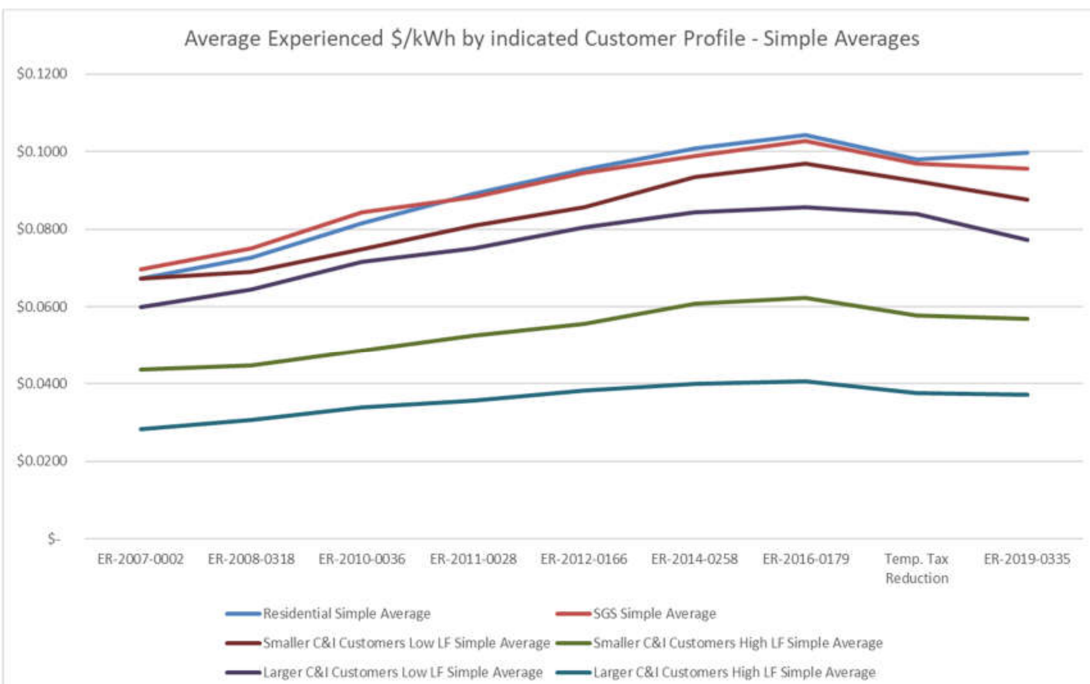
A. No. The Customer Profiles and experienced average $/kWh provided above are illustrative of the variation that occurs in bills among Ameren Missouri's customers. Given the changes in revenue responsibility and rate design that have occurred since 2007, and given the abilities of non-Residential customers to participate in rate switching, it is misleading at best to assert that any particular customer has experienced any given bill impact without simply comparing that customer's bill from 2007 with the same determinants as billed today (or vice versa).

Q. What additional conclusions can one draw from this information?

A. Across the LGS, SPS, and LPS classes, lower load factor customers have consistently experienced greater increases than higher load factor customers. For facilitation of comparison, Staff found the simple averages of experienced average $/kWh for the Customer Profiles by (1) rate schedule, (2) by load factor for the LGS, SPS, and LPS classes combined, (3) by relative size within class for the LGS, SPS, and LPS classes combined, and (4) by relative size across classes, and by load factor across the LGS, SPS, and LPS classes. These results are provided in the table below:

| | 2007 Average $/kWh | 2017 Average $/kWh | 2021 Average $/kWh | % Change |
|---|---|---|---|---|
| Residential Simple Average | $ 0.0673 | $ 0.1043 | $ 0.0998 | 48% |
| SGS Simple Average | $ 0.0697 | $ 0.1028 | $ 0.0957 | 37% |
| LGS Simple Average | $ 0.0553 | $ 0.0790 | $ 0.0731 | 32% |
| SPS Simple Average | $ 0.0543 | $ 0.0784 | $ 0.0677 | 25% |
| LPS Simple Average | $ 0.0398 | $ 0.0568 | $ 0.0533 | 34% |
| Low Load Factor C&I Customer Simple Average | $ 0.0636 | $ 0.0913 | $ 0.0824 | 30% |
| High Load Factor C&I Customer Simple Average | $ 0.0361 | $ 0.0515 | $ 0.0470 | 30% |
| Smaller within Class C&I Customers Simple Average | $ 0.0504 | $ 0.0723 | $ 0.0657 | 30% |
| Larger within Class C&I Customers Simple Average | $ 0.0492 | $ 0.0705 | $ 0.0638 | 29% |
| Smaller C&I Customers Low LF Simple Average | $ 0.0673 | $ 0.0969 | $ 0.0876 | 30% |
| Smaller C&I Customers High LF Simple Average | $ 0.0437 | $ 0.0624 | $ 0.0568 | 30% |
| Larger C&I Customers Low LF Simple Average | $ 0.0598 | $ 0.0856 | $ 0.0772 | 29% |
| Larger C&I Customers High LF Simple Average | $ 0.0284 | $ 0.0406 | $ 0.0372 | 31% |

The Residential and SGS simple averages are graphed below, with the LGS/SPS/LPS simple averages stratified by overall size and load factor:




Q. What immediate conclusions can one draw from this information?

A. The Larger C&I customers experienced lower average $/kWh throughout the study period. While the experienced average $/kWh associated with these customers is increasing (excepting the impacts of the Temporary Tax Reduction) it is at a lower rate than those experienced by the other profiles. Lower load factor C&I customers regardless of size are experiencing increases of magnitudes approaching that experienced by the SGS and Residential simple averages.[8]

Q. What changes to the LGS rate elements have occurred since Case No. ER-2007-0002?

A. The LGS rate structure with the rate of each element since July 2007 are provided below:

| Large General Service | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Customer Charge | $ 66.79 | $ 67.11 | $ 72.26 | $ 79.39 | $ 83.04 | $ 92.35 | $ 94.51 | 94.51 | 94.51 |
| Low - Income Program Charge | | | | $ 0.50 | $ 0.50 | $ 0.50 | $ 0.56 | 0.56 | 0.78 |
| Summer Energy Charge | | | | | | | | | |
| First 150 kWh per kW of billing demand | $ 0.0751 | $ 0.0751 | $ 0.0809 | $ 0.0889 | $ 0.0930 | $ 0.1034 | $ 0.1058 | 0.1058 | 0.0969 |
| Next 200 kWh per kW of billing demand | $ 0.0565 | $ 0.0566 | $ 0.0609 | $ 0.0669 | $ 0.0700 | $ 0.0778 | $ 0.08 | 0.0796 | 0.0729 |
| All Over 350 kWh per kW of billing demand | $ 0.0380 | $ 0.0380 | $ 0.0410 | $ 0.0450 | $ 0.0470 | $ 0.0523 | $ 0.0535 | 0.0535 | 0.0491 |
| Summer Demand Charge | $ 3.51 | $ 3.51 | $ 3.78 | $ 4.15 | $ 4.34 | $ 4.83 | $ 5.40 | 5.4 | 5.4 |
| Winter Energy Charge | | | | | | | | | |
| First 150 kWh per kW of billing demand | $ 0.0473 | $ 0.0473 | $ 0.0509 | $ 0.0560 | $ 0.0586 | $ 0.0651 | $ 0.0665 | 0.0665 | 0.0609 |
| Next 200 kWh per kW of billing demand | $ 0.0351 | $ 0.0351 | $ 0.0378 | $ 0.0415 | $ 0.0434 | $ 0.0483 | $ 0.0494 | 0.0494 | 0.0452 |
| All Over 350 kWh per kW of billing demand | $ 0.0276 | $ 0.0276 | $ 0.0297 | $ 0.0326 | $ 0.0341 | $ 0.0380 | $ 0.0389 | 0.0389 | 0.0356 |
| Seasonal Energy Charge | $ 0.0276 | $ 0.0276 | $ 0.0297 | $ 0.0326 | $ 0.0341 | $ 0.0380 | $ 0.0389 | 0.0389 | 0.0356 |
| Winter Demand Charge | $ 1.30 | $ 1.30 | $ 1.40 | $ 1.54 | $ 1.61 | $ 1.79 | $ 2.00 | $ 2.00 | $ 2.00 |

## DISTRIBUTION ALLOCATIONS

Q. Ameren Missouri witness Mr. Hickman states "In this case, as it did in the Company's prior electric general rate case, the Company has used the 'Minimum-Size Method' which is outlined in the National Association of Regulatory Utility Commissioners ("NARUC")

[8] The Customer Profiles and experienced average $/kWh provided above are illustrative of the variation that occurs in bills among Ameren Missouri's customers.

January 1992 Cost Allocation Manual."[9] How does the 1992 NARUC Manual summarize the minimum-size method?

A. The 1992 NARUC Manual provides "[c]lassifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and the customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method…."[10]

Q. How did Ameren Missouri's minimum system study vary from this description?

A. Ameren Missouri's variations to the NARUC descriptions fall into two broad categories – first, Ameren Missouri based its study on the minimum-size poles, conductors, cables, and devices associated with the portions of its distribution system that operate at primary voltage; second, Ameren Missouri performed its calculations in a sequence that resulted in factoring-up the customer-related costs when finding the difference between the total investment in the account and the customer-related costs.

Q. Is it necessarily concerning for a CCoS analyst to vary a method described in a CCoS manual when conducting a given CCOS Study?

[9] Hickman Direct, page 10.
[10] NARUC Manual at page 91

A. No. CCoS Studies are very data intensive and are also subject to system-specific considerations as well as jurisdiction-specific requirements that may apply. However, Mr. Hickman did not identify these variances in his testimony and they became apparent only through review of his workpapers and responses, when provided, to data requests.

**<u>Ameren Missouri performed its calculations in a sequence that resulted in factoring-up the customer-related costs when finding the difference between the total investment in the account and the customer-related costs.</u>**

Q. How does the sequence of calculations affect the final allocation of plant and expense?

A. In this case, Mr. Hickman's workpapers indicated his calculation of the minimum-size systems-per account using a version of the Continuing Property Record with data as of roughly 1/1/2021. For each account (except Account 366 – Conduit) he found the percentage of minimum-size system based on the total of the CPR costs, excluding non-unitized costs and miscellaneous costs.[11] For example, in Account 365 – Overhead Conductors & Devices, Mr. Hickman reviewed plant records and calculated a minimum system cost of $777,463,914, and the account balance after Mr. Hickman removed non-unitized and miscellaneous costs was $1,368,414,640. Mr. Hickman used these numbers to create a percentage of 56.8149%, which he decided to use as the "365 Allocator." However, he applied this percentage to the gross balance of this account in the Ameren Missouri CCoS Study of $1,752,037,567. 56.8149% of $1,752,037,567 is not $777,463,914, it is $995,332,542. $995,332,542 is $217,868,628 more than $777,463,914.

[11] Mr. Hickman's workpapers state that he relied on his calculations for Account 367 – Underground Conductors & Devices, for Account 366 – Conduit.

Q. Are the CPR amounts studied by Mr. Hickman reflective of the Gross Plant amounts allocated by Mr. Hickman?

A. This varies by account. Overhead conductors and devices, AMI Meters, Meter Installations, Poles Towers & Fixtures, and Lighting are particularly concerning.

| Account | Description | CPR Total | Ameren Direct | Difference $ | ifference ! |
|---|---|---|---|---|---|
| 364 | Poles, Towers, & Fixtures - DP | $ 1,253,077,844 | $ 1,282,350,821 | $ 29,272,977 | 2% |
| 365 | Overhead Conductors & Devices - DP | $ 1,420,249,106 | $ 1,752,037,567 | $ 331,788,461 | 23% |
| 366 | Underground Conduit - DP | $ 591,799,313 | $ 591,799,313 | $ 0 | 0% |
| 367 | Underground Conductors & Devices - DP | $ 955,320,836 | $ 955,320,836 | $ (0) | 0% |
| 368 | Line Transformers - DP | $ 521,169,770 | $ 521,169,770 | $ (0) | 0% |
| 369.1 | Services - Overhead - DP | $ 214,886,697 | $ 214,886,697 | $ 0 | 0% |
| 369.2 | Services - Underground - DP | $ 182,120,703 | $ 182,120,703 | $ 0 | 0% |
| 370 | Meters - DP | $ 103,632,157 | $ 103,632,157 | $ (0) | 0% |
| 370.1 | AMI Meters | $ 49,460,710 | $ 94,675,627 | $ 45,214,917 | 91% |
| 371 | Meter Installations - DP | $ 135,359,360 | $ 164,613 | $ (135,194,747) | -100% |
| 373 | Street Lighting and Signal Systems - DP | $ 53,927,096 | $ 189,286,456 | $ 135,359,360 | 251% |

Q. Could it be reasonable to factor up the minimum-size-derived amount under certain circumstances, and what circumstances caused the variation between the amount Ameren Missouri used to find the customer percentage and the account balance reflected in the Ameren Missouri CCoS study?

A. Yes. If, for example, Ameren Missouri purchased a system from another utility it may be reasonable to assume the same proportion of minimum system is associated with the additional plant as the studied plant if there was not time or documentation to study the additional plant composition. However, the cause of the growth in Accounts 365 between the time of Mr. Hickman's minimum-size study and his CCoS Study is related to reconductoring of existing line miles and to the installation or upgrade of devices such as switches and lightening arrestors. Additional variation in the balance used to derive the customer percentage and the balance used in the CCoS was introduced by Mr. Hickman's decision to remove the portion of the CPR balance associated with non-unitized plant. Non-unitized plant is included in the CCoS account balances, so removing it from the CPR balance used to find the customer percentage exacerbated the overstatement of customer-related costs in the Ameren Missouri CCoS Study.

Q. What is the impact of this order of calculations on the amount of distribution plant allocated on customer counts, and the amount of distribution plant allocated as demand-related?

A. On a net-plant basis, approximately $167,173,289 of Accounts 364-367 that should have been allocated as demand-related were allocated to the classes based on customer counts. This is about 7% of the net plant associated with these accounts.

| Account | Calculated Minimum System | Amount Allocated as Customer-Related | Total Account Gross Plant in CCoS Study | Gross Amount Over-Allocated | Net Plant in CCoS Study | Net Plant as % of Gross | Net Amount Over-Allocated |
|---|---|---|---|---|---|---|---|
| 364 - Poles, Tower & Fixtures | $ 750,137,286 | $ 786,126,910 | $ 1,282,350,821 | $ 35,989,624 | $ 151,910,646 | 12% | $ 4,263,425 |
| 365 - Overhead Conductors & Devices | $ 777,463,914 | $ 995,332,542 | $ 1,752,037,567 | $ 217,868,628 | $ 1,193,332,398 | 68% | $ 148,392,761 |
| 366 - Conduit | | $ 181,268,130 | $ 591,799,313 | $ *5,606,119* | $ 459,220,581 | 78% | $ 4,350,200 |
| 367 - Underground Conductors & Devices | $ 277,958,892 | $ 292,614,772 | $ 955,320,836 | $ 14,655,880 | $ 662,713,833 | 69% | $ 10,166,903 |

Ameren Missouri's reliance on the distribution plant allocation to allocate distribution expense also results in an overallocation of distribution expenses to classes with large numbers of customers such as SGS and Residential, and an underallocation of distribution expenses to classes with relatively few customers, such as LPS.

Q. How does the RAP Manual address the relationship between the calculated minimum-size cost for a given account and the total account balance?

A. On page 146 the RAP Manual states "The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related."

This description emphasizes the importance of recognizing that the CPR cost-per-unit of retirement units currently being installed will reflect current pricing, while the other plant in the account will reflect the installed costs of the time it was installed.[12] A simplified example is provided below:

| Retirement Unit | Year Installed | Number of Units | Total Cost | Cost per Unit |
|---|---|---|---|---|
| 100' tower | 1980 | 100 | $ 1,000,000 | $ 10,000 |
| 100' tower | 2020 | 2 | $ 40,000 | $ 20,000 |
| 40' pole | 1980 | 10 | $ 5,000 | $ 500 |
| 40' pole | 2020 | 5,000 | $ 5,000,000 | $ 1,000 |
| | | 5,112 | $ 6,045,000 | |

In this example, the system contains 5,112 poles and towers. Most of the 100' towers were installed in 1980, and most of the 40' poles were installed in 2020. The actual system cost is $6,045,000.

The minimum-size system cost would be calculated by finding the average per-unit cost of 40' pole, then multiplying that cost by the 5,112 poles in the system, as provided below:

| Retirement Unit | Year Installed | Number of Units | Total Cost | Cost per Unit |
|---|---|---|---|---|
| 100' tower | Average Cost | 102 | 1,040,000 | $ 10,196 |
| 40' pole | Average Cost | 5,010 | 5,005,000 | $ 999 |
| | | Minimum-Size System $: | $ 5,106,898 | |
| | | Minimum-Size System %: | 84% | |

Note that $5,106,898 is 84% of the actual system cost of $6,045,000.

[12] Mr. Hickman does include a step recognizing that some per-unit costs are less than the selected minimum-size per unit cost.

However, the RAP Manual suggests bringing the dollars associated with each retirement unit to a consistent basis. This could be done various ways, depending on the data available. In this example, the most straightforward approach would be to multiply the number of 100' towers by the 2020 average cost for 100' towers, and to multiply the number of 40' poles by the 2020 average cost for 40' poles, as provided below:

| Retirement Unit | Year Installed | Number of Units | Total Cost | Cost per Unit |
|---|---|---|---|---|
| 100' tower | Adjusted Cost | 102 | $ 2,040,000 | $ 20,000 |
| 40' pole | Adjusted Cost | 5,010 | $ 5,010,000 | $ 1,000 |
| | Adjusted System Total $: | | $ 7,050,000 | |
| | Minimum-Size System $: | | $ 5,112,000 | |
| | Minimum-Size System %: | | 73% | |

Note that when the Minimum-Size dollars are quantified as a percentage of the Adjusted System Total dollars, the resulting percentage is reduced to 73%, however, this approach may result in a higher or lower percentage relative to the first calculation, depending on the average age of system components and the average age of the minimum-size component.

Q. Would the customer-related component found in Ameren Missouri's minimum-size study be expected to be increased or decreased had this analysis been performed?

A. Staff reviewed the average age of poles and towers in Account 364. The average age of 40' wood poles was 22 years. The average of age of poles that had a lower per-unit cost than 40' wood poles was 37 years. The average age of poles that had a higher per-unit cost than 40' wood poles was 27 years. In other words, the per-unit cost of the selected minimum-size unit of 40' wood poles were not in consistent dollars with the balance of the account. This indicates that Ameren Missouri's method classified more costs as customer-related and over-allocated distribution costs and expenses to classes with high customer numbers while under-allocating distribution costs and expenses to classes with lower customer numbers than adherence to a minimum-size method conducted pursuant to the RAP Manual.

**<u>Ameren Missouri based its study on the minimum-size poles, conductors, cables, and devices associated with the portions of its distribution system that operate at primary voltage.</u>**

Q. Was it reasonable to rely on primary voltage components for a "minimum-size" classification of the distribution system?

A. No, 1,294,668 of million Ameren Missouri's 1,295,396 customers are served at secondary voltage. As discussed in Staff's CCoS and Rate Design Report, it is unreasonable to use primary-size components as the basis for a minimum-size study without significant adjustments.

Q. How does Ameren Missouri's reliance on primary voltage components for its "minimum-size" study affect the evidentiary reliability of its results?

A. Ameren Missouri's distribution allocation is not based on a reliable analysis under the circumstances. Data availability and limitation are always factors in the design and conduction of CCoS Studies. However, Ameren Missouri is responsible for the maintenance and organization of Ameren Missouri's plant data, and Ameren Missouri has unique access to the operation and design of the Ameren Missouri distribution system. Ameren Missouri's CCoS results in an overallocation of distribution plant and expenses to classes with large numbers of customers such as SGS and Residential, and an underallocation of distribution expenses to classes with relatively few customers, such as LPS, such that it cannot provide evidentiary support for increasing the revenue responsibility of classes with large numbers of customers, nor decreasing the revenue responsibility of classes with relatively few customers.

Q. Is Mr. Hickman's testimony describing the minimum-size study factually accurate?

A. Based on Ameren Missouri's data request responses, portions of Mr. Hickman's testimony are not factually accurate, and mischaracterize the nature of the plant discussed and the degree of input of the Ameren Missouri Distribution Planning Group to the minimum-size study.

Q. What is the minimum-size retirement unit actually installed by Ameren Missouri for each of the distribution accounts?

A. Ameren Missouri has not provided this information to date. Staff requested this information in its DR 533.1, issued June 22, 2021. Ameren Missouri's July 26, 2021 response, ATTACHED, did not answer this question. This response also stated that "Mr. Hickman's informal conversations with the Distribution Planning Group were focused on reviewing the reasonableness of retirement unit selections previously made. Specific alternatives and selection parameters were not specifically a part of these conversations, as those would have been discussed at the time of the original study. The conversations included the purpose of the minimum distribution study, how it is utilized in cost of service, and whether the previously selected minimum size items were reasonable in the context of the study. There are no specific notes, presentations, or documents from these conversations." In contrast, Mr. Hickman's testimony at page 10 provides:

> Q. How were the customer-related costs of FERC Account 364-—-poles, towers, and fixtures — determined using the minimum-size method?
>
> A. First, the average installed book cost of the minimum height pole currently being installed for the Company's distribution system was determined through discussions with Ameren Missouri's Distribution Planning Group. Then, the average book cost was multiplied by the number of poles to find the customer-related cost component. Poles with

> average book cost less than the minimum height pole are included at their lower cost…."

Tom Hickman's testimony at page 11 is:

> Q. How were the customer-related costs of FERC Account 365-—-overhead conductors and devices — determined?
>
> A. The current minimum size conductor being installed was determined through discussions with the Distribution Planning Group. A weighted average cost of conductor was developed by including every foot of conductor with an average book cost greater than or equal to the average book cost of the minimum size conductor at the average book cost of the minimum size conductor….

Tom Hickman's testimony at page 12 is

> Q. How were the customer-related costs of FERC Accounts 366 and 367-—-underground conduits, conductors and devices — determined?
>
> A. For Account 367 (underground conductors and devices), the average minimum size underground conductor was determined through discussions with the Distribution Planning Group. A weighted average cost of conductor was developed consistent with the process described for Account 365 above….

Tom Hickman's testimony at page 12 is

> Q. How were the customer-related costs of FERC Account 368 — line transformers — determined?
>
> A. The cost of a minimum size transformer currently being installed was determined through discussions with the Distribution Planning Group. The average cost of the minimum size transformer was multiplied by the number of transformers in the plant account to determine the current cost of the minimum-size system….

Q. At what voltage do the retirement units selected by Mr. Hickman operate?

A. In its response to DR 533.1, Ameren Missouri represented that the following retirement units operate at the voltages indicated, with the predominant voltage of operation specified:

> 364 Poles – POLE,WOOD,40' – 240V, 480V, 4160V, 12000V, 12470V, 13200V, 13800, 25000V – Predominantly 12000V

365 Overhead Conductor & Device – WIRE,1/0,ALUMINUM - 240V, 480V, 4160V, 12000V, 12470V, 13200V, 13800, 25000V, 34500V – Predominantly 12000V

367 Underground Conductor & Device – CABLE, 5KV,1-2,RUBBER,CONC NEUT –4160V

368 Line Transformers – TRANSFORMER,0025KVA,1PH,7200V – 12000V

All of these items operate exclusively or predominantly at primary voltage. Further, in its June 15, 2021 response to Staff's May 18, 2021 Data Request 474, Ameren Missouri stated "For a typical installation of 40' poles and 1/0 AAAC wire, this conductor could and would be operated at 4.16kV or 12.47kV, based on current Ameren Missouri construction standards."

Q. What rationale does Mr. Hickman provide for his choice to use primary system components as the minimum-size component in his minimum-size system?

A. No explanation was provided.

Q. How much of each distribution account is sized to operate at secondary voltage?

A. Staff does not have access to that information and attempts to obtain that information from Ameren Missouri have largely been unsuccessful. On September 8, 2021, Ameren Missouri provided a supplemental response[13] to Staff's DR 104.9, issued July 2, 2021[14] indicating that "a very rough guess of miles of overhead secondary would be a range 50%

[13] "There would not be much mileage of overhead secondary circuit alone. Overhead secondary would most likely be collocated with overhead primary in the areas where primary exists. Secondary would exist in areas that have a higher customer density. Very little overhead secondary would exist in rural areas due to distance between customers. Based this assumption, a very rough guess of miles of overhead secondary would be a range 50% to 60% of the miles of overhead primary. Please note that this is a very subjective estimate, and as we get our secondary into the mapping system over time this information should be updated. The miles of underground secondary should be able to be derived fairly closely from the information on retirement units in the 367 accounts."

[14] DR 104.9, "Refer to company's response to DR 104.5. Please confirm whether the company operates any circuits below 2.4 kV. If the company does operate circuits below 2.24 kV please provide a list of such circuits and identify the voltage at which it operates, the length of each circuit underground and length of each circuit overhead. Please identify the number of customers served on each such circuit. Please identify the accounts to which assets associated with these circuits are recorded. Please provide any information available that quantifies the value of assets associated with these circuits."

to 60% of the miles of overhead primary." This "very rough guess" indicates approximately 11,000 miles of overhead secondary system exists. However, on September 13, 2021, Ameren Missouri provided a supplemental response[15] to Staff's DR 104.9, issued July 2, 2021. This response provided a list of retirement unit names in accounts 365 and 367 which "could be used for Secondary Voltages (600v and below). Please note, a few of these retirement units may have mixed used, but the majority would be used for secondary exclusively." Using the version of the CPR contained in Mr. Hickman's workpapers, these retirement units comprise $10,628,489, (approximately 0.75%) of the account balance of Account 365, Overhead Conductors & Devices. By length, these retirement units comprise about 1.6 million feet of secondary distribution system, or about 315 miles.

However, Mr. Hickman's CCoS is based on the valuations of the secondary system —-beyond the level included in the customer-related portion of each account – indicated in the following table:

| Account | Account % of Dollars Deemed Secoondary | Non-Customer % of Account Deemed Secondary | Gross Plant $ Deemed Secondary |
|---|---|---|---|
| 364 - Poles, Tower & Fixtures | 9.72% | 25.11% | $ 124,601,778 |
| 365 - Overhead Conductors & Devices | 1.69% | 3.91% | $ 29,609,435 |
| 366 - Conduit | 19.37% | 27.92% | $ 114,631,527 |
| 367 - Underground Conductors & Devices | 19.37% | 27.92% | $ 185,045,646 |

Q. What explanation did Mr. Hickman provide for representing that primary-voltage components were the "minimum size" component "currently being installed" while simultaneously classifying at least $453,888,386 in assets as secondary voltage?

[15] "Please see the attached excel file MPSC 104.9s2 Response.xlsx. Each tab contains the retirement units for the respective major which could be used for Secondary Voltages (600v and below). Please note, a few of these retirement units may have mixed used, but the majority would be used for secondary exclusively."

A. No explanation was provided. The concept of using primary-sized components of the distribution system for a minimum-size study because there is minimal investment in a secondary distribution system is inconsistent with the practice of classifying significant portions of the distribution accounts as secondary. The logical inconsistency is compounded by failing to net the secondary-deemed portion from the customer-related allocation. For example, if the customer-related portion is assumed to replace the entire distribution system as-built with the "minimum-size" component, but the minimum-size component is bigger than the system as-built, then the cost of those components that are smaller than the minimum-size component should be assumed to be subsumed into the minimum-size system.

Q. What explanation did Mr. Hickman provide for treating all lightening arrestors and essentially all switches and reclosers as customer-related?

A. On page 10 Mr. Hickman states "Also included in the minimum-size distribution system costs are safety/reliability equipment, like protective relays and lightning arrestors as well and other basics like land and fencing — essentials necessary for providing electrical service regardless of customer usage characteristics." He provides no further explanation, and his explanation does not account for the differences in cost for a device sized to operate at secondary voltage versus a higher voltage.[16] Aside from an adjustment to the cost of 1,131 out of 424,449 devices to adjust their costing from three phase to one phase, no other adjustments were made in the Ameren Missouri minimum-size study to account for costs differences between devices rated for operation at primary or HV voltage versus what those device costs would have been at secondary voltage.

[16] In DR 477 Staff inquired as to the situations in which distribution poles are fenced on Ameren Missouri's system and Ameren Missouri responded that "there is no typical situation in which a distribution pole would be fenced on the Ameren Missouri system." This is apparently inconsistent with the inclusion of the fencing in the poles account as customer-related by Mr. Hickman and his reference to this fencing as essential.

**<u>SUMMARY AND CONCLUSION REGARDING DISTRIBUTION ALLOCATION</u>**

Q. Did Staff's adjustments to Ameren Missouri's distribution account allocators correct for these issues?

A. Not fully. Staff did not have access to data in Ameren Missouri's possession, and eventually ran out of time to perform the adjustments necessary to correct for the issues with Ameren Missouri's allocators. In addition to the issues described above, as discussed in the Staff CCOS and Rate Design Report, Ameren Missouri's study reliability is undermined by the following factors:

1. Ameren Missouri made no attempt to assign or allocate the costs of customer-specific distribution lines or equipment to customers served by those lines and equipment at primary,

2. Solar infrastructure was allocated as though it was a distribution system "device."

3. Obvious misrecordings were discussed in the CCoS and Rate Design Report concerning the underground services account and indicate concerns with the thoroughness and accuracy of Ameren Missouri's review of the accounts for allocation.

Q. Are the effects of these issues consistent in direction of impact, or offsetting?

A. These issues consistently result in overallocation of revenue responsibility to Res and SGS, and under allocation to LPS and to a lesser extent SPS.

Q. What is the purpose of classifying the distribution accounts by secondary, primary, and HV voltage?

A. This classification process is performed so that customers served at primary and HV do not contribute to the revenue requirement of secondary voltage assets.

Q. What is the purpose of classifying the distribution accounts to identify a customer-related portion?

A. The purpose of this step is to identify a level of distribution costs, if any, to allocate to the classes on the basis of customer count. The RAP Manual is generally critical of the minimum-size approach and recommends the basic customer method as best practice.[17] Concerning the minimum system approach, the RAP Manual offers the following critique at page 146 et seq:

> This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.
>
> 1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number.[149] Bonbright found that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concluded that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems … clearly indefensible. [Cost analysts are] under impelling pressure to fudge their

[17] Under the basic customer method, only those costs that actually vary with the number of customers are classified as customer-related. The RAP Manual recommends that the analysist divide the vast majority of distribution costs between demand-related and energy-related using an energy weighted method, such as the average-and-peak method under which demand-related distribution costs are allocated using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for diversity in customer usage.

cost apportionments by using the category of customer costs as a dumping ground" (1961, p. 348).

2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers.150 Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage duration).

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, and higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.

4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system (Sterzinger, 1981, pp. 30-32).

5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.[151] However, the transformer industry could

produce truly minimum-sized utility transformers, the size of those used for cellular telephone chargers, if there were a demand for these.

6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.

7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.

8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with contributions in aid of construction, as discussed in Section 15.2. Factoring in the entire length of the system, including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines. Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid overhead distribution equipment only under several unusual circumstances.[152] These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility,

particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

> [149] As noted above, for some rural utilities, particularly cooperatives that extend distribution without requiring that the extension be profitable, a portion of the distribution system may effectively be customer-specific.

> [150] Adding transformers also reduces the length of the secondary lines from the transformers to the customers, reducing losses, voltage drop or the required gauge of the secondary lines.

> [151] For example, in many cases, utilities that make an allocation based on a minimum system use 10-kVA transformers, even though they installed 3-kVA or 5-kVA transformers in the past some utilities also have used conductor sizes and costs significantly higher than the actual minimum conductor size and cost on their systems.

> [152] These circumstances are: (1) if the customer would have been the farthest one from the transformer along a span of secondary conductor that is not a service drop; (2) if the customer is the only one served off the last pole at the end of a radial primary feeder, a pole and a span of secondary, or span of primary and a transformer; and (3) if several poles are required solely for that customer.

Q. As it relates to the distribution plant and expense accounts, what considerations should the Commission keep in mind when interpreting the Ameren Missouri CCoS Study results?

A. Staff has several concerns with the study and notes that generally the deficiencies of the study relate to Ameren Missouri's inability or unwillingness to provide (1) the data necessary to differentiate the costs of primary assets, HV assets, and secondary assets to insulate customers served at HV and primary voltages from the costs of the secondary system, (2) the data necessary to perform a minimum-size study,[18] and (3) the customer-specific

[18] Under a best practices approach as described in the RAP manual, these first two sets of data may be unnecessary.

assets that are recorded in accounts other than the meters accounts and services accounts. In general, these deficiencies shift revenue responsibility to the residential and SGS classes, and away from the LPS, SPS, and to a lesser extent, the LGS classes. If Ameren Missouri continues to allocate assumed secondary costs away from higher-voltage customers and continues to rely on an approach other than the basic customer approach, Staff notes that identification of the assets or the book value of the assets of (1) the secondary-voltage components of each account, (2) the primary-voltage components of each account, and (3) the HV components of each account is essential. Regardless of whether the RAP best practice is implemented, identification of the customer-specific assets that are recorded in accounts other than the meters accounts and services accounts remains necessary.

Q. Does this conclude your rebuttal testimony?

A. Yes.