# BEFORE THE PUBLIC SERVICE COMMISSION
# OF THE STATE OF MISSOURI

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| In the Matter of Union Electric Company<br>d/b/a Ameren Missouri's Tariffs to<br>Increase Its Annual Revenues for<br>Electric Service | )<br>)<br>)<br>) | **File No. ER-2022-0337** |

## STAFF'S INITIAL BRIEF

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# TABLE OF CONTENTS
## STAFF'S INITIAL BRIEF
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| | | |
|---|---|---|
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## STAFF'S INITIAL BRIEF

**COMES NOW** the Staff of the Missouri Public Service Commission, by and through counsel, and tenders this *Initial Brief* in this matter:

### I. ISSUE 1 -- CLASS COST OF SERVICE, REVENUE ALLOCATION, RATE DESIGN AND RATE-SWITCHING TRACKER

This brief addresses the issues identified in the Updated Issues List previously filed herein. However, to improve clarity, some of the issues contained therein have been reorganized as indicated herein.

### II. The Commission realistically has two options in this case, to move forward with Staff's recommendations, or to move backward as urged by Ameren Missouri, MECG, and MIEC.

a. Overview of Staff's recommended path forward:

The Commission can dispose of I**ssues 1A**[1] **and 1B**[2] by determining as a matter of policy on **Issue 1.D.**[3] that an equal percentage increase in class revenue responsibility (with or without the non-contested lighting revenue allocation issue) is appropriate in the face of its rate modernization objectives. Or, the Commission can agree with Staff's positions on **Issues 1A and 1B**, then either order Staff's proposed class revenue responsibility shifts, or order an equal percentage increase in class revenue responsibility (with or without the non-contested lighting

[1] "How should production costs be allocated among customer classes within a Class Cost of Service Study?"
[2] "How should distribution costs be allocated among customer classes within a Class Cost of Service Study?"
[3] "How should any rate increase be allocated to the several customer classes?"

revenue allocation issue) as appropriate in the face of its rate modernization objectives. [4] As will be discussed below, Staff's CCoS study is reasonable and reliable, and Staff's recommended shifts in revenue responsibility are appropriate. However, Staff is not opposed to setting those revenue responsibility shifts aside in this case to lessen customer impact to customers in the Large General Service (LGS), Small Primary Service (SPS), and Large Primary Service classes concurrent with incorporation of a time of use overlay into the rate structures of those schedules, as well as the SGS rate schedules.[5] This overlay is designed to not only send a cost-based price signal to customers, but also to provide information and education to those customers, and to facilitate the data retention necessary to develop more differentiated rates in a future proceeding.

What the Commission may not reasonably do is rely on the unreasonable treatment of distribution classification and subfunctionalization in the Ameren Missouri and derivative studies, nor rely on the unreasonable treatment of production subfunctionalization and allocation in the Ameren Missouri and derivative studies. The Ameren Missouri CCoS study is wholly unreasonable in the manner in which distribution costs and expenses are allocated, and relies on an approach for allocation of the production revenue requirement that is inconsistent with Ameren Missouri's participation in the MISO energy and capacity markets. The unreasonable revenue requirement allocations resulting from these functions are exacerbated by the indirect

[4] A similar equal percentage result can be achieved should the Commission take a conservative approach to rely on Staff's direct-filed CCOS Study modified to (1) eliminate use of the RA Allocator, and to rely on a 1 CP allocator instead, and (2) to remove customer-specific allocation of distribution accounts 364-367, and (3) to rely on Mr. Hickman's unsupported voltage subfunctionalization of accounts 364-367, presented in Sarah Lange Surrebuttal, see pages 34 L 18 – p 38 L 9. Such an order should include clarifying language that the result reached is not an endorsement of any of the methods contained therein, including but not limited to the unreliable "Vandas" results from 2009.

[5] See discussion of Issue 1.G. and subparts.

allocation of much of the remaining revenue requirement on the basis of the direct allocations in these functions. The recommendations of Mr. Chriss and Mr. Brubaker are based on this study.[6],[7]

Moving beyond this case,[8] Staff recommends the development of modern rate structures for Ameren Missouri which, pending further study, it anticipates to consist of (1) Customer and facilities charges related to customer annual NCP to recover customer-related costs and the cost of customer-specific infrastructure; (2) CP demand charges to collect remaining distribution and transmission. Staff suggests that CP periods of 12:01 pm – 8:00 pm are appropriate for the months May, June, July, August, September, and October, and that CP periods of 6:01 am – 10:00 am, and 4:00 pm – 8:00 pm are reasonable periods for the initial study of appropriate determinants and charges, subject to refinement; (3) ToU-based energy charges and determinants, where the differential of such charges is approximated to the difference in the average DA LMP across the time periods, but also recovers the costs of variable and stable revenue requirement production. Of note, no party provided criticism of this suggested starting point for rate structure development. Refining these elements and developing relevant rates requires access to reasonable and reliable data, generally discussed under **Issue 1.H**,[9] and an open and inquisitive approach to study, generally discussed under **Issue 1.C**.[10]

Staff's recommendations also include its recommended strategy to standardize the use of time-based rates for residential customers, as well as discussion of best practices should the Commission decide as a matter of policy to pursue more aggressive implementation of time-based

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[6] Sarah Lange Rebuttal, pp. 22-54.

[7] Ameren Missouri's position on **Issue 1.D**. is an equal percent adjustment to all rate classes except for the intraclass lighting issue.

[8] Staff's recommended steps for rate modernization were spelled out in the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245.

[9] "Rate Structures," with subparts a. – i..

[10] "Which party's Class Cost of Service Study should be used in this case and used as a starting point for the non-residential rate design working case agreed to by the parties to the Company's last electric general rate case, File No. ER-2021-0240?"

rates. Under either approach, Staff recommends (1) development of appropriate customer charges that support understandability, and (2) appropriate revenue risk retention. Finally, Staff will discuss the introduction by Ameren Missouri of superfluous "average rate" data, and appropriately contextualize this information and the discussion of Ameren Missouri's unreasonable extrapolation of the data presented.

b. The Commission should not persist in the use of outdated and unreasonable assumptions in determining class revenue responsibilities.

While the distribution and production cost functions do not comprise the entirety of Ameren Missouri's net cost of service,[11] much of the remaining cost of service in a class cost of service study is allocated based on the overall allocation of these functions to the classes, under all study approaches considered in this case.[12] Staff's allocation of these areas is consistent with best practices and reflective of current market conditions, while Ameren Missouri's study relies on unreasonable assumptions, outdated data, and is not consistent with industry guidance

i. Ameren Missouri's distribution study relies on unreasonable and outdated voltage subfunctionalization estimates.[13]

In the Ameren Missouri CCoS Study, classes of customers that include customers served at a voltage other than secondary are insulated from an estimate of the costs of the distribution system that operate at a lower voltage. This is known as subfunctionalization or classification by voltage. To estimate the costs from which customer classes are insulated, Mr. Hickman relies on the work product of "Vandas" from 2009, prior to Ameren Missouri's multi-billion dollar distribution system expansion campaign.[14]

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[11] See table "Fuctionalized Ameren Missouri Cost of Service," Lange CCoS Direct p 9 Line 11
[12] Transcript Vol. 8 p 412 Line 14- p 414 line 14
[13] This section includes a portion of Staff's discussion of **Issue 1.A.**, "How should distribution costs be allocated among customer classes within a Class Cost of Service Study?"
[14] Sarah Lange Rebuttal, p. 37.

Mr. Vandas is not available as a witness in this case.[15] Mr. Vandas did not assist Mr. Hickman in preparing Mr. Hickman's workpapers in this case, nor did he directly assist in the conduct of Ameren Missouri's CCoS,[16] which was relied upon by MIEC and MECG. Mr. Hickman relied on the percentages of plant balances found in 2009 to come up with "a percentage breakdown of how much of those poles should be allocated to high voltage, primary, and secondary voltages."[17]

Mr. Hickman admits that the pre-2009 data relied upon in 2009 by Mr. Vandas for the values used to subfunctionalize distribution accounts was not available to himself nor to other parties who requested such data.[18] There is no indication that Mr. Hickman performed a check of the account balances as they existed in 2009 against the account balances of those accounts for Ameren Missouri's updated test year in this case.[19] The distribution system today is much different than it was in 1994 when the Vandas study was performed.[20] Mr. Hickman's credibility on this issue is undermined by his response to his counsel's question provided in transcript volume 7 at page 155, lines 7 – 17, "Does the age impact your use of the Vandas study?" Mr. Hickman responded, "No, it does not. The Vandas study as I described it is informative to percentage allocations of certain types of assets between voltage. And I think as I kind of indicated in my earlier description of how it's used, unless there's some reason to think that we're using distribution assets in a different way now than we were back in 2009 at the time that the study was performed,

[15] Transcript Vol. 7 p 99 L 2-6.
·Q.· · ·Okay.· Is he available to testify here ·3· ·today if the Commission were to call on him? ·4· · · ·A.· · ·I'm not a lawyer; I don't know how this ·5· ·process works, but I know that he's no longer ·6· ·employed by the company.
[16] Transcript Vol. 7 p 99 lines 7 – 25
[17] Transcript vol. 7 p 108 Line 24 – p. 109 line 10.
[18] Transcript vol. 7 p 100 line 1 – p 101 line 10
[19] Transcript vol. 7 p 101 line 11 – p 103 line 19.
[20] Tr. Vol. 8 p 465 line 4 – p. 467 line 12

and I have no belief that we have, [sustained objection on remainder of answer]." Beyond the Commission's general knowledge of Ameren Missouri's recent ramp in distribution infrastructure spending since 2009, specific examples of the disparity in spending across voltages are available in the record in this case. Ameren Missouri's distribution system has changed to implement desired "grid resiliency" projects, including "operating flexibility" projects designed to provide the "ability to switch power flow on demand,"[21] which include projects to "convert select 4kV substations to 12kV substations," and includes "improved ability to handle severe weather events due to the upgrading and replacement of old infrastructure at new standards."[22] Ameren Missouri's "Smart Grid Deployment Strategy" has been targeted to "12kV Worst Performing Circuits," with "limited 4kV deployment."[23] Ameren Missouri has built a private LTE network which is recorded to its distribution accounts.[24]

The unreasonableness of Mr. Hickman's voltage subfunctionalization is apparent in Exhibit 181, an excerpt from his workpapers,[25] which indicates he allocated 10 percent of Account 364, "Poles, Towers, Fixtures" as secondary voltage, while allocating only 2% of Account 365 "Overhead Conductor [and Devices]" as secondary voltage. 20% of the poles account is allocated as primary voltage, while 32% of the overhead conductor account is allocated as primary voltage. These disparities should give a reasonable analyst pause.

Critically, Mr. Hickman's admission during redirect by his counsel that "the results of those are percentages based on a review of the snapshot of our system at any point in time"[26] refer to dollars, not numbers of assets. Ms. Lange's rebuttal at pages 43 line 19 – page 47 line 4 discusses

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[21] Claire Eubanks Rebuttal, Schedule CME-r5 page 2.
[22] Claire Eubanks Rebuttal, Schedule CME-r5 page 3.
[23] Claire Eubanks Rebuttal, Schedule CME-r5 page 9.
[24] Claire Eubanks Rebuttal, Schedule CME-r5 page 9.
[25] Exhibit 181
[26] Transcript v 7 p 152 Lines 20 – 22

the actual percentages provided in Mr. Hickman's workpapers as the "Vandas" results. Even if absolutely nothing had changed in the Ameren Missouri distribution system other than replacement of an old asset with an identical asset, the dollars attributable to each voltage level within each account would change due to changes in the costs of assets versus the historical cost of those assets.

Finally, as concerns the "Vandas" subfunctionalization of the distribution system by voltage, Mr. Hickman failed to reasonably net his customer-allocated classification by plant account from the "Vandas"-determined voltage subfunctionalizations.[27] In other words, while Mr. Hickman allocated the cost of all or most of the primary assets in each distribution account to the customer classes on the basis of customer count, he did not subtract this amount from the "Vandas"-determined primary account dollars for that account. Rather, he prorated the customer-allocated values across all "Vandas"-determined voltage dollar values within each account. A table and graphics indicating the magnitude of this issue are provided in Sarah Lange rebuttal, at page 46.

ii. Ameren Missouri's distribution study is unreasonable and is not consistent with NARUC guidance, nor did Ameren Missouri make reasonable adjustments to better align with NARUC guidance. [28]

In addition to the distribution-subfunctionalization by voltage issue discussed above, in its distribution study Ameren Missouri did not attempt to identify for separate allocation its generation-related assets recorded to distribution accounts.[29] As further discussed in this section Ameren Missouri chose to rely on a "minimum-size" classification method despite the inherent

[27] Lange Rebuttal page 43 line 19 – page 47 line 4
[28] This section includes a portion of Staff's discussion of **Issue 1.A.**, "How should distribution costs be allocated among customer classes within a Class Cost of Service Study?"
[29] Sarah Lange Rebuttal, p. 35 lines 16-17.

inconsistency of that approach with its current design and booking of its distribution system.[30] Further, in conducting this "minimum-size" classification, Ameren Missouri's study is inconsistent with NARUC guidance in that Ameren Missouri failed to account for the demand-serving capability of the selected "minimum"-size infrastructure, Ameren Missouri failed to identify or allocate customer-specific substations and other infrastructure other than the 369 service line accounts, and Ameren Missouri classified devices as customer-related.[31]

Ameren Missouri chose to perform what it describes as a minimum distribution system study. The minimum-size classification method inherently assumes that each account contains infrastructure that is sized to serve the smallest customers at the lowest loads possible.[32] However Mr. Hickman's selected "minimum" components operate at primary voltages[33] while most Ameren Missouri customers take service at secondary voltage, at 120 or 240 volts, with a demand of 20 kW or less.[34]

Since the minimum size used by Ameren Missouri for component infrastructure operates at primary voltage, if those components are to be used for determining the "customer" portion for all classes, the customer counts by class should be weighted by the relationship of the class average maximum hour to the Small Primary Service (SPS) class average maximum hour.[35] This step is necessary to attempt to overcome the Ameren Missouri decision to use primary plant components as the foundation of its minimum size study, despite the fact that primary voltage infrastructure is significantly oversized for service to the majority of Ameren Missouri's customers, and is

[30] Sarah Lange Rebuttal, p. 35 lines 5-6.
[31] Sarah Lange Rebuttal p 35 Lines 9 – 15.
[32] Sarah Lange Rebuttal, pp. 35-37, see also NARUC manual at pp. 95, 138.
[33] Sarah Lange Rebuttal, p, 37.
[34] Sarah Lange Rebuttal, pp. 35-36.
[35] Sarah Lange Rebuttal, p. 48.

discussed in the NARUC Manual.[36] Review of relevant load data indicates that the average SGS customer has a demand not quite twice that of the average residential customer, and that the average LPS customer served at transmission voltage is not quite 1,500 times the size of a residential customer.[37] These basic facts are ignored by Ameren Missouri.

Ameren Missouri also failed to account for the demand-serving capability of the selected "minimum"-size infrastructure.[38] The NARUC Manual at page 95 clarifies that when using the minimum-size method "the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost."[39]

At pages 90-91, regarding embedded cost of service studies, the NARUC manual states:[40]

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

Discussing marginal costs studies, the minimum-size method, at page 136 the NARUC manual states: [41]

> Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather

[36] Sarah Lange Rebuttal, p. 47.
[37] Sarah Lange Rebuttal, p. 48.
[38] Sarah Lange Rebuttal, p. 40.
[39] Sarah Lange Rebuttal, pp. 40-41.
[40] Sarah Lange Rebuttal p 41 L 17 – 43 L 3.
[41] Sarah Lange Rebuttal p 41 L 17 – 43 L 3.

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

The portion of the discussion quoted above informs this language, found at page 87 of the NARUC Manual: [42]

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

Ameren Missouri made no attempt to identify or allocate customer-specific substations and other infrastructure in the major distribution accounts. [43] This deviation from reasonable classification of the distribution system impacts not only CCoS study results, but due to this critical failure, the Ameren Missouri study is not reliable for valuing reasonable credits under Rider B, nor for reliance on estimating the revenue to be reasonably collected from various elements of classes' rate structures. [44]

Regarding Ameren Missouri's improper classification of essentially all distribution devices as customer related, Ameren Missouri's own witness, Craig Brown, admits in his surrebuttal at page 12 that "I can see Staff's point that devices such as lightning arrestors and switches should

[42] Sarah Lange Rebuttal p 41 L 17 – 43 L 3.
[43] Sarah Lange Rebuttal p 41 L 17 – 43 L 3.
[44] Sarah Lange Rebuttal p 41 L 17 – 43 L 3.

be considered demand related and are part of "balance of plant." The value of these items comprise approximately \$813.5 million dollars of Accounts 364 – 368.[45] Further, at hearing, Ameren Missouri witness and CCoS study sponsor, Mr. Hickman, admitted that 70 percent of Smart Energy Plan spending is being allocated under the Ameren Missouri study to small customers, and that he is "reviewing and considering modifications in future cost of service studies" to revise Ameren Missouri's current approach to "identify devices as being driven by customers."[46]

During opening statements, Chairman Rupp posed the following question, found in the transcript at Volume 7, page 62, line 7 - page 63 line 3, "…when I first came on the commission a long time ago, I remember there was quite an indiscrepancy, especially on the residential class, of subsidization of rates. And it was a common argument from the industrials and the others that, you know, were out of whack. And I remember us taking active steps in each rate case to bring that closer to the cost of service. Also remember that we deviated from that in the last one due to the extraordinary events of COVID and everything that is there. That being said, I thought we had gotten pretty darn close to relative, you know, of rates reflecting the class cost of service. Now, I'm coming to understand that depending on who you ask now because everybody has a different class cost of service study that you're going to get varying answers. But looking back at the previous case and the previous cases before that, how far away are we, based off of the A&E in the previous class cost of service studies that we relied upon, are we from parity in the different rate classes?"

While Chairman Rupp accurately notes that it is a common argument from the industrials that revenue responsibilities are "out of whack," it is a virtual certainty that when Ameren Missouri

[45] Sarah Lange Surrebuttal, p. 28.
[46] Transcript vol. 7 p 164

submits a study under which 70 percent of billions of dollars in increasing rate base categories is allocated to small customers, that the study will show that revenue targets established in a prior case no longer align with a new cost of service calculation bloated by hundreds of millions of dollars of additional ratebase.

At page 91 the NARUC Manual provides the methodologies for determining the minimum size of distribution plant for use in calculating the customer-classified portion of the minimum-size method.[47] The entirety of the entries for Accounts 365 and 367 are set out below:

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

Significant context can be established from the discussion of applications of the minimum-intercept method,[48] using the text quoted below from pages 93-94 of the NARUC Manual:

> 2. Account 365 – Overhead Conductors and Devices
>
> **- If accounts are divided between primary and secondary voltages**, develop a customer component separately for each. The total investment assigned to primary and secondary; then the customer component is

[47] Sarah Lange Rebuttal p 37 l 15 – p 41, L 9
[48] Sarah Lange Rebuttal p 37 l 15 – p 41, L 9

developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- **When developing the customer component, consider only the investment in conductors, and not in devices such as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component,** based on the conductor assignment.

  - Determine the feet, investment and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - **Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor ratio.**

3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices

  - The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

  - The conductor sizes and types for the customer component derivation are restricted to I/c able. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

    - Determine the feet, investment and average installed book cost per foot for I/c cables by size and type of cable.

    - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

    - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.

> - Balance of cable investment is assigned to demand.
>
> - Total dollars in Account 366 and 367 are assigned to customer and demand components based on conductor investment ratio. **[Emphasis added.]**

While there is discussion of the classification of devices in Account 365 pursuant to the minimum intercept method, under the discussion of Account 365 classification using the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 365 are classified as demand-related. This is in contrast to the decision of Ameren Missouri to classify $594,445,713 of plant related to lightening arrestors, switches, and reclosers, as "customer-related".[49], [50]

For the underground accounts under the minimum intercept method, not all devices are classified as demand-related; however, they are neither classified as customer-related. Rather, they are reflected on the ratio of minimum-intercept dollars associated with cables to total cable dollars in Account 366. Again, in contrast to the description of the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 366 are classified as demand-related. For the minimum size method, the ratio of minimum-size cable dollars in Account 366 to total dollars in Account 366 that is the basis for the classification of Account 367 dollars. [51]

Ameren Missouri failed to account for the demand-serving capability of the selected "minimum"-size infrastructure consistent with the guidance provided at page 95 of the NARUC Manual: [52]

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

[50] Sarah Lange Rebuttal p 37 line 15 – p 41, Line 9

[51] Sarah Lange Rebuttal p 37 line 15 – p 41, Line 9

[52] Sarah Lange Rebuttal p 37 line 15 – p 41, Line 9

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

iii. Staff's distribution study is reasonable and consistent with NARUC guidance. [53]

For purposes of estimating the relative net cost of service for each studied class in this case, based on the data available, it is most reasonable to allocate the functionalized distribution revenue requirement using the following process, as employed by Staff:

1. Sub-functionalize approximately $750,000 of plant as generation-related where that plant is associated with interconnection of distribution-voltage generation facilities. This plant should be allocated consistent with the production allocation process. [54]
2. Sub-functionalize customer specific infrastructure recorded in accounts 364, 365, 366, and 367. This plant is allocated to the relevant classes. [55]
3. Allocate the remaining amounts in Accounts 364, 365, 366, and 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. [56]

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[53] This section includes a portion of Staff's discussion of **Issue 1.A**., "How should distribution costs be allocated among customer classes within a Class Cost of Service Study?"
[54] Sarah Lange Direct, pp. 12, 13-14, and Schedule SLKL-d2.
[55] Sarah Lange Direct, pp. 12, 14, and Schedule SLKL-d3.
[56] Sarah Lange Direct, p 14.

Given the data available, Staff's study most closely applies the guidance provided at page 87 of the NARUC Manual, that "[a]ssignment or 'exclusive use' costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components."[57] These customer-specific (exclusive use) assets are directly analogous to the service lines which are allocated entirely to secondary customer classes.[58] Given the unavailability of reliable information to subfunctionalize the distribution system costs by voltage, as well as the changing and increasingly interconnected nature of today's "smart" grid, Staff did not attempt to subfunctionalize Ameren Missouri's distribution accounts by voltage.[59],[60]

Staff's approach to distribution network cost allocation is not only reasonable for this case, it is also highly relevant to development of higher-differential ToU rate elements. As discussed by Ms. Lange in volume 8 of the transcript at pages 454 L 14 – 457 L 8, " to allocate the cost of the network distribution system, I took the demand of each class from Ameren's load research in each hour and I squared the values of the hour so that what I would end up with is the relationship between the -- let me put it this way. The hours with the highest demand had the highest [weighting][61] and the hours with the lowest demand had the lowest [weighting][62] And I think that while the parties have seized on, you know, this belief that it's producing an energy result, it doesn't. I can state the differences if that's helpful. But it's not the same. But what it does show us is that when we've had these assumptions for years that have said, you know, well, these classes cause these costs, these classes are peaky, these classes whatever, what that ignores is that some

[57] Sarah Lange Rebuttal, p. 42.
[58] Sarah Lange Surrebuttal, pp. 22-28.
[59] Sarah Lange CCoS Direct p 12 lines 5 – 19.
[60] To facilitate subfunctionalization by voltage as appropriate in future cases, Staff recommends in future cases, Ameren Missouri provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage. See Sarah Lange CCoS Direct p 14 Lines 12 – 13.
[61] Transcript "rating."
[62] Transcript "rating."

of classes with high load factor -- well, classes with high load factor, it's not only that they're using energy [in][63] hours with low load factor or with low demands, it's that's they are also causing contributions to demand in hours with high demands. * * * And that's not to say that they should be penalized for having a consistent demand. It's just that if you're looking at a system that has to exist in every hour of the year, I think that you·need to start looking at what the requirements are on that. Because it's not just peak demands that drive the distribution planning. And where this kind of ties back into what Mr. Williams was getting at, and this is very important, when you do this on a class level, you do get numbers that aren't too far off of the energy allocators. But if you do this on a customer level, you see huge differences in customers. And this is a method that I developed in costing out distribution costs to time periods for TOU rate development. So if you want to have a higher differential TOU rate than what Staff has proposed in recent cases, you have to look at costing out of revenue requirement to those hours to reasonably allocate cost of those hours to see a cost difference. And what you find is that, you know, you have some customers who are using exclusively in high-cost hours. You have some customers who are using exclusively in low-cost hours. And a lot of customers are somewhere in between. And that's true across all classes which is what gets missed when it's aggregated to the class level."

iv. Ameren's production allocation is not relevant to the realities of its generation fleet development nor the realities of today's integrated energy market[64]

[63] Transcript "and"

[64] **Issue 1.B.** How should production costs be allocated among customer classes within a Class Cost of Service Study?, and **Issue 1.C.** Which party's Class Cost of Service Study should be used in this case and used as a starting point for the non-residential rate design working case agreed to by the parties to the Company's last electric general rate case, File No. ER-2021-0240?

Ameren Missouri's A&E 4 NCP approach is neither reasonable for Ameren Missouri's fleet as currently constituted,[65] nor "traditional."[66] Its premise is not consistent with how Ameren Missouri has built its generation fleet.[67]

For purposes of estimating the relative net cost of service for each studied class in this case, based on the data available, Ameren Missouri's fleet characteristics, and Ameren Missouri's participation in the MISO integrated energy market,[68] it is most reasonable to use different allocation methods for fundamentally different generation resources.[69] This is the Staff approach.

It is imperative to be cognizant of the allocation of the costs and expenses of no/low cost generating resources when allocating the revenues of those resources. This is the Staff approach. However, 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, renders the results of that study unreasonable and unreliable.[70] It is not reasonable to recover the majority of the revenue requirement for wind, solar, and hydro generation from one set of customers and to refund the majority of the revenue from the energy sales of those units to a different set of customers.[71] This allocation approach, which was used by Ameren Missouri and relied upon by MECG and MIEC ignores the requirements of the Missouri Renewable Energy Standard, which are based on energy consumption.[72]

Ameren Missouri's study is also unreasonable in that it fails to recognize Ameren Missouri's participation in the MISO IM, which causes its fuel costs to vary with the

[65] Tr. Vol. 8 p 461 lines 18 – 21; Tr. Vol. 8 p 462 line 8 – p. 463 line 6.
[66] Tr. Vol. 8 p 427 line 3 -p 430 line 23.
[67] Tr. Vol. 8 p 451 line 25 – p. 453 line 6.
[68] Sarah Lange Direct, p. 21, Sarah Lange Rebuttal, p. 21.
[69] Sarah Lange Direct, p. 20.
[70] Sarah Lange Surrebuttal, p. 13.
[71] Sarah Lange Rebuttal, p. 23.
[72] Sarah Lange Rebuttal, p. 23.

demand for energy in a given hour of the regional load, not vary with the Ameren Missouri load.[73] 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.[74] For this reason, the Staff study relies on hourly class loads and MISO DA LMPs to find the variable cost of energy for each class; however the Ameren Missouri and derivative studies assume every kWh of energy consumed throughout the year and regardless of season or time of day has the same cost.[75]

While there are cases where sufficient hourly load data is not available to conduct a more reliable study, and while there are utilities where capacity additions are driven by summer peak demands of retail load,[76] neither are applicable in this case. In contrast to the shortcomings of the Ameren Missouri production cost allocations, Staff's treatment of production cost allocation in this case is consistent with its approach in the recent Empire rate case, and builds on the Detailed BIP method, as well as the Capacity Utilization method (aka "TOU Method") that Staff has relied on as far back as 1985.[77] Staff's distribution treatments in this case are a straightforward application of the theories that have underlain Staff's understanding of distribution allocation for decades.[78]

[73] Sarah Lange Rebuttal, p. 26.
[74] Sarah Lange Surrebuttal, p. 17.
[75] Sarah Lange Rebuttal, p. 26.
[76] Sarah Lange Surrebuttal, p. 16, Sarah Lange Rebuttal, p. 21, and pp. 23 – 26.
[77] Transcript vol. 8 p 414 line 15 – p. 415 line 23
[78] Transcript vol. 8 p 415 line 24 – p. 416 line 24

Staff recommends allocating production costs and revenues through the following process:

> Step 1: Identify those resources with no or low variable cost and allocate the costs and expenses of owning and operating those resources to each class 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.[79] Note, while these assets do not include nuclear or fossil generating units to which the Commission's allocation discretion is limited by Section 393.1620, Staff's allocation of these units on the basis of energy is consistent with an approach identified in the National Association of Regulatory Utility Commissioners 1992 manual.[80]
>
> Step 2: Prorate the generation in each hour from no/low variable cost resources to each class, and subtract 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 assets, even though they were allocated based on energy requirements.[81]
>
> Step 3: Identify those resources with significant variable costs of operation which are avoidable if the unit is offline, fully dispatchable with limited exceptions, which includes the nuclear and fossil generating units to which the Commission's allocation discretion is limited by Section 393.1620,[82] and allocate the costs and expenses of owning and operating those resources to each class using the NARUC "All Peak Hours Approach," described at page 47 of the 1992 NARUC Manual,[83] on the basis of each class's contributions to the identified MISO Resource Adequacy hours that is not met by no/low variable cost resources.[84] As an alternative, Staff has prepared an alternative CCoS using the 1 Coincident Peak (CP) approach, which is presented in the Surrebuttal of Sarah Lange at pages 34 - 38.
>
> Step 4: Allocate the net value of the production sales and purchases to the classes by first calculating the value of energy consumed by each class based on each class's load in each hour and the cost of energy in each hour, then by calculating the value of energy generated by the assets allocated to each class. The value of each, scaled to the expenses and revenues reflected in the cost of service calculation, are then allocated to each customer class.[85]

[79] Sarah Lange Surrebuttal, p. 14, see also Sarah Lange Direct, pp. 20-23.
[80] Sarah Lange Direct, pp. 21-22.
[81] Sarah Lange Surrebuttal, p. 15, see also Sarah Lange Direct, pp. 21-22, Sarah Lange Rebuttal, pp. 23-24.
[82] Sarah Lange Direct, p. 20.
[83] Sarah Lange Direct, p. 21.
[84] Sarah Lange Direct, pp. 17-18.
[85] Sarah Lange Direct, p. 22.

> This approach ensures that each class is responsible for the cost of the energy that class uses in a year, as offset by the value of the energy generated by the assets and variable costs allocated to each class as described above.[86]

In his surrebuttal Mr. Wills presented his opinion at page 25 that "I would strongly suggest that, if the Commission is interested in a constructive future rate design process to address these non-residential rate issues, that it specifically evaluate the competing CCOS approaches in its order in this case and provide clear direction for the future by determining in its Report and Order which CCOS study is reasonable."[87] Mr. Wills states at page 9 of his surrebuttal testimony that he views the goal of design of a time-based rate to "avoid incremental investments that may be needed to meet future peak loads, not to retire existing equipment that is used and useful in serving customers." However, the studies filed in this case include only limited information on incremental cost (Staff's study did allocate the net value of the production sales and purchases to the classes by first calculating the value of energy consumed by each class based on each class's load in each hour and the cost of energy in each hour, then by calculating the value of energy generated by the assets allocated to each class. The value of each, scaled to the expenses and revenues reflected in the cost of service calculation, are then allocated to each customer class.[88] This approach ensures that each class is responsible for the cost of the energy that class uses in a year, as offset by the value of the energy generated by the assets and variable costs allocated to each class as described above.[89]) The Ameren Missouri study fails to recognize

[86] Sarah Lange Direct, p. 22.

[87] While the issue statement refers to an agreement among the parties, the Report and Order in ER-2021-0240 states "The Commission agrees that the Large General Service and Small Primary Service rates should be redesigned to make them more comprehensible for customers. That redesign process can begin now with Ameren Missouri gathering information and insight from customers who are already being served by AMI meters. The Commission will establish, by separate order, a working case to facilitate the collaboration between Ameren Missouri, Staff, Public Counsel, and the affected customers in redesigning these rates."

[88] Sarah Lange Direct, p. 22

[89] Sarah Lange Direct, p. 22.

Ameren Missouri's participation in the MISO IM, which causes its fuel costs to vary with the demand for energy in a given hour of the regional load, not vary with the Ameren Missouri load.[90] The Ameren Missouri and derivative studies assume every kWh of energy consumed throughout the year and regardless of season or time of day has the same cost.[91] It is an utter abuse of resources to discuss rate modernization in the context of a study premised on the idea that the cost of energy is the same in every hour of the year. Further, no filed study provides sufficient information to redesign customer and facilities charges to incorporate the effect of Riders B & C and to reasonably refine customer charges to vary by customer requirements, as opposed to obsolete class definitions.[92]

Given advances in metering and billing technology and the advent of integrated energy markets, Ameren Missouri's rates no longer are limited to historic shortcut of classification. The premise of classification is to reduce complex cost causation realties to simplified relationships to monthly energy, noncoincident demand, or customer counts. Staff's contemplated modernized rate structures can rely on a ground-up study of the costs of serving customers by reasonable characteristics.[93] To get there, a meaningful rate modernization workshop[94] would provide an opportunity for Commission input in determining which customer characteristics should be considered in the development of new rate structures, as well as an opportunity for all stakeholders to access information concerning what data is already available in one form or another, and what information may not be realistically obtainable. Further, development of multiple CCoS Studies in the context of a rate modernization workshop from a common cost of service and revenue basis

[90] Sarah Lange Rebuttal, p. 26.
[91] Sarah Lange Rebuttal, p. 26.
[92] See Class Cost of Service (CCoS) Direct Testimony of Sarah Lange, at pp. 51-53.
[93] Transcript vol. 8 p 409 line 8 – p 411 line 4.
[94] Ordered in File No. ER-2021-0240, but not yet opened.

would enable focus on the differences that arise in allocation due to allocations themselves, distinct from disputes about revenue requirements.[95] Historic assumptions about distribution system utilization, even if accurate in the past, may no longer be reasonable.[96]

To facilitate the provision of data by Ameren Missouri necessary to facilitate a meaningful workshop, Staff suggests holding the order imposing Staff's positions on **Issue 1.H** "Rate Structure" sub issues in abayence, pending the reasonable provision of analgous information in the context of the Rate Modernization workshop.[97],[98] **Staff's requested information is detailed in Exhibit 183.** Further, in an effort to facilitate rate modernization, as discussed above, Staff is willing to back off of its recommended, supported, and reasonable shifts in customer class revenue responsibility[99] to support the promulgation of its recommended time-based rate overlay for non-residential non-lighting customers.[100]

c. The shifts advocated by MECG and MIEC are not reasonable.[101]

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[95] Transcript Vol. 8 p 411 line 5 - p 414 line 14.

[96] Tr. Vol. 8 p 454 line 6 – p. 457 line 8.

[97] Transcript Vol. 8 p 418 line 22 – p 419 line 12.

[98] This approach would be appropriate for a general rate case if filed prior to the conduct of the rate modernization workshop, see Transcript v 8 p 468 L 17 – p 469 line 3, "17· · · ·Q.· · ·And would this be for purposes of the 18· ·rate -- the modernization workshop that we talked 19· ·about or the -- or a future rate case or for what 20· ·purpose exactly? 21· · · ·A.· · ·Either of those.· I guess it depends on 22· ·timing.· You know, if they file a rate case, you 23· ·know, July 3rd as has been something of a tradition, 24· ·you know, and I'm not speaking from knowledge if 25· ·that's proposed or not, you know, then we would want Page 469 ·1· ·it for that.· Ideally this is something that we would ·2· ·take a little bit more time with and work through in ·3· ·a rate modernization workshop."

[99] Based on its Direct CCoS results, Staff recommends that the revenue responsibility of the Lighting class should be held at the current level; the LGS class should receive an initial increase in its revenue responsibility of approximately 3.75%, and the SPS and LPS classes should receive an increase in revenue requirement responsibility of approximately 7.50%; then, the remaining increase should be applied as an equal percent increase to the Residential, SGS, LGS, and LPS classes. *Sarah Lange CCoS Direct,* p. 28. However, Staff is not opposed to including the customer-owned segment of the lighting class for "Equal", while holding the company owned-segment of the lighting class constant. *Sarah Lange Rebuttal*, pp. 3-4.

[100] Transcript Vol. 8 p 407 line 10 – p 409 line 7.

[101] Relevant to **Issue 1.D**. How should any rate increase be allocated to the several customer classes?

In addition to the concerns Staff has described above related to Ameren Missouri's CCoS Study, upon which MIEC and MECG rely, the recommended shifts in revenue responsibility assume unreasonable precision in CCoS Study results,[102] and rely on unreasonable adjustments of those results to fit the stipulated revenue requirement. [103]

CCoS studies serve as a guide to setting rate class revenue requirements and should not be solely relied upon for establishing each class' revenue requirement because they are not precise, and are not updated for changes from the studied revenue requirement and billing determinants to the ordered revenue requirement and billing determinants.[104]

CCoS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless that study is updated, or unless the Commission approves that exact set of accounting schedules as well as the direct-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCoS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case. [105]

Policy considerations, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices should also be taken into account, as well as promotion of revenue stability and efficiency, balanced, to the extent possible, with retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the number

[102] Sarah Lange Rebuttal p 60 l 30 – p 61 L 3.
[103] Tr. Vol. 8 p 425 line 11 – p. 426 line 5.
[104] Sarah Lange CCoS Direct p 27
[105] Sarah Lange CCoS Direct p 27

of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understandable by all parties, customers, and the utility as to proper application and interpretation. [106]

## III. RESIDENTIAL RATES

a. **Issues 1.F**., "What changes should be made, if any, to the Residential rate plans offered by the Company?," **1.F.a**.. "Should Staff's proposal to eliminate the Anytime (flat) rate option for any Residential customers who have an AMI meter be approved?," and **1.F.b**.. "What changes, if any, should be made to the deployment of residential ToUrate plans?"

Staff recommends revision in the applicability of the Anytime rate schedule to default customers to the Evening/Morning Savers tariff and/or to encourage customers exercising the optionality of service on a higher-differential time-based rate schedule, consistent with recent Commission action. The Anytime rate schedule should be modified to state that it is not available to customers equipped with an AMI meter, except to conclude the customer's then-current billing month at time of meter installation.[107]

Staff recommends that the Evening/Morning Savers be the default rate schedule for all residential customers equipped with an AMI meter. Customers should be able to opt into a different time-based rate schedule if they choose after adequate education, but the "Anytime" rate schedule should no longer be available for customers equipped with an AMI meter. [108] Staff recommends that the Evening/Morning Savers rate schedule be modified so that the lead-in time of six months should be eliminated and customers should begin receiving service on the schedule starting the first billing month after they are equipped with an AMI meter. This change is (1) consistent with the modernization of rate structures in Missouri (2) serves to educate

[106] Sarah Lange CCoS Direct p 27 - 28
[107] Sarah Lange CCos Direct, p. 34.
[108] Sarah Lange CCos Direct, p. 32.

customers who may not currently be cognizant of the times in which they consume energy, and (3) improves the relationship of cost causation and revenue responsibility for Ameren Missouri's residential customers  Staff also recommends that the name of the rate schedule as referenced in the "Availability" section of the Evening/Morning Savers schedule be consistent with the name of the rate schedule.[109]

Staff is open to a provision of temporary grandfather status to those who already opted out of the Evening/Morning Saver rate plan, 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. [110]

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.[111]

If the Commission determines that it is appropriate to order high-differential ToU rates for all residential customers equipped with AMI metering as the outcome of this case, an intermediate overlay design is reasonable for customer impact mitigation and for customer education. This approach would give customers a moderated price signal for a year so customers will be getting meaningful information rather than relying on some sort of utility marketing effort.

Specifically, Staff suggested that the Commission order modification of the Evening/Morning Saver overlay plan to align with the time periods that the Commission establishes for a higher differential rate plan.  This revised Evening/Morning Saver overlay plan would become the default rate for residential customers equipped with AMI meters immediately

[109] Sarah Lange CCos Direct, p. 34.
[110] Sarah Lange Surrebttal, p. 3.
[111] Sarah Lange Surrebttal, p. 4.

out of this rate case, and would be applicable to remaining residential customers upon installation of an AMI meter. After a year on the modified Evening/Morning Saver plan, those customers would be moved to the higher differential plan. The purpose of this intermediate rate plan is to give customers education for their actual time periods of usage, and to give mild price signal of the differentials between time periods, while retaining the existing winter declining block element. This mitigates customer impacts while giving customers time and an opportunity to make decisions they need to make about what they want to do in future heating and cooling seasons. [112]

b. Residential Customer Charges[113]

The customer charge for all residential rate schedules should be retained at the current level, \$9.00/month.[114] However, 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.. Staff does not object to a \$0.50 increase in all residential customer charges if Ameren Missouri's depreciation rates are ordered by the Commission.[115]

In valuing the residential customer charge, Staff relied on the basic customer method of cost causation, which holds that the customer charge should include (1) the costs and expenses of metering and billing customers, (2) the cost of the infrastructure that varies with the number of customers served, including related income taxes, and (3) the proportionate labor, non-labor, and distribution expense associated with the infrastructure. In this case for its calculation, Staff also

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[112] Tr. Vol. 8 p 438 line 4 – p. 440 line 25; Tr. Vol. 8 p 453 lines 14 – 23.

[113] **Issue 1.E**. "What should the customer charges associated with the Residential Class rate plans be?" and **Issue 1.E.a.** "If the customer charges for the Ultimate Saver and Smart Saver Plans are discounted relative to other residential rate plans, should a minimum demand charge be imposed with customers to be fully educated on the minimum demand charge?"

[114] Sarah Lange CCoS Direct, p 32.

[115] Sarah Lange Surrebuttal, p. 8.

included additional customer service expenses, and also included approximately $11.9 million of the functionalized "Other/General" revenue requirement out of an abundance of caution. However, Ameren Missouri exceeds this allocation in two main ways. First, Ameren Missouri includes as "customer-related" its entire minimum-size distribution costs and expense calculation, and second, the Ameren Missouri minimum-size distribution calculation is poorly calculated. In other words, Ameren Missouri errs in making the decision to include this category of revenue requirement, but even if it were reasonable to include it, Ameren Missouri's calculation is wrong.[116]

Finally, Ameren Missouri includes Account 903 in its customer charge calculation. This account may include some items which could vary with the addition of a new customer, or the discontinuance of service of an existing customer; however, the only information Ameren Missouri provided concerning this account related to "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. The information Ameren Missouri has made available in this case indicates that items which could vary with the addition of a new customer, or the discontinuance of service of an existing customer, do not constitute any appreciable portion of the Account 903 balance.[117]

While the Ultimate Savers plan has the highest bill risk, Ameren Missouri has proposed to discount its customer charge relative to the other residential rate plans and to market this discounted customer charge to risk-averse customers.[118]

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[116] Sarah Lange Rebuttal, p. 56.
[117] Sarah Lange Surrebuttal, pp. 7-8.
[118] Tr. Vol. 8 p 432 line 14 – p. 433 line 1 (objected testimony omitted)

The customer charges for the Ultimate Saver and Smart Saver plans should not be discounted relative to other Residential Rate Plans. The evidence in this case does not support increases to the customer charges of other residential rate plans,[119] and therefore Ameren Missouri's proposal to maintain the current customer charge for the Ultimate Saver rate plan while increasing it for other rate plans is moot. However, it is contrary to good public policy to reduce the customer charge for Ultimate Savers rate plan, relative to other residential rate plans, under the circumstances of this case, because unfortunately, Ameren Missouri markets its most sophisticated rate plan under which participants bear the risk of the highest bill as "Ultimate Savers," and its least risky plan from a customer perspective as "Anytime Users." There is a very real risk that customers will perceive the plans as exactly the opposite of their relative risks, especially if "Ultimate Savers" is presented as having the lowest fixed monthly bill in Ameren Missouri's marketing efforts. Staff recommends the Ultimate Saver and Smart Saver customer charges not be discounted.[120]

Staff reviewed the demand charges that would be incurred for 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.[121]

[119] Sarah Lange Rebuttal, p. 56.
[120] Sarah Lange Rebuttal, p. 57.
[121] Sarah Lange Surrebuttal, p. 5.

For overall bill impact, of the 99 sample customers billing on the Ultimate Saver plan relative to the Anytime Savers plan, 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%. For overall bill impact, of the 99 sample customers billing on the Smart Saver plan relative to the Anytime Savers plan, forty-five customers would experience a decrease, with an average value of 5%, and 54 customers 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. 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.[122]

In his rebuttal testimony at 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." However, this is the exact risk Staff is concerned about in recommending that a year should be used to provide customer comparisons on highly differentiated rates.

If against Staff's primary recommendation the customer charge for the Ultimate Saver plan is discounted relative to other rate plans, Staff recommends that a minimum demand charge equal to the difference in the customer charges be incorporated into the rate structure. This should be

[122] Sarah Lange Surrebuttal, p. 5-7.

plainly disclosed in all relevant marketing and education materials.[123] Unfortunately, as stated above, Ameren Missouri markets its most sophisticated rate plan under which participants bear the risk of the highest bill as "Ultimate Savers," and its least risky plan from a customer perspective as "Anytime Users." There is a very real risk that customers will perceive the plans as exactly the opposite of their relative risks, especially if "Ultimate Savers" is presented as having the lowest fixed monthly bill in Ameren Missouri's marketing efforts.[124]

## IV. NON RESIDENTIAL RATE STRUCTURES AND DESIGNS[125]

For the current non-ToU SGS, LGS, SPS, and LPS rate schedules, Staff recommends minimization of intraclass revenue responsibility changes for the non-residential non-lighting classes in order to mitigate unexpected bill volatility as the Staff's recommended ToU overlay is introduced. Specifically, Staff recommends that all rate elements for the SGS, LGS, SPS, and LPS rate schedules be adjusted uniformly within each rate class, except for the Reactive kVar charges which should be adjusted consistent with the overall increase applicable to non-residential non-lighting classes, but held consistent across rate schedules. Finally, any changes related to the Low Income charges should be implemented.[126]

Staff recommends the Commission order in this case that customers with AMI metering be billed time based rates through the introduction of a revenue neutral ToU Overlay to be introduced into a parallel rate structure for each non-residential non-lighting rate class.[127] Specifically, Staff recommends creation of a parallel rate schedule for each non-residential non-lighting rate class

[123] Sarah Lange Rebuttal, p. 57-58.
[124] Sarah Lange Rebuttal, p. 56.
[125] Generally corresponds to **Issue 1.G**."What changes should be made, if any, to the Non-Residential, Non-Lighting rate options offered by the Company?" **Issue 1.G.a**, "Should Staff's proposal to introduce a time-based overlay for all Non-Residential, Non-Lighting classes for all customers who have an AMI meter and are not served on a time-based schedule be adopted?" **and Issue 1.G.b.** "Should MECG's proposed shift to increase the demand component for Large General Service and Small Primary Service and decrease energy charges be adopted?"
[126] Sarah Lange CCos Direct, p. 39.
[127] Sarah Lange CCoS Direct, p. 40.

which includes a time-based overlay applicable to all customers equipped with an AMI meter. When calculating compliance rates for each of these time-based rate schedules, each distinct rate element will require adjustment to ensure that application of the ToU overlay retains revenue neutrality within the rate schedule. The amounts applicable to each class are identified in the section of Sarah Lange's Direct testimony titled "Customer Bill Changes Related to Recommended ToU Overlay." Because all customers are not currently equipped with AMI metering, it is necessary to have two sets of rates for each non-residential rate element in the tariffs promulgated in compliance with the Commission's order in this case. One set will reflect the adjustment to preserve revenue neutrality and will include the ToU Overlay in its structure. The other set will not include the ToU Overlay and will not be adjusted for the ToU Overlay.[128]

Staff suggests that reasonable time periods for initial rate structure development are Summer Off-Peak, 12-9 AM, Summer On Peak, 1 – 9 PM, NonSummer Off-Peak 11 PM – 6 AM, and NonSummer On Peak 7-9 AM and 5-9 PM.[129]

Non-Residential non-lighting customers currently have access to "Optional Time-of-Day-Adjustments," although very few customers have self-selected into these adjustments. Of the 39 customers in the LPS class, 31 have AMI metering (39%), and only 3 are charged a rate adjusted by time of day (7.69%). Of the 539 SPS customers, 303 have AMI metering (56%), and only 15 are charged a rate adjusted by time of day (2.78%). Of the 10,069 LGS customers, 6,311 have AMI metering (63%), and only 51 are charged a rate adjusted by time of day (0.51%).[130]

Staff designed its recommended overlay structure time periods and adjustment values based on its study of Ameren Missouri's cost of obtaining energy to serve its load in the

[128] Sarah Lange CCoS Direct, p. 43.
[129] Sarah Lange CCoS Direct p 42 table
[130] Lange CCoS Direct p 40 L 14 – p 41 L 4, values as of end of Staff update period of July, 2022.

MISO DA energy market for the five years from January 2017 through December 2022.[131] The CCoS Direct Testimony of Sarah Lange provides a detailed walk through of the steps to be taken in calculating rates for compliance tariffs at pages 44 – 46, as well as Staff's recommendation concerning the tariff sheets to be retained and developed until all customers on the SGS, LGS, SPS, and LPS schedules have AMI metering.[132] This discussion concludes with estimated customer impacts of the proposed overlay at Staff's proposed overlay rate values of an off-peak discount of $0.015/kWh in summer billing months and $0.01/kWh in non-summer billing seasons, and an on-peak adder of one-half of one cent year round.[133] Those impacts, summarized in tables provided at Lange CCoS Direct p 48 L 13 and p 49 L 5 indicated that the largest expected impact to an LPS customer is 1.43%, to an SPS customer is 2.91%, to an LGS customer is 2.5%, and to an SGS customer is 3.48%, with only 46 of the 363 studied customers (12.7%) experiencing an average bill change equal or greater to 2 cents per kWh. So why should such a small change in customer bills be implemented? Currently, non-residential non-lighting customers are unable to

[131] Lange CCOS Direct p 41 L 5 – p 43 L 4.

[132] See, Lange CCoS Direct, p 43 l 5 – 44 L 6, "Q. How should these changes in rate structure be implemented in this case? A. Staff recommends creation of a parallel rate schedule for each non-residential non-lighting rate class which includes a time-based overlay applicable to all customers equipped with an AMI meter. When calculating compliance rates for each of these time-based rate schedules, each distinct rate element will require adjustment to ensure that application of the ToU overlay retains revenue neutrality within the rate schedule. The amounts applicable to each class are identified in the section "Customer Bill Changes Related to Recommended ToU Overlay." Because all customers are not currently equipped with AMI metering, it is necessary to have two sets of rates for each non-residential rate element in the tariffs promulgated in compliance with the Commission's order in this case. One set will reflect the adjustment to preserve revenue neutrality and will include the ToU Overlay in its structure. The other set will not include the ToU Overlay and will not be adjusted for the ToU Overlay. Q. Should existing optional rate codes that include time or proxies for time as a factor in billing be retained at this time? A. At this time, Staff is not opposed to retention of existing rate structures that include time or proxies for time as a factor, including Rider I, Optional Time-of-Day Adjustments, and the Legacy SGS Optional Time-of-Day Rate for customers on the non-ToU Overlay rate schedule. However, such structures should likely be phased out or significantly redesigned as rates are modernized to incorporate more accurate time based elements upon completion of AMI deployment."

[133] Lange CCoS Direct p 43 L 4. Summer off peak times are 12-9 AM, NonSummer off peak times are 11 pm – 6 am. Summer on-peak times are 1-9 PM, NonSummer on-peak times are 7-9 am and 5 – 9 pm. See Lange CCoS p 42 L 13. The consistency of these times with the shapes provided in Exhibit 182, Staff's Response to the Commission Order to Provide Load Data, are apparent.

get information from Ameren Missouri concerning how much energy they used at various times.[134] Currently, class level hourly data corresponding to billing months is not available to parties interested in rate modernization.[135] Currently, data is unavailable to study customer-specific relationships between on-peak usage and billing demand determinants.[136]

Through the ToU overlay for non-residential non-lighting customers, the Commission can accomplish two things. First, the Commission can get information about how more-differentiated rates will impact customers into the hands of those customers; second, the Commission can get information to inform rate structure design and cost rate elements into the hands of Staff and other parties who are designing the structure and costing of modern rates.[137]

**Issue 1.G.d. "Should the Rider C factor be adjusted?"**

Yes. In light of Ameren Missouri's response to Staff DR 460, Staff recommends that the Rider C factor be modified from 0.68% to 0.72%, assuming that there are not transformers on the Ameren Missouri system that are dramatically oversized, which may warrant creation of adjustment factors particular to the customers served by such transformers.[138]

**Issue 1.G.e. "Should the values for the monthly customer charge, Rider B credits, and Reactive Charge remain consistent for SPS and LPS customers because these costs are effectively the same regardless of the customer class?"**

No. While parties have often grouped these classes together in CCoS Studies because customers can switch between them, these are in fact different rate schedules with different requirements. Given the growth in the utility cost of service related to distribution rate base, the

[134] Transcript Vol. 7 p 196 Line 21 – p 197 line 5.
[135] Transcript vol. 7 p 197 Line 6 – p. 198 Line 22.
[136] Transcript vol. 7 p 198 Line 23 – p. 199 Line 12.
[137] Transcript Vol. 8 p 406 lines 4 – 15.
[138] Sarah Lange Rebuttal, p. 16.

time has come to undertake more granular study of the costs caused by and properly allocated to customers on these rate schedules separately. [139]

**Issue 1.G.c. "Should the Commission approve MECG's proposed optional EV charging 3M/4M rate design?"**

No. If implemented, this proposal would substantially reduce the accretive earnings assumed in justifying the Charge Ahead portfolio. This proposal is not cost based. In its development, Mr. Chriss moves dollars and determinants around to the benefit of an assumed load shape, without any regard for cost-causation. This proposed end use rate is preferential to EV charging customers over any customer with a high demand and low load factor, such as welding shops, smelters, grain dryers, millers and other customers currently served on the LGS, SPS, and LPS rate schedules who would prefer to avoid the demand charges that Mr. Chriss references. Any customer with a low load factor or a high demand contributes more revenue per kWh than customers with a high load factor or a low demand under the current Ameren Missouri rate designs for these schedules. These customers may or may not cause more costs than one another. The solution is not the creation of a multitude of specialty end-use rates, rather the solution is rate schedule modernization as described in Ms. Lange's direct testimony, which would align cost causation with revenue responsibility based on the actual time of energy consumption and the level of infrastructure required for customers.[140]

If promulgated, it is imperative that any alternative optional LGS ("LGS-EV") and SP ("SP-EV") rates for EV charging customers be reserved exclusively to EV charging use

[139] Sarah Lange Rebuttal, p. 3.
[140] Sarah Lange Rebuttal, pp. 63-64.

(with attendant lighting) and that it be time-based rather than designed as proposed by Mr. Chriss.[141] At hearing, Mr. Chriss admitted that his proposal did not include needed details.[142]

If alternative optional LGS ("LGS-EV") and SP ("SP-EV") rates for EV charging customers with load sizes that would qualify to take service on LGS or SP rates are authorized, Mr. Wills' request to bill future customers to recoup bill savings is not reasonable. 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. 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.[143]

## V. DATA AND RATE STRUCTURE ISSUES, ISSUES 1.H. WITH INDICATED SUBPARTS

### a. Should the cost-causation and rates of Riders B & C be fully evaluated?

Yes.[144] Staff recommends continuation of the ordered studies and reviews discussed in Sarah Lange's CCoS testimony, and the retention of data that is sufficient and appropriate for the rate modernization discussed therein.[145]

**b. Ordered Rider B Study - Did Ameren Missouri comply with the Report and Order in ER-2021-0240 at pages 31 – 34, where the Commission addressed whether it should require "Performance of a study of the reasonableness of the calculations and assumptions underlying Rider B to be filed as part of the Company's direct filing in its next general rate case?" The decision paragraph at pages 33-34 states "The Commission will not suspend the Rider B credits, but it believes the question of the proper calculation of those credits should**

[141] Sarah Lange Surrebuttal, pp. 43-44.
[142] Transcript Vol 9 pages 594-595.
[143] Sarah Lange Surrebuttal, p. 44.
[144] Sarah Lange CCoS Direct, p. 52.
[145] Sarah Lange CCoS Direct, p. 56.

**be further addressed in Ameren Missouri's next rate case. Therefore, the Commission will direct Ameren Missouri to study the reasonableness of the calculations and assumption underlying Rider B and to file the results of that study as part of its direct filing in its next general rate case."**

No.[146] Rider B is available to customers served under rate schedules 4(M) or 11 (M) who take delivery of power and energy at a delivery voltage of 34kV or higher, specifically at 34.5kV, 69kV, 115kV, or higher, when those customers own their own customer-specific infrastructure. So, the relevant customers to study would be those served under rate schedules 4(M) or 11 (M) taking delivery of power and energy at a delivery voltage of 34kV or higher, specifically at 34.5kV, 69kV, 115kV, or higher, when those customers rely on customer specific infrastructure which is included in Ameren Missouri's rate base and reflected in Ameren Missouri's regulated cost of service. Because Rider B is intended to provide a credit to customers who do not cause Ameren Missouri to own and operate their customer-specific infrastructure, it is appropriate to determine the cost of service to own and operate comparable customer-specific infrastructure.

The necessary information to perform the ordered study is a survey of the actual equipment installed in and on the ground that is included in the Ameren Missouri rate base, and is used to serve these specific customers but not otherwise interconnected with the Ameren Missouri grid. Obtaining this information would likely follow one of two paths:

1. A site visit to facilities associated with these customers,
2. Identification of the type, size, and quantity of assets located at representative customer locations that are Ameren Missouri assets,
3. Identification of the accounts to which the assets identified are booked.

The alternative path to obtaining this information is:

1. Review of Ameren Missouri records of assets known to be customer specific, such as substations and lines named for those customers for which they serve as customer-specific assets.
2. Identification of the type, size, and quantity of assets.
3. Identification of the accounts to which the assets identified are booked.

This information is the same information that would ideally inform the allocation of customer-specific infrastructure in a well-conducted CCoS Study. Therefore, Staff recommends that the Commission order Ameren Missouri to complete a study of the cost of customer-specific assets associated with customers taking service at each major voltage level, including but not limited to: secondary low voltage single phase, secondary low voltage three phase, secondary high voltage, primary, sub-transmission, and transmission.[147]

[146] Sarah Lange Rebuttal, p. 17.
[147] Sarah Lange Rebuttal, pp. 19-20.

c. **Should Ameren Missouri be ordered to record transmission assets related to maintenance of voltage support due to the retirement of large synchronous generators be recorded to new subaccounts?**

Yes. [148]

d. **Should Ameren Missouri be ordered to retain customer and rate schedule characteristics related to draws of reactive demand?**

Yes. Staff recommends a reasonable level of information be retained for study for potential use in allocators, and for potential creation of determinants for customer billing.[149]

e. **Should Ameren Missouri be ordered to create subaccounts within distribution accounts and transmission accounts (plant and reserve) for recording infrastructure related to utility-owned generation?**

Yes.[150]

f. **Should Ameren Missouri be ordered to provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage, in its next general rate case?**

Yes. [151]

g. **Should Ameren Missouri be ordered to provide data concerning the level of rate base and expense associated with radial transmission facilities including substation components, by customer?**

Yes. Ameren Missouri should also be prepared to aggregate such customers into groups of customers set out by characteristics to be described in a tariff such as voltage level, distance from substation, annual demand, or other characteristics. Ameren Missouri should also provide potential determinants associated with such groupings for development of new rate elements or refinement of existing elements such as customer charges and credits associated with Riders B & C.[152]

h. **What information should Ameren Missouri provide for any rate modernization workshop, or for its next general rate case?**

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"

[148] Sarah Lange Rebuttal, p. 34.
[149] Sarah Lange Rebuttal, p. 34.
[150] Sarah Lange Rebuttal, p. 14.
[151] Sarah Lange Rebuttal, p. 14.
[152] Sarah Lange Rebuttal, p. 24.

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.

   a. In distribution accounts 364-367 in total, and

   b. In substation accounts in total.

   c. 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,

   a. In distribution accounts 364-367 in total, and

   b. In substation accounts in total.

   c. 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.

   d. 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.[153]

**i. Should Ameren Missouri be required to study potential rate structures and make available related determinants?**

Yes. As Ameren Missouri completes its installation of AMI metering, it is reasonable to require Ameren Missouri to prepare information to develop modern rate structures for potential implementation in its next rate case.[154]

The rate structures to be studied should include but not be limited to:

1. Customer and facilities charges related to customer annual NCP to recover customer-related costs and the cost of customer-specific infrastructure, with related determinants.

2. CP demand charges to collect remaining distribution and transmission costs, with related determinants. Staff suggests that CP periods of 12:01 pm – 8:00 pm are appropriate for the months May, June, July, August, September, and October, and that CP periods of 6:01 am – 10:00 am, and 4:00 pm – 8:00 pm are reasonable periods for the initial study of appropriate determinants and charges, subject to refinement.

3. ToU-based energy charges and determinants, where the differential of such charges is approximated to the difference in the average DA LMP across the time periods, but also recovers the costs of variable and stable revenue requirement production.

    a. Study and potential introduction of shoulder seasons to replace a portion of the existing "winter" season of 8 months.

    b. Identification of reasonable time periods for ToU charges.

Any revisions to the design and structure of the Reactive Demand charge that may be appropriate, with relevant determinants.[155]

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[153] Sarah Lange Surrebuttal, pp. 42-43.
[154] Sarah Lange CCoS Direct, p. 51.
[155] Sarah Lange CCoS Direct, pp. 52-53.

## VI. TRACKER

**Issue I. Should the Commission authorize Ameren Missouri to track some valuation of estimated revenue changes that may arise from residential customer rate switching?**

Staff recommends that the general request for "the authority to track revenues lost through this migration," be denied as unreasonable.[156] The benefits Ameren asserts from the opt-in ToU rates are (1) lower bills for opt-in participants, which are not a benefit for all ratepayers which could reasonably justify a tracker;[157] (2) benefits arising from the shifting of usage away from periods of high demand, and therefore higher cost, on the system[158], however Ameren Missouri admits that the customers who have opted into these rates are almost certainly free riders, and (3) while Ameren Missouri asserts that a tracker would encourage the Company to propose more advanced TOU rates and otherwise pursue modernization of rates in the future as well, and will allow the Company to consider additional promotional activities around TOU rates if they appear to provide benefits through the IRP analysis, the Commission can and should order rate modernization in this and future rate cases.[159]

This tracker is essentially the same as the rate migration tracker request Ameren agreed to drop in its ER-2019-0335 rate case when it chose to move forward with these opt-in rates without the tracker. The test Mr. Wills suggests in this case is that a deferral mechanism should be authorized when authorizing a new program that is beneficial to customers, but where without the deferral mechanism it place, it could be financially detrimental to the utility to pursue. These opt in rates are not a new program, and the potential financial detriments to the utility were known to the utility when it agreed to pursue these rate plans in its 2019 rate case. In that ER-2019-0335

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[156] Sarah Lange Rebuttal, p. 6.
[157] Sarah Lange Rebuttal, p. 7.
[158] Id. pp. 7-8.
[159] Sarah Lange Rebuttal, p 8.

case, Ameren freely acknowledged that the customers most likely to take advantage of the rates are customers who would experience bill savings without any changes in usage that may result in system benefits that could be passed on to other ratepayers.

In Mr. Wills' Direct Testimony from ER-2019-0335 he testified regarding the EV Savers' rate plan, which has been renamed to the current "Overnight Saver" rate plan. His testimony in ER-2019-0335 included his estimated bill impact that changing to the EV Savers rate would have for 800 customers without any change in their behavior or usage. Mr. Wills' testimony in ER-2019-0335 was that close to 200 of those 800 customers would see a bill reduction of up to $25 a year without changing anything His testimony also indicated that a little over 100 of the 800 customers would see a bill reduction of between 25 and 50 dollars a year without doing anything differently or changing any behavior. He further testified in ER-2019-0335 that another roughly 25 of the 800 customers would see a bill reduction of more than $50 without doing anything differently or changing behavior. [160]

Concerning the plan currently known as the Ultimate Saver Plan, in ER-2019-0335 Mr. Wills testified that "approximately half of all of the Ameren Missouri residential customers [of the 800 studied] would be able to save money under the [Ultimate Savers] TOU rate plan without making any behavior changes at all."[161] Mr. Wills further testified in ER-2019-0335 that "I analyzed the scenario where all customers that, based on their actual historical usage patterns, would have been able to save more than 5 percent on their electric bill by switching to the Smart Savers rate, adopt that rate after they receive an AMI meter. Of the sample customers, 27.4 percent fall into that category of saving 5 percent or more. The average savings in the

[160] Tr. Vol. 7 page 207 line 18 – page 211 line 10.
[161] Tr. Vol. 7 p 211 line 11 – p. 212 line 7.

Smart Saver rate for those customers with no changes in consumption pattern at all in response to the price signal reflected in that rate would be approximately $68 per year."[162]

In his direct testimony in ER-2019-0335, Mr. Wills conceded that "Because the rates are being offered on an opt-in basis and the Company is planning to provide education and tools for customers in order to help them make informed decisions about the best rate for them, bill impacts are generally expected to be favorable on balance for customers (i.e., customers will opt in if they're likely to save money.)"[163] He further testified in that case that opt-in rates are "particularly prone to revenue erosion" for two reasons, "First, the rate design changes proposed -- proposed in this case are designed to be revenue neutral for the class as a whole, i.e., for the average customer. However, most customers are not average. None of them are precisely average. Every customer could naturally be a winner or loser on a new rate before making a single behavior change in response to the new rate. This is not a bad thing as long as the rate is aligned well with the cost of serving customers. The bill changes that create the various customer outcomes should generally be moving customers' bills closer to their true cost of service. This is generally a good thing to be sure. But because the Company intends to work with customers to help them make informed rate choices using enhanced usage information from AMI meters, adoption should be very asymmetric. Expected winners should adopt new rates readily realizing bill savings that reflect the lower cost of serving these customers that generally have more favorable load characteristics. Customers whose rates are likely to increase under the new optional rate structures due to inconsistent loads with peakier usage may simply choose to stay on the status quo rate. Therefore, the revenue erosion caused by bill savings and adopters will not be immediately offset by increases for others. I would

[162] Tr. Vol. 7 p 212 line 8 – p. 213 line 19.
[163]Tr. Vol. 7 p. 213 line 20 – p 214 line 4.

note that this revenue shortfall should be made up in a subsequent rate case so the issue I'm addressing is really one of regulatory lag."[164] Mr. Wills admitted during the hearing in the current rate case that Ameren Missouri has not presented evidence of benefits to Ameren Missouri customers or the Ameren Missouri system arising from the shifting of usage away from periods of high demand and, therefore, higher costs on the system.[165] Mr. Wills admitted during the hearing in the current rate case that it could be possible to have benefits arising from the adoption of time-of-use rates and not have any benefits from the tracker as requested by Ameren Missouri in this case.[166]

The result is that the "cost" to Ameren shareholders of regulatory lag due to rate plan migration is a cost that Ameren shareholders chose to take on, and it is not offset at this time by any "benefit" of avoided system costs, or savings due to early retirements.

In ER-2019-0335 Ameren Missouri requested a "Rate Mitigation Tracker," which is substantially similar to the tracker Ameren Missouri has requested in this case, ER-2022-0337, to the extent either are sufficiently defined in the relevant testimony.[167] Ameren Missouri settled ER-2019-0335 with its current opt-in ToU rate plans, and without its requested rate mitigation tracker.[168]

In the "Charge Ahead" order, ET-2018-0132, at page 29, the Commission stated "Further, by allowing the opportunity for Ameren to request the non-rate-based treatment in a future rate case and retain any electricity sales revenues between rate cases, Ameren Missouri and the customers interested in the program become aligned. Thus, it is in the public interest to authorize

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[164] Tr. Vol. 7 p. 214 line 5- p. 216 line 1
[165] Tr. Vol. 7 p. 217 line 5 – p. 219 line 2.
[166] Tr. Vol. 7 p. 220 line 22 – p. 221 line 17.
[167] Tr. Vol. 7 p. 216 lines 2 – 15.
[168] Tr. Vol. 7 p. 216 line 16 – p. 217 line 4.

a deferral accounting mechanism or tracker."[169] In the hearing in the instant case, Mr. Wills agreed that "the alignment of Ameren Missouri's interest and the customers['] interest was going to come from Ameren getting extra revenues between rate cases and customers getting those extra revenues recognized in rate cases."[170]

In his surrebuttal testimony in this case, Mr. Wills' included the following exchange at page 14 lines 1 - 14:

> Q. What about Staff's other claim about customers increasing their electric usage, which I will paraphrase as – customers will buy more EVs as a result of their adoption of TOU rates, and the additional electricity sales to power those vehicles will make up for the TOU-related revenue losses?
> A. Staff raises issues from the Company's "Charge Ahead" case (File No. ET-2018-0132) related to incentives for EV charging, claiming that incremental revenue from new EV load will enhance Company revenues, presumably suggesting that the new revenues will make up for the revenue shortfall from customers saving on TOU rates. While it is true that any incremental revenues from new EVs do benefit the Company in the short run, it is also true that these EV-related revenues represent a very small amount of total usage as compared to the total household usage of residential customers that may be adopting TOU rates and creating customer savings (and utility revenue shortfalls as a result). But even more importantly, Staff ignores the fact that any incremental revenues that may arise from an increasing number of EVs were a critical element of the business case, and cost recovery solution, that underpinned the Charge Ahead program….

However, at hearing in response to a question from Mr. Keevil that "Okay. But in this case you're arguing that Ameren Missouri needs this tracker because Ameren Missouri is not getting the amount of extra revenues between rate cases it believes it should get" Mr. Wills protested that "I think this is a totally different issue than the revenues that arose from the charge-ahead case. The charge-ahead case was related to us incentivizing customers to put in EV charging that we hoped would cause additional EV adoption in our service territory **and create revenues** that would help pay for the charge-ahead program financing costs. In this case we're talking about revenues,

[169] Tr. Vol. 7 p 221 line 18 – p. 222 line 24.
[170] Tr. Vol. 7 p. 222 line 25 p. 224 line 3.

existing revenues of customers that will decline because they are shifting load and saving money on time-of-use rates. I think those are just different buckets of revenues that are being addressed by the use of trackers."[171]

However, in file ET-2018-0132 Mr. Wills testified that ""My expectation is that no TOU rate is likely to be established that doesn't fully cover the marginal cost of service and make a contribution to covering the Company's fixed costs so that those customers that do charge during off-peak times will still provide positive margin when netting the reduced revenues with the reduced incremental costs of serving EVs." [172] At the hearing in this case Mr. Wills testified that he believes that the Ultimate Savers, Smart Savers and Overnight Savers rate plans each cover the marginal cost of service and make a contribution to covering the Company's fixed costs.[173]

**Issue I.a. Is the Ameren Missouri requested method for calculating the tracker balance reasonable?**

No. The calculation Mr. Wills describes will calculate a value in excess of the bill savings experienced by Ameren Missouri customers. [174] In his surrebuttal at page 14 Mr. Wills for the first time makes the utility's case that in the Charge Ahead case, ET-2018-0132, Ameren Missouri chose to not include the regulatory asset in rate base because Ameren Missouri expected that the incremental revenues it would receive from load growth would offset or exceed the financing costs. Now, Ameren Missouri is expecting non-participating ratepayers to make up the difference between what EV customers would have paid on the Anytime Saver rate and the highly-differentiated ToU rates. This approach takes the "customer benefit" of accretive revenues from

[171] Tr. Vol. 7 p 224 line 4 – line 21.
[172] Tr. Vol. 7 p. 207 line 5 -- line 13.
[173] Tr. Vol. 7 Page 204 line 7 – p. 205 line 12.
[174] Sarah Lange Rebuttal, p. 6.

Charge Ahead, and turns it into a customer cost as a tracker balance.[175] Ameren Missouri's proposed tracker calculation is not reasonable because it will overcompensate Ameren Missouri for the revenue differential associated with increased usage due to effective energy storage, [176] Ameren Missouri's proposed tracker calculation is not reasonable because it will overcompensate Ameren Missouri for the revenue differential associated with increased usage due to accretive energy usage,[177] and Ameren Missouri's proposed tracker calculation is not reasonable because it would doubly account for bill differences encompassed by the FAC, because to the extent that pricing disparities in the opt-in ToU rate plans are intended to reflect differences in the cost of wholesale energy over various time periods, any savings actually realized are passed in part to ratepayers and retained in part by shareholders through the FAC. It would not be appropriate to consider the energy portion of differences between rate plan charges in calculating an avoided revenue or bill savings.[178]

**Issue I.b. Are alternative approaches available to address what Ameren Missouri characterizes as an inherent disincentive for the utility to pursue a rapid transition toward broad adoption?**

Yes. The first way to address this problem would be to redesign these rate plans so that the differentials in the rate plans correspond to the variations in the cost of providing service in selected time periods. The second way to address this problem would be to increase the Overnight Savers, Smart Savers, and Ultimate Savers rates so that customers who have opted into the plans provide the same average revenue per kWh as those who have not opted into the plans, based on the billing determinants associated with each rate plan.[179] If the requested authority is granted, the

[175] Sarah Lange Rebuttal, p. 12.
[176] Sarah Lange Rebuttal, pp. 11-12.
[177] Sarah Lange Rebuttal, pp. 11-12.
[178] Sarah Lange Rebuttal, p. 12.
[179] Sarah Lange Rebuttal, p. 15.

appropriate customer group from which to seek recovery are those customers taking service on the highly-differentiated Time of Use ("ToU") rate plans. [180]

## VII. Ameren Missouri chose to introduce "EEI Average Realization Rates," but failed to provide meaningful context, and relies on unreasonable interpretations of Staff's study relative to that data, rather than Staff's actual study results.

Ameren Missouri's opening claimed Staff's study produces the outcome of industrial customer's rates being 10% over the national average.[181] Ameren Missouri's position statement claimed that Mr. Hickman "Demonstrates that if Staff's study were followed to set rates, Ameren Missouri would have residential rates 23 percent below the national average while industrial rates would be 14 percent above the natural average," relying on Mr. Hickman's Surrebuttal table TH-1, which is an expansion of Mr. Hickman's Rebuttal table TH-1.

Ameren Missouri chose in Mr. Hickman's Rebuttal testimony at page 3 to introduce a presentation of Average Realization Rates by "Residential," "Commercial," and "Industrial" customers in Rebuttal table TH-1. Ameren Missouri does not have "Commercial" or "Industrial" classes.[182] Exhibit 179 establishes that Ameren Missouri's SGS class during the test year was 2.57% industrial, by kWh sold, that Ameren Missouri's LGS class was 10.08% industrial, by kWh sold, that Ameren Missouri's SPS class was 31.46% industrial, by kWh sold, and that Ameren Missouri's LPS class was 60.92% industrial, by kWh sold. Using these percentages and the Average Realization Rates provided by Mr. Hickman in his Rebuttal table TH-1, Mr. Hickman verified the values provided in Exhibit 179 and reproduced in Exhibit 180 for "USA Average Commercial / Industrial $/kWh weighted to Ameren Missouri Commercial/Industrial Makeup by

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[180] Sarah Lange Rebuttal, p. 6.
[181] Transcript Vol. 7 page 24 Lines 15 – 23
[182] Transcript Vol. 7 p 143 line 23 – p 144 line 10

Class" of $0.11629 per kWh for SGS, $0.11305 per kWh for LGS, $0.10381 per kWh for SPS, and $0.09108 per kWh for LPS.[183]

Exhibit 180 demonstrates that Staff's CCoS Study results are all below the Average Realization Rates provided by Mr. Hickman in his Rebuttal table TH-1 weighted for Ameren Missouri's Commercial/Industrial composition for each Ameren Missouri rate class.

Review of Exhibit 180 indicates that Staff's CCoS Study results on a per-kWh basis range from 28% below the EEI average value for "Residential" usage, to 13% below the EEI average weighted value for the SGS class, while Ameren's CCoS Study resutles on a per-kWh basis vary from 41% below the EEI average weighted value for the LPS class, and 12% below the EEI average weighted value for the SGS class.[184] Staff's study results are not higher than the EEI average weighted results for any class, including SPS and LPS. Note, these Staff results do not reflect the Economic Development "EDI" incentives that are made available to customers in non-residential classes which would further reduce the actual bills paid by those customers receiving discounts and reduce the average $/kWh resulting from those classes.**[185]** Finally, while RESRAM, FAC, and MEEIA payments are excluded from the stated study results, it should be recalled that pursuant to Ameren Missouri's effective tariffs, qualifying commercial and industrial customers can and do opt out of MEEIA, but residential customers cannot.

[183] Transcript Vol. 7 p 128 line 17 – p 129 line 6

[184] 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. For 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. "Residential" average values presented by EEI may trend higher because 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 are reflected in the EEI calculation *See Sarah Lange Surrebuttal p 11 l 15 – p 12 L 8.*

[185] Transcript vol. 7 p 146 lines 4 -20·

Despite the availability to Mr. Hickman of Staff's actual CCoS results and the commercial and industrial compositions of its actual rate classes, Mr. Hickman chose to provide what he characterized as "Staff Proposed CCOSS" in his Surrebuttal table TH-1 at page 5 of his surrebuttal. Mr. Hickman testifies that he created these values "by applying Staff's proposed revenue requirement allocations by class to residential, commercial, and industrial categories in proportions informed by company load research."[186] However, the values Mr. Hickman provided in his Surrebuttal Table TH-1 for his interpretation of Staff's CCoS results reflect an increase of 8.38%.[187] Staff's overall recommended increase in its direct CCoS was 7.32%.[188] Mr. Hickman insisted that a simple reading of the labels provided in his table was "a mischaracterization," and that there was no apparent flaw in a table that indicated that Staff's study was based on an average $/kWh value of 10.17 cents per kWh.[189]

In short, Mr. Hickman attempted to adjust average results in a manner that is not mathematically reasonable.[190]

Under cross examination Mr. Hickman admitted that Staff's actual CCoS study results, presented on a $/kWh basis, for the LPS class, were 7.34,[191] which is lower than value Mr. Hickman attributed to Staff for "industrial" rates in his Table TH-1, and lower than the "commercial" and "industrial" national average weighted for the mix of industrial and commercial kWh sales occurring in Ameren Missouri's LPS class, which is 9.11.[192] He further agreed that Staff's actual SPS class $/kWh results of 8.21 cents are lower than the 8.43 cents he reported for

[186] Hickman surrebuttal p 5, footnote 4.
[187] Transcript vol. 7 p 125 line 14 – p. 126 Line 5.
[188] Transcript Vol. 7 p 125 Lines 7 – 13.
[189] Transcript Vol. 7 p 134 Line 8 – p. 137 line 16.
[190] Transcript Vol. 8 p 459 line 11 – p 459 line 22.
[191] Transcript Vol. 7 p 143 lines 4 – 10.
[192] Exhibit 180.

Staff's results in his creation of Surrebuttal TH-1,[193] which is lower than the SPS average value of 10.38 cents per kWh provided as the USA Class-Weighted Average in Exhibit 180.

In the end, despite introducing this metric and misrepresenting it in its testimony, its position statement, and its opening, Ameren Missouri's study results are more out of line with industry averages than are the results of Staff's CCoS study.[194]

a. Issue 2 – Depreciation/Continuing Property Record ("Cpr").

**1. Should the Company be ordered to change the manner that property retirements are recorded to its CPR?**

Issue 2 was formerly Issue 24B. The question before the Commission is whether the Company should be ordered to change the manner that property retirements are recorded in its Depreciation/Continuing property record. Staff's position is that the Company should be so ordered, all as set out more specifically in the conclusion of this Issue.

Currently, when the Company retires a mass asset, it does not use that specific mass asset's previously recorded actual vintage year to select and then record the asset in its Continuing Property Record ("CPR"). Reference to the chart at page of 4 of Cedric Cunigan's Surrebuttal/True-Up Direct Testimony illustrates the Company's practice.[195]

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[193] Transcript Vol. 7 p 143 lines 11 – 22.
[194] Transcript Vol. 8 p 413 lines 11 – 13.
[195] This excerpt from the CPR was filtered for the Cross arm 30' and over retirement unit and the Miller-Zion and Explorer Tap asset location. Cedric Cunigan Surrebuttal, p. 4.

| Asset Id | Utility Account | Vintage | Retirement Unit | Asset Location | Activity Quantity | Activity Cost | Average Cost |
|---|---|---|---|---|---|---|---|
| 39060388 | 1364001-Poles-Towers-TAPS | 2020 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 5 | $291,080.76 | $58,216.15 |
| 39798622 | 1364001-Poles-Towers-TAPS | 2020 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 0 | $0.00 | $0.00 |
| 39743791 | 1364001-Poles-Towers-TAPS | 2019 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 27 | $237,587.45 | $8,799.54 |
| 2119302 | 1364001-Poles-Towers-TAPS | 2005 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 1 | $2,854.47 | $2,854.47 |
| 985107 | 1364001-Poles-Towers-TAPS | 1999 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 2 | $5,476.84 | $2,738.42 |
| 958262 | 1364001-Poles-Towers-TAPS | 1976 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 105 | $9,675.06 | $92.14 |
| 958261 | 1364001-Poles-Towers-TAPS | 1971 | CROSSARM,30' AND OVER | 001-MILLER-ZION AND EXPLORER TAP | 80 | $13,549.83 | $169.37 |

As reflected in the foregoing record, the Company's CPR listed five poles together with an asset identification number of 39060388. The CPR listed a vintage year of 2020, and an average per unit cost of $58,216.50. The Company's PowerPlan software is designed to select a unit to retire that matches its chosen Iowa Curve pattern. Suppose that the company retires a 39060388 pole. But suppose that to serve the Company's chosen Iowa Curve pattern, the Company's PowerPlan software does not like that pole. Suppose it likes a $169.37 pole better. In that case, the software can simply jump down the chart and record, in its CPR, the retirement of a 958261 one pole with an average cost of $169.37. In this scenario, a non-existing $58,216.15 asset will remain on the books and in rate base although it is not in plant in service. At no time has the Company denied that such is its practice.

Rule 20 CSR 4240-20.030 Uniform System of Accounts—Electrical Corporations directs electrical corporations within the Commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major electric utilities. Specifically, 20 CSR 4240-20.030 (3)(A) requires an electric corporation subject to the Commission's jurisdiction to "maintain plant records of the year of each unit's retirement as part of the 'continuing plant inventory record,' as the term is otherwise defined at Part 101 Definitions 8 and paragraph 15,001.8." Rule 18 CFR Part 101 Definition 8 requires the following with respect to recording the retirement of mass property assets in the CPR:

> B. For each category of mass property:
>
> > (1) A general description of the property and quantity;
> >
> > (2) The quantity placed in service by vintage year;
> >
> > (3) The average cost as set forth in Plant Instructions 2 and 3 of this part;
> >
> > and
> >
> > (4) The plant control account to which the costs are charged.

18 CFR Part 101, Electric Plant Instructions, 2.A, states:

> 2. Electric Plant To Be Recorded at Cost.
>
> A. All amounts included in the accounts for electric plant acquired as an operating unit or system, except as otherwise provided in the texts of the intangible plant accounts, shall be stated at the cost incurred by the person who first devoted the property to utility service. *All other electric plant shall be included in the accounts at the cost incurred by the utility* [emphasis added] except for property acquired by lease which qualifies as capital lease property under General Instruction 19. *Criteria for Classifying Leases,* and is recorded in Account 101.1, Property under Capital Leases, or Account 120.6, Nuclear Fuel under Capital Leases. Where the term *cost* [emphasis in rule] is used in the detailed plant accounts, it shall have the meaning stated in this paragraph.

18 CFR Part 101, Electric Plant Instructions, 10.D, states:

> 10. Additions and Retirements of Electric Plant.
>
> D. The book cost of electric plant retired shall be the amount at which such property is included in the electric plant accounts, including all components of construction costs. The book cost shall be determined from the utility's records and if this cannot be done it shall be estimated. Utilities must furnish the particulars of such estimates to the Commission, if requested. When it is impracticable to determine the book cost of each unit, due to the relatively large number or small cost thereof, an appropriate average book cost of the units, with due allowance for any differences in size and character, shall be used as the book cost of the units retired.

Folded over these rules is 20 CSR 4240-20.030 (3) (G), which states:

> "Regarding plant acquired or placed in service after 1993, when implementing section (1), each electrical corporation subject to the Commission's jurisdiction shall- . . . .
>
> (G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 101 Electric Plant Instructions to 10.D and paragraph 15.060.10.F

Distilled to their essence as applicable to this case, the regulations require that when a mass asset is *acquired*, it be included in the accounts at the cost incurred by the utility. The regulations then require that when that asset is subsequently *retired*, the retirement book cost be the amount at which such property was previously included in the electric plant accounts. When an asset is retired, retirement data will be recorded by

- *general description*, e.g., Poles, Tower, TAPS;
- *quantity by vintage year*, e.g., one pole, vintage year 2020;
- *average cost*, e.g., $58,216.15; and
- *plant control account*, e.g.,1364001.

In the course of pre-hearing discovery, prefiled testimony and the hearing, it has become apparent that there is no dispute about what the Company is doing: When retiring mass assets, the Company is not considering an asset's originally recorded (actual) vintage year in the CPR. While we do not know whether, by design, the wrong vintage year is selected every time, we do know that by design the Company's PowerPlan software is making no effort to choose the right one. The Company has presented no testimony denying that it is conducting business as Staff has described above. Cedric Cunigan, Staff's witness, testified that Ameren has stated:

> "Vintage, location, voltage, etc. are not a part of the asset information collected (which is by design because not collecting such information is the essence of and a key benefit of using mass property account." Ameren also stated, "The information sent to PowerPlan includes the retirement unit (40' pole) and the quantities retired (2). PowerPlan then

> automatically uses the Iowa survivor curve for the account where the cost of 40' poles are recorded to determine what quantities within any given vintage year it will select for retirement. That vintage year will, not except by pure coincidence, match the vintage of the actual asset retired in the field."[196]

The Company has not denied Mr. Cunigan's testimony Mr. Cunigan went on to testify:

> Vintage year is specifically required to be recorded in the CPR and depreciation database by 20 CSR 4240-20.030 (3)(A). It appears from this response that Ameren is not recording its actual vintage years when retiring assets, but is letting its depreciation software determine the vintage years to retire. This is an issue because the CPR is no longer accurate, expect by pure coincidence. In addition, the records of asset lives are used to determine the very survival curves that Ameren is using to select vintage years to retire. That in itself is a circular argument that will only continue to reinforce the current survival curve choice rather than reflect the actual plant in service.[197]

The Company has not denied Mr. Cunigan's description of its conduct. Thus, it is not denied that the Company is not recording mass asset retirement information as required by Rule 20 CSR 4240-20.030; that vintage year will not, except by pure coincidence, match the vintage year of the actual asset retired in the field; that the CPR is no longer accurate except by pure coincidence; and that the process is circular, serving only to make future survival curve choices self-reflect past and present survival curve choices rather than reflect the Company's actual plant in service.

The Company contends that its approach does not violate the regulations because a) the regulations allow it to make estimates; and b) identifying the actual vintage of a mass asset is not realistic and is impracticable:[198]

> The amount of effort required to conduct physical inventories and specifically identify every asset being retired for mass property is impracticable, extremely burdensome, and does not render value or significantly improved accuracy relative to the mass property retirement methodology the Company uses today, which is widely accepted in the industry as a best practice. Extensive work would require hiring numerous staff for both property accounting and field personnel and would delay proper recording of entries that adversely would affect rate base, and would cause increased costs related to the incremental personnel that would ultimately be reflected in the form of higher customer rates.[199]

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[196] Quoting from the Company's DR responses, Cedric Cunigan Direct Testimony, p. 11.
[197] Cedric Cunigan Direct Testimony, p. 11-12.
[198] John Spanos Rebuttal, p. 18.
[199] John Spanos Surrebuttal, pp. 6-7.

The Company's argument fails in two respects. First, its estimates fail to satisfy any reasonable understanding of the term "estimate." Rule 10.D states: "The book cost shall be determined from the utility's records and if this cannot be done it shall be estimated." No reasonable understanding of the phrase "estimated book cost" can include an estimate that bears only a "purely coincidental" relationship to actual book cost and actual plant in service or can contemplate a resulting estimated overall CPR based on a circular loop that amounts to self-replication and not reality. By its own admissions, the Company's method fails even to meet the threshold requirement of 10.D: By its own admission, its estimates do not even pretend to be reasonable estimates. A Venn diagram of "reasonable" does not include "purely coincidental."

The Company's argument that the regulations allow it to make estimates fails "right at the gate" because its system does not provide a reasonable estimate, i.e., an estimated number that is demonstrably close or even demonstrably related to any actual number—as a predicate then for a rate base for just and reasonable rates. But regardless of whether the Company's procedure does or does not provide a reasonable estimate, unless book cost cannot be determined from the utility's records or it is impracticable to do so because of large numbers or small costs; when the Company retires a mass asset, it must record in the CPR its actual book cost, vintage year and all the other information mandated by the regulations. The Company might like and prefer estimates, but a preference is not a "gate pass" to skirt the rule's requirements that before estimates are allowed, the Company show that it either cannot get at the real facts or cannot practicably do so.

The Company's evidence was insufficient to sustain its burden to show impracticability. At most, the Company's case supported a conclusion that it might not always have the data. Beyond any cavil, however, the evidence also compelled the conclusion that the Company certainly could acquire the data without any difficulty and only lacked it when it chose not to obtain it. In fact, at the end of the day, the evidence raises the question of whether the Company is not obtaining the needed data, not because it is impracticable to obtain it, but, instead, because such data will subvert the PowerPlan's purpose to choose an input number that will produce its preferred output number.

At the hearing, Company witness John Spanos expanded on his prefiled testimony about how rule compliance would require the Company to hire more accountants and field personnel, delay linemen's work, delay proper recording of entries, adversely affect rate base, incur increased costs related to the needed incremental personnel, and ultimately increase customer rates.[200] At the hearing, however, in the course of cross examination it developed that Witness John Spanos simply had no knowledge at all of the Company's record keeping procedures that linemen actually used in the field when making inspections.

> Q. Isn't it true, sir, yes or no, that under the procedure that you have described after a lineman or whoever has gone out and done an inspection, if there -- if he doesn't identify anything about the pole that's wrong, there's not going to be a record?
>
> A. I don't know the procedure that he has to record what he's done. There is a guidance for inspections that have to happen, and they do their recording based on their inspection. But I don't know the degree that you're asking.
>
> Q. Yes or no. I'm -- yes or no. Do you know what the procedure is that the Company follows, if any, for recording data when it goes out and inspects poles? Do you know that procedure?
>
> A. Can you identify what data means?
>
> Q. Whatever it might mean. There's -- you do not know what the procedure is?
>
> A. Under the pole inspection process, I do not know what their specific procedure is for identifying that they've completed their work.
>
> Q. Do you know whether they have a procedure for recording data, information observed during these inspections when nothing is done to the pole after the inspection?· Is there any procedure at all for that?

[200] John Spanos Surrebuttal, pp. 7-8.

A. I don't know, but I'm not sure how this relates to the property records. . . .[201]

Company witness John Spanos' conclusions about record-keeping linemen's work and the trouble and expense of recording, e.g., retired asset tag numbers, appear to lack foundation. Company witness Mitchell Lansford's testimony then confirms that there actually was no foundation available for witness John Spanos' conclusions and confirms that through its inspections the Company is able, with respect to poles, to acquire all information necessary fully to comply with the rules.

> Q. My question is when an asset is placed out there or at some point after it's out there, isn't it assigned by the company, a lineman or someone assigns it an ID number that's specific to that asset.
>
> . . .
>
> MR. LANSFORD: I know for certain that there is no assignment of an asset ID to those poles or any section of our conduit or -- or overhead ·conductor that can correspond with our plant accounting records. I -- I'm aware generally that we -- in -- that we do put a pole tag on some of these poles so that we can do our pole inspection program, but my knowledge of that pole inspection program is -- is limited to that.
>
> BY MR. GRAHAM:
>
> Q. So there is a pole tag?
>
> A. At least for some of our poles. I don't ·know what our pole -- pole inspection program entails, but I'm aware that we have some pole tags on some of our poles. Similarly or, you know, in contrast to that, I'm definitely aware that we have no asset IDs on any of our overhead conductor.

Cross examination of Company witness Mitchell Lansford then focused on Staff Exhibit 185 and its attached slide, which was the Company's response to Staff's Data Request 439.[202] The slide is set out on the following page:

[201] Hearing Transcript, pp. 513 – 514.
[202] Hearing Transcript 541 et seq.

| JOB_NUMBER | TAG_NUMBER | FEEDER_NAME | is_pole_reject | is_facility_reject | inspection_date | age_at_inspection | age_bin | large_age_bin |
|---|---|---|---|---|---|---|---|---|
| 201410239 | 182156 | 198002 | FALSE | TRUE | 10/25/2014 | 40 | 31-40 years | 30-45 years |
| 201410239 | 182159 | 198002 | FALSE | FALSE | 10/25/2014 | 48 | 41-50 years | 45 or more years |
| 201410239 | 362285 | 198002 | FALSE | FALSE | 10/25/2014 | 21 | 21-30 years | 0-30 years |
| 201410239 | 395139 | 198002 | FALSE | FALSE | 10/25/2014 | 48 | 41-50 years | 45 or more years |
| 201410239 | 395140 | 198002 | FALSE | TRUE | 10/25/2014 | 48 | 41-50 years | 45 or more years |
| 201410239 | 395142 | 198002 | FALSE | TRUE | 10/25/2014 | 28 | 21-30 years | 0-30 years |
| 201410239 | 395143 | 198002 | FALSE | FALSE | 10/25/2014 | 47 | 41-50 years | 45 or more years |
| 201410239 | 395144 | 198002 | FALSE | FALSE | 10/25/2014 | 49 | 41-50 years | 45 or more years |
| 201410239 | 395146 | 198002 | FALSE | TRUE | 10/25/2014 | 54 | 51-60 years | 45 or more years |
| 201410239 | 395148 | 198002 | FALSE | FALSE | 10/25/2014 | 47 | 41-50 years | 45 or more years |
| 201410239 | 395149 | 198002 | FALSE | TRUE | 10/25/2014 | 47 | 41-50 years | 45 or more years |
| 201410239 | 395150 | 198002 | FALSE | FALSE | 10/25/2014 | 54 | 51-60 years | 45 or more years |
| 201410239 | 395152 | 198002 | FALSE | TRUE | 10/25/2014 | 54 | 51-60 years | 45 or more years |
| 201410239 | 395153 | 198002 | FALSE | TRUE | 10/25/2014 | 40 | 31-40 years | 30-45 years |
| 201410884 | 2015055 | 922042 | FALSE | FALSE | 3/31/2014 | 37 | 31-40 years | 30-45 years |
| 201410884 | 2015066 | 922042 | FALSE | FALSE | 3/31/2014 | 35 | 31-40 years | 30-45 years |
| 201410884 | 2015067 | 922042 | FALSE | FALSE | 3/31/2014 | 37 | 31-40 years | 30-45 years |
| 201410884 | 2015075 | 922042 | FALSE | FALSE | 3/31/2014 | 38 | 31-40 years | 30-45 years |
| 201410884 | 2015085 | 922042 | FALSE | FALSE | 3/31/2014 | 37 | 31-40 years | 30-45 years |
| 201410884 | 2019729 | 922042 | FALSE | FALSE | 3/31/2014 | 40 | 31-40 years | 30-45 years |
| 201410884 | 2019731 | 922042 | FALSE | TRUE | 3/31/2014 | 40 | 31-40 years | 30-45 years |
| 201410884 | 2019887 | 922042 | FALSE | FALSE | 3/31/2014 | 30 | 21-30 years | 0-30 years |
| 201410884 | 2019888 | 922042 | FALSE | FALSE | 3/31/2014 | 38 | 31-40 years | 30-45 years |
| 201410884 | 2019897 | 922042 | FALSE | FALSE | 3/31/2014 | 36 | 31-40 years | 30-45 years |
| 201410884 | 2099601 | 922042 | FALSE | FALSE | 3/31/2014 | 37 | 31-40 years | 30-45 years |
| 201410884 | 2780012 | 922042 | FALSE | FALSE | 3/31/2014 | 15 | 11-20 years | 0-30 years |
| 201410884 | 3769902 | 922042 | FALSE | FALSE | 3/31/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3660309 | 935042 | FALSE | FALSE | 11/24/2014 | 3 | 0-10 years | 0-30 years |
| 201411069 | 3711929 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3711978 | 935042 | FALSE | FALSE | 11/12/2014 | 3 | 0-10 years | 0-30 years |
| 201411069 | 3711980 | 935042 | FALSE | FALSE | 11/12/2014 | 3 | 0-10 years | 0-30 years |
| 201411069 | 3721918 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721919 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721922 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721923 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721924 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721925 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721927 | 935042 | FALSE | FALSE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721928 | 935042 | FALSE | TRUE | 11/12/2014 | 4 | 0-10 years | 0-30 years |
| 201411069 | 3721930 | 935042 | FALSE | TRUE | 11/12/2014 | 4 | 0-10 years | 0-30 years |

The Company produced the above record in partial response to Staff's DR 439.[203] Company Witness Mitchell Lansford testified as follows:

> Q. Now, to this document and provided with this document is the schedule there concerning poles. Do you have it in front of you?
>
> A. I do.
>
> Q. Does it not identify for each one of those poles a tag number?
> A. For this page, this section of poles that we have there is a pole tag number.
>
> Q. And an age?
>
> A. And an age.

[203] Hearing Exhibit 185.

Q. Okay. And that information is not produced by an Iowa curve or your software. That was actual information for the assets that are recorded there. Correct?

A. *It was produced by the inspections* [emphasis added].[204]

Judge Clark asked witness Mitchell Lansford a series of questions that laid the global foundation for the relevance of Exhibit 185 and the relevance of witness Mitchell Lansford's testimony that the information contained on its slide had not been generated by Iowa curves but had been collected by direct inspections.

Q. Now, you state on page 10 of your Rebuttal that Ameren has approximately 900,000 poles. And the difficulty is in tracking the location and vintage of each pole. Is that correct?

A. That's correct. In no way does our accounting system for these categories of mass property like poles and the example you bring up here have location information where you can go find the pole in our system along with vintage, quantity, cost, et cetera.

Q. Now, according to its 2021 annual report, Ameren Missouri has over a million residential customers and approximately 1.2 million customers in total. Is that correct?

A. I believe it's correct based on -- yeah. Based on my knowledge of those approximate amounts.

Q. How does Ameren manage to identify each customer by location and bill them each month?

A. We -- we do -- we do keep those records. We -- that's a record that we -- that we do keep.

Q. Now, when you say you do keep these records, so you do keep them for customers, but not for mass property in the same manner?

A. Right. Yeah. The -- the records that you need to be able to bill your customers accurately and collect -- collect from your customers have different characteristics than what's necessary to account for categories of mass property.· So yes, the data that that we collect, retain, and otherwise keep is different for those two data elements.[205]

[204] Hearing Transcript, pp. 547-548.
[205] Hearing Transcript, pp. 533-534

Judge Clark's questions put the nail in the coffin of Witness Spanos' testimony: Witness Lansford's testimony showed that there was no foundation for Witness Spanos' insistence that linemen could not be expected to gather the information required by the rule when retiring an asset. The global takeaway from the Company's responses to Judge Clark's questions is a Company admission that "where there is a will, there is way." Applying then this lesson of Company witness Mitchell Lansford's testimony about the Company's tagging procedures involving direct inspection of mass assets, Staff's witness Cedric Cunigan established that there is, going forward, a practicable way, based on the tagging procedures already employed by the company, for the company to bring its future records into rule compliance.

Q. Have you heard any evidence from Ameren concerning the cost of compliance?

A. I believe Mitch Lansford answered a question on it, but I haven't seen any evidence provided to actually list out what the cost would be.[206]

.....

Q. Would it be easier for a field worker to record the retirement of pole 900,001 or to report the retirement of a 43-foot class 4 pole?

A. I mean, if it's both one data point, it just -- just depends on what you're --
Q. Let's explore -- let's explore that. If there's a tag on there that says pole 900,001, would it be difficult to associate that tag number with all of the data reports or all of the data points that are required by the rule and reference them all back to a tag number, vintage number, the whole thing?· Or vintage year, the whole thing.

A. If the database already had that tag number and the required information, it would be simple to do that.

Q. Yeah. Be simple for the lineman to do that?

A. Yes.
Q. Okay. Is it your understanding that some asset groups are recorded to multiple accounts? For example, are transformers, switches, poles assets types found in multiple accounts?

A. Yes.

206 Hearing Transcript, p. 576.

> Q. Would it be easier or harder to communicate the retirement of one of those asset types with or without an identifying asset number?
>
> A. Can -- you asked a couple different --
>
> Q. I'll try that again. Would it be easier or would it be harder, which would it be, to communicate the retirement of one of the asset types, with or without an identifying asset number?
>
> A. It would be easier to retire one of the different asset types with an asset number.
>
> Q. The last few questions that I've asked you, would these be the kinds of questions one would expect reasonably to be asked and answered in determining what it would cost to bring this system into compliance?
>
> A. Yes. That would be reasonable.[207]

The Company evidence supports no conclusions that conflict with Mr. Cunigan's testimony.

Judge Clark asked Witness Cunigan: ". . .I guess how big of an issue is this? Why is – why in kind of a nutshell, why is this an issue?"[208] In response, Witness Cunigan walked the Commission through an example of the problem similar to the one Staff had set one out in Staff's opening statement:

> A. So if you go to my Surrebuttal testimony on that chart on page 5, this is the 30-foot cross arm and over, this is one account. If they retire the wrong vintage year, say -- say the third line, the 2019 vintage year has 27 poles in it. If that pole is taken out, there's about $9,000 associated with that pole on their books. So if it's physically taken out but they choose a different vintage year, say they choose 1971 because it's older, that value associated with that pole is only $170. And so the difference between those amounts would remain in rate base and they'd recover their return on that even though that asset is gone. And while most of the time the curve might pick the right year or it may not, I just don't know, but the rate of -- rate base is different from what's in the field if it's not actually recorded. And, you know, I picked that number, but, you know, if it was a 2020 poll, average cost of that is 58,000. And so every time you're off on the vintage year that you pick, you're off on the cost that's still in rate base.[209]

[207] Hearing Transcript, pp. 576-578
[208] Hearing Transcript, pp. 568.
[209] Hearing Transcript, pp. 568-569.

To restate Judge Clark's question: How big of an issue is this in the big picture? The combined plant balance and book reserve for the accounts is $6,391,076,638 and <$2,945,110,727>, respectively.[210] The failure to accurately adjust gross plant will result in three subsequent issues impacting revenue requirements in future rate cases.

First, the existing depreciation rate will be applied to the erroneous plant balance, resulting in an inaccurate level of depreciation expense to be reflected in revenue requirements.[211] Second, the improper depreciation expense will accrue to reserve, resulting in a difference between what the reserve should be with reasonable accounting practices, and what the reserve will be with the accumulated inaccurate depreciation expense.[212] This will result in a change in net plant balance from what would result with reasonable accounting practices, and, therefore, will impact subsequent revenue requirements.[213] Third, the erroneous retirements will result in calculation of an erroneous depreciation rate in a subsequent rate case.[214] This will further drive inaccuracy in the revenue requirement calculation, and compound the issue first identified, which will compound the second issue identified, and the errors in revenue requirement calculations will compound. These compounding errors will affect whether rates are just and reasonable.

To now answer Judge Clark's question: Where the Company has admitted that with respect to mass property its books bear only a purely coincidental relationship to actual plant in service; where the Company's evidence has not even placed a bracket on the margin of possible error; and

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[210] Cedric Cunigan Rebuttal Testimony, p. 5.
[211] For example, the Account 364 poles and fixtures rate is 3.78 per the Stipulation and Agreement filed in this case on April 7, 2023, so for every $1 million in erroneous retirements depreciation expense would be $37,800.
[212] For example, for Account 364 poles and fixtures, for each $1 million of erroneous retirements for each year, the reserve balance will be off by $37,800 assuming no other changes to plant. For example, $1 million of erroneous retirements recorded each year for 3 years would result in $340,200 in reserve inaccuracy.
[213] For example, for Account 364 poles and fixtures, for each $1 million of erroneous retirements for each year, the net plant balance will be off by $37,800 assuming no other changes to plant. For example, $1 million of erroneous retirements recorded each year for 3 years would result in $340,200 in net plant inaccuracy.
[214] Staff has no means of estimating the impact of these errors.

where the Company cannot, therefore, now be heard to claim that its mass asset account balances, recorded assets in service, reserve balances, depreciation rates, and depreciation expense are accurate, the Company's violation of the regulation is an issue. Indeed, with numbers in the billions, knowing that a correlation between the books and the actual plant in service is a matter of pure coincidence makes the matter a "big issue."

## VIII. SUMMARY AND CONCLUSION

Rule 10.D put the burden on Ameren Missouri to adduce evidence and persuade the Commission that at least going forward from now it would be impracticable to provide the data which the regulations required for recording mass asset retirements in the Company's Continuing Property Record. The Company's testimony established that it is now recording actual vintage years when an asset is acquired. The Company's records showed it is now actually tagging mass assets on a regular and continuing basis and recording those tag numbers in mass asset inspection records. But the Company never addressed why it could not simply cross reference its tag numbers to the information required by 20 CSR 4240-20.030 when an asset was retired. When a lineman retires pole 900,001, why would he need to do any more than simply report that he retired pole 900,001 and let the company's computer system do the rest--pick up, record and adjust its CPR with all of 20 CSR 4240-20.030 information already cross referenced to that tag number? If it is practicable through a tagging system for the Company *to obtain* the data that the regulations require, but the Company has chosen a PowerPlan/Iowa curve system that renders it impracticable *to use* the data, that does not mean that the Company gets its "impracticability ticket punched" and a "bye" on the rule. It does not mean that the Company has sustained its burden of proof. It means the Company has simply chosen to violate the rule.

The Commission should order the Company, going forward, to change the manner that mass property retirements are recorded in its depreciation/continuing property record as follows:

When retiring a mass asset, the Company should record in its CPR all data required by Rule 20 CSR 4240-20.030, including its vintage year and its book cost when acquired.

**ISSUE 3 -- IDENTIFICATION OF AVOIDED CAPITAL INVESTMENTS FOR THE SIOUX AND LABADIE COAL PLANTS**

**A. Should the Company be required to identify avoided capital investments should the Sioux or Labadie Energy Centers retire earlier than currently planned as recommended by Sierra Club witness Comings?**

Staff takes no position on this issue.

**WHEREFORE**, Staff prays that the Commission issue its order finding in favor of Staff on each of the issues set forth herein and making such further orders as the Commission deems just and reasonable.

Respectfully submitted,

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## CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, or transmitted by facsimile or electronic mail to counsel of record as reflected on the certified service list maintained by the Commission in its Electronic Filing Information System this 5th day of May, 2023.

**/s/ Jeffrey A. Keevil**