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# MISSOURI PUBLIC SERVICE COMMISSION

# FILE NO. ER-2022-0337

# REBUTTAL TESTIMONY

# OF

# TOM HICKMAN

# ON

# BEHALF OF

# UNION ELECTRIC COMPANY

# D/B/A AMEREN MISSOURI

**St. Louis, Missouri**
**February, 2023**

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**REBUTTAL TESTIMONY**

**OF**

**TOM HICKMAN**

**FILE NO. ER-2022-0337**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. Tom Hickman, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

**Q. Please state your name and business address.**

A. My name is Tom Hickman. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

**Q. Are you the same Tom Hickman that submitted direct testimony in this case?**

A. Yes, I am.

## II. PURPOSE OF TESTIMONY

**Q. To what testimony or issues are you responding?**

A. My rebuttal testimony responds to the overall reasonableness of Class Cost of Service Studies ("CCOSS") filed in this case. My testimony will highlight some key differences between the Company's CCOSS and Staff's CCOSS. I will briefly respond to minor CCOSS differences with Midwest Energy Consumers Group's ("MECG") and the Missouri Industrial Energy Consumers' ("MIEC") production cost allocation methods or results. I will correct the record on allegations made regarding an analysis of Rider B charges. Finally, I will describe how a few requests for the Commission to order specific data collection or retention by the Company are unreasonable.

## III. THE COMPANY'S COST OF SERVICE STUDY IS REASONABLE

**Q. As a cost of service expert in this case, what is your opinion on what should drive the Commission's decision making relative to cost of service studies?**

A. The reasonableness of a study is the critical aspect that should drive a Commission decision. More specifically, the Commission's goal should be to determine the overall reasonableness of a study, not evaluate hundreds, if not thousands, of individual nuanced modeling decisions made during a study.

**Q. What is your opinion on the overall reasonableness of CCOSS results presented by the other parties in this case?**

A. There are only two complete CCOSS provided in the direct round of testimony in this case, one by the Company and one by Staff. The results of these two studies tell incredibly different stories. The Company's results indicate that Residential and Small General Service ("SGS") customers are providing well below target returns and Large Primary Service ("LPS") customers are providing above target returns. Staff's results indicate almost the opposite, showing Residential and SGS customers close to target and Large General Service ("LGS"), Small Primary Service ("SPS"), and LPS customers are paying below target. These directional differences and the magnitude of difference expressed cannot lead someone to conclude that both studies are reasonable.

**Q. What opinions were expressed relative to CCOSS by the other parties in this case?**

A. MECG witness Steve Chriss's position is aligned with the Company's with one exception related to production allocations. MIEC witness Maurice Brubaker used Ameren Missouri's CCOSS as a starting point and modified only a few allocations. The actual revenue adjustment recommended by both parties mostly closely align with the results of the Company's CCOSS. While only the Company's CCOSS was available to review at the time of other parties filing direct testimony, the obvious way in which their results and proposals most closely align with the Company's proposed CCOSS and do not align with Staff's use of new, unorthodox methodologies indicates they will likely not find Staff's results reasonable.

**Q. Are there any useful measures of the reasonableness of rates and underlying CCOSS that can be sourced outside of parties in this case?**

A. Yes. The Edison Electric Institute collects sales and revenues data from a large number of Investor-Owned Utilities ("IOUs") twice per year and publishes data related to the Average Realization Rates experienced by Residential, Commercial, and Industrial customers. Please see Table TH-1 below for how the Company's rates compare to national averages as of the most recent report.

Table TH-1

| | Residential | Commercial | Industrial | Total Retail |
|---|---|---|---|---|
| USA Average | 14.39 | 11.74 | 7.42 | 11.68 |
| Ameren Missouri | 11.10 | 8.58 | 6.82 | 9.48 |
| Ameren Missouri vs. USA Average | -23% | -27% | -8% | -19% |

**Q. What do these realization rates indicate about the reasonableness of CCOSS and associated revenue allocation recommendations in this case?**

A. While realized rates may not necessarily provide the best comparison of CCOSS results between two individual utilities, the averages of realization rates across a large number of utilities should be considered informed by CCOSS results and generally indicate the Company's CCOSS results provide a much more reasonable perspective. If Staff's study results and recommendations were followed, the Industrial Rates (most representative of rates impacting LPS and SPS customers) would increase higher relative to the rates of smaller customers (Residential and Commercial). This comparison is helpful because it does not look at a single utility, area, market, or data point. It is the average across IOUs throughout the country. At this high level, it indicates that the Company's CCOSS results are much more reasonable than Staff's.

**Q. Can any high-level conclusions on the reasonableness of CCOSS approach be made from within the Company's current and prior rate case proceedings?**

A. Yes. As I did in the Company's prior rate case, File No. ER-2021-0240, I compared the allocation of net book value of Distribution Plant accounts 364 through 368 (Poles, Overhead Conductor, Underground Conduit, Underground Conductors, and Line Transformers), as these accounts have driven a lot of difference in allocation between the Company and Staff in the prior case and this case. In the prior case, a focus of mine was to show the relatively immaterial allocation differences between two historically used approaches for dividing distribution investment between customer-related and demand-related cost components. I've carried my table from that case forward and added two new data points. One representing the split within the Company's proposed CCOSS in this case and one representing the split within Staff's proposed CCOSS study in this case. See Table TH-2 below.

Table TH-2

| | Allocated Percentage of Net Book Value (Accounts 364-368) | | | | |
|---|---|---|---|---|---|
| | **Residential** | **SGS** | **LGS/SPS** | **LPS** | **Lighting** |
| **2016 Staff - Zero Intercept** | 69.17% | 11.10% | 15.20% | 1.90% | 2.62% |
| **2021 Ameren - Min System** | 68.91% | 11.90% | 15.56% | 1.39% | 2.24% |
| **2021 Ameren - Zero Intercept** | 70.50% | 11.84% | 13.83% | 1.34% | 2.49% |
| **2022 Ameren - Min System** | **68.31%** | 12.28% | 15.46% | **1.62%** | 2.35% |
| | | | | | |
| **2021 Staff - Min System as Adjusted** | 58.21% | 12.86% | 25.10% | 2.13% | 1.69% |
| | | | | | |
| **2022 Staff** | **41.65%** | 10.92% | 36.06% | **10.75%** | 0.62% |

**Q. What conclusions can be drawn from Table TH-2?**

A. Consistent with my testimony in the prior case, Staff's results are trending significantly away from accepted and reasonable results for distribution allocators. In the prior case, Staff presented distribution allocations which dramatically reduced the Residential share of distribution costs, with an offsetting increase primarily to the LGS/SPS class. In this case, an even more dramatic decrease to the percent of distribution investment allocated to Residential customers is being proposed, with an offsetting increase to both LGS/SPS and LPS classes.

**Q. At a high level, are such large swings reasonable?**

A. No. Staff presented and supported CCOSS results only two cases ago that allocated approximately 70% of the net book value of distribution plant to Residential customers. Staff indicates that changes such as how the distribution system is networked and how smart meters can communicate with switches to reduce the duration of an outage in some cases justifies this incredibly dramatic shift in proposed cost responsibility. But that simply does not make sense. While the increasingly networked nature of the system and remote operation of certain devices like switches does provide benefits to all customers, it most certainly does not fundamentally change how the most core and substantial components of distribution cost are utilized on the Company's distribution system to serve customers – nor the long-accepted economic rationale the underlying determination of cost causation of those components, nor the cost allocation methodologies that reflect that cost causation.

The largest components of investment in distribution accounts are poles, wires and cables (jointly referred to as conductors), and line transformers. An incremental benefit of devices communicating, which can provide the benefit of reduced outage times among other things, does not mean those assets that substantially make up the balance of the distribution accounts are being utilized in a different way than they historically have; or therefore, that the cost causation of those items has been radically altered. In no way would those small incremental changes support a drastic shift of distribution related cost responsibility from 70% for a class down to 40%, as Staff's analysis of the Residential class has done in the last few years. In no way should those small incremental changes support a shift of those same costs to indicate that a larger customer class (LPS) should be responsible for *more than five times as much* of cost associated with that underlying investment, as Staff's analysis also suggests.

**Q. Are there any obvious and specific issues with Staff's underlying approach that you feel contribute to the unreasonable outcomes of Staff's study? If so, please describe.**

A. Yes, there are. Specifically, I believe a number of Staff's approaches related to distribution investment have severe flaws and create bias in terms of cost allocation. Staff attempted to perform direct assignment of distribution assets that it describes as customer-specific.[1] It is critical to note that the assets that Staff is assigning directly may be utilized by a specific customer, but the cost is being assigned to the entire rate class to which that customer belongs. However, inasmuch as there may be such assets on the distribution system that Staff can identify as only providing direct benefit to a single large customer within a particular class – and therefore they assign that cost to that class because no other classes benefit from it, there are undoubtedly equally important and offsetting assets that only provide direct benefits to a small subset of customers within a common rate class, which could be assigned to that class on the exact same basis that Staff is using to assign customer-specific infrastructure costs – these are costs that similarly only benefit one class and do not provide any benefits to the other rate classes.

Consider a hypothetical circuit constructed in a radial manner which only connects one large customer to a substation. It might seem reasonable to identify the average costs associated with that specific circuit and assign the cost responsibility to that customer's class. Now consider a lateral section of a primary distribution circuit that runs down a street in a Residential subdivision. Consider that several Residential customers may be connected

[1] Note, Staff's focus on customer-specific infrastructure is tied to Staff's recommendation that the Company be ordered to provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage, and Staff's request for the Commission to order the Company study and present data related to the use of radial transmission facilities by customer.

to the assets on that lateral section. Even though this example represents several customers, those customers are all Residential customers and the assets associated with the circuit are not utilized to provide service to customers from any other rate class.

If it seems reasonable that Residential customers should not pay for a portion of the primary distribution infrastructure used to connect the large customer to the substation, it should seem equally reasonable that large customers should not pay for a portion of the primary distribution infrastructure used to connect the group of several small customers. However, Staff's biased analysis only attempts to account for one side of this equation. Staff has focused on assignment of costs for infrastructure used by large customers but fails to consider the reality of similar circumstances impacting small groups of like customers that could also theoretically be assigned the costs of assets that are exclusively used by it. And if Staff did seek to pursue this theoretical offset that would be needed to reduce the obvious bias inherent in their approach, acquiring data regarding the exclusive use of primary distribution assets by groups of Residential customers would essentially require the Company to review its entire distribution system and to try to assign a ratio of benefit on every individual distribution asset, and then revise that ratio every time components or customers were added or replaced. Practically speaking, that effort would be time-consuming and tedious, incur significant costs, and yield voluminous data, to the point where the benefits of performing the analysis could not possibly justify the costs. This level of detailed analysis is what would be necessary in completing a CCOSS absent the industry-accepted practice of using allocations based on studies of assets conducted at a much higher level.

**Q. Are there any other issues with Staff's proposed handling of distribution related costs?**

A. Absolutely. Even without considering the offsetting impact of assets used in areas of predominantly small customers against those used predominantly by large customers, Staff has made no attempt to reflect the fact that assets assigned to a class as customer-specific serve a portion or even the entirety of that customer's load. Staff allocated most of the cost associated with Accounts 364 through 367 "proportionate to each class's contribution to the system requirements in each hour, and proportionate to each hour's utilization of the distribution system."[2] This allocation method creates allocators that are nearly identical to those used to allocate costs on an energy (kWh) basis. In any case, if the radial circuit example where a large customer is connected directly to a substation and exclusively uses that portion of the distribution system (customer-specific, in Staff's eyes), why should that customer's contribution to system requirements in each hour be the basis for allocating any other assets? That customer's needs of the distribution system are fully met, in this example, by assets that were already assigned to their class. It is wholly inappropriate to make no attempt at removing their contribution to the allocator used for the remainder of distribution system assets.

[2] File No. ER-2022-0337, Class Cost of Service Direct Testimony of Sarah L.K. Lange, at p. 14, ll. 17 – 19.

**Q. Your testimony has utilized an example of a single large customer connected to a substation by a radially constructed circuit that the customer exclusively uses. Is this a practical view of something occurring on the Company's distribution system?**

A. No, it is not. I want to clarify that there are two ways in which "radial" can be used to describe a circuit. The first is a circuit which is truly a radially constructed circuit. In this example, that circuit has absolutely no existing interconnection to any other circuits on the system. That type of a circuit would be rare to exist on the Company's distribution system. Another use of the term "radial" is to describe a circuit that is operating as a radial circuit. In this example, the circuit may be connected to other circuits by a tie switch. If that tie switch is normally open, then the circuit in question is operating as a radial circuit. At any point in time, however, that tie switch can be changed to a closed position and the circuit in question can now be providing benefit to customers other than those normally served by that specific circuit. A significant number of circuits that operate radially on the Company's system have normally open tie switches. This fact was noted in data request responses to Staff, which were quoted by Staff witness Sarah Lange in direct testimony, at Schedule SLKL-d3 Page 7. The point is that such a circuit is not just benefitting the one customer.

Staff requested the Company subdivide the assets of a circuit by where they exist on that circuit relative to any tie switches. This is not a small or even reasonable request. The Company intended to highlight that available data indicates there is not a largely identifiable subset of distribution assets that provide exclusive benefits to individual customers (specifically, large individual customers). Staff incorrectly took that to be a data shortcoming and proceeded to utilize the information for customer-specific assignment.

**Q. Staff testimony states "Ameren Missouri has installed significant rate base to develop system resiliency and to enable what has been called "self-healing" properties. This increased integration as well as refinement of the customer-specific assignments described above have rendered the concept of severable levels of service obsolete."[3] Do you agree with this assertion?**

A. No. Further, I think this assertion is non-sensical and shows an obvious disconnect between Staff's proposed CCOSS and the reality of what a distribution system is designed to do. To be clear, the Company's study in this case and the Staff's study in past cases – completely consistent with industry best practices, including as advocated in the NARUC Manual – has recognized the distinction between the voltage levels at which assets on the system operate as an important factor in allocating their costs to customers based on their utilization of those voltage levels. For example, customers served at very low (i.e., secondary) voltage utilize infrastructure that would not and cannot provide service to customers served at higher (i.e., primary) voltages. In much the same way that Staff has tried – albeit in a biased manner – to isolate the costs of assets that serve only one customer from other customers that do not utilize that asset, separation of the costs by different voltage levels isolates costs of distribution assets at certain voltage levels that could never be involved in providing service to customers at higher voltage levels. And it is done in a balanced manner based on a thorough study of the utilization of different assets and asset classes by the voltage levels of the system that does not unfairly disadvantage one group

[3]File No. Er-2022-0337, Class Cost of Service Direct Testimony of Sarah L.K. Lange, at p. 15, ll. 4 – 7.

of customers over another, unlike Staff's customer-specific cost analysis does as I discussed above.

Staff, however, attempts to illustrate its point by pointing to an anecdotal scenario it invented related to the communicative nature of smart devices and their ability to reduce or prevent outage times for nearby large customers. Staff made no apparent attempt to determine whether this anecdote reflects anything that has ever actually happened, or to quantify the amount of the secondary distribution system where this anecdotal example even could or would happen. Further, this assertion undermines the core idea that distribution systems are built to deliver power to customers. Not only by attempting to make the allocation of the distribution system assets agnostic to voltage, but in also taking it a step further to state that the entire concept of severable levels of service by voltage of the distribution system has been rendered obsolete, Staff blatantly disregards what has and continues to be generally accepted within industry CCOSS practices.

**Q. You noted Staff's allocation for the remaining portion of distribution as being essentially an energy allocator. Please elaborate.**

A. Staff described a process for allocation that applied some level of weighting related to contributions to system peak in each hour. It seems there was an attempt to provide higher weighting to higher system hours, but the impact of this weighting was small. Please see Table TH-3 below.

Table TH-3

| | Res | SGS | LGS | SPS | LPS | Lighting | Total |
|---|---|---|---|---|---|---|---|
| Staff Allocator | 44.65% | 10.29% | 23.35% | 10.87% | 10.44% | 0.41% | 100% |
| Energy Allocator | 43.63% | 10.20% | 23.63% | 11.21% | 10.88% | 0.46% | 100% |

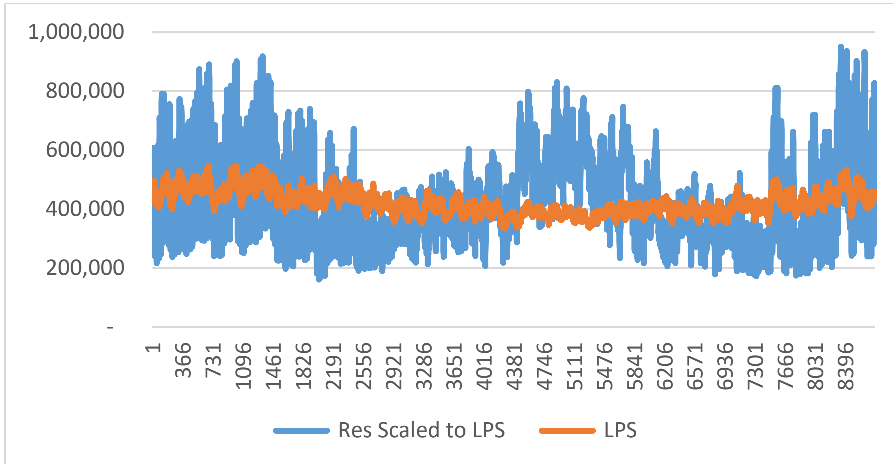
As the table shows, the allocators calculated by Staff are very close to the allocators based on total energy using the same set of underlying data.

**Q. Do you think using what is essentially an energy allocator for any portion of distribution investment is reasonable?**

A. No, it is not reasonable. Standard industry practice, as reflected in the NARUC manual, recognize significant portions of the investment in the distribution system to be classified as demand-related, and none of the costs to be energy-related. This means that the primary cost driver of much of the distribution system is generally recognized to be peak demands, not total energy delivered.

To illustrate a clear issue with using an energy allocator for what is otherwise appropriately classified as demand-related distribution investment, I used the same underlying data Staff did to produce its distribution allocator. In my illustration, I focused in on two classes, Residential and LPS. To create an appropriate comparison, I scaled the energy consumed by the Residential class in every hour by a ratio of total kWh across all LPS hours divided by total kWh across all Residential hours. The resulting hourly load represents the same relative distribution of energy across hours for the Residential class in a way that the total kWh matches that of the LPS class, putting the two class's loads on an equivalent energy basis. I used this newly created "Residential Scaled to LPS" hourly load and graphed it against the hourly LPS load. Please see Figure TH-1 below:

Figure TH-1




The use of an energy allocator (essentially consistent with what Staff used) would imply that an equal amount of Distribution investment is needed to serve both classes represented on this chart, as the total Energy across all hours is the same. Please note, however, the extreme difference in the maximum energy in the highest hour between the two classes. The highest hourly energy for the LPS class in the graph is approximately 545,000 kWh. The highest hourly energy for the Residential class (as scaled) in the graph is approximately 950,000 kWh. To simplify this comparison even further, imagine each class has only one customer. Staff's allocator implies the same amount of distribution would be required to serve a single customer who utilizes 545,000 kWh of energy in its single highest utilization hour as a customer who utilizes 950,000 kWh of energy in its single highest utilization hour. This is incredibly unreasonable. Please note, the Staff allocators in Table TH-3 are closely aligned with the overall results of distribution plant allocation from Staff's CCOSS highlighted in Table TH-2. It is clear to me that this decision to utilize what is essentially an energy allocator to allocate the costs of what are generally recognized to be demand-related costs substantially drove Staff's allocation of distribution investment, which were already highlighted as unreasonable in the high level of review provided earlier in my testimony.

**Q. Please describe Staff's approach to production allocation in this case and specific similarities and differences with the Company's approach.**

A. Staff's approach and the Company's approach are similar in that each identifies a component of production asset cost causation is energy-related and a component is demand-related. The two approaches assign the level of cost causation driven by each in different ways. Staff labeled each type of generation as "Type 1" and "Type 2." Staff identifies "Type 1" assets as those with "significant variable costs of operation which are avoidable if the unit is offline, fully dispatchable with limited exceptions" and "Type 2" assets as those with "no or minimal variable costs of operation, dispatch often limited by weather conditions or other factors beyond the control of the utility, many eligible for compliance with Missouri's Renewable Energy Standard."[4] Staff then allocates "Type 1" assets on the basis of demand, utilizing an "All Peak Hours Approach" based on MISO Resource Adequacy hours. Staff allocates "Type 2" assets on the basis of energy. The Company's approach does not seek to identify the underlying assets as specifically demand driven or energy driven, but rather seeks to use system load information to split the energy driven needs and demand driven needs of that underlying system load.

**Q. Given these differences, do you find Staff's approach reasonable?**

A. No, Staff's approach is not reasonable. Any given production asset has both energy value and demand value. I think trying to assign the value of a production asset as exclusively energy or demand is problematic. Consider new load being added to the

[4] File No. ER-2022-0337, Class Cost of Service Direct Testimony of Sarah L.K. Lange, at p. 20, ll. 16 – 21.

Company's system. That load would come with both energy requirements and capacity requirements. If the production system was not sufficient to provide for this new load, Staff's approach implies that the Company would build one asset (a "Type 1" asset) to serve the energy of that customer and a second asset (a "Type 2" asset) to serve the demand of that customer. This is illogical. The Company's use of average and excess production allocations provides for a more reasonable allocation of production assets that have varying levels of mixed energy and capacity value, but together form a complete production system capable of serving both energy and demand. It doesn't seek to assign only energy or capacity value to individual assets, but rather seeks to determine what the requirements of the system load are to inform how much underlying cost of the entire generating fleet that provides for both the total energy and demand needs of customers should be assigned to each.

**Q. Has the Commission recently ruled on the Company's CCOSS approach?**

A. Yes. In the Commission's Report and Order from the Company's recent electric general rate case, File No. ER-2021-0240, the Commission found: "For purposes of this case, the Commission finds that Ameren Missouri's class cost of service study offers a reasonable estimation of class cost of service."[5] The fundamental way that the Company's infrastructure is used to serves customers has not changed in the year since the Commission found the Company's CCOSS to be reasonable, nor has the Company materially changed its CCOSS approach. Despite the lack of change, Staff continues to aggressively modify its approach. This is highlighted on a subset of allocations by Table TH-1. The Company's

[5] File No. ER-2021-0240, Report & Order, at p. 23, effective February 12, 2022.

CCOSS and Staff's CCOSS cannot both be viewed as reasonable outcomes. The directional difference and magnitude of difference tied to what they tell us about how certain costs should be allocated to classes of customers are not close.

**Q. What is your recommendation to the Commission regarding CCOSS?**

A. Given the issues I have highlighted with Staff's CCOSS and associated positions, including but not limited to:

- Inconsistency of rate recommendations against national industry averages, driven by CCOSS results;
- Inconsistency of CCOSS results recommended by Staff over three recent Company general electric rate cases; and
- Fundamental flaws highlighted with apparent incomplete or inequitable distribution and production allocators.

I recommend the Commission maintain that the Company is proposing a study that offers a reasonable estimation of class cost of service and reject Staff's unreasonable CCOSS. While specific rate adjustments and outcomes are not only and entirely based on CCOSS, the results of CCOSS have several purposes and applications. For example, CCOSS results might inform things like reviews of specific charges or splits of energy and demand charges based on the costs associated with underlying capital allocations. It's very important for parties to have directive from the Commission that can guide what a reasonable basis for these types of analysis should be.

## IV. BRIEF RESPONSE TO MECG'S AND MIEC'S PRODUCTION COST ALLOCATION METHODS

**Q. MIEC witness Steve Chriss noted that the Company's proposed Average and Excess 4 non-coincident peak ("A&E 4 NCP") allocator differs from that specified in Section 393.1620.1(1), RSMo. Do you agree?**

A. I partly agree with Mr. Chriss's statement. I acknowledge that the section includes a specific definition of A&E 4NCP consistent with Mr. Chriss's testimony. Please note, however, that the definition of the months used in the statute differs from the classic definition of NCP per the NARUC Manual. The NARUC Manual defines Class Non-coincident Demand (class peak) as the maximum demand of a rate class, regardless of when it occurs.[6] By restricting the time period of demand to the four months with highest peak loads, the selected NCP demands are not consistent with the definition of the NARUC Manual. I do not contend that Mr. Chriss's application is not allowed under the statute, as I believe it would be given the way the statute is written. I do contend though that an alternative method of selecting the NCPs more consistent with the NARUC Manual definition is also allowed by the statute as the basis of a production analysis eligible to be considered by the Commission. While both approaches are allowed to be considered by the Commission, I believe that the method which uses the more traditionally accepted definition of NCP contained in the NARUC Manual is more reasonable.

**Q. Are there any other issues in other parties' testimony relating to production costs you would like to address?**

A. Yes. MIEC witness Maurice Brubaker disagrees with the Company's treatment of the non-labor component of production non-fuel operations and maintenance

[6] NARUC *Electric Utility Cost Allocation Manual*, at p. 167 (1992).

("O&M") expenses. He believes that these costs do not vary in any appreciable way with the number of kilowatt-hours generated and allocates them on the basis of demand.[7]

**Q. Do you agree with this approach?**

A. I do not agree with this approach for a few reasons. Mr. Brubaker highlights the fact that maintenance on coal and nuclear generation units is scheduled based on the passage of time. I think focusing on how maintenance is scheduled misses the bigger point of how much non-labor material is used during each maintenance period, and what causes the need for maintenance in the first place. The fact that maintenance occurs is a significant driver of labor costs, and the Company has classified the labor portion as fixed. The extent of maintenance performed is variable in nature and can vary significantly with the amount of time and extent to which a plant has run. Further, the need for this regularly scheduled maintenance is related to utilization of the unit – the wear and tear that occurs as energy is generated, making the energy-related allocator consistent with cost causation.

In our production operations, there are components of non-labor O&M expense, which are actually budgeted based on anticipated plant generation. Our engineers have identified a number of specific examples where this is the case, including but not limited to: conveyers, coal mills, chemicals, and the limestone in scrubbers. To the extent we are even budgeting costs on the basis of kilowatt-hours generated, it seems hard to justify these costs being allocated by a different means. For these reasons, I continue to support the Company's classification of these costs.

[7] File No. ER-2022-0337, Rate Design Direct Testimony of Maurice Brubaker on behalf of MIEC, at p. 33.

## V. ANALYSIS OF RIDER B CHARGES

**Q. Staff alleges the Company has not prepared a study of the reasonableness of calculations and assumptions underlying Rider B and filed those results in its direct filing in this case. Is this true?**

A. No. This was addressed in both my direct testimony and related workpapers, specifically the "Rider B Analysis Final" excel document file included in my workpapers.

## VI. STAFF'S UNREASONABLE REQUEST FOR DATA COLLECTION AND RETENTION

**Q. Staff's testimony recommends "… retention of data that is sufficient and appropriate for the rate modernization discussed here-in."[8] Should such retention be ordered?**

A. No. The ambiguous request for "sufficient and appropriate data" has no limits or boundaries attached to it. There's no consideration of the reasonableness or costs of that data retention. There's no clear definition or scope for that data retention. Staff has had a recent track record of requesting more and more increasingly granular data from utilities in this state. Difficulties with satisfying the requests from Staff relevant to CCOSS are not isolated to a single utility. Company Witness Mitch Lansford separately addresses the sufficiency of our plant accounting records relative to FERC guidelines, but I want to address this issue a little further as it relates to reasonable CCOSS. Staff has repeatedly requested plant accounting information by voltage. For good reason, voltage is not an attribute typically contemplated by utility plant accounting.

[8] File No. ER-2022-0337, Class Cost of Service Direct Testimony of Sarah L.K. Lange, at p. 56, ll. 5 – 7.

Consider the nature of a pole. The voltage of equipment on a specific pole can change over time. A pole that initially only has primary equipment and conductor may later be determined to be a necessary location to add a line transformer to convert primary voltage to secondary voltage. This pole may also have a span of pole-to-pole secondary run from the low side of that transformer. This change in operational characteristics occurs at a time after a pole has been recorded as capital and before it is retired from service. Nothing about the pole itself (the material, the size, or the age) is changing. Nothing about this change would typically require any kind of entry in the accounting system; however, Staff's belief that this is an appropriate location to retain voltage information would necessitate a change in accounting records where one wouldn't otherwise exist. This is completely unreasonable.

Other existing sources of data are reasonable sources that can drive reasonable cost allocations. Consider poles as a continued example. The Company cannot produce a version of accounting records with voltage information attached. What the Company does have, has utilized in the past, and plans to continue to utilize in the future, are operational records. Relative to poles, the Company does recurring inspections of poles and records the results of those inspections. These inspections occur over periods of years, such that the information is never perfectly current. An attribute noted during these inspections is whether the pole has primary equipment, secondary equipment, or both. Despite this information not being perfectly current, and despite the fact that the exact count of this multiyear recurring inspection may never match exact operational or accounting counts of the number of poles in service, it can still be a reasonable source of information to characterize the overall population of poles in a manner that is totally sufficient to inform allocations of the costs that are reflected in the accounting records. The best part is that it comes with very little incremental cost, considering other aspects of the pole must be visually inspected regardless of the need to capture this information.

It is not appropriate to require the Company to undertake unreasonable data collection processes to facilitate the further refinement of results of Staff's unreasonable approach to CCOSS. The Company's CCOSS is historically viewed as reasonable and produces reasonable results while utilizing reasonable levels of data. Staff never mentions (or perhaps even contemplates) the level of effort and costs that attempting to provide the granular level of data requested would require (if even possible), nor any estimate of the resulting "benefit" of such information.

**Q. Does this conclude your rebuttal testimony?**

A. Yes, it does.

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

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

**AFFIDAVIT OF TOM HICKMAN**

**STATE OF MISSOURI )**
**) ss**
**CITY OF ST. LOUIS )**

Tom Hickman, being first duly sworn states:

My name is Tom Hickman, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Rebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

*/s/ Tom Hickman*
Tom Hickman

Sworn to me this 15th day of February, 2023.