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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

SURREBUTTAL TESTIMONY

OF

THOMAS HICKMAN

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a Ameren Missouri

St. Louis, Missouri
March, 2023

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SURREBUTTAL TESTIMONY

OF

THOMAS HICKMAN

FILE NO. ER-2022-0337

Q. Please state your name and business address.

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

Q. Are you the same Thomas Hickman that filed direct and rebuttal testimony in this proceeding?

A. Yes, I am.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. My surrebuttal testimony responds to Staff allegations that the Company did not appropriately study Rider B. I also respond to Staff's proposed Rider C changes based on the Company's Rider C study. Finally, I address the reasonableness of Staff's criticisms of the Company's Class Cost of Service Study ("CCOSS"), certain proposed adjustments, and certain recommendations made by Staff.

II. RESPONSE TO STAFF ON RIDER B STUDY AND RIDER C UPDATE

Q. Staff alleged that the Company did not "study the relationship of cost causation and revenue sufficiency associated with the discounts provided to certain customers under Rider B."[1] Please respond to this allegation.

A. Staff's assertions related to the Company's review of Rider B is riddled with misunderstandings and misstatements. Staff states that a review of Rider B should focus on determining the cost of service to own and operate specific infrastructure, but this misunderstands how the Company's underlying CCOSS and rate design work. Customers do not pay rates that reflect specific investment in specific substation infrastructure. The rates reflect use of average system costs. The Company is agnostic to the precise decisions or costs that a Rider B customer incurs to own and operate their own substation in terms of rate design and credits. That decision is a free-market decision made by the specific Rider B customer, and it makes no sense for the Company's rates for the service it provides to be set based on any consideration of the specific costs being incurred by that customer as a function of its decision. The Company's goal is to remove from the rates charged to these customers any underlying allocation of Company-owned distribution substation costs – costs of assets not used by the Rider B customer due to their decision to self-provide that service - that are reflected in the base rate for all customers receiving Small Primary Service ("SPS") or Large Primary Service ("LPS"). Said another way, Staff asserts that the discount should be based on compensating the customer for investment the Company did not have to make in a substation to serve that customer. Calculating the value of a substation the Company did not invest in would have challenges, as not all such marginal substations would be the same. The discount should be based on removing the investment the Company did make, which

[1] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 18, ll. 17 – 19.

is a known sum and the costs of which are reflected in the rate the customer pays - from those rates for customers who do not utilize such investment. This is a much more reasonable and appropriate approach since the allocation of substations within the Company's CCOSS is uniform and based on averages. In conclusion, the Company fully complied with the Commission's direction to "study the reasonableness of the calculations and assumption underlying Rider B and to file the results of that study as a part of its direct filing in its next general rate case."[2]

Q. Staff recommended an update to the Rider C factor based on analysis performed by the Company. Do you think such an update is necessary?

A. No. The Rider C factor applies to a broad set of customers in order to adjust the usage billed to customers to account for energy losses in circumstances where the meter is configured on the opposite side of a transformer than it would be in standard circumstances. The losses in question are incurred due to the transformer that is adjusting the voltage of power delivered to these customers. The appropriate loss rate reflected in Rider C should be applicable over a range of different transformers that may be used to serve customers in these types of circumstances. The objective of our analysis was to review whether the loss rate was reasonable given that range, and our conclusion that it was. The difference between the 0.68% factor in effect and the 0.72% calculated as a part of the review is very marginal. Please see the Surrebuttal Testimony of Company witness Michael Harding for more information related to efforts to implement Rider C changes and the Surrebuttal Testimony of Company witness Nicholas Bowden for more information related to necessary adjustments to billing units that would be required with a Rider C change.

[2] File No. ER-2021-0240, Report & Order, Effective February 12, 2022, at pp. 33 – 34.

III. RESPONSE TO STAFF ON CCOSS ISSUES AND RESULTS

Q. Staff went through great efforts to criticize the reasonableness of the Company's distribution allocations. Please provide a high-level response to those criticisms.

A. As I explained in my rebuttal testimony and as further supported by Company witness Craig Brown in surrebuttal testimony, 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. Staff's rebuttal testimony dives straight into those individual nuanced modeling decisions. In fact, Staff spends more of its written testimony explaining its arguments or concerns with what I did in a variety of individual decisions related to specific allocations than it does on trying to make the big picture any clearer. Staff went into detail on a handful of calculations and adjustments relative to these individual decisions that only covered a portion of the difference between Staff's CCOSS and the Company's CCOSS. Staff ended by concluding that if we made those handful of adjustments and also recognized a few other high level criticisms, individual impacts for which were not calculated, that Staff "would expect the Ameren Missouri study results to be generally consistent with the Staff's study results."[3]

I disagree with this statement. In fact, in my rebuttal testimony, I compared the rates of Ameren Missouri to USA Average rates. I would like to expand this table to include a row of what Ameren Missouri's rates would look like if the Company were to follow Staff's CCOSS results. Please see the expanded comparison in Table TH-1 below.

[3] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 53, ll. 11 – 12.

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%
Staff Proposed CCOSS[4]	11.11	9.89	8.43	10.17
Staff CCOSS vs. USA Average	-23%	-16%	14%	-13%

It is striking that Industrial customers as a high level category of customers were already the closest to national averages (substantially less below the national average than Residential or Commercial categories). Staff's results would not just push them closer towards national averages but would push them to be well above national averages, while our overall rates remain well below national averages. This makes no sense. Staff effectively states that, if the Company would just agree with Staff's positions, the Company would achieve results consistent with Staff. That outcome would be unreasonable, despite any individual nuanced criticism contributing to it.

Please recall that my rebuttal testimony included a table that compared certain allocations of distribution net plant. My tables focused on a specific subset of accounts (364 through 368) which are the subject of most disagreement. Staff's analysis focused on the entirety of accounts 360 through 370, a broader set of distribution accounts. See Table TH-2 below, which can be viewed as an update to my original table, focusing on the same accounts and making a direct comparison between Staff's CCOSS and Staff's proposed changes to Company CCOSS.

[4] These values were created by applying Staff's proposed revenue requirement allocations by class to residential, commercial, and industrial categories in proportions informed by company load research. Please note, this line represents an overall increase in rates (consistent with Staff's direct filed position). The fact that the Residential category remains 23% below national averages is due to the category receiving almost no perceptive share of the overall increase.

Table TH-2

	Allocated Percentage of Net Book Value (Accounts 360-370)				
	Residential	SGS	LGS/SPS	LPS	Lighting
2022 Ameren	62.91%	12.61%	19.94%	2.85%	1.69%
2022 Staff	44.98%	11.53%	33.56%	9.33%	0.61%

Please note that the difference in this comparison is less dramatic than the one included in my rebuttal testimony. This is due, in large part, to the fact that the matters being criticized (Company use of the Minimum Distribution System methodology) are most apparent in the smaller subset of accounts that I discussed in my rebuttal (364 to 368). By expanding the accounts included in this analysis, the differences between the two studies seem less substantial, but doing so allows me to highlight the relative magnitude of some of Staff's primary issues with the Company's distribution study in this case.

Q. Given the importance of understanding the high-level impacts, what are some important things to understand about Staff's distribution study criticisms, specifically the adjustments Staff made to the Company's analysis as discussed in its rebuttal testimony?

A. Two specific adjustments Staff made are unreasonable. First, Staff broadly asserts that the application of values from the "Vandas" study were inappropriate, and the Company's allocations were based on a "study of primary-voltage infrastructure."[5] While I do not completely understand Staff's rationale for making this claim, I would like to make it clear that the application of the factors from the "Vandas" study were not in any way inappropriate. The "Vandas" study was a study of distribution assets in a specific subset of distribution plant accounts comprising assets from those distribution plant accounts that exist across the entire system. At the time the

[5] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 45, l. 12.

"Vandas" study was performed, both the Company and Staff were utilizing the "Minimum-Intercept Method" for apportioning plant between demand related and customer related components. As a result, the Vandas study percentages (which added up to 100) were applied only to the demand-related portion of distribution. That study had two key functions. The first was to apportion the distribution investments in these accounts into demand-related and customer-related components. The second was to characterize the demand-related components by the voltages they served so that they could be allocated to the customer classes that utilize those voltages in receiving service. For an illustrative example, the study may have found that for a particular size and type of pole installed on the system, 25% of the costs were appropriately considered customer-related. For purposes of allocating the remainder of the costs, which are demand-related, the study might have said that that type of pole is utilized 20% in the provision of service at secondary voltages, 70% in the provision of service at primary voltages, and 10% in the provision of service at sub-transmission voltages. As a result, the Vandas study percentages (which added up to 100) were applied only to the demand- related portion of the value of assets in these distribution accounts. The Vandas study workpapers that the Company still relies on create a composite allocation factor. In this example, the factor would show 25% of the cost of that type of pole as being customer related, 15% (the 75% of plant that is demand-related times the 20% proportion of that plant that serves secondary voltages) secondary, 52.5% (same math as the secondary, except using 70% of the plant supporting primary service) primary, and 7.5% (again similar) sub-transmission. In the zero-intercept world, this composite allocator (which sums to 100%) would be applied to the value of that asset in the account to fully allocate all of its costs to rate classes that benefit from that asset. This process created the percentages quoted in Staff's testimony. As the Company is no longer using Minimum-Intercept, it is important for those values to be grossed back to the 100%

total they represented coming out of the original study – meaning that, since we no longer utilize the zero intercept method, only the second part of the Vandas study – the part that characterizes the voltages that the asset serves – is needed to fully allocate the demand-related cost of that asset from that account. In my example, we just need to revert back from the 25% customer, 15% secondary, 52.5% primary, and 7.5% sub-transmission allocation factors, to the original results of the voltage study – 20% secondary, 70% primary, and 10% sub-transmission. It was an analytic short cut to leave the old values in and gross them up to remove the influence of the zero-intercept determined customer portion of the study, but also showed that the values were the same as those historically relied upon. Staff's allegation appears to be an error in understanding this dynamic.

The second assertion I want to address at a high-level is Staff's assertion about the inclusion of devices in the minimum sized system. Staff vigorously quotes the NARUC manual's[6] specific steps for apportioning distribution between demand-related and customer-related components, despite Staff's own use for similar allocations within its study of what is effectively an energy allocator – I will go into more on that later. Even though the NARUC manual lumps all non-conductor devices into a single category to consider demand related, there is a reasonable rationale to consider a portion of devices as customer related. Switches exist to redirect the flow of power. My view of the minimum sized system approach is that it seeks to identify the assets necessary to interconnect customers between the transmission system and each customer service point. It then multiplies the number of said assets by the cost of a minimum size asset to determine how much of the cost of that asset simply related to interconnecting customers. Switches (and other devices) are absolutely a piece of interconnecting customers, and some amount of their cost should be

[6] National Association of Regulatory Utility Commissioners ("NARUC"), *Electric Utility Cost Allocation Manual* (1992).

viewed as customer-related. Nuanced arguments aside, Staff made the following adjustments to attempt to "correct" for their assertions. See Table TH-3 below.

Table TH-3

	Impact on Percentage of Net Book Value (Accounts 360-370)				
	Residential	SGS	LGS/SPS	LPS	Lighting
"Primary" Minimum System/Vandas	-0.54%	-0.13%	0.30%	0.38%	-0.01%
Devices as Minimum System	-0.03%	-0.26%	0.61%	-0.02%	-0.29%

Recall from my previous table that the difference between Staff's and the Company's allocations associated with these accounts was approximately 18% for Residential and 6.5% for LPS. Using these two classes as representative examples, these nuanced differences that Staff spends pages and pages criticizing, account for only 0.57% and 0.36% of the 18% and 6.5% differences in total distribution cost allocations to those respective classes. Stated another way, these issues that Staff spends substantial time "down in the weeds" discussing are not really driving the differences that arise from the different allocation methods being proposed in this case. A study approaching allocation in either of these methods Staff and the Company identify for this particular item could very likely be considered reasonable, but what is clear is the point that this issue is not driving a significant amount of the differences between the Company and Staff's overall distribution allocations in this case.

Q. If these criticisms by Staff are not causing the substantial differences in distribution allocation, what is?

A. There is one additional apparent cause for the stark differences between the Staff and Company's allocations that Staff covered in rebuttal testimony. This cause relates to Staff's use of demand-weighting customer counts. For some important context on demand-weighting of customer allocation factors, consider this quote from the NARUC manual Staff relies upon in its rebuttal testimony: "While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications."[7] Staff characterized this quote as "condoning use of customer weighting to address Ameren Missouri's failure to perform a minimum size study that is based on what anyone could reasonably consider the minimum size of infrastructure necessary to provide service to customers, but that it would be better to not make unreasonable assumptions to begin with."[8] Staff's solution is to demand weight customer counts. Interestingly, the output of Staff's demand weighted customer counts is **very close** to the Company's Class NCP demand at primary and high voltage level allocators and **nowhere near** the Company's customer count allocators. This appears to be another scenario where Staff has used convoluted language to describe a method it is advocating for in an attempt to differentiate it from what it effectively is – in this case Staff's demand-weighted customer allocation effectively is just another construction of a demand allocator. To illustrate the point, see Table TH-4 below.

Table TH-4

	Sample Allocators				
	Residential	**SGS**	**LGS/SPS**	**LPS**	**Lighting**
Ameren Class NCP at Primary	53.407%	12.486%	30.583%	3.021%	0.503%
Ameren Class NCP at High Voltage	51.393%	12.015%	29.429%	6.679%	0.484%
Ameren Customer Count	82.975%	11.916%	0.870%	0.005%	4.235%
Staff Demand Weighted Customer	53.702%	14.505%	25.918%	3.134%	2.741%

[7] NARUC *Electric Utility Cost Allocation Manual*, at p. 98 (1992).
[8] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 47, ll. 20 – 23.

Note, the first three allocators are those taken from the Company's CCOSS. Staff's "Demand Weighted Customer" allocator, the fourth row of the table, looks nothing like Ameren Missouri's Customer allocator, nor any other predominantly customer-focused metric. It looks nearly identical to Class NCP allocators. It is so heavily weighted by demand that it should be considered, for all intents and purposes, as a demand allocator.

Q. Is using only what is essentially a demand allocator for the allocation of distribution plant reasonable?

A. No. Staff argued its quote of the NARUC manual is justification for the approach it used in creating adjustments, but just a few pages prior in the introduction of Distribution Plant, the NARUC manual states "When the utility installs distribution plant to **provide service to a customer and meet the individual customer's peak demand requirements**, the utility **must** classify distribution plant data separately into **demand- and customer-related** costs."[9] *Emphasis Added.* I cannot fathom the NARUC manual authors intended the anecdote on weighting factors to be utilized to undermine the very concept of customer-related distribution infrastructure by manipulating a customer allocator into what is essentially a demand allocator.

The NARUC Manual further states: "[t]he minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although **the differences may be relatively small**."[10] *Emphasis Added.* The NARUC manual goes on to state: "[w]hen allocating distribution costs determined by the minimum-size method, some cost analysists argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of

[9] NARUC *Electric Utility Cost Allocation Manual*, at p. 90 (1992).
[10] NARUC *Electric Utility Cost Allocation Manual*, at p. 92 (1992).

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 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.**" [11] *Emphasis Added.*

These quotes collectively show that although an argument can be made that the minimum size method may technically overlook the demand carrying capabilities of minimum sized equipment, that the expected difference between the two methods of apportioning distribution plant between customer-related and demand-related components, one of which is viewed to explicitly be impacted by the issue Staff identified and one of which is not, should be *relatively small*. This notion is supported by the table in my rebuttal testimony, which displayed the change in distribution allocations made by Staff in past Ameren Missouri rate cases that have occurred over time. The Company's change from one method supported by NARUC (the zero intercept method) to another method supported by NARUC (the minimum size method) is not responsible for the substantial difference between the distribution allocation being proposed by Staff and the Company in this case – the Staff's change to methodologies that are wholly inconsistent with the NARUC manual are responsible for the difference. In fact, using the Residential class as an example, Staff's suggested adjustments to the Company's study only account for approximately 9.5% of the approximate 18% difference between Company allocators and Staff allocators. This level of difference could be substantially quantified by moving from either of the two supported

[11] NARUC *Electric Utility Cost Allocation Manual*, at p. 95 (1992).

methodologies for apportioning distribution investment between customer-related and demand-related to allocating the entirety of distribution on a demand basis, which is an approach not supported by the NARUC manual. Despite ongoing investment in the distribution system, the very purpose of that system, which is to deliver power to customers using conductors, poles, transformers, and a subset of other related devices, has not changed since the NARUC manual was published.

Q. You stated that Staff's proposed adjustments only account for approximately 9.5% of approximate 18% difference in the residential share of distribution investment between Staff's study and the Company's study. What makes up the rest?

A. Staff alleges that even with these adjustments, "Ameren Missouri's study remains unacceptably deficient due to the failure to address customer-specific infrastructure that is recorded in Accounts 364-368, and due to the general inapplicability of the minimum-size approach to a primary-based system. Further, the minimum-size approach predates the modern 'smart grid' which is more appropriately allocated using the weighted hour method provided in the Staff study, which is also more compatible with rate structure modernization."[12] The reality is, the Company used one of two NARUC sponsored approaches to apportioning demand investment between customer-related and demand-related. Staff used a method which is effectively allocating distribution investment on the basis of energy, as was shown in a table in my rebuttal testimony. Staff may argue its results are the sum of differences and that the weighted hour method does something other than what I'm describing, but the results tell a different story. That story is that Staff essentially allocated the 364-368 distribution accounts on the basis of energy.

[12] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 51, ll. 18 – 21 & p. 52, ll. 1 – 2.

Q. Does the NARUC manual support the use of an energy allocator for the allocation of distribution related investments?

A. No. In fact, Staff quoted the NARUC Manual 10 individual times in rebutting Company distribution allocations. Included in those **10** individual quotes were **24** references to demand-related (or demand costs, assigned to demand, demand components, or demand classifications) and **29** references to customer-related (or customer costs, assigned to customer, customer components or customer classifications). At no point did any of the relevant quotes by Staff mention energy as a basis for allocating distribution investment.

Q. Staff criticizes the use of Average and Excess (A&E) in Company production allocations. Respond to these criticisms.

A. Staff argues "[t]he reasonableness of this allocator for Ameren Missouri has declined since at least 2005, when MISO integrated marketplace was introduced."[13] Section 393.1620.2 RSMo. states "[i]n determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocations contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual." It is interesting that Staff argues the reasonableness of this allocator has declined since 2005 due to MISO being introduced, but MISO had been introduced for over a decade before the Missouri Legislature passed a law specifying it, and specifically highlighting it, as an acceptable method for consideration by the Commission. The Company still identifies the need for investment in production through an Integrated Resource Planning ("IRP") process, which

[13] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 25, ll. 3 – 4.

results in the Company's production plant mix that is used to meet its customers' energy and capacity needs. It is the embedded cost of that production investment which we are allocating. Whether and how the MISO market changes the way the Company engages in purchases and sales of energy and capacity, it changes nothing about the cost causation of the decision to invest in those power plants – i.e., to directly provide for the energy and capacity requirements of its customers.

Q. Staff proposed a few adjustments to the Company's A&E production allocator. Please describe them.

A. The first adjustment relates to whether the NCPs for the combined Large General Service ("LGS") and SPS should be summed or not. Staff calculated the impacts and found that the increase on the combined class specifically affected by this change in allocation would be 0.0455%. Staff asserts that because this small percentage is multiplied against large dollar totals that it creates a significant impact. Staff notes the amount of Revenue Requirement directly allocated by this allocator is approximately $1.1 billion but does not calculate the actual impact. The actual impact of this small change to the allocator would be approximately $528,000. While I understand every dollar matters, the relative impact of this difference compared to other differences in allocation methodology is small.

The second adjustment Staff made was to pull specific investment in wind production out and allocate it on the basis of energy only. As I stated in my rebuttal testimony, the task in CCOSS is allocating a system of production costs that serve both energy and capacity. It is not appropriate to try to isolate specific assets as relating to only a specific requirement of customers on the production system, for the purposes of cost allocation. My position is that the cost represents an embedded system designed to meet both customer energy and customer demand needs and focusing on what those needs are and how they affected overall investment is the better approach.

Q. Even if Staff's approach was viewed as reasonable, are there any issues with how it was performed?

A. Yes. Staff identifies a subset of investment as relating to energy and allocates it as such. Staff made no discernable efforts to identify how much energy represented in the A&E approach should be removed from the A&E calculation before the A&E results were applied to the remaining investment. Said another way, Staff asserts that a certain amount of a customers' energy needs are served by wind investment. But then Staff fails to remove that energy that was served by the wind investment from the remaining production plant allocators. This results in a double counting of energy relative to wind investment and then again against the remaining investment allocated using A&E. This is similar to a fundamental issue with customer specific distribution infrastructure I noted with Staff's approach in my rebuttal testimony.

Q. Staff recommends "customer and rate schedule characteristics related to draws of reactive demand be recorded for study for potential use in allocators, and for potential creation of determinants for customer billing."[14] Please respond to this recommendation.

A. The Company currently measures and bills reactive power for SPS and LPS customers. Our current residential and small commercial meters are not capable of measuring reactive power. To measure reactive power for these smaller customers, we would have to install new meters at a meter cost of approximately $100 and installation cost of approximately $35 per meter. We have over 1.17 million of these meters, creating the potential for an incremental cost to

[14] File No. ER-2022-0337, Sarah L. K. Lange Rebuttal Testimony, at p. 34, ll. 6 – 8.

replace said meters of over $150 million. Staff has either ignored current metering's capability to record this information or overlooked the significant additional cost that would need to be undertaken to acquire a data set that could "potentially" be used. Additionally, Staff appears to misunderstand the reason for installation of the StatCom devices, the allocation of which is a driver of Staff's stated concern about reactive demand. Installation of these devices is heavily driven by the distance between newer production facilities and customers being served, without any obvious change in customer demand of reactive power. Staff also recommends the creation of a sub-account to specifically track these devices. This is unnecessary both for the reasons stated above but also because the Company can estimate the net book value of these devices at any time without creating these additional accounting requirements. As a result, the Commission should not order the Company to record measures of reactive demand for customers other than those already subject to such charges and with the requisite metering in use nor should the Commission order additional accounting requirements for these devices.

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission order, consistent with the Company's prior electric rate case, that the Company has performed a reasonable CCOSS, not only for the purposes of informing allocations of revenue requirement between classes, but for the purposes of informing rate design. Further, I recommend that the Commission not order the Company to undertake the additional data collection efforts recommended by Staff, as they are at an unnecessary level of detail required to inform reasonable CCOSS.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF THOMAS HICKMAN

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

Thomas Hickman, being first duly sworn states:

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

\s\ Thomas Hickman
Thomas Hickman

Sworn to me this 13th day of March, 2023.