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Thomas Hickman
Direct Testimony
File No. ER-2022-0337

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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

THOMAS HICKMAN

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2022

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DIRECT TESTIMONY

OF

THOMAS HICKMAN

FILE NO. ER-2022-0337

I. INTRODUCTION & PURPOSE

Q. Please state your name and business address.

A. Thomas Hickman, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company") as a Regulatory Rate Consultant.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Accounting from Missouri State University in 2010, and subsequently earned a Master's of Accountancy with a Certificate in Forensic Accountancy from Missouri State University in 2012. I worked at BKD, LLP in Springfield, Missouri, as an Audit Associate from July 2012 to November 2013. During this time, I performed financial statement and compliance audits, primarily on health care and financial services clients. In November 2013, I came to work for Ameren Services as an Auditor in Internal Audit. In this role, I performed data analysis and detailed audit testing on a number of different topics, including Sarbanes Oxley testing and testing of Ameren Illinois' Riders. In May 2015, I transferred to the Controller's group as a Financial Specialist in Margin Analysis. In this role, I prepared monthly reporting on actual-to-budget and actual-to-year-over-year margin variances. In December 2015, I transferred back to Internal Audit as an Auditor where I continued working on the same subjects, with a focus on leading audits. In April 2017, I moved into the role of Regulatory Rate Specialist in the Ameren Missouri Regulatory group. In February 2022, I was promoted to my current role of Regulatory Rate Consultant. In my current position, I perform analysis of our Electric Class Cost of Service. This work includes preparing and submitting testimony in electric rate review cases. I also work on surveys and reporting relating to average realization rates and other ad-hoc analyses.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to discuss the development and results of the Company's class cost of service study ("CCOSS").

II. CLASS COST OF SERVICE STUDY

Q. Please summarize the results of the Company's CCOSS.

A. Table 1 below is a summary of the CCOSS results indicating the return on rate base ("RORB") currently being earned on the service being provided to the Company's major retail customer classes based on current rate levels and proposed revenue requirement in this proceeding. A more detailed summary can be found in Schedule TH-D1.

Table 1 – Summary of Class Cost of Service Study Results

Customer Class	Actual RORB	Target RORB
Residential Service	3.85%	7.186%
Small General Service (SGS)[1]	4.88%	7.186%
Large General (LGS) and Small Primary Service (SPS)	7.09%	7.186%
Large Primary Service (LPS)	9.04%	7.186%
Company-Owned Lighting	6.60%	7.186%
Customer-Owned Lighting	-1.27%	7.186%
Total	**5.15%**	**7.186%**

[1] Includes Metropolitan St. Louis Sewer District

Q. What general conclusions can be drawn from the information contained in the table above?

A. Overall, the actual RORB is less than the target RORB across all classes except for LPS, which is greater than target RORB. The Residential and SGS classes are providing a below average rate of return while the LGS, SPS, LPS, and Company-Owned Lighting classes are providing rates of return well above average. Customer-Owned Lighting rates are providing a negative rate of return.

Q. Please describe the method used to equalize rates of return for each customer class, as reflected in your Schedule TH-D2.

A. The total net original cost rate base of each customer class was multiplied by the Missouri electric test year return on rate base proposed by the Company of 7.186% to obtain the required total net operating income for each class. This net operating income was then added to the operating expenses for each class to obtain the total operating revenue for each class required for equal class rates of return. The resulting cost of service of each customer class is set forth on line 6 of Schedule TH-D2.

Q. How are the results of the class cost of service study used?

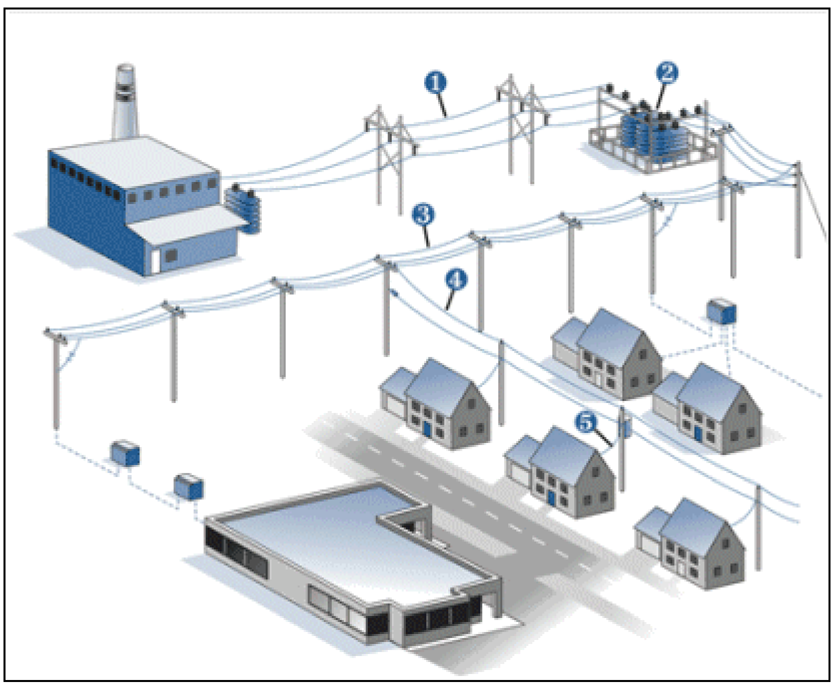
A. The results of the study are utilized as the foundation of revenue allocation and rate design as discussed further in the testimony of Company witnesses Michael Harding and Steven Wills.

i. <u>Class Cost of Service Concepts</u>

Q. As background for additional discussion on the CCOSS the Company is sponsoring in this case, please provide a general description of the various facilities utilized by the Company in producing and delivering electricity to its customers.

A. Figure 1 below is a simplified diagram illustrative of the Ameren Missouri electric system showing how power flows from the generating station and is then transmitted and distributed to the home of a residential customer. Other customers receiving service at higher voltage levels are also served from various points on the same system.

Figure 1 – Simplified Diagram of Electrical System



1. Electrical power is produced at the Company's energy centers at voltage levels ranging from 11,000 to 23,750 volts. To achieve transmission operating economies, this voltage is raised, or stepped up, by power transformers at the energy center sites to voltages generally ranging from 138,000 to 345,000 volts for transmission to the Company's bulk substations, which are strategically located throughout its service area.

2. At a substation, the electricity's voltage is lowered so that it can travel over the distribution system. Although this diagram does not show this level of detail, there are two main classes of substations: bulk substations and distribution substations. The bulk substations are used to

lower the voltage but still keep the voltage relatively high (usually 34,500 or 69,500 volts) while the distribution substations lower the voltage even further (4,160 to 13,800 volts) to distribute power closer to customer premises.

- The Company serves 80 customers at voltages above the 13,800 volt level. These are referred to as "high voltage" or Rider B customers.
- Approximately 648 large non-residential customers receive service at 4,160 to 13,800 volts and are referred to as "primary" voltage customers.

3 Main distribution power lines, typically 3-phase circuits, bring electricity into communities.

4 Local distribution power lines serve neighborhoods and individual customers.

5 Service lines carry electricity from pole-mounted or pad-mounted transformers — which lowers the voltage again — to customer premises.

- Residential customers are served at either 120 or 240 volts depending upon the customer's service entrance panel size and connected appliances.
- Non-residential customers on the Company's SGS or LGS rates are served at voltages from 120 to 480 volts due to the wide variety of electricity consuming devices utilized by such customers.

Q. Are you using the term "lines" in a general sense in your description of the Ameren Missouri generation, transmission, and distribution system?

A. Yes. Those "lines" may be overhead conductors or underground cables. Overhead "lines" include all poles, towers, insulators, cross arms, and all other hardware associated with such installations. Underground "lines" include direct buried cable, as well as that installed in single or multi-duct conduit, and other associated hardware.

ii. <u>CCOSS Process</u>

Q. Why is a CCOSS performed?

A. A CCOSS is performed to allocate costs to customer rate classes on the basis of which customer rate class is causing them. In other words, a CCOSS is a tool for designing rates that equitably assign cost responsibility to each customer rate class. The allocated costs can vary significantly between customer classes depending upon the facilities required to serve each class of customers and the nature of their use of the Company's electric system. As mentioned above and by way of example, the Company's approximately 648 primary voltage customers receive service at 4,160 to 13,800 volts, and require different facilities to serve them, than SGS non-residential customers served at voltages from 120 to 480 volts. The results of the study set a target "cost to serve" or "revenue requirement" for each rate class, which helps guide rate design and pricing changes proposed by the Company within each rate classification so that the rates of each class reasonably reflect the costs caused by that class.

Q. What rate classes were included in the Company's CCOSS?

A. The Company's study includes the following existing rate classes: Residential or 1(M); Small General Service or 2(M); Large General Service or 3(M); Small Primary Service or 4(M); Street & Outdoor Area Lighting – Company-Owned or 5(M); Street & Outdoor Area Lighting – Customer-Owned or 6(M); and Large Primary Service or 11(M) classes. These rate classes were established to group customers with similar service voltages, usage, and demands together, and therefore, the rate classes assist in distinguishing the different costs caused by each class.

Q. Please explain the steps in performing a CCOSS.

A. The three major steps to develop a CCOSS are:

1. Functionalization — the process of assigning the Company's total revenue requirement to specified utility functions, i.e., production, transmission, distribution, etc. This step is done mainly in the jurisdictional cost of service utilizing the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts for Electric Utilities.

2. Classification — is a further refinement of the functionalized revenue requirement. Cost classification identifies the various elements of functionalized revenue, on a cost-causative basis, as demand-related, energy-related, or customer-related.

3. Allocation — is the process of allocating the classified costs among the Company's customer rate classes. Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatt-hour or kWh) requirements at the generation level of the Company's system, which includes applicable system energy losses. The use of this common point on the Company's system to allocate such costs ensures that each customer class will be assigned the appropriate portion of the Company's total incurred variable fuel and purchased power costs. Customer-related costs are normally allocated on the basis of the number of customers associated with each rate class. In some instances where non-residential customers have multiple or advanced metering installations, weighting factors may also be used. In addition, where specific costs can be identified as being attributable to one or more specific customer class(es), such as credit and collection expenses, a direct assignment of such costs may be made.

iii. <u>Functionalization and Classification</u>

Q. Please describe the components of costs and revenues that are contained in the class cost of service study that the Company is filing in this case.

A. A traditional cost of service study incorporates the aggregate jurisdictional (Missouri or FERC) accounting and financial data normally submitted to a regulatory commission by a utility in support of a request for an adjustment in its overall rate levels. Such a study is required to determine the level of revenues necessary for the Company to recover its operating and maintenance expenses through rates, depreciation applicable to its investment in utility plant, property taxes, income and other taxes, and provide a fair rate of return to the Company's investors. The Company's CCOSS allocates, or distributes, these total jurisdictional costs to the various customer classes in a cost-based manner that fairly and equitably reflects the cost of the service being provided to each customer class.

Q. What major categories of costs were examined in the development of the CCOSS?

A. All elements of the Company's Missouri jurisdictional rate base investment and expenses during the test year (April 2021 through March 2022) and pro forma adjustments described by Company witness Mitchell Lansford in his direct testimony were analyzed in detail for the purpose of allocating such items to the Company's customer classes. This analysis consisted of classifying the various elements of costs into their customer-related, energy-related, and demand-related cost categories.

Q. Why are the Company's costs classified into these three categories?

A. It is generally accepted within the industry that the costs in each of these categories result from different cost causation factors and hence should be allocated among the various customer classes by different methodologies which consider such cost causation.

Q. What are customer-related costs?

A. Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of the extent to which such service is utilized. Examples of such costs include billing, postage, customer accounting and customer service expenses, investment in meters and service lines, as well as a portion of line transformers, and other distribution system facilities. The customer components of the distribution system are those costs necessary to simply provide reliable and safe service to a customer, without the consideration of the amount of the customer's electrical use.

Q. What are energy-related costs?

A. Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kWh) and consist primarily of fuel, fuel handling, interchange power costs, and a portion of production plant maintenance expenses.

Q. What are demand-related costs, the third category of costs to which you referred?

A. Demand-related costs are rate base investment and related operating expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. During such peak periods, this usage is expressed in terms of the customer's maximum power consumption, commonly referred to as "kilowatts of demand". As defined, demand-related costs include those costs in excess of the aforementioned customer and energy-related costs. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant.

iv. <u>Minimum Distribution System Study</u>

Q. What is a Minimum Distribution System Study?

A. The distribution system is commonly classified into both demand and customer-related costs. However, many of the distribution system components need to be apportioned between the customer- and demand-related classifications. In order to do so, one must determine how much of the distribution system is needed to make service available versus how much of the distribution system is needed to meet the maximum demand requirements of each customer class. The Minimum Distribution System Study is an analytical process that apportions the distribution system into the customer- and demand-related classifications.

Q. What approach is the Company using to apportion the distribution system between the customer-related and demand-related classifications?

A. In this case, as it did in the Company's three prior electric general rate review cases, the Company has used the "Minimum-Size Method" outlined in the National Association of Regulatory Utility Commissioners ("NARUC") January 1992 Cost Allocation Manual.

Q. What is the process to develop a Minimum-Size Distribution System Study?

A. As prescribed by the NARUC Electric Utility Cost Allocation Manual, developing the Minimum-Size Distribution System Study involves determining the minimum size pole, conductor, cable, and transformer that is currently installed or used by the Company – the size of these assets that would generally be deployed across the system if there was not a need to meet higher levels of customer demand, the costs of which are classified as demand-related. This equipment should be consistent with the safety codes and any other requirements the Company designs for and would take into account the impact of snow and ice, minimum electrical clearances, etc. The average book cost for that minimum standard item of equipment normally determines the customer-related cost of all installed units. In situations where items of equipment have a lower average book cost than the minimum standard item, the lower average book cost of those items was utilized. Also included in the minimum-size distribution system costs are safety/reliability equipment, like protective relays and lightning arrestors as well and other basics like land and fencing — essentials necessary for providing electrical service regardless of customer usage characteristics.

Q. How were the customer-related costs of FERC Account 364 — poles, towers, and fixtures — determined using the minimum-size method?

A. First, the average installed book cost of the minimum height pole currently being installed for the Company's distribution system was determined through discussions with Ameren Missouri's Distribution Planning Group. Then, the average book cost was multiplied by the number of poles to find the customer-related cost component. Poles with average book cost less than the minimum height pole are included at their lower cost. Required fencing and land rights are also included as customer-related costs. The results of a historic analysis, previously referred to as the "Vandas study," assist in further dividing certain distribution system costs into high voltage, primary voltage, and secondary voltage categories and allocated to the classes accordingly.

Q. How were the customer-related costs of FERC Account 365 — overhead conductors and devices — determined?

A. The current minimum size conductor being installed was determined through discussions with the Distribution Planning Group. A weighted average cost of conductor was developed by including every foot of conductor with an average book cost greater than or equal to the average book cost of the minimum size conductor at the average book cost of the minimum size conductor. Every foot of conductor with an average book cost less than that of the minimum size conductor was included at its lesser average book cost. This weighted average cost was multiplied by the number of circuit miles and multiplied by two[2] to determine the customer-related

[2] While many of the circuits are three-phase circuits (three wires carrying current, one neutral), the minimum size standard cost is that of a one-phase circuit (one current carrying conductor, one neutral), thus the multiplication of two in the calculation.

cost component for this account. Protective equipment such as lightning arrestors, re-closers, and switches are also included in the customer component. The number of circuit miles was broken down between circuit miles of high voltage and primary voltage, and in turn, the respective number of circuit miles was used to divide these costs into high voltage and primary voltage categories. Since the count of circuit miles used to determine the customer-related costs did not include secondary voltage circuits, no secondary overhead costs were included in this customer-related portion. The historic analysis has shown that a relatively immaterial amount of the overall cost in this account related to secondary voltage, approximately 2.5%, so no further steps were taken to include secondary voltage costs in the customer-related category at this time.

Q. How were the customer-related costs of FERC Accounts 366 and 367 — underground conduits, conductors and devices — determined?

A. For Account 367 (underground conductors and devices), the average minimum size underground conductor was determined through discussions with the Distribution Planning Group. A weighted average cost of conductor was developed consistent with the process described for Account 365 above. This weighted average cost of the minimum size primary cable was multiplied by the number of underground circuit miles to determine the customer-related cost components for these accounts. As with the other accounts, protective equipment was also included in the customer component. The number of underground circuit miles was broken down between underground circuit miles of high voltage and primary voltage. This breakdown was used to divide these costs into high voltage and primary voltage categories. Since the count of underground circuit miles used to determine the customer-related costs did not include underground secondary voltage circuits, no secondary underground costs were included in this customer-related portion. Historic analysis has shown that a relatively immaterial amount of the overall cost in this account related to secondary voltage, approximately 9%, so no further steps were taken to include secondary voltage costs in the customer-related category at this time. Account 366 (underground conduits) used the same customer-related percentage as Account 367.

Q. How were the customer-related costs of FERC Account 368 — line transformers — determined?

A. The minimum size transformer currently being installed was determined through discussions with the Distribution Planning Group. The average cost of the minimum size transformer was multiplied by the number of transformers in the plant account to determine the customer-related cost components for this account.

Q. How were the customer-related costs of FERC Account 369.1 — overhead services — determined?

A. The current minimum size conductor being installed as an overhead service was determined through discussions with the Distribution Planning Group. The average book cost of that conductor was determined. Every foot of conductor with an average book cost less than that of the minimum size conductor was included at its lesser average book cost. The amount of feet of conductor remaining in the account was multiplied by the average book cost of the minimum size conductor to determine the customer-related cost components for this account. As with the other accounts, protective equipment was also included in the customer component.

Q. How were the customer-related costs of FERC Account 369.2 — underground services — determined?

A. Underground services followed the same process as overhead service, detailed above, to determine customer-related costs for this account.

v. <u>Cost Allocations</u>

Q. After the Company's costs are categorized into one of the three major classifications, how are they allocated to the various rate classes?

A. Customer-related costs are normally allocated on the basis of the number of customers in each rate class. In some instances where non-residential customers have multiple metering installations, weighting factors may also be used. Where specific costs can be identified as being attributable to one or more specific customer classes, such as credit and collection expenses, a direct assignment of such costs will be made. Finally, for costs that can be identified as applying to specific customer classes on the basis of the voltage served within that class, counts of customers served at that voltage were used.

Energy-related costs are allocated to the customer classes on the basis of their respective energy (kWh) requirements at the generation level of the Company's system, which includes applicable system energy losses.

Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Demand-related transmission costs are allocated to customer classes on a 12 coincident peak ("CP") basis, as that methodology is consistent with the method utilized to assign cost responsibility of the demands of the Ameren operating companies and all of the other utilities participating in the Midcontinent Independent System Operator, Inc. ("MISO"), per MISO’s Attachment O Rate Formulae in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff on file at the FERC. Demand-related production costs are allocated on the basis of the Average and Excess ("A&E") Demand Method referenced in the NARUC Cost Allocation Manual. As not all customers have demand meters, customer class and individual customer kilowatt demand data is obtained from the Company's on-going load research program.

Q. After determining customer, energy and demand allocation factors for the various components of the Company's costs, what was the next step?

A. The next step was to apply the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The aggregation of such cost allocations indicates the total annual costs, or annual revenue requirement, at equalized rates of return associated with serving a particular customer class. The operating revenues of each customer class minus its total operating expenses provide the resulting net operating income for each class. This net operating income divided by the rate base allocated to each class will indicate the percentage rate of return being earned by the Company from a particular customer class.

Q. Please describe how costs and expenses were allocated to the customer classes.

A. The original cost and depreciation reserves of the major functional components of the Company's electric rate base were allocated to customer classes as described below. The resulting dollar amount (in thousands) allocated to each class is shown in Schedules TH-D1 and TH-D2.

(1) <u>Production Plant</u>. Production plant was allocated to each customer class on the basis of the Four Non-Coincident Peak ("4 NCP") Average and Excess Demand allocation factors for each customer class at the Company's energy centers. Non-coincident peak demand is the customer class’s maximum load at any time of the study period regardless of the time of occurrence or magnitude of the Company’s system peak. The 4 NCP demands are the averages of the customer class’s four maximum monthly loads. A manual adjustment was made so that the Lighting Classes,

5(M) and 6(M), only received an allocation of excess for 1 of their 4 non-coincident peaks, because their 4 non-coincident peaks occur during off-peak overnight periods. For the majority of other classes and the system as a whole, three of the four periods included in the 4 NCP calculation are summer daytime periods. This adjustment to the Lighting Classes' NCP more accurately reflects the lower contribution that lighting load makes to the summer peak loads that tend to drive investment in production capacity.

(2) Transmission Plant. Transmission line and substation investment was allocated to each customer class on the basis of the Twelve Coincident Peak ("12 CP") demands of each class at their point of input to the Company's transmission system. Coincident peak demand is the customer class’s load at the time of occurrence of the Company’s system peak. The 12 CP demands are the customer class’s twelve monthly loads at the time the Company’s twelve monthly system peaks occur. Such 12 CP allocation is consistent with the development of the Ameren system transmission revenue requirement, under the MISO Attachment O Rate Formulae in the Open Access Transmission, Energy and Operating Reserve Markets Tariff on file at the FERC.

(3) Distribution Plant. The Company's Distribution Plant was allocated to each customer class based upon the results of an analysis of the functions performed by the facilities in Distribution Plant Accounts 360–369. This analysis determined the breakdown of each account based on its customer-related and demand-related components. The demand-related component was further broken down by high voltage, primary voltage, and secondary voltage demand-related functions. High voltage is 34.5 kilovolts up to 69 kilovolts, primary distribution voltage is above 600 volts up to 34.5 kilovolts, while secondary distribution voltage is 600 volts or less.

The portion of the Distribution Plant accounts classified as customer-related costs was derived using the Minimum-Size Method described above. The remaining, or demand-related, portion of the Company's Distribution Plant accounts were split among the high voltage, primary voltage, and secondary voltage levels on the basis of a review of the functional utilization of various equipment and hardware in such accounts. For all Distribution Plant accounts, with the exception of Account 369, Services, the demand-related investment in each account was allocated to each customer class on the basis of the non-coincident peak demand of each class at the appropriate high voltage, primary, and secondary voltage levels.

The demand-related investment in Account 369, Services, was allocated to each customer class on the basis of the sum of the maximum demand of all customers in the class at the secondary voltage level. The maximum individual customer demand was used to reflect the fact that the maximum demand of individual customers dictates the sizing of their service facilities.

Distribution Account 370, Meters, was allocated to each of the customer classes by allocation factors that weigh the results of multiplying the current cost of a metering arrangement by the number of meters installed in that arrangement, by class. This process was performed on counts of customers who have advanced metering infrastructure ("AMI") meters utilizing AMI current costs separately from counts of customers who have automated meter reading ("AMR") meters utilizing AMR current costs. These results were combined into a composite allocator and applied to the relevant costs. All metering cost is classified as customer-related.

Account 371-1, Installation on Customer's Premises Substation Equipment, was allocated to the Primary classes on the basis of such customers' historical use of these facilities.

Account 373, Street Lighting & Signal Systems, was directly assigned to the Company-Owned Lighting or 5(M) class.

(4) General Plant. General Plant was allocated to each customer class on the basis of the proportion of labor expense allocated to each class.

(5) Accumulated Reserves for Depreciation. Because such reserves are functionalized by type of plant, these reserves were allocated on the same basis as the allocation of the various plant accounts, as described above.

(6) Materials & Supplies. This component consists of fuel inventories and general materials and supplies related to energy centers, transmission facilities, and distribution facilities. Fuel inventories, the energy centers, and transmission facilities materials are directly related to the generation and transmission of energy and were therefore allocated on the basis of each customer class's respective energy (kWh) requirements at the generation level of the Company's system, which includes applicable system energy losses. The local distribution materials were allocated on the basis of the composite allocation of Distribution Plant, as previously described.

(7) Cash Working Capital. This item is related primarily to operating expenses and was therefore allocated to each customer class in proportion to the total operating expenses allocated to each class.

(8) Customer Advances for Construction and Deposits. This component of rate base was assigned to each customer class on the basis of an analysis of the sources of such deposits in Missouri.

(9) Total Accumulated Deferred Income Taxes. This component is related primarily to investment in property and was therefore allocated to each customer class on the basis of allocated gross plant.

Q. As generation (production) plant comprises more than half of the Company's total plant investment, please summarize the most common cost allocation methodologies employed within the electric utility industry for the allocation of generation plant.

A. The most common and generally accepted methodologies used for the allocation of generation plant can be grouped into the following three categories:

Coincident Peak – Costs are allocated on the basis of the relative customer class demands at the time of occurrence of the company's system peak during the period of study (referred to as the "CP" method). One or more system peak hours, or a number of monthly or seasonal system peaks, are normally used in applying the CP methodology. For instance, transmission costs are allocated using a "12 CP" method, which is based on averaging the test year's 12 monthly coincident peaks.

Non-Coincident Peak – Costs are allocated on the basis of the maximum peak demand of each customer class at any time during the study period, without regard to the time of occurrence or magnitude of the Company's coincident system peaks (referred to as the "NCP" method). As with the CP method, the NCP method can employ one or more customer class peaks in its application. As a simple example consider the Lighting Classes, the summer street lighting non-coincident peak occurs at night when the street lights are active, yet street lighting demand is zero at the time of the summer system coincident peak (usually at 4 p.m. or 5 p.m.).

Average and Excess – Costs are allocated based upon a weighting of average class demand throughout the year (kilowatt-hours ÷ 8,760 hours) and class "excess" demand(s) (referred to as the "A&E" method). The excess demand(s) used in this determination are the class NCP demand(s) in excess of the average class demand during the study period. As with the CP and NCP methodologies, this method can also employ the use of one or more customer class NCP demands to determine class excess demands. Average class demands are weighted by the Company's annual system load factor ("LF") (LF = average demand ÷ peak demand) and excess class demands are weighted by the complement of the load factor (1.0 – LF) in the development of cost allocation factors using this methodology.

Q. Which cost allocation methodology is the Company using for production plant in its class cost of service study in this case?

A. The Company is utilizing the 4 NCP version of the A&E demand methodology for allocating production plant in this case.

Q. From a generation perspective, what were the considerations associated with the Company's election to utilize the A&E demand allocation methodology for production plant in this case?

A. Two major factors associated with generation capacity planning prompted the use of the A&E demand cost allocation methodology. Generally, system peak demands and, to a somewhat lesser extent, excess customer demands, are the motivating factors that influence the <u>amount</u> of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the <u>type</u> of capacity (base, intermediate, or peaking) that the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt-hours, that will be required to be generated by such capacity, i.e., the generation unit's utilization factor. A cost allocation methodology that gives weight to both class peak demands and class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt-hours divided by total hours in the year (8,760 hours), and the excess NCP demands of each class.

As indicated earlier, the Company's A&E cost allocation study used both the 4 NCP and average class demands in the determination of class excess demands.

Q. Is there also quantitative support for the Company's selection of the 4 NCP version of the A&E demand allocation methodology for production plant?

A. Yes. The 4 NCP version of the A&E methodology, which uses the four maximum non-coincident monthly peak demands for each customer class during the test year, was selected due to the fact that 15 of the 16 maximum 4 NCP monthly demands for the Company's major (i.e., non-lighting) customer classes occurred during the Company's summer peak demand months of June - September. The use of the 4 NCP demand option, rather than a lesser number of monthly NCP demands, also prevents the demand allocator for any customer class from being unduly influenced by any extreme demand in a given month.

Q. How did you allocate the electric test year operating and maintenance expenses to the customer classes?

A. With very few exceptions, operating and maintenance expenses were allocated to the customer classes on the same basis as the related investment in plant was allocated. This type of allocation employs the familiar and widely used "expenses follow plant" principle of cost allocation. For example, the allocator for Transmission Lines was used to allocate Transmission Line expenses. The only exceptions to this procedure are as follows:

(1) Production Expenses. This item consists of two categories: (a) fixed, which includes standard operating and maintenance ("O&M") crews, nuclear support staff and a portion of non-labor production plant O&M expenses; and (b) variable, which includes fuel, fuel handling, interchange power costs, and the remaining portion of non-labor production plant O&M expenses. The fixed portion of production expenses was allocated on the same basis as Production Plant,

while the variable portion was allocated using a variable allocator based on the megawatt-hours required at the generator to provide service to each respective customer class.

(2) Customer Accounts Expenses. An analysis of Account 903, Customer Records and Collection Expenses, indicated that approximately 24% of such expenses are devoted to credit and collection activities. Therefore, this portion of Account 903 and all of Account 904, Uncollectible Accounts, were allocated to each customer class on the basis of the annual level of collection activities applicable to each customer class. The remaining 76% of Account 903 expense was allocated to each customer class utilizing a weighted billing and customer accounts administration allocation factor. Account 902, Meter Reading Expenses, was allocated to each class by the number of meters in each customer class, consistent with the process previously described for Account 370, Meters. This allocation of Meter Reading Expenses is only based on counts and allocation of AMR meters. Account 901, Supervision, was allocated to each class on the basis of the composite allocation of all other Customer Accounts Expenses.

(3) Customer Service & Sales Expenses. These expenses were allocated to each customer class using the composite allocation of Customer Accounts Expenses.

(4) Interest on Customer Surety Deposits. These expenses were allocated to each customer class on the basis of the previously allocated Customer Advances and Deposits, since advances and deposit accounts are typically representative of where surety deposits are booked.

(5) Administrative and General ("A&G") Expenses. With the exception of property insurance expense, A&G expenses were allocated to the customer classes on the basis of the class composite distribution of previously allocated labor expense. Property insurance expense was allocated using a composite allocator based on gross production, transmission, distribution, and general plant.

(6) Transmission Operating Expenses. MISO Schedule 26A charges, which are related to the large regional Multi-Value Projects, are allocated to the Company on an energy basis, therefore those costs are allocated in the class cost of service based on the megawatt-hours required at the generator to provide service to each respective customer class. The remaining transmission operating expenses are allocated on the same basis as the related investment in plant, a 12 CP basis.

Q. How did you allocate off-system sales revenues?

A. Off-system sales revenues were allocated to each class using their variable production allocation factor based on the megawatt-hours required at the generator to provide service to each respective customer class. This allocation is consistent with the Commission's Report and Order in File No. ER-2010-0036.[3]

Q. How did you allocate the test year depreciation expenses?

A. Since depreciation expenses are functionalized and are directly related to the Company's original cost investment in plant, depreciation expense within each function was allocated to each customer class on the basis of the previously allocated original cost production, transmission, distribution and general plant.

Q. How did you allocate Plant-in-Service Accounting ("PISA") amortization expense?[4]

A. The PISA regulatory asset, as described by witness Lansford, is made up of deferred depreciation, return on investment, and carrying costs. Depreciation is the primary driver of the asset balance, and therefore, the amortization expense. The PISA balance was divided into the same buckets as depreciation expense based on the FERC accounts of the underlying assets. Each bucket was allocated using the same allocator as the related depreciation expense.

[3] File No. ER-2010-0036, Report and Order, p. 87, paragraph 20, issued May 28, 2010.
[4] As authorized by Section 393.1400, RSMo.

Q. How did you allocate the test year real estate and property taxes?

A. Real estate and property tax expenses are directly related to the Company's original cost investment in plant, so these expenses were allocated to customer classes on the basis of the sum of the previously allocated production, transmission, distribution and general plant investment.

Q. How did you allocate the test year income taxes?

A. Income tax expense is directly related to the Company's net operating income as a proportion of its net rate base investment, i.e., rate of return on its net original cost rate base. As a result, income taxes were allocated to each class on the basis of the net original cost rate base allocated to each customer class.

III. LIGHTING CLASS DESCRIPTIONS AND LIGHTING COST OF SERVICE

Q. Can you describe the difference between the 5(M) and 6(M) lighting classes?

A. Yes. The difference between the 5(M) and 6(M) rate classes is ownership of the lighting fixtures and poles. The Company owns, operates, and maintains the lighting fixtures and post top poles for the 5(M) class, and customers taking service under the 6(M) class purchased, and therefore own, the lighting fixtures and poles used to serve them. Thus, the main reason for the difference in rates for these two classes is Ameren Missouri's non-energy related cost of providing facilities used to serve the 5(M) class.

Q. Is the Company responsible for the maintenance of any lights in the 6(M) class?

A. As stated above, the Company owns, operates, and maintains the lighting fixtures and post top poles for all of the 5(M) customers. The Company provides limited maintenance to facilities in its 6(M) class that are served on the energy and maintenance rates; however, non-standard maintenance items (e.g., wire, bracket, fixture, post top pole, etc.) for the 6(M) class are the responsibility of the customer because the customer owns the facilities and provides the fixtures and parts necessary to maintain those facilities. When repairs are needed, the Company is responsible for disconnecting and reconnecting lines between the lights and the distribution system so that the 6(M) customer can repair its own facilities. Therefore, maintenance rates for the 6(M) class are based on the costs associated with only limited activities performed by the Company.

Q. How does the lighting CCOSS differ from the study conducted covering all classes?

A. The study conducted covering all classes provides a basis for allocating and/or assigning the Company's total jurisdictional cost of providing electric service to Ameren Missouri's customers in a manner that reflects cost causation. While I used the study covering all classes as a starting point for my analysis of the lighting classes, I further analyzed the lighting classes down to the fixture level to develop cost reflective rates for all of the different lights permitted by our tariffs.

Q. Why is it useful to perform a separate CCOSS for the two lighting classes?

A. The lighting classes are different from the other rate classes as a result of the large variety of services that are available to lighting customers. As a result, it is appropriate to conduct a CCOSS within these two classes to allocate the costs to the different types of fixtures, and also to the different service levels such as energy only service and energy, and maintenance service on customer-owned fixtures in the 6(M) rate class.

Q. If you were to fully align the revenue requirements of the 5(M) and 6(M) classes with the revenues calculated by the lighting CCOSS, how much would they need to change?

A. The table below shows the revenue requirement shifts that would be required to fully align the 5(M) and 6(M) classes with their cost to serve.

	CCOSS	Current	Change Required
5(M)	$ 41,366,2992	$ 39,010,796	6.0%
6(M)	$ 4,469,736	$ 2,933,100	52.4%

Q. How are the results of the lighting CCOSS being used to inform the Company's rate design proposal in this case?

A. Please refer to the testimony of witness Harding for specific rate recommendations based in part on this analysis.

IV. RIDER B REASONABLENESS STUDY

Q. In the Company's last electric general rate review, File No. ER-2021-0240,[5] the Commission directed the Company to "study the reasonableness of the calculations and assumption [sic] underlying Rider B and to file the results of that study as part of its direct filing in its next general rate case." Has the Company performed such a study?

A. Yes, it has.

Q. Please describe Rider B.

A. In File No. ER-2021-0240, Staff stated "Rider B is a credit received by customers who are billed at primary but who own their own substation equipment. It is sized to compensate those customers for the revenue requirement associated with customer-specific substations that did not have to be built."[6] This description of Rider B is inaccurate. Rider B is not sized to compensate

[5] File No. ER-2021-0240, Report and Order, pp. 33-34, issued February 2, 2022.
[6] File No. ER-2021-0240, Hearing Ex. 205, Staff's Class Cost of Service Report, p. 24, lines 11-13, filed 9/17/2021.

customers for the marginal cost avoided on investment the Company would have otherwise had to make. Rider B is sized to acknowledge the fact that primary rates are established assuming some use of distribution substation investment made by the Company. As these customers own their own substation equipment, the Rider B credit serves to adjust those customer's effective rates down so that their rate does not reflect that investment in plant that is not utilized to serve these customers. In other words, allocating Rider B customers the costs of other substation equipment used to serve other customers does not follow cost causation principles. Therefore, the calculation of the Rider B credit has no direct relationship to how substations serving individual customers are allocated.

Q. Please describe your study of the reasonableness of the calculations and assumptions underlying Rider B.

A. With the purpose of Rider B described above in mind, I calculated an estimate of the revenue requirement attributable to distribution substations (FERC Account 362). This estimate was made up of the return and taxes calculated against the rate base of Account 362 (original book value, less reserves for depreciation and accumulated deferred income tax), O&M from FERC accounts 582 and 592 (the accounts that relate to distribution substations), annual depreciation expense related to account 362, and a portion of property taxes related to account 362.

I took this revenue requirement amount times the Class NCP Demand at the High Voltage Level (A.F.8) for the SPS and LPS classes, consistent with how the underlying capital and O&M are allocated, in order to determine the revenue requirement associated with substations that are allocated to these classes. This break out of revenue requirement was divided by the combined total billing demand of the SPS and LPS classes to determine an implicit rate applicable to these classes that reflects this revenue requirement. Rider B customers implicitly pay this amount by being assessed standard tariff charges applicable to their rate classes. The result was a calculated discount of $1.34 per kW. Rider B is broken in to two different rates, one for customers served at 115 kV and above (currently set at $1.47/kW), and one for customers served at 34.5 or 69 kV (current set at $1.24/kW). The calculated result from the study should most closely match the 115 kV and above rate, as those customers do not utilize any substations in the 362 account, whereas customers served at 34.5 or 69 kV would utilize a subset of those substations but not all of them – and far less than customers served at standard primary or secondary voltages. Although the calculated discount of $1.34 per kW is slightly different from the $1.47 per kW discount currently being given to those customers, because the Company is recommending equal percentage increases for all customer classes, the Company recommends making an equal percentage adjustment to Rider B consistent with all customer classes. Please refer to the direct testimony of witness Harding for more specific information on the equal percentage of increase allocation proposal. The Company will consider this study's results in future rate making proposals and will look for opportunities to bring this specific discount more in line with the CCOSS results consistent with other class adjustments in future cases.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AMEREN MISSOURI
CLASS RATES OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED MARCH 2022

TITLE: SUMMARY CURRENT ROR RESULTS ($000'S)

		MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LIGHTING COMPANY OWNED	LIGHTING CUST. OWNED
1	BASE REVENUE	$ 2,717,585	$ 1,373,010	$ 305,323	$ 791,487	$ 205,821	$ 39,011	$ 2,933
2	OTHER REVENUE	$ 84,989	$ 46,549	$ 9,613	$ 22,287	$ 5,336	$ 1,113	$ 91
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 509,488	$ 220,215	$ 51,990	$ 178,882	$ 56,586	$ 1,175	$ 640
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,312,062	$ 1,639,774	$ 366,926	$ 992,656	$ 267,743	$ 41,299	$ 3,665
7								
8	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 1,746,220	$ 857,593	$ 186,767	$ 532,688	$ 152,375	$ 14,267	$ 2,530
9	TOTAL DEPR AND AMMORT EXPENSES	$ 847,997	$ 469,870	$ 99,397	$ 216,343	$ 48,508	$ 12,696	$ 1,183
10	REAL ESTATE AND PROPERTY TAXES	$ 172,314	$ 96,522	$ 20,369	$ 42,906	$ 9,383	$ 2,905	$ 229
11	INCOME TAXES	$ (73,867)	$ (40,399)	$ (8,688)	$ (19,235)	$ (4,255)	$ (1,183.81)	$ (106.99)
12	PAYROLL TAXES	$ 21,758	$ 12,049	$ 2,444	$ 5,580	$ 1,309	$ 333	$ 43
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,714,422	$ 1,395,634	$ 300,289	$ 778,282	$ 207,320	$ 29,018	$ 3,878
17								
18	NET OPERATING INCOME	$ 597,640	$ 244,140	$ 66,636	$ 214,374	$ 60,423	$ 12,281	$ (214)
19								
20	GROSS PLANT IN SERVICE	$ 23,278,954	$ 13,036,443	$ 2,746,567	$ 5,800,936	$ 1,271,883	$ 391,658	$ 31,468
21	RESERVES FOR DEPRECIATION	$ 9,221,602	$ 5,308,480	$ 1,085,559	$ 2,172,069	$ 476,391	$ 167,576	$ 11,526
22								
23	NET PLANT IN SERVICE	$ 14,057,353	$ 7,727,963	$ 1,661,008	$ 3,628,866	$ 795,492	$ 224,083	$ 19,941
24								
25	MATERIALS & SUPPLIES - FUEL	$ 286,344	$ 123,766	$ 29,219	$ 100,536	$ 31,803	$ 660	$ 360
26	MATERIALS & SUPPLIES -LOCAL	$ 281,607	$ 180,540	$ 34,403	$ 48,004	$ 6,523	$ 11,631	$ 506
27	CASH WORKING CAPITAL	$ (31,955)	$ (15,694)	$ (3,418)	$ (9,748)	$ (2,788)	$ (261)	$ (46)
28	CUSTOMER ADVANCES & DEPOSITS	$ (19,362)	$ (6,527)	$ (5,357)	$ (6,452)	$ (943)	$ (76)	$ (7)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,968,207)	$ (1,662,651)	$ (350,867)	$ (739,080)	$ (161,627)	$ (50,039)	$ (3,944)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 11,605,779	$ 6,347,397	$ 1,364,988	$ 3,022,126	$ 668,459	$ 185,999	$ 16,810
32								
33	RATE OF RETURN	5.15%	3.85%	4.88%	7.09%	9.04%	6.60%	-1.27%

AMEREN MISSOURI
CLASS RATES OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED MARCH 2022

	TITLE: SUMMARY EQUAL ROR ($000's)	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LIGHTING COMPANY OWNED	LIGHTING CUST. OWNED
1	BASE REVENUE	$ 3,033,214	$ 1,628,352	$ 346,099	$ 814,927	$ 198,000	$ 41,366	$ 4,470
2	OTHER REVENUE	$ 84,989	$ 46,549	$ 9,613	$ 22,287	$ 5,336	$ 1,113	$ 91
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 509,488	$ 220,215	$ 51,990	$ 178,882	$ 56,586	$ 1,175	$ 640
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,627,691	$ 1,895,116	$ 407,702	$ 1,016,096	$ 259,922	$ 43,654	$ 5,201
7								
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$ 1,746,220	$ 857,593	$ 186,767	$ 532,688	$ 152,375	$ 14,267	$ 2,530
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 847,997	$ 469,870	$ 99,397	$ 216,343	$ 48,508	$ 12,696	$ 1,183
10	REAL ESTATE AND PROPERTY TAXES	$ 172,314	$ 96,522	$ 20,369	$ 42,906	$ 9,383	$ 2,905	$ 229
11	INCOME TAXES	$ 5,411	$ 2,960	$ 636	$ 1,409	$ 312	$ 87	$ 8
12	PAYROLL TAXES	$ 21,758	$ 12,049	$ 2,444	$ 5,580	$ 1,309	$ 333	$ 43
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,793,700	$ 1,438,992	$ 309,614	$ 798,926	$ 211,886	$ 30,288	$ 3,993
17								
18	NET OPERATING INCOME	$ 833,991	$ 456,124	$ 98,088	$ 217,170	$ 48,035	$ 13,366	$ 1,208
19								
20	GROSS PLANT IN SERVICE	$ 23,278,954	$ 13,036,443	$ 2,746,567	$ 5,800,936	$ 1,271,883	$ 391,658	$ 31,468
21	RESERVES FOR DEPRECIATION	$ 9,221,602	$ 5,308,480	$ 1,085,559	$ 2,172,069	$ 476,391	$ 167,576	$ 11,526
22								
23	NET PLANT IN SERVICE	$ 14,057,353	$ 7,727,963	$ 1,661,008	$ 3,628,866	$ 795,492	$ 224,083	$ 19,941
24								
25	MATERIALS & SUPPLIES - FUEL	$ 286,344	$ 123,766	$ 29,219	$ 100,536	$ 31,803	$ 660	$ 360
26	MATERIALS & SUPPLIES -LOCAL	$ 281,607	$ 180,540	$ 34,403	$ 48,004	$ 6,523	$ 11,631	$ 506
27	CASH WORKING CAPITAL	$ (31,955)	$ (15,694)	$ (3,418)	$ (9,748)	$ (2,788)	$ (261)	$ (46)
28	CUSTOMER ADVANCES & DEPOSITS	$ (19,362)	$ (6,527)	$ (5,357)	$ (6,452)	$ (943)	$ (76)	$ (7)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,968,207)	$ (1,662,651)	$ (350,867)	$ (739,080)	$ (161,627)	$ (50,039)	$ (3,944)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 11,605,779	$ 6,347,397	$ 1,364,988	$ 3,022,126	$ 668,459	$ 185,999	$ 16,810
32								
33	RATE OF RETURN	7.186%	7.186%	7.186%	7.186%	7.186%	7.186%	7.186%
34								
35								
36	IMPLIED COST-BASED RATE INCREASE	11.61%	18.6%	13.4%	3.0%	-3.8%	6.0%	52.4%

SCHEDULE TH-D2

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 *Direct 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 1st day of August, 2022.