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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2019-0335

DIRECT TESTIMONY

OF

THOMAS HICKMAN

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
July 2019

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DIRECT TESTIMONY

OF

THOMAS HICKMAN

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I. INTRODUCTION

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 Specialist.

Q. Please describe your educational and professional background.

A. I received a Bachelor's 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 was promoted to my current role of Regulatory Rate Specialist in the Ameren Missouri Regulatory group. In my current position, I perform analysis of our Electric Class Cost of Service. I also work on surveys and reporting relating to average realization rates and other ad-hoc analysis.

II. PURPOSE OF TESTIMONY

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. I will also discuss the process by which we allocated the residential class cost of service to a sample of individual residential customers. Those results are further analyzed in the testimony of Company witness Steven M. Wills.

III. CLASS COST OF SERVICE STUDY

Q. Please summarize the results of the Company's class cost of service study.

A. Table 1 on the following page is a summary of the class cost of service study indicating the return on rate base ("RORB") currently being earned on the service being provided to the Company's major retail customer classes. A more detailed summary can be found in Schedule TH-D2.

Table 1 – Summary of Class Cost of Service Study

Customer Class	Actual RORB	Target RORB
Residential Service	4.94%	7.359%
Small General Service[1] (SGS)	7.51%	7.359%
Large General (LGS) and Small Primary Service (SPS)	11.35%	7.359%
Large Primary Service (LPS)	10.69%	7.359%
Company-Owned Lighting	11.25%	7.359%
Customer-Owned Lighting	-3.74%	7.359%
Total	**7.37%**	**7.359%**

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

A. The Residential class is 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-D1.

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 7.359% 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-D1.

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

[1] Includes Metropolitan St. Louis Sewer District

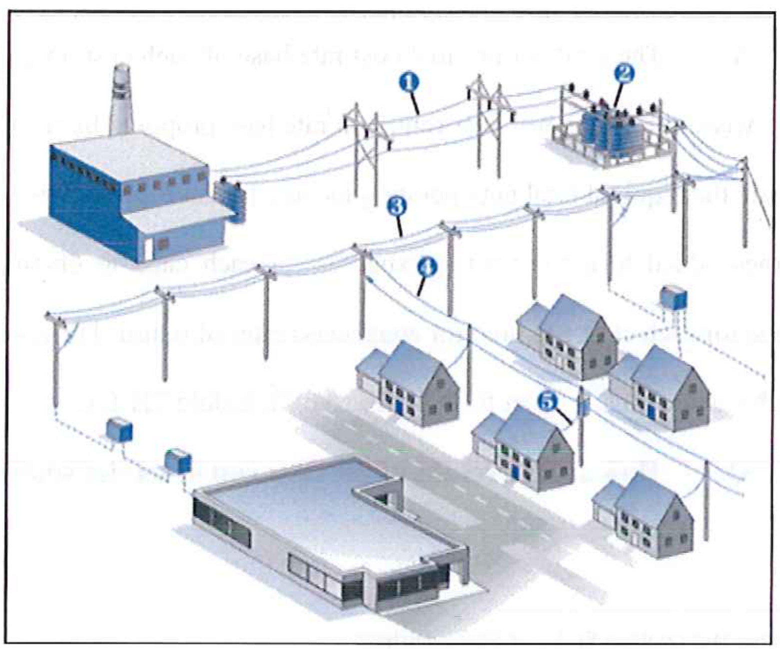
A. The results of the study are utilized as the starting point of revenue allocation and rate design as discussed further in the testimony of Company witnesses Michael Harding, Ryan Ryterski, and Steven Wills.

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

Q. As background for additional discussion on the class cost of service study 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. The 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 generating stations 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 generating station 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 83 customers at voltages above the 13,800 volt level. These are referred to as "high voltage" or Rider B customers.
    - Approximately 730 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. In your description of the Ameren Missouri generation, transmission, and distribution system are you using the term "lines" in a general sense?

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.

Q. Why is a class cost of service study performed?

A. A class cost of service study is performed to allocate costs to customer rate classes on the basis of which customer rate class is causing them. 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, the Company's approximately 730 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 reflect the costs caused by that class.

Q. What rate classes were included in the Company's class cost of service study?

A. The Company's study includes the following existing rate classes: Residential or 1(M); Small General Service or 2(M); the Large General Service or 3(M); the 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.

Q. Please explain the steps in performing a class cost of service study.

A. The three major steps to develop a class cost of service study 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 Commissions ("FERC") Uniform System of Accounts.

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) 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 will be made.

ii. Functionalization and Classification

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 class cost of service study 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 class cost of service study?

A. A detailed analysis was made of all elements of the Company's Missouri jurisdictional rate base investment and expenses during the test year for the purpose of allocating such items to the Company's present 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 monthly meter reading, 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 (kilowatt-hours) 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.

iii. <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 the 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 and demand-related classifications?

A. In this case, as it did in the Company's prior electric general rate case, the Company has used the "Minimum-Size Method" which is outlined in the National Association of Regulatory Utility Commissioners ("NARUC") 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, 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. 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, except legacy poles still in service which are included at their actual lower cost. 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. There are some poles installed in special situations or legacy poles that are less expensive, and these are included at their lower cost. Required fencing and land rights are also included as customer-related costs.

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. The average cost of the minimum size conductor was multiplied by the number of circuit miles and multiplied by two to determine the customer-related cost component for this account. 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. Protective equipment such as lightning arrestors, re-closers, and switches are also included in the customer component.

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 primary cable cost was determined through discussions with the Distribution Planning Group. The 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. 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 cost of a minimum size transformer currently being installed was determined through discussions with the Distribution Planning Group. The average cost of the minimum size transformer was multiplied by the number of transformers in the plant account to determine the current cost of the minimum-size system.

iv. <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. In addition, 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. Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatt-hour) 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 generating stations. Non-coincident peak demand is the customer class' 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 average of the customer class' 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 winter periods. For the majority of other classes and the system

as a whole, three of the four months included in the 4 NCP calculation are summer months. 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' load at the time of occurrence of the Company's system peak. The 12 CP demands are the customer class' 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 the typical metering arrangement for each customer class by the number of meters used in serving that class. 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 power plants, transmission facilities and distribution facilities. Fuel inventories and the power plants 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 (kilowatt-hour) 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 amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type 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: a) class peak demands and b) 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. 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 each class' 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.

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? [2]

A. The PISA regulatory asset, which is described in detail by Company witness Laura Moore, is made up of depreciation and a carrying cost. 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.

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.

IV. INDIVIDUAL RESIDENTIAL COST OF SERVICE

Q. Please summarize the process used to calculate the cost of service of the sample of 800 individual residential customers in support of Mr. Wills' Residential Class Rate Design testimony.

[2] As authorized by Section 393.1400, RSMo.

A. I started with the results of our class cost of service study described above. Specifically, I used the fully functionalized and classified costs allocated to the Residential customer class. For each functionalized and classified component (Customer, Production Demand, Production Energy, Transmission Demand, and Distribution Demand), I identified the primary cost allocator applicable to that component. I allocated the total Residential customer class components to the Residential class sample utilizing the allocation factors identified and calculated using the results of the individual customer load research data, where applicable.

Q. Were there any challenges identified in allocating the costs to an individual customer?

A. Yes. In performing this analysis, we realized that allocating a cost to an individual customer on a single coincident or non-coincident demand time period may not be representative of the cost to serve that customer. Overall, class loads used in analyzing the class cost of service are relatively homogeneous and predictable. On a hot summer day, it is possible to predict with a high degree of accuracy what the Residential class load will be. Individual customer loads lack that homogeneity and have a randomness associated with the level of usage experienced in any given hour that is associated with each household's lifestyle and schedule that makes an individual hour's load unpredictable, and therefore potentially less representative of that customer's typical contribution to peak loads. As an example, Distribution Demand costs are typically allocated on the basis of class non-coincident peak demand. The issue with using the class's non-coincident peak demand, is that an individual customer may not have been using energy in a way that is typical to that individual customer at that one point in time.

To further illustrate the example, an individual customer may be on vacation or experiencing a home renovation at the time when the class non-coincident peak demand is set. If this customer was using little to no energy, as a result, they would get little to no allocation of this cost. This customer could typically be a large user of energy at similar class peak condition hours. It would be unfair, then, for this customer to be allocated little or no share of those costs. Conversely, treating each individual customer as their own non-coincident source of demand may unfairly allocate too much cost to a customer if their non-coincident peak occurs during hours where additional distribution capacity is typically available. To alleviate these challenges, my analysis takes an average of each customer's load during hours with characteristics that are similar to the time periods that the non-coincident peaks typically occur and better accounts for the fact that an individual customer may have been using energy in a non-typical way at a specific peak hour.

Q. Please describe, in more detail, the process of allocating each cost component from the class to the individual customer.

A. The process of allocating each cost component to the individual customer is as follows:

(1) <u>Customer Costs</u>. Customer costs are typically allocated on the basis of customer count. I allocated these costs to each customer within the sample equally. I would like to note that because of the source of these costs, the distribution-related costs identified as Minimum Distribution are included in these costs.

(2) <u>Transmission Demand Costs</u>. Transmission Demand costs are typically allocated on the basis of 12 CP, except for the MISO Schedule 26A charges as noted previously. Due to the challenges noted above, I elected to calculate the 12 CP by

using an average of each individual customer's demand during the five highest CP hours per month of the test year taken as a percentage of the sample's demand at each of those same hours. Transmission Demand costs were allocated to each customer using the results of this calculation. The MISO Schedule 26A charges were allocated to each customer on the basis of their total kilowatt-hours for the test year as a percentage of the sample's kilowatt-hour usage for the test year.

(3) Distribution Demand Costs. Distribution Demand costs are typically allocated on the basis of class NCP. Due to the challenges noted above, I elected to calculate the class NCP by using an average of each individual customer's demand during the 30 highest Residential class NCP hours of the test year taken as a percentage of the sample's total demand at each of those same hours.

(4) Production Energy Costs. Production Energy costs are typically allocated on the basis of energy. I allocated these costs to each customer on the basis of their total kilowatt-hours for the test year as a percentage of the sample's kilowatt-hour usage for the test year.

(5) Production Demand Costs. Production Demand costs are typically allocated on the basis of a 4 NCP A&E calculation. Effectively, a percentage of the costs equal to the class's load factor ends up being allocated on an energy basis (the same basis as Production Energy Costs noted above). This amount represents the "average" use. The "excess" use is allocated on the basis of a 4 NCP calculation. In my analysis, I used the class load factor from the class cost of service study to break the costs out between an "Average" and "Excess". The "Average" dollars were allocated the same as Production Energy Costs above. The "Excess" dollars were allocated using a 4 NCP calculation. Due

to the challenges noted above, I elected to calculate the class 4 NCP by using an average of each individual customer's demand during the five highest Residential class NCP hours per month of the test year reflected in the 4 NCP cost of service calculation as a percentage of the sample's demand at each of those same hours.

The total allocation of each of the above-mentioned cost components to each individual customer represents that individual customer's cost of service. These allocations were further used in Mr. Wills' Residential Rate Design analyses.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AMEREN MISSOURI
CLASS RATES OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED DECEMBER 2018

TITLE: SUMMARY EQUAL ROR ($000's)

				SMALL	LARGE G.S. /	LARGE	LIGHTING	
		MISSOURI	RESIDENTIAL	GEN SERV	SMALL PRIMARY	PRIMARY	COMPANY OWNED	CUST. OWNED
1	BASE REVENUE	$ 2,620,466	$ 1,382,807	$ 293,815	$ 721,529	$ 186,039	$ 31,362	$ 4,913
2	OTHER REVENUE	$ 98,826	$ 53,570	$ 10,878	$ 26,797	$ 6,680	$ 779	$ 122
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 311,519	$ 128,884	$ 32,071	$ 113,921	$ 35,291	$ 854	$ 498
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,030,811	$ 1,565,260	$ 336,765	$ 862,247	$ 228,010	$ 32,996	$ 5,534
7								
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$ 1,611,626	$ 787,710	$ 173,663	$ 494,252	$ 140,385	$ 12,515	$ 3,101
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 610,101	$ 337,078	$ 70,615	$ 155,502	$ 36,721	$ 9,148	$ 1,037
10	REAL ESTATE AND PROPERTY TAXES	$ 148,096	$ 82,309	$ 17,157	$ 37,296	$ 8,738	$ 2,354	$ 242
11	INCOME TAXES	$ 52,560	$ 28,481	$ 5,993	$ 13,930	$ 3,348	$ 718	$ 90
12	PAYROLL TAXES	$ 21,330	$ 11,555	$ 2,393	$ 5,669	$ 1,420	$ 236	$ 57
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,443,712	$ 1,247,132	$ 269,820	$ 706,649	$ 190,611	$ 24,971	$ 4,528
17								
18	NET OPERATING INCOME	$ 587,099	$ 318,128	$ 66,944	$ 155,598	$ 37,399	$ 8,024	$ 1,006
19								
20	GROSS PLANT IN SERVICE	$ 18,985,409	$ 10,546,097	$ 2,198,045	$ 4,786,848	$ 1,123,158	$ 299,820	$ 31,442
21	RESERVES FOR DEPRECIATION	$ 8,595,769	$ 4,870,694	$ 998,101	$ 2,076,415	$ 482,342	$ 154,270	$ 13,946
22								
23	NET PLANT IN SERVICE	$ 10,389,640	$ 5,675,403	$ 1,199,944	$ 2,710,433	$ 640,816	$ 145,550	$ 17,496
24								
25	MATERIALS & SUPPLIES - FUEL	$ 286,365	$ 118,477	$ 29,481	$ 104,722	$ 32,441	$ 785	$ 458
26	MATERIALS & SUPPLIES -LOCAL	$ 221,192	$ 145,354	$ 26,030	$ 34,502	$ 5,662	$ 9,183	$ 461
27	CASH WORKING CAPITAL	$ (17,308)	$ (8,460)	$ (1,865)	$ (5,308)	$ (1,508)	$ (134)	$ (33)
28	CUSTOMER ADVANCES & DEPOSITS	$ (34,537)	$ (14,155)	$ (11,714)	$ (7,845)	$ (30)	$ (772)	$ (21)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,867,380)	$ (1,593,638)	$ (332,186)	$ (722,116)	$ (169,180)	$ (45,570)	$ (4,690)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 7,977,973	$ 4,322,982	$ 909,690	$ 2,114,388	$ 508,201	$ 109,042	$ 13,670
32								
33	RATE OF RETURN	7.359%	7.359%	7.359%	7.359%	7.359%	7.359%	7.359%
34								
35								
36	IMPLIED COST-BASED RATE INCREASE	-0.03%	8.2%	-0.5%	-10.5%	-8.3%	-11.9%	44.7%

AMEREN MISSOURI
CLASS RATES OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED DECEMBER 2018

	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	$ 2,621,240	$ 1,278,256	$ 295,197	$ 805,846	$ 202,942	$ 35,602	$ 3,396
2	OTHER REVENUE	$ 98,826	$ 53,570	$ 10,878	$ 26,797	$ 6,680	$ 779	$ 122
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 311,519	$ 128,884	$ 32,071	$ 113,921	$ 35,291	$ 854	$ 498
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,031,585	$ 1,460,710	$ 338,146	$ 946,563	$ 244,914	$ 37,236	$ 4,017
7								
8	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 1,611,626	$ 787,710	$ 173,663	$ 494,252	$ 140,385	$ 12,515	$ 3,101
9	TOTAL DEPR AND AMMORT EXPENSES	$ 610,101	$ 337,078	$ 70,615	$ 155,502	$ 36,721	$ 9,148	$ 1,037
10	REAL ESTATE AND PROPERTY TAXES	$ 148,096	$ 82,309	$ 17,157	$ 37,296	$ 8,738	$ 2,354	$ 242
11	INCOME TAXES	$ 52,366	$ 28,375	$ 5,971	$ 13,878	$ 3,336	$ 716	$ 90
12	PAYROLL TAXES	$ 21,330	$ 11,555	$ 2,393	$ 5,669	$ 1,420	$ 236	$ 57
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,443,518	$ 1,247,027	$ 269,798	$ 706,598	$ 190,599	$ 24,969	$ 4,527
17								
18	NET OPERATING INCOME	$ 588,068	$ 213,683	$ 68,347	$ 239,966	$ 54,315	$ 12,267	$ (511)
19								
20	GROSS PLANT IN SERVICE	$ 18,985,409	$ 10,546,097	$ 2,198,045	$ 4,786,848	$ 1,123,158	$ 299,820	$ 31,442
21	RESERVES FOR DEPRECIATION	$ 8,595,769	$ 4,870,694	$ 998,101	$ 2,076,415	$ 482,342	$ 154,270	$ 13,946
22								
23	NET PLANT IN SERVICE	$ 10,389,640	$ 5,675,403	$ 1,199,944	$ 2,710,433	$ 640,816	$ 145,550	$ 17,496
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25	MATERIALS & SUPPLIES - FUEL	$ 286,365	$ 118,477	$ 29,481	$ 104,722	$ 32,441	$ 785	$ 458
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27	CASH WORKING CAPITAL	$ (17,308)	$ (8,460)	$ (1,865)	$ (5,308)	$ (1,508)	$ (134)	$ (33)
28	CUSTOMER ADVANCES & DEPOSITS	$ (34,537)	$ (14,155)	$ (11,714)	$ (7,845)	$ (30)	$ (772)	$ (21)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,867,380)	$ (1,593,638)	$ (332,186)	$ (722,116)	$ (169,180)	$ (45,570)	$ (4,690)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 7,977,973	$ 4,322,982	$ 909,690	$ 2,114,388	$ 508,201	$ 109,042	$ 13,670
32								
33	RATE OF RETURN	7.37%	4.94%	7.51%	11.35%	10.69%	11.25%	-3.74%

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 Decrease Its Revenues for Electric Service.	)))	File No. ER-2019-0335

AFFIDAVIT OF THOMAS HICKMAN

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

Thomas Hickman, being first duly sworn on his oath, states:

1. My name is Thomas Hickman. I work in the City of St. Louis, Missouri, and I am employed by Union Electric Company d/b/a Ameren Missouri as a Regulatory Rate Specialist.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 27 pages and Schedule(s) TH-D1 & TH-D2, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Thomas E Hickman
Thomas Hickman

Subscribed and sworn to before me this 28th day of June, 2019.

Geri A. Best
Notary Public

My commission expires:

GERI A. BEST
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis County
My Commission Expires: February 15, 2022
Commission Number: 14839811