Exhibit No.:
Issue(s): CCOSS; Riders B and C; Supplementary Service
Witness: Thomas Hickman
Type of Exhibit: Direct Testimony
Sponsoring Party: Union Electric Company
File No.: ER-2026-0291
Date Testimony Prepared: June 26, 2026

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2026-0291

DIRECT TESTIMONY

OF

THOMAS HICKMAN

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
June, 2026

P

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

THOMAS HICKMAN

FILE NO. ER-2026-0291

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 Manager of Rates and Analysis.

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. In November 2013, I came to work for Ameren Services. I worked in Internal Audit and Margin Analysis over the next three and a half years. In April 2017, I joined the Ameren Missouri Rates and Regulatory group as a Regulatory Rate Specialist. Since that time, I was promoted to Regulatory Rate Consultant and subsequently to Manager of Rates and Analysis. In my time in the Rates and Regulatory group, I have performed and maintained the Company's Electric Class Cost of Service, overseen tariff filings and rate changes, and performed other regulatory analysis work.

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 ("CCOSS"). I will also discuss the elimination of Rider B (discounts for customers who own their own substations) and the related addition of four new distribution voltage differentiated subclasses. I will explain changes to Rider C (meter reading voltage adjustments) that mostly tie to the Rider B elimination. Finally, I propose the elimination of Rider SSR (standby service rider) and the reactivation of Rider E (the Company's legacy supplementary service rider).

III. CLASS COST OF SERVICE STUDY

Q. Before describing the CCOSS results and process, was the Large Load Customer ("LLC") rate class represented in the study in this case?

A. No. While the revenue requirement did include minor incremental costs that are anticipated to exist by the true-up date attributable to LLC customers who have signed Electric Service Agreements ("ESAs"), those customers did not exist as customers in the test year (12 months ending March 31, 2026) and have no associated allocation factors for study. The terms of those customers' ESAs have also not started and will not start until after the true-up cutoff date in this case. However, as discussed in Company witness Steven Wills' Direct Testimony, the Company is making a discrete revenue adjustment in this case to impute revenues from those customers expected roughly concurrent with the operation of law date in this case which is more than sufficient to cover the relatively minor level of incremental costs associated with providing service to them that is reflected in the Company's proposed revenue requirement.

Q. Did you study those relatively small incremental costs?

A. Yes. The CCOSS model I'm sponsoring in this testimony and by way of the attached schedules includes those small incremental costs and that discrete revenue adjustment. To highlight the impact of those values more explicitly, I created a second CCOSS model that removed those incremental costs and the discrete revenues. I also performed a reconciliation between the two files to show what those impacts were and where in the model they were removed. That second version of the model, which supports the overall reduction in revenue requirement and class level impacts, is referenced in Company witness Wills' Direct Testimony.

Q. Are classes in this CCOSS broken out the same way as they historically have been?

A. No. Certain classes that used to be combined for presentation in CCOSS have been broken out discretely and additional subclasses within a few of the classes have been broken out for discrete study as well. These changes relate to the proposed removal of Rider B in this case. See section IV of my testimony for more information.

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 the proposed revenue requirement in this proceeding. A more detailed summary can be found in Confidential Schedule TH-D1.

Table 1 – Summary of Class Cost of Service Study Results

Customer Class	Actual RORB	Target RORB
Residential Service	4.61%	7.506%
Small General Service (SGS)[1]	6.99%	7.506%
Large General (LGS) and Small Primary Service (SPS)	7.82%	7.506%
Small Primary Service (SPS) - Primary	8.44%	7.506%
Small Primary Service (SPS) – High Voltage	12.46%	7.506%
Small Primary Service (SPS) - Transmission	16.38%	7.506%
Large Primary Service (LPS) - Primary	6.84%	7.506%
Large Primary Service (LPS) – High Voltage	13.27%	7.506%
Large Primary Service (LPS) - Transmission	13.18%	7.506%
Company-Owned Lighting	2.81%	7.506%
Customer-Owned Lighting	-2.05%	7.506%
Total	**5.97%**	**7.506%**

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 for Residential, SGS, LPS-Primary, and both lighting classes. The actual RORB is greater than target RORB for LGS, SPS-Primary, SPS-High Voltage, SPS-Transmission, LPS-High Voltage, and LPS-Transmission. The High Voltage and Transmission subclasses are providing well above average rates of return. 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 Confidential 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 7.506% to obtain the

[1] Includes Metropolitan St. Louis Sewer District.

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 for each customer class is set forth on line 6 of Confidential Schedule TH-D2.

Q. How are the results of the CCOSS used?

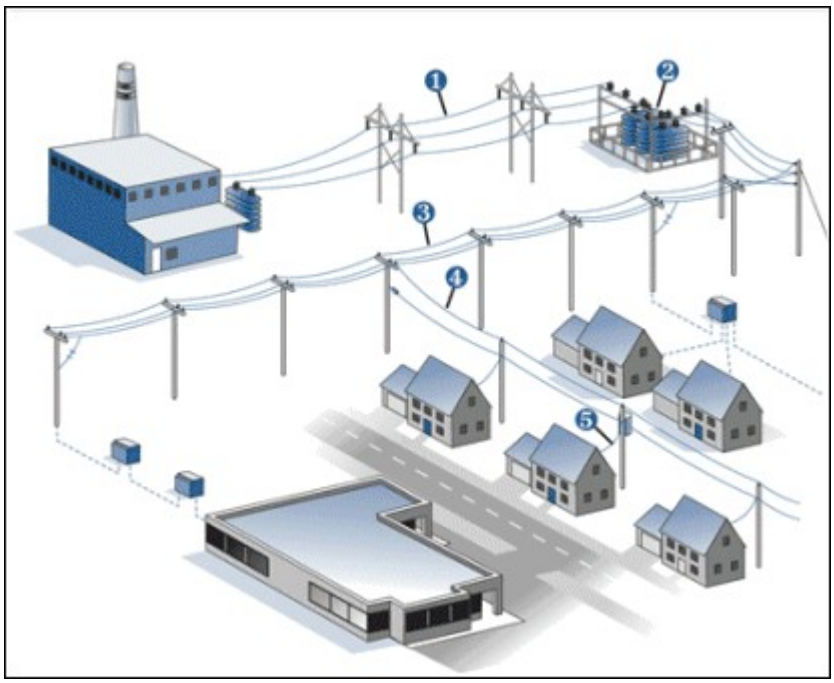
A. The results of the study are utilized as the foundation of revenue allocation and rate design as discussed further in the testimony of Company witness Nicholas Bowden.

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 plant 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 115,000 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.
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 typically 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. To illustrate, the Company's primary voltage customers receive service at 4,160 to 13,800 volts, and require different facilities to serve them, than, for example, 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)[2] classes. The 4(M) and 11(M) Classes are further divided and studied for subclasses of customers served at Primary Voltage, High Voltage[3], and Transmission Voltage. 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 — is 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 requirement, on a cost-causative basis, as demand-related, energy-related, or customer-related.

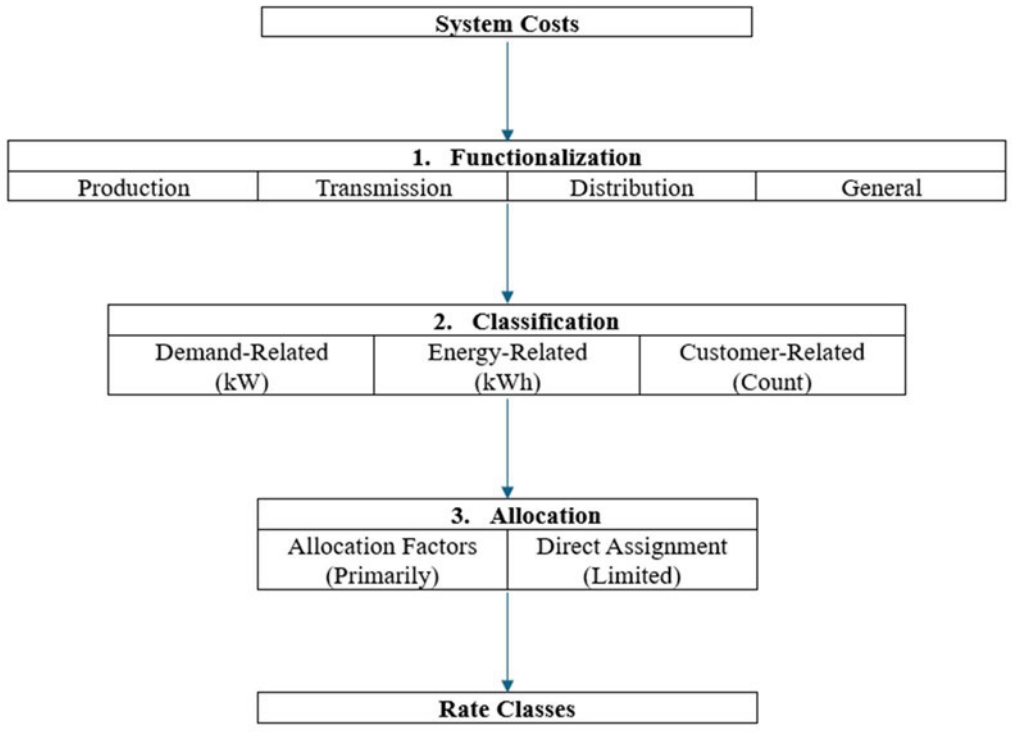
3. Allocation — is the process of allocating the classified costs among the Company's customer rate classes. Demand-related costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatt-hour

[2] As I discussed earlier, there are no impacts from the Large Load Customer "subclass" currently within 11(M). Those customers will be served under a new Rate Classification 14(M) once this case is completed, as discussed in Mr. Wills' Direct Testimony.
[3] The terms "High Voltage" and "Subtransmission" as used in the Company's CCOSS model are interchangeable.

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 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.

Please see Figure 2 below for a visual representation of the major steps in the development of CCOSS.

Figure 2 – Class Cost of Service Study Steps



iii. 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 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 1, 2025 through March 31, 2026) and pro forma adjustments described by Company witness Stephen Hipkiss 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 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?

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. Minimum Distribution System Study

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 simply 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. The Company continues to use 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. 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. The installed book cost of assets included in this study were first normalized to a single base year utilizing the Handy-Whitman Index. The Handy-Whitman Index of Public Utility Construction Costs is an inflation index that provides an annual cost index for various FERC accounts. This step helps account for the fact that certain historic assets that are no longer being installed as standard could be disproportionately underrepresented or larger new asset types could be overrepresented in their contribution to distribution system costs due to inflation. References to "book cost" for the remainder of this section of testimony should be thought of as being inflation adjusted. 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 safe and reliable 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. Then, the average book cost of that type of pole was multiplied by the number of poles to find the customer-related cost component. Poles with an average book cost less than the minimum height pole are included at their lower cost rather than the cost that was determined for the minimum size pole. Required fencing and land rights and a portion of pole anchoring relative to the customer-related percentage of poles are also included as customer-related costs. The results of a study of distribution poles

and what voltage of equipment is attached to them based on Company pole inspection records 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. 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[4] to determine the customer-related 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. No secondary overhead costs were included in this customer-related portion because the count of circuit miles used to determine the customer-related costs did not include secondary voltage circuits.

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

[4] 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.

A. For Account 367 (underground conductors and devices), the average minimum size underground conductor was determined. 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. Again, no secondary underground costs were included in this customer-related portion because the count of underground circuit miles used to determine the customer-related costs did not include underground secondary voltage circuits. 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. 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 and the average book cost of that conductor was identified. 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-related 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 based on current rates.

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) Production Plant. Production plant was allocated to each customer class on the basis of the Four Non-Coincident Peak ("4 NCP") A&E Demand allocation factors for each customer class. 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 one of their four non-coincident peaks, because their four 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.

Despite the Company dividing the historically studied classes into more subclasses (i.e., SPS and LPS are now divided by voltage level) in this case, the Company decided to keep the previous aggregate 'class' definitions in the development of this allocator. The incremental subclasses are necessary to provide more precise study results as it relates to customers taking service at different voltages and how that relates specifically to distribution investment. However, the Company does not currently support the use of their individual sub-divided NCPs for production cost allocations. The core principle driving the increase in studied classes to include those subclasses is to better understand which groups of customers are driving distribution investment. To allocate production costs based on subclass NCP would create incremental cost differentiation above and beyond that core principle. To the extent CCOSS ultimately informs

rate design, it could create unintended pricing consequences whereby customer's decisions whether to own and maintain various points of transformation are driven by access to differentiated production cost allocations rather than the difference in distribution cost allocations that should be the economic basis for such a decision.

To accomplish the objective of allocating production costs while maintaining historic class-level definitions, the Company performed the calculations to derive this allocator using a two-step approach. First, an allocator was developed at the level of the previous 'class' levels. Second, that allocator was further subdivided to the subclasses based on their contribution to that group allocator. This two-step approach ensures that the overall production cost apportionment remains consistent with the prior 'class' levels and is the intended outcome.

(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 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 utilizing various types of operational records. Poles were specifically updated as a part of the Company's CCOSS presented in File No. ER-2024-0319. Overhead and underground cables and wires and distribution substations were reviewed in developing the CCOSS for this case. Because of the nature of line transformers on the Company's system and the minimal existence of line transformers that are utilized in a capacity other than transformation to secondary voltage, the demand component of line transformers was allocated exclusively on the basis of secondary demands. 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. All metering costs are classified as customer-related.

Account 371-1, Installation on Customer's Premises Substation Equipment, was allocated to the primary voltage subclasses 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 based on 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 close to half of the Company's total plant investment, please summarize common cost allocation methodologies employed within the electric utility industry for the allocation of generation plant.

A. Three common and generally accepted methodologies used for the allocation of generation plant are:

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 streetlights 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, which 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 appropriate 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 14 of the 16 maximum 4 NCP monthly demands for the Company's 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. Consistent with what was stated earlier, the facts relating to NCP stated above relate to the historic 'classes' that were studied in previous rate cases. Those NCPs were further subdivided to the subclass level based on each subclass's contribution to the historic 'class' level factor.

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 9% 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 91% of Account 903 expense was allocated to each customer class utilizing customer counts. 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. 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.[5]

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 of production, transmission, distribution and general plant.

[5] File No. ER-2010-0036, *Report and Order*, p. 87, paragraph 20, issued May 28, 2010.

Q. How did you allocate Plant-in-Service Accounting ("PISA") amortization expense?[6]

A. The PISA regulatory asset, as described by Company witness Hipkiss, 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.

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.

Q. Are there any other items of note you would like to highlight about your allocations in this case?

A. Yes. In my Surrebuttal Testimony in File No. ER-2024-0319, I acknowledged Staff's position relating to assets recorded in distribution accounts that support certain solar facilities. I performed analysis in that case to show the impacts of treating the approximately $1 million worth

[6] As authorized by Section 393.1400 RSMo.

of capital at issue consistent with production allocations rather than distribution allocations. The results showed class level impacts of approximately $16,000 for the largest impacted class. Because that change requires moving dollars from several different distribution level accounts, incorporating the change into our recurring CCOSS modeling is administratively burdensome given the very small impact doing so would have. In this case, I acknowledge that this impact continues to exist but am choosing not to incorporate the modeling change to reflect it. The value of those assets continues to be approximately $1 million today, meaning the actual impact continues to be extremely small. I will continue to monitor the dollars associated with these assets and reevaluate inclusion in the model if the dollars even grow enough to support the additional modeling effort.

IV. RIDER B ELIMINATION

Q. Please describe Rider B.

A. Rider B is a discount historically applied to customers taking service under one of the Company's primary service — 4(M) SPS or 11(M) LPS — rate schedules but served at 34 kilovolt ("kV") or higher. The discount accounted for the fact that those customers purchased and owned their own substation transformation. One way in which Rider B may have been viewed as insufficient, is that it only accounted for those substation costs. Also embedded in the primary service class's cost of service were other portions of the primary distribution system including poles, wires, and cables, which are costs that are not caused by customers served at these higher voltages.

Q. How is the Company addressing the issues related to Rider B from File Nos. ER-2021-0240 and ER-2022-0337?

A. To address the issues related to Rider B from the referenced cases and consistent with the notice filed on June 14, 2024 (ER-2022-0337) and referenced to by the Company in File No. ER-2024-0319, the Company's filing in this case places the customers served in unique voltage classes into their own subclasses for study in a CCOSS. This change places customers who are taking service at different voltages into different subclasses and provides the most significant allocation factors broken out in more detail than they were historically to support the reasonable and proper allocation of costs to those subclasses.

Q. What does the further division of primary voltage rate classes into more specific subclasses in the CCOSS show?

A. The updated CCOSS shows that customers served at subtransmission or transmission voltages should have lower rates relative to customers served at primary voltages. This is because customers taking service at higher voltages do not require, and therefore do not cause, the investment in lower-voltage facilities. For example, primary voltage equipment should not be paid for by customers served at higher than primary voltages, and subtransmission equipment should not be paid for by customers served at transmission voltages. The Rider B discounts were applied in an attempt to more appropriately reflect that relationship.

Q. In lieu of Rider B, how is this fact being reflected in the Company's rate design proposal in this case?

A. The Company proposes voltage-specific rates. The Company embedded the existing Rider B discount into the demand charges for customers served at subtransmission and transmission voltages. This is cost-justified within the CCOSS results. Rider B as a standalone discount is proposed to be eliminated in this case. Future rate decisions for the higher voltage subclasses should be informed by the CCOSS results for those subclasses and embedded in the

rates specific to those subclasses. Please refer to the testimony of Company witness Bowden for more information on other specific rate design proposals in this case.

V. RIDER C RESTRUCTURING

Q. What is Rider C?

A. Rider C is a metering adjustment applied to an applicable customer's kWh and kW billing units, when the customer is metered at a voltage other than the service voltage stated in their respective service class. This happens in two subtly different situations. First, Rider C applies when a customer is metered at a voltage different from their service voltage when a customer takes service at the voltage specified in their service class. Think of this as moving the meter to the service voltage stated in the tariff. Second, Rider C applies when a customer is metered at a voltage that is the same as their service voltage, but when the service voltage is different from the service voltage specified by their service class. The second case is applicable to Rider B customers. Think about the second case this way: Rider B 'moves' the customer from their subtransmission or transmission service voltage to the primary service voltage specified in their service classification and Rider C 'moves' the customers meter with them.

Q. Why is the Company proposing to restructure Rider C in this case?

A. The elimination of Rider B described above and the underlying division of primary voltage classes into additional subclasses consistent with a customer's actual service voltage creates a need to remove certain Rider C provisions, insert new Rider C provisions, and provides an opportunity to make the tariff clearer. The Rider C tariff historically referenced the voltage in the rate schedule, but with the update to the 4(M) SPS and 11(M) LPS tariffs, it is appropriate for the Rider C tariff to explicitly reference the service voltage. Along with this revision, incremental applications of Rider C are now included to make it clear that if a customer served at a

subtransmission or transmission voltage is metered at a voltage other than that service voltage, then Rider C applies. This revision also removes the universal application of Rider C to any customer on an 4(M) SPS or 11(M) LPS rate schedule if metered at 34 kV or higher. Because of the related changes to Rider B, service voltages will now be explicitly stated in the SPS and LPS tariffs for customers served at those higher voltages. This change clarifies the application or non-application of Rider C for those customers.

Rates and billing units were adjusted in the rate design proposal to eliminate potential bill impacts caused by changes to Rider B and Rider C in this case. Please note that the effectively lower bill paid by LPS and SPS customers who had Rider B and were metered at 34 kV or higher as a result of Rider C is justified by the CCOSS results, as shown in Table 1 of this testimony. Those customer classes, even with this historic reduction to their bill, are substantially overpaying their cost of service. For more information on how this step was applied in rate design, see the testimony of Company witness Bowden.

VI. ELIMINATION OF RIDER SSR AND REACTIVATION OF RIDER E

Q. What are you proposing with respect to Rider SSR in this case, and why?

A. I am proposing the elimination of Rider SSR in the current rate case. This is due primarily to the administrative burden and overall complexity associated with the rate and the lack of interest expressed by customers over time, as evidenced by no customer ever taking service under this rider since its inception. I am the Company's primary contact for inquiries related to Rider SSR. Since 2018, I have been contacted only one single time regarding Rider SSR.

The rate is currently presented as a table with three columns of unique rate values. That table would necessarily need to expand to seven unique sets of rates because of our delineation of rate subclasses related to Rider B in this case. I believe that would significantly impede customer

understandability of those underlying rates. The Company is also proposing a gradual simplification of 3M and 4M rates in this case, as is discussed in the testimony of Company witness Bowden. That gradual shift over time in underlying rate structure will make any present-day evaluation of the economics of a Rider SSR project much more difficult.

Due to the lack of interest in the Rider, the Company has also never programmed systematic billing for these rates and would face an administrative burden if an interested customer were to pursue this rate option.

Q. Do you propose anything as an alternative to Rider SSR for customers?

A. Yes. I propose ending the grandfathering provision in Rider E to maintain an option for customers seeking supplementary service. Incremental changes have been proposed in the Rider E language to accommodate other rate tariff changes that have occurred since it was put into grandfathered status. Additionally, the Company has inserted provisions so that contract demand is not necessarily automatically increased based on a single scenario where the maximum service requirements were exceeded. The Company maintains discretion but will evaluate the situation and may increase the contract demand but will not do so automatically and without review.

Q. Which redlined tariffs are included in your Schedule TH-D3?

A. The redlined tariffs showing the elimination of Rider B, modifications to Rider C, elimination of Rider SSR, and reactivation of Rider E as discussed above are provided in Schedule TH-D3.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	**)** **)** **)**	Case No. ER-2026-0291

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 26th day of June, 2026.

ER-2026-0291

Schedules TH-D1 and TH-D2 are Confidential in their Entirety

P

~~**RIDER B**~~

~~**DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP**~~

~~*Where a customer served under rate schedules 4(M) or the non Large Load Customer Service provisions of 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:~~

~~1. A monthly credit of $1.24/kW of billing demand for customers taking service at 34.5 or 69kV.~~

~~2. A monthly credit of $1.47/kW of billing demand for customers taking service at 115kV or higher.~~

* THIS SHEET RESERVED FOR FUTURE USE

*Indicates Change.

RIDER C

ADJUSTMENTS OF METER READINGS FOR METERING AT A VOLTAGE OTHER THAN SERVICE VOLTAGE~~NOT PROVIDED FOR IN RATE SCHEDULE~~

Where service is metered at a voltage other than the service voltage~~ provided for under the applicable rate schedule~~, an adjustment in both the kilowatt-hour (kWh) and kilowatt (kW) meter readings for the applicable service will be made as follows:

The following customers will have their meter readings (kWh and kW) decreased by 0.68%:

1. Customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage and metered at primary voltage or higher.
2. Customers on rate schedule 4(M) or 11(M) taking delivery at primary voltage and metered at 34 kV or higher.
3. Customers on rate schedule 4(M) or 11(M) taking delivery at 34 kV or 69 kV and metered at 115 kV or higher.

The following customers will have their meter readings (kWh and kW) increased by 0.68%:

4. Customers on rate schedule 4(M) or 11(M) taking delivery at primary voltage and metered at secondary voltage.
5. Customers on rate schedule 4(M) or 11(M) taking delivery at 34 kV or 69 kV and metered at primary voltage or lower.
6. Customers on rate schedule 4(M) or 11(M) taking delivery at 115 kV or higher and metered at 69 kV or lower.

~~For customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage:~~

~~1. Metered at Primary Voltage or higher, meter readings (kWh and kW) will be decreased by 0.68%.~~

~~For customers on rate schedule 4(M) or 11(M):~~

~~2. Metered at 34kV or higher, meter readings (kWh and kW) will be decreased by 0.68%~~

~~3. Metered at Secondary voltage, meter readings (kWh and kW) will be increased by 0.68%~~

~~4. Delivered at 34 kV or higher, served through a single transformation to secondary voltage, and metered at secondary voltage, no Rider C adjustment will apply.~~

~~*5. Served at transmission voltage, metered kWh will be increased to account for the energy line losses from the use of a transmission system other than Company's, if any.~~

Company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons.

* Indicates Addition.

RIDER E

SUPPLEMENTARY SERVICE

A. DEFINITION

Where the service supplied by Company is available in the event of failure or shutdown of customer's private plant service or any other source of electrical energy or motive power through electrical or mechanical means or by means of operational procedure, or where the service in effect serves to relieve, sustain or augment any other source of power, such service shall constitute Supplementary Service. Customers with emergency backup, solar or wind generation that is not integrated with a storage system or where the generation capacity is less than 100 KW are excluded from this Rider.

*** B. AVAILABILITY**

Supplementary Service will be supplied whenever, in the opinion of the Company, it will have capacity available for the supply of such service during the term of the proposed Electric Service Agreement. ~~This Rider is limited to those customers receiving Supplementary Service prior to April 1, 2017. After April 1, 2017 all new customers or those customer(s) on Rider E who experience a significant change to the customer's generating equipment shall have Supplementary Service supplied under Standby Service.~~

C. RATE FOR SERVICE

1. Supplementary Service will be delivered to customer under Service Classification No. 3(M) Large General Service, Service Classification 4(M) Small Primary Service, or Service Classification 11(M) Large Primary Service~~the Primary Service Rate at a primary service voltage to be selected by Company~~. All provisions of the ~~Primary Service~~applicable ~~R~~rate under which supplementary service is to be supplied shall remain in effect, except as hereinafter specifically provided.

2. Electric service actually used each month shall be charged for under the applicable rate selected by customer or specified in customer's Electric Service Agreement.

3. The monthly bill to be paid by customer, whether or not any electric service is actually used, shall in no case be less than the minimum charge specified in the applicable rate or the amount based on the Contract Demand (as hereinafter defined) computed on the schedule of charges set forth on Sheet No. 63, Miscellaneous Charges, whichever is greater.

D. GENERAL PROVISIONS

1. Contract Demand is defined as the higher of either:

a. The number of kilowatts mutually agreed upon by Company with customer as representing customer's maximum on-peak service requirements under all conditions of use, and such demand shall be specified in customer's Electric Service Agreement; or

b. The maximum on-peak demand established by customer in use of Company's service.

To the extent an abnormal situation results in Contract Demand being set under item b. above and in Company's discretion customer has implemented measures adequate to ensure that such abnormal situation will not reoccur, Company may adjust the Contract Demand to a value less than the maximum demand established by item b. except in no circumstance will the adjusted Contract Demand be less than the maximum on-peak service requirement specified or revised under item a.

* Indicates Change.

* THIS SHEET RESERVED FOR FUTURE USE

*Indicates Change

~~**RIDER SSR**~~

~~**STANDBY SERVICE RIDER**~~

~~**APPLICABILITY**~~

~~Applicable to each customer not currently served by Rider E, at a single premises with behind the meter on-site parallel distributed generation and/or storage system(s) with a capacity over 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Large General Service 3(M), Small Primary Service 4(M), or Large Primary Service 11(M). Customers with emergency backup, solar or wind generation that is not integrated with a storage system are excluded from this Rider.~~

~~**DEFINITIONS**~~

~~DISTRIBUTED GENERATION AND/OR STORAGE – Customer's private on site generation and/or storage that:~~

~~1. is located behind the meter on the customer's premises,~~
~~2. has a rated capacity of 100 kW or more,~~
~~3. operates in parallel with the Company's system, and~~
~~4. adheres to applicable interconnection agreement entered into with the Company.~~

~~SUPPLEMENTAL SERVICE – Electric service provided by the Company to customer to supplement normal operation of the customer's on site parallel distributed generation and/or storage in order to meet the customer's full service requirements.~~

~~STANDBY SERVICE – Service supplied to the premises by the Company in the event of the customer exceeding its Supplemental Contract Capacity. Standby Service may be needed on either a scheduled or unscheduled basis. Standby Service comprises capacity and associated energy during the time it is used.~~

~~1. BACKUP SERVICE – Unscheduled Standby Service.~~

~~2. MAINTENANCE SERVICE – Scheduled Standby Service.~~

~~BACK UP SERVICE – The portion of Standby Contract Capacity and associated energy used without advance permission from the Company. The customer must notify the Company within thirty (30) minutes of taking Back up Service for amounts over five (5) megawatts (MW). For Back up Service billed, the customer shall be charged the daily standby demand charge for back up service and back up energy charges associated with Standby Service. The rates for these charges as well as the monthly fixed charges are stated in this Rider. Back up Service charges will be shown and calculated separately on the customer bill.~~

~~MAINTENANCE SERVICE – The portion of Standby Contract Capacity used with advance permission from the Company. The customer must schedule Maintenance Service with the Company not less than six (6) days prior to its use. Unless otherwise agreed to by the Company, Maintenance Service shall be limited to not more than six (6) occurrences and not more than sixty (60) total and partial days during twelve (12) consecutive billing periods (based on billing dates). Maintenance Service may be available during all months and shall not be greater than the seasonal Standby~~

~~Contract Capacity. The scheduling of Maintenance Service may be restricted by the Company during times associated with system peaking conditions or other times as necessary. For Maintenance Service billed, the customer shall be charged the daily standby demand charge for maintenance service associated with Standby Service Demand.~~

* THIS SHEET RESERVED FOR FUTURE USE

*Indicates Change

~~**RIDER SSR**~~

~~**STANDBY SERVICE RIDER (Cont'd.)**~~

~~**DEFINITIONS (Cont'd.)**~~

~~MAINTENANCE SERVICE (Cont'd.) – The rates for these daily demand charges as well as the monthly fixed charges are stated in this Rider. Energy charges for Maintenance Service associated with the Standby Service will be billed as standard energy charges per the applicable tariffed rate schedule. Maintenance Service charges will be shown and calculated separately on the customer bill.~~

~~SUPPLEMENTAL CONTRACT CAPACITY – The customer must designate and contract by season the maximum amount of demand, in kW, taken at the premises through the billing meter that may be billed on the applicable standard tariffed rate and shall be mutually agreeable to customer and Company. The Supplemental Contract Capacity shall insofar as possible estimate ninety percent (90%) of the historic or probable loads of the facility as adjusted for customer generation.~~

~~STANDBY CONTRACT CAPACITY – The higher of:~~

~~1. The number of kilowatts mutually agreed upon by Company with customer as representing the customer's maximum service requirements under all conditions of use less Supplemental Contract Capacity, and such demand shall be specified in customer's Electric Service Agreement. Such amount shall be seasonally designated and shall not exceed the nameplate rating(s) of the customer's own generation. The amount of Standby Contract Capacity will generally consider the seasonal (summer or winter billing periods) capacity ratings and use of the generator(s), or may be selected based on a Company approved load shedding plan.~~

~~2. The maximum demand established by customer in use of Company's service less the product of Supplemental Contract Capacity and 110%.~~

~~Fixed monthly charges for generation and transmission access and facilities shall be levied upon a capacity not to exceed the nameplate rating(s) of the customer's generating unit(s).~~

~~SUPPLEMENTAL DEMAND – The lesser of:~~

~~1. Supplemental Contract Capacity or~~

~~2. The Total Billing Demand in this Rider.~~

~~STANDBY SERVICE DEMAND – The Total Billing Demand as determined in this Rider in excess of the Supplemental Contract Capacity.~~

~~TOTAL BILLING DEMAND – Total Billing Demand for purposes of this Rider shall be the maximum 15 minute demand established during peak hours or 50% of the maximum 15 minute demand established during off-peak hours, whichever is greater, but in no event less than 100 kW for Large General Service or Small Primary Service, nor less than 5,000 kW for Large Primary Service.~~

~~Peak and off-peak hours are defined as follows:~~

~~Peak hours: 10:00 A.M. to 10:00 P.M.,~~

~~Monday through Friday~~

~~Off-peak hours: All other hours including the entire 24 hours of the tariffed holidays as defined in the base tariff. All times stated above apply to the local effective time~~.

* THIS SHEET RESERVED FOR FUTURE USE

~~**RIDER SSR**~~

~~**STANDBY SERVICE RIDER (Cont'd.)**~~

~~**GENERAL PROVISIONS**~~

~~The contract term shall be one (1) year, automatically renewable, unless usage, plant modifications or additional generation requires a change to Supplemental Contract Capacity or Standby Contract Capacity.~~

~~The Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder. The Company may inspect generation logs or other evidence that the customer's generator is being used in accordance with the provisions this Rider.~~

~~Power production equipment at the customer site shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed. The sale of excess energy to the Company may be included in the interconnection or other agreement.~~

~~If at any time customer desires to increase demand above the capacity of Company's facilities used in supplying said service due to plant modifications, customer will sign a new agreement for the full capacity of service required and in accordance with applicable rules governing extension of its distribution system.~~

~~In addition to the charges in the applicable rate schedule, customers taking service under this Rider will be subject to the applicable Administrative Charge, Generation and Transmission Access Charges, and the Facilities Charge each month contained herein. If customer chooses the Time-Of-Day (TOD) option under the applicable rate schedule such option will apply to this Rider SSR as well.~~

~~Those customers choosing to install more than one (1) generating unit on the same premises will have a twenty five percent (25%) discount applied to the monthly Generation and Transmission Access Charges and Facilities Charges applicable to each additional generator on the same premises.~~

~~In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this Rider.~~

~~In the event a customer adds distributed generation and/or storage after investments are made by the Company in accordance with the net revenue test described in the Company's line extension policy, the Company may require reimbursement by the customer. Such reimbursement shall be limited to that investment which was incurred within the previous five years and shall be based upon the change in load requirements on the Company's electric system.~~

~~Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all billed kilowatt-hours (kWh) of energy under this Rider.~~

~~*Energy Efficiency Investment Charge (Rider EEIC). Applicable to all billed kilowatt-hours (kWh) of energy under this Rider excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.~~

~~**Renewable Energy Standard Rate Adjustment Mechanism (Rider RESRAM). Applicable to~~

~~all billed kilowatt-hours (kWh) of energy under this Rider.~~

*Indicates Change. ~~**Indicates Addition.~~

* THIS SHEET RESERVED FOR FUTURE USE

~~**RIDER SSR**~~

~~**STANDBY SERVICE RIDER (Cont'd.)**~~

~~*STANDBY RATE~~	~~Large General Service~~	~~Small Primary Service~~	~~Large Primary Service~~
~~Standby Fixed Charges~~			
~~Administrative Charge~~	~~$197.24/month~~	~~$197.19/month~~	~~$190.90/month~~
~~Generation and Transmission Access Charge per month per kW of Contracted Standby Demand~~	~~$0.88/kW~~	~~$0.88/kW~~	~~$1.04/kW~~
~~Facilities Charge per month per kW of Contracted Standby Demand:~~			
~~Summer~~	~~$5.95/kW~~	~~$4.93/kW~~	~~$4.93/kW~~
~~Winter~~	~~$1.58/kW~~	~~$1.15/kW~~	~~$1.15/kW~~
~~Daily Standby Demand Rate – Summer~~			
~~Per kW of Daily Standby Service Demand:~~			
~~Back-Up~~	~~$0.04/kW~~	~~$0.04/kW~~	~~$1.20/kW~~
~~Maintenance~~	~~$0.02/kW~~	~~$0.02/kW~~	~~$0.60/kW~~
~~Daily Standby Demand Rate – Winter~~			
~~Per kW of Daily Standby Service Demand:~~			
~~Back-Up~~	~~$0.02/kW~~	~~$0.02/kW~~	~~$0.56/kW~~
~~Maintenance~~	~~$0.01/kW~~	~~$0.01/kW~~	~~$0.28/kW~~
~~Back-Up Energy Charges – Summer~~			
~~kWh in excess of Supplemental Contract Capacity~~			
~~Energy(1)~~	~~12.33¢/kWh~~	~~11.99¢/kWh~~	~~4.06¢/kWh~~
~~On-Peak Energy(2)~~	~~13.47¢/kWh~~	~~12.83¢/kWh~~	~~4.70¢/kWh~~
~~Off-Peak Energy(2)~~	~~11.54¢/kWh~~	~~11.44¢/kWh~~	~~3.69¢/kWh~~
~~Back-Up Energy Charges – Winter~~			
~~kWh in excess of Supplemental Contract Capacity~~			
~~Energy(1)~~	~~7.74¢/kWh~~	~~7.55¢/kWh~~	~~3.71¢/kWh~~
~~On-Peak Energy(2)~~	~~8.09¢/kWh~~	~~7.86¢/kWh~~	~~4.00¢/kWh~~
~~Off-Peak Energy(2)~~	~~7.52¢/kWh~~	~~7.36¢/kWh~~	~~3.54¢/kWh~~
~~High Voltage Facilities Charge Discount~~			
~~Facilities Charge Credit per month per kW of Contracted Standby Demand~~			
~~@ 34.5 or 69kV~~	~~N/A~~	~~$1.24/kW~~	~~$1.24/kW~~
~~@ 115kV or higher~~	~~N/A~~	~~$1.47/kW~~	~~$1.47/kW~~

~~(1) Applicable to customers not on TOD rates.~~

~~(2) Applicable to customers on TOD rates for its non-back-up energy charges.~~

*Indicates Change.