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	)))	**File No. ER-2022-0337** Tracking No. YE-2023-0031

REPORT AND ORDER

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REPORT AND ORDER

This case involves Union Electric Company d/b/a Ameren Missouri's (Ameren Missouri or "the Company") request to increase its annual revenues. Ameren Missouri says an increase is needed because of investments in its infrastructure, increases in its cost of capital since its last rate case, higher depreciation costs, and other changes in the cost of providing service.[1] This Report and Order approves a Stipulation and Agreement (Agreement) between several of the parties resolving most of the issues in this rate case. This Report and Order also resolves the remaining unsettled issues not addressed in the Agreement.

Procedural History

Ameren Missouri filed tariff sheets on August 1, 2022, to increase its electric rate base annual revenues by $316 million. Ameren Missouri calculates that its request would raise a typical residential customer's bill by approximately 11.64 percent. Filing those tariff sheets initiated a general rate case. So that the Commission would have time to review Ameren Missouri's request, and so the parties would have time to prepare for an evidentiary hearing, the Commission suspended Ameren Missouri's general rate increase tariff sheets until July 1, 2023, the maximum amount of time allowed under the statute.

The Commission granted the intervention requests of Midwest Energy Consumers Group (MECG); Missouri Industrial Energy Consumers (MIEC); Renew Missouri Advocates d/b/a Renew Missouri; Consumers Council of Missouri (Consumers Council); Sierra Club; National Association for the Advancement of Colored People (NAACP); and

[1] Ameren Missouri's last general rate case concluded in February 2022.

Metropolitan Congregations United (Metropolitan Congregations), allowing them to become parties in this rate case. The Staff of the Commission (Staff) and the Office of the Public Counsel (Public Counsel) are parties by statute.

The Commission established the test year for this case as the 12-months ending March 31, 2022, trued-up for known and measurable revenue, rate base, and expense items through December 31, 2022. The test year is a 12-month period used to determine the cost of Ameren Missouri providing service to customers. The Commission also issued a procedural schedule with an evidentiary hearing, for the parties to present evidence to the Commission on disputed case issues.

The Commission held six public comment hearings between January 31[2] and February 9, for the public to comment on Ameren Missouri's proposed revenue increase. Four of the public comment hearings were conducted in-person and two were conducted by video and teleconference. The Commission also received numerous written comments.

The parties prefiled direct, rebuttal, surrebuttal, and true-up direct testimony.

The Commission held an evidentiary hearing on April 12 through April 13, and an on-the-record presentation about the Agreement on April 14. The parties filed initial post-hearing briefs on May 5, and reply briefs on May 15.

The Agreement

On April 7, the parties filed the Agreement resolving all issues in the case related to Ameren Missouri's revenue requirement. The Agreement also resolves additional issues. The Commission will not address the issues the Agreement resolves, because

[2] Unless a year is specifically attached, date references are to 2023.

this Report and Order approves the Agreement as a resolution of those issues. Ameren Missouri, Staff, Public Counsel, MIEC, MECG, and Consumers Council cosigned the Agreement. The Agreement states that the remaining parties, Sierra Club, NAACP, Metropolitan Congregations, and Renew Missouri do not oppose the Agreement.

The revenue requirement is the amount Ameren Missouri is authorized to collect to cover its costs and a return on its investment. The Agreement resolves the revenue requirement allowing Ameren Missouri to increase its revenues by $140 million. That amount is less than half of the $316 million Ameren Missouri originally requested. The Agreement is a “black box” settlement. A “black box” settlement means that, while the parties reached an agreement on the issues, the Agreement does not address the details of how those agreements were reached, or how the global numbers were calculated.

The Agreement includes setting Ameren Missouri’s Weighted Average Cost of Capital at 6.82 percent for Plant-in-Service Accounting deferrals, Ameren Missouri’s Allowance for Funds Used During Construction, and the Renewable Energy Standard Rate Adjustment Mechanism. The Agreement sets the base amount for the Renewable Energy Standard Rate Adjustment Mechanism at $7,205,895. The Agreement sets the base factor for Ameren Missouri’s Fuel Adjustment Clause (FAC) at $0.01439 per kWh for summer and $0.01328 per kWh for winter. The Agreement establishes trackers for taxes, retirement benefits, and Renewable Energy Standard compliance. The Agreement also increases the budget for specific Low-Income Programs and provides that half of the contributions for those programs will come from shareholders and half will come from ratepayers.

Commission Rule 20 CSR 4240-2.115(1)(B) provides that the Commission may resolve part of a contested case based upon a stipulation and agreement. The Agreement is not considered unanimous by the Commission's rule 20 CSR 4240-2.115(2), even though no party objected to the Agreement, because all parties did not sign the Agreement. That rule allows parties seven days to object to a non-unanimous stipulation and agreement. That rule also allows the Commission to treat a non-unanimous stipulation and agreement as unanimous if no party timely objects. More than seven days have passed since the signatories filed the Agreement, and no party has objected. So, the Commission will treat the Agreement as unanimous.

After examining the Agreement, the Commission finds that it reasonably resolves the issues it addresses. Though it is a "black box" agreement, the Commission finds that the interests of the signatory parties were represented, and the non-signatory parties did not oppose the Agreement. As such, the Commission finds the interests of the Company, the ratepayers, Staff, and the various intervening entities were adequately represented and the Agreement provides for just and reasonable rates. The Commission will approve the Agreement and will direct the signatories to the Agreement to comply with its terms.[3]

Pending Motions

Staff filed a motion to strike portions of the testimony of Ameren Missouri witness Nicholas Bowden. At the evidentiary hearing, counsel for Staff stated that its motion to strike was moot if the Commission approved the Agreement.[4] Staff's motion is moot, so the Commission will not address it.

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[3] A copy of the agreement is attached to this order.
[4] Transcript, pages 365-366.

Sierra Club filed a motion for leave to late file its initial brief. The Commission will grant that motion.

General Findings of Fact[5]

The Commission makes the following general findings of fact:

1. Ameren Missouri is an investor-owned electric utility providing retail electric service to a 24,000 square mile area in central and eastern Missouri, including the greater St. Louis area.[6]

2. Ameren Missouri is the largest public utility in Missouri[7] and provides electric service to more than 1.2 million customers.[8]

3. Ameren Missouri is a member of the Midcontinent Independent System Operator, Inc. (MISO), a regional transmission organization (RTO). The Commission has authorized Ameren Missouri to participate in MISO through May 2024.[9]

4. Section 386.710(2), RSMo, and Commission Rule 20 CSR 4240-2.010(10), designates Public Counsel as a party this case.

5. Commission Rule 20 CSR4240-2.010(10) designates Staff as a party to this case.

General Conclusions of Law

A. Ameren Missouri is a public utility, and an electrical corporation, as defined in Subsections 386.020(15) and (43), RSMo. So, Ameren Missouri is subject to the Commission's jurisdiction under Chapters 386 and 393, RSMo.

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[5] All findings of fact and conclusions of law are cumulative and are not limited to the section where they are introduced.
[6] Exhibit 166, Won Direct, page 19.
[7] Exhibit 12, Bulkley Direct, page 33.
[8] Exhibit 23, Reed Direct, page 3.
[9] Exhibit 166, Won Direct, page 19.

B. The Commission has subject matter jurisdiction over Ameren Missouri's rate increase request under Section 393.150, RSMo.

C. Section 393.150, RSMo, authorizes the Commission to suspend the effective date of a proposed tariff for 120 days beyond its effective date, plus an additional six months.

D. Ameren Missouri can charge only those amounts set forth in its tariffs.[10]

E. Subsection 393.140(11), RSMo, gives the Commission authority to regulate the rates Ameren Missouri may charge its customers for electric service.

F. Utilities are required to provide safe and adequate service.[11]

G. The Commission must determine whether the proposed rates are just and reasonable when deciding the rates Ameren Missouri may charge its customers.[12]

H. Ameren Missouri has the burden of proving its proposed rates are just and reasonable, under Section 393.150.2, RSMo: "[a]t any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the … electrical corporation . . . ."

I. Ameren Missouri must meet the preponderance of the evidence standard to satisfy its burden of proof.[13] Ameren Missouri must convince the Commission it is "more likely than not" that its proposed rate increase is just and reasonable" to meet this standard.[14]

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[10] Sections 393.130 and 393.140, RSMo.
[11] Sections 393.130 and 393.140, RSMo.
[12] Section 393.150.2, RSMo.
[13] *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, 120 (Mo. App. 2007).
[14] *Holt v. Director of Revenue, State of Mo.*, 3 S.W.3d 427, 430 (Mo. App. 1999).

J. Witness credibility is a matter for the fact-finder, “which is free to believe none, part, or all of the testimony.”[15]

K. As fact-finder, an administrative agency like the Commission receives deference when choosing between conflicting evidence.[16]

L. A reviewing court will not substitute its judgment for the Commission’s judgment, where that decision involves an exercise of the Commission’s regulatory discretion, particularly on issues within Commission’s area of expertise.[17]

M. MECG’s proposed shift to increase the demand component for Large General Service and Small Primary Service, and decrease energy charges, allocation of production and distribution costs, and the reasonableness of Rider B calculations were also issues in File No. ER-2021-0240.[18]

Issues for Commission Determination

The remainder of this Report and Order decides the issues not settled in the Agreement. The parties presented evidence to the Commission on the unsettled issues at the evidentiary hearing and argued these issues in briefs.

The parties separated unsettled issues into three categories: 1) Class cost of service, revenue allocation, rate design, and Ameren Missouri’s request for a rate switching tracker; 2) Ameren Missouri’s continuing property record; and 3) identification of avoided capital investments for two power plants. Commission decisions on some

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[15] *State ex rel. Public Counsel v. Missouri Public Service Com'n*, 289 S.W.3d 240, 247 (Mo. App. 2009).
[16] *State ex rel. Missouri Office of Public Counsel v. Public Service Com'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009).
[17] *State ex rel. Missouri Gas Energy v. Public Service Com’n*, 186 S.W.3d 376, 382 (Mo. App. 2005).
[18] ER-2021-0240, Report and Order (issued February 2, 2022).

issues make deciding other issues unnecessary. The Commission rearranged issues within these categories for clarity.

1. Class Cost of Service, Revenue Allocation, Rate Design and Rate Switching Tracker.

A. Which parties' Class Cost of Service Study should be used in this rate case and used as a starting point for the non-residential rate design working case agreed to by the parties in Ameren Missouri's last electric general rate case, File No. ER-2021-0240?

B. How should any rate increase be allocated to the customer classes?

These issues are related and the Commission will address them together.

Findings of Fact:

6. A Class Cost of Service Study (CCOSS) is a tool used to design equitable rates. The purpose of a CCOSS is to allocate cost responsibility to customer classes based on causation.[19]

7. Ameren Missouri organizes customers with similar service voltages, uses, and demands into classes. Ameren Missouri currently serves the following customer classes: Residential or 1(M); Small General Service (SGS) or 2(M); Large General Service (LGS) or 3(M); Small Primary Service (SPS) or 4(M); Company-Owned Street & Outdoor Area Lighting 5(M); Customer-Owned Street & Outdoor Area Lighting 6(M); and Large Primary Service (LPS) or 11(M) classes.[20]

8. Ameren Missouri and Staff each developed a CCOSS to support their class allocation proposals. MECG and MIEC did not prepare their own CCOSSs, but used Ameren Missouri's CCOSS as a starting point and modified it to support their allocation proposals.

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[19] Exhibit 35, Hickman Direct, page 5.
[20] Exhibit 35, Hickman Direct, page 6.

9. Ameren Missouri prepared a CCOSS for its production plant using the 4 Non-Coincident version of Peak Average and Excess methodology (4NCP A&E).[21] The Average and Excess method allocates costs based on a weighting of average class demand and class excess demand during the CCOSS period. The Non-Coincident Peak method allocates costs based on the peak demand of each customer class at any time during the study period, without regard to the time of occurrence or magnitude of the coincident system peaks.[22] Ameren Missouri's application of the 4NCP A&E considers the four maximum non-coincident peaks months for each customer class that occurred during the test year. Ameren Missouri's study determined that those peaks occurred from June to September. [23]

10. Ameren Missouri witness Thomas Hickman credibly testified that Ameren Missouri has used the 4NCP methodology in Missouri rate cases since at least 2016, and he does not believe that Ameren Missouri has used a method other than the 4NCP in the last decade.[24]

11. Production plant investment is classified for allocation purposes as demand-related or energy-related. Production costs that are fixed do not vary with the amount of kWhs generated and are considered to be demand-related. Production fuel expense is considered a variable cost. The amount of fuel burned or fuel expense is closely related to the amount of energy that customers use. Fuel expense is an energy-related cost. Most production operation and maintenance (O&M) expenses are fixed and

[21] Exhibit 35, Hickman Direct, page 20.
[22] Exhibit 35, Hickman Direct, page 19.
[23] Exhibit 35, Hickman Direct, page 21.
[24] Transcript, page 158.

classified as demand-related. Variable production O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.[25]

12. 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. 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. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant.[26]

13. The 4NCP method does not include any considerations for renewable generation plant characteristics that are different from baseload generation. The 4NCP method also does not include any consideration for use of advanced metering infrastructure (AMI) data that can differentiate between class energy consumption during hours of the day.[27]

14. The electric distribution system is classified as both demand-related and customer-related. A portion of the cost of the distribution system consisting of poles, wires and transformers is required simply to construct a system’s electrical pathways that comply with local or national safety and reliability codes, and to attach customers to that system, regardless of their demand or energy requirements. This portion of the electric

[25] Exhibit 350, Brubaker Direct, pages 10-11.
[26] Exhibit 35, Hickman Direct, page 9.
[27] Transcript, page 158.

distribution system may be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage. Electric distribution system components that are sized to accommodate additional load beyond the capacity of the system, required by local or national safety and reliability codes, are considered demand-related cost.[28]

15. The customer-related cost 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.[29]

16. Ameren Missouri used a minimum size study to classify distribution costs between demand and customer components.[30] A minimum-size distribution study uses the minimum size pole, conductor, cable, and transformer that is currently installed or used by Ameren Missouri to serve its customers and classifies those costs as demand-related. The average book cost for the minimum standard item of equipment normally determines the customer-related cost of all installed units.[31]

17. The National Association of Regulatory Utility Commissioners' (NARUC) cost allocation manual from 1992 describes over 18 different production cost allocation methods, many of which have multiple variations.[32]

18. The 1992 NARUC manual, when addressing embedded cost of service studies like Ameren Missouri's minimum distribution study, states that classifying distribution plant using the minimum-size method "assumes that a minimum size

[28] Exhibit 350, Brubaker Direct, pages 11-12.
[29] Exhibit 35, Hickman Direct, page 9.
[30] Exhibit 38, Brown Surrebuttal, page 12.
[31] Exhibit 35, Hickman Direct, page 10.
[32] Exhibit 136, Lange Direct, page 19.

distribution can be built to serve the minimum loading requirements of the customer."[33] Ameren Missouri has approximately 648 primary voltage customers.[34] Ameren Missouri's minimum distribution study for plant accounts 364-368 uses components that operate at primary voltages,[35] but most of Ameren Missouri's customers take service at secondary voltage.[36] So, Ameren Missouri's minimum size study is oversized for a majority of Ameren Missouri's customers.[37]

19. Customers served at higher voltages, including 25 kV, have generally not had to pay costs for lower-voltage infrastructure under the theory that customers served at higher voltages do not use that infrastructure. Likewise, a customer served at 13.2 kV has not had to pay for secondary-voltage infrastructure on the premise that they are not using that infrastructure.[38]

20. Staff argues that the Average and Excess allocator is less reasonable for allocation of the revenue requirement associated with Ameren Missouri's production plant included in rate base since MISO's integrated marketplace was introduced.[39] This is largely because Ameren Missouri's fuel costs vary with the demand for energy in a given hour of the regional load, and do not vary with the Ameren Missouri load relied on in Ameren Missouri's Average and Excess allocator analysis.[40]

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[33] Exhibit 137, page 34.
[34] Exhibit 35, Hickman Direct, page 6.
[35] Exhibit 137, Lange Rebuttal, page 37.
[36] Exhibit 137, Lange Rebuttal, page 36.
[37] Exhibit 137, Lange Rebuttal, page 47.
[38] Exhibit 136, Lange Direct, page 12.
[39] Exhibit 137, Lange Rebuttal, page 25.
[40] Exhibit 137, Lange Rebuttal, page 26.

21. In November of 2021, MISO submitted proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff to establish seasonal resource adequacy requirements.[41]

22. Staff prepared a CCOSS in an effort to move toward rate modernization. Staff used different allocation methods for different generation resources. Staff's generation allocation study categorized generation assets as those with significant variable operation costs that can be avoided if the generation resource is offline (Type 1) and generation assets with no or minimal variable operation costs that are limited by weather or other factors beyond Ameren Missouri's control (Type 2).[42] Staff allocated Type 1 assets on the basis of demand, utilizing an "All Peak Hours Approach" (described in the 1992 NARUC manual) based on each class's contribution to identified MISO Resource Adequacy hours. That is then offset by a class's allocation of Type 2 assets.[43]

23. Staff's CCOS approach differs from other parties' CCOSSs in that it attempts to allocate specific utility infrastructure to the customers who /predominantly use that infrastructure.[44]

24. Staff sees its approach in this case as an interim step toward rate modernization. Staff believes an interim step is necessary because Staff has struggled to gather sufficient information from Ameren Missouri for rate modernization. Staff does not

[41] Exhibit 136, Lange Direct, page 17.
[42] Exhibit 136, Lange Direct, pages 20-21.
[43] Exhibit 36, Hickman Rebuttal, page 15, and Exhibit 136, Lange Direct, pages 21.
[44] Transcript, page 409.

know the totality of what information exists and believes a workshop (working docket) where information is exchanged would be productive. [45]

25. As an alternative to Staff's CCOSS allocation, Staff supports as reasonable an equal percentage increase to all classes other than Company-owned lighting.[46] Staff Witness, Sarah Lange, indicated that Staff would not oppose postponing rate modernization to the Company's next rate case, if the Commission ordered Ameren Missouri to retain and provide the minimum information Staff believes is necessary for rate modernization.[47]

26. Public Counsel also supports an equal increase for all classes with the exception of Company owned lighting.[48]

27. MECG's witness Steve Chriss supports using the 4NCP A&E allocation method as a reasonable allocation method.[49] Chriss suggests that Ameren Missouri's CCOSS does not comply with the requirements of Section 393.1620.1(1) RSMo because the 4NCP in the 4NCP A&E should be determined using the four months with the highest system peak loads. Chriss testifies that Ameren Missouri's 4NCP used different months depending on class. Chriss's modification of Ameren Missouri's CCOSS uses the four highest system peak load months.[50]

28. MIEC's witness Maurice Brubaker used Ameren Missouri's CCOSS as a starting point and modified a few allocations.[51] MIEC's CCOSS was not based on a

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[45] Transcript, page 409-412. Staff's use of workshop here does not refer to the non-residential rate design docket, but a workshop including all rate structures and classes.
[46] Exhibit 137, Lange Rebuttal, page 53, Footnote 9.
[47] Transcript, pages 418-419.
[48] Transcript, page 343.
[49] Exhibit 400, Chriss Direct, pages 3-4.
[50] Exhibit 400, Chriss Direct, page 18.
[51] Exhibit 36, Hickman Rebuttal, page 3.

particular revenue requirement, but was revenue neutral.[52] Brubaker disagrees with Ameren Missouri's treatment of non-labor component of production non-fuel O&M. Ameren Missouri allocates a larger proportion of non-fuel production O&M expense to energy than Brubaker. Because these expenses are more a function of the existence of generation facilities and the passage of time, he allocated them as a demand-related cost. Another change from Ameren Missouri's CCOSS is that Brubaker calculated taxes at the current rate based upon the taxable income of each class. He states that this alteration reduces the costs charged to the Residential class and increases the rate of return from the Residential class.[53]

29. CCOSSs serve as a guide for setting class revenue requirements, but should not be strictly relied upon for establishing each individual class's revenue requirements. CCOSSs are not precise, and are not updated for changes from the studied revenue requirement ($316 million) and billing determinants.[54] CCOSSs do not account for the settled revenue requirement ($140 million) and ordered billing determinants.

30. Staff testified that a utility's physical characteristics and accessible data fluctuate, and accordingly, the Commission hardly ever approves a particular allocation method because the appropriate method can vary from rate case to rate case.[55] If the revenue requirement is evenly distributed across the rate classes a CCOSS is not necessary.[56]

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[52] Transcript, page 369.
[53] Exhibit 350, Brubaker Direct, page 3.
[54] Exhibit 136, Lange Direct, page 27.
[55] Exhibit 136, Lange Direct, page 20.
[56] Transcript, page 373.

30. Outside of a CCOSS, other considerations exist to guide setting class revenue requirements. Policy considerations like rate continuity, rate stability, revenue stability, and minimizing rate shock are useful for setting class revenue responsibilities.[57]

31. The Company-owned lighting class is paying rates above its rate of return on base rate cost of service. The Customer owned lighting class is paying rates below its class cost of service. To avoid potential rate shock, Ameren Missouri is not proposing to adjust each lighting class to an equal return. Instead, Ameren Missouri proposes small adjustments over time to gradually align the two classes with their respective costs of service. This smaller revenue neutral shift toward cost of service for both lighting classes is what the Commission ordered in Ameren Missouri's last rate case.[58] The Company proposes a small incremental of $60,000[59] revenue neutral shift for the lighting classes. Customer owned lighting would be increased by $60,000 and Company owned lighting would decrease $60,000.

32. As an alternative to a $60,000 revenue neutral shift, Staff proposes that, based upon the results of Ameren Missouri's CCOSS, it would be reasonable to hold the Company's lighting class revenue requirement constant, and to apply an equal percent increase to the revenue requirements of all other classes including customer owned lighting.[60]

33. The two complete CCOSSs prepared in this case are very different. Ameren Missouri's CCOSS shows the Residential and SGS customers pay below target rates of

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[57] Exhibit 136, Lange Direct, page 27.
[58] Exhibit 32, Harding Direct, page 7-8.
[59] Exhibit 32, Harding Direct, Schedule MWH-D2.
[60] Exhibit 137, Lange Rebuttal, page 53.

return, while LPS customers pay above target rates of return. Staff's CCOSS, conversely, shows Residential and SGS customers pay close to target rates of return and LGS, SPS, and LPS customers pay below target rates of return. Both of these cannot be correct.[61]

34. Ameren Missouri's witness Steven Wills, MIEC's witness Maurice Brubaker, and MECG's witness Steve Chriss recommend postponing Staff's proposed changes to non-residential rate plans to a separate proceeding.[62]

35. Ameren Missouri says that without guidance from the Commission about which CCOSS should be used, any collaborative process concerning future rate design (such as the non-residential working docket) between the parties may become strained.[63]

36. Ameren Missouri has implemented Plant-In-Service-Accounting (PISA). A cost recovery mechanism to recover costs associated with the Company's capital expenditures between rate cases.[64]

Conclusions of Law:

N. Section 393.1620.2 RSMo states that the Commission must only consider CCOSS results that allocate production plant costs from nuclear and fossil power plants using the average and excess method, or one of the methods in the NARUC 1992 manual, to allocate an electrical corporation's total revenue requirement in a general rate case.

O. Section 393.130.3 RSMo, states;

> No … electrical corporation … shall make or grant any undue or unreasonable preference or advantage to any person, corporation or locality, or to any particular description of service in any respect whatsoever, or subject any particular person, corporation or locality or any particular

[61] Exhibit 36, Hickman Rebuttal, page 2.
[62] Exhibit 41, Wills Surrebuttal, page 23.
[63] Exhibit 41, Wills Surrebuttal, pages 24-25.
[64] Exhibit 12, Bulkley Direct, page 59.

> description of service to any undue or unreasonable prejudice or disadvantage in any respect whatsoever.

In interpreting that statute more than 90 years ago, the Missouri Supreme Court said: "[R]ates or charges to be valid must not be unjust, unreasonable, unjustly discriminatory, or unduly preferential."[65]

P. The Commission has much discretion in determining the theory or method it uses in determining rates[66] and can make pragmatic adjustments called for by particular circumstances.[67]

Q. Cost-allocation is a discretionary determination frequently delegated to an expert administrative agency such as the Commission. In that regard, the Missouri Court of Appeals quoted approvingly the United States Supreme Court as saying "[a]llocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[68]

R. For an electrical corporation that has elected PISA under Section 393.1400, RSMo, (as has Ameren Missouri) Section 393.1655.6, RSMo, provides that:

> If the difference between (a) the electrical corporation's class average overall rate at any point in time while this section applies to the electrical corporation, and (b) the electrical corporation's class average overall rate as of the date rates are set in the electrical corporation's most recent general rate proceeding concluded prior to the date the electrical corporation gave notice under subsection 5 of section 393.1400, reflects a compound annual growth rate of more than two percent for the large power service rate class, the class average overall rate shall increase by an amount so that the increase shall equal a compound annual growth rate of

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[65] *State ex rel. Laundry, Inc. v. Public Service Com'n* 34 S.W.2d 37, 44, 327 Mo. 93, 109 (Mo. 1931)

[66] *State ex rel. Public Counsel v. Public Service Com'n*, 274 S.W.3d 569, 586 (Mo. App. 2009).

[67] *State ex rel. U.S. Water/Lexington v. Missouri Public Service Com'n* 795 S.W.2d 593, 597 (Mo. App. 1990)

[68] *Spire Missouri, Inc. v. Missouri Public Service Com'n* 607 S.W.3d 759, 771 (Mo. App. 2020), *quoting National Ass'n of Greeting Card Publishers v. U.S. Postal Service*, 462 U.S. 810, 103 S.Ct 2727, 77 L.Ed. 2d 195 (1983). That decision was quoting an earlier United State Supreme Court decision, *Colorado Interstate Gas Co. v. Federal Power Commission,* 324 U.S. 581, 589, 65 S.Ct. 829, 833, 89 L.Ed. 1206 (1945).

> two percent over such period for such large power service class, **with the reduced revenues arising from limiting the large power service class average overall rate increase to two percent to be allocated to all the electrical corporation's other customer classes through the application of a uniform percentage adjustment to the revenue requirement responsibility of all the other customer classes. (**Emphasis added)

This statute does not have any direct impact on this rate case because the cap it imposes has not yet been met. But it does mean that in a future rate case the Residential rate class, as well as Ameren Missouri's other rate classes, could be statutorily required to subsidize the Large Power Service class. It also means that the legislature has recognized that class cost of service decisions can be based on consideration of public policy interests rather than a strict mathematical calculation.

Decision:

The Commission finds none of the parties' CCOSSs suitable for setting rates that are just and reasonable in this rate case. The Commission finds Staff's concerns about Ameren Missouri's CCOSS credible. The Commission finds Staff's CCOSS insufficient for allocating class revenue responsibilities because Staff was unable to obtain the necessary information to complete more than an interim step toward its goal of rate modernization. MECG and MEIC's modifications to Ameren Missouri's CCOSS do not address the underlying problems with the CCOSS they modify. Accordingly, with the exception of the Company owned lighting class, to which no increase is applied, no rate class allocation adjustments are necessary. The Commission finds that the revenue increase settled in the Agreement should be allocated to all customer classes on an equal percentage basis.

This issue also asked which party's CCOSS to use as a starting point for the non-residential rate design working case agreed to by the parties in Ameren Missouri's last rate case, File No. ER-2021-0240. The Commission will not select a CCOSS to be a starting point to the non-residential working docket. The Commission does not find it appropriate to endorse a particular CCOSS methodology. The non-residential working docket should not be constrained to a particular rate design methodology. Instead, as addressed elsewhere in this order, that collaborative process is largely dependent on Ameren Missouri providing sufficient data and information to Staff and participants so an exploration of non-residential rate design is productive.

The Commission finds it reasonable to hold Company owned lighting rates constant and apply the revenue requirement as an equal percentage to all other classes.

Though the Commission did not find any party's CCOSS suitable for allocating Ameren Missouri's revenue requirement in this case, the Commission continues to believe that cost-based rates are appropriate. It also believes that this decision will result in rates that are not unduly prejudicial to members of any of Ameren Missouri's rate classes.

C. How should production costs be allocated among customer classes within a CCOSS?

D. How should distribution costs be allocated among customer classes within a CCOSs?

These issues are related and the Commission will address them together.

Findings of Fact:

There are no additional findings of fact for these issues.

Conclusions of Law:

S. The Commission is not authorized to issue advisory opinions.[69]

Decision:

The allocation of production and distribution costs among customer classes are major components of the CCOSS. The Commission is not making a determination concerning the appropriate CCOSS. Any determination by the Commission on how to allocate production and distribution costs would have no practical effect and would essentially be an advisory opinion that the Commission is not authorized to issue. The Commission is allocating Ameren Missouri's revenue requirement on an equal percentage basis, so it does not need to decide these sub-issues.

E. What customer charges should apply to residential rate plans?

a. If the customer charges for the Ultimate Saver and Smart Saver Plans are discounted relative to other residential rate plans, should a minimum demand charge be imposed with customers to be fully educated on the minimum demand charge?

Findings of Fact:

37. The customer charge covers customer related costs. The customer charge includes the costs of meters and service lines that connect to a customer’s premises, billing costs, and a share of the fixed costs of the distribution grid.[70]

38. Customer charges are fixed and cannot be avoided by customers. They are incurred regardless of a customers demand or energy requirements.[71]

[69] *State ex rel. Laclede Gas Co. v. Public Service Com’n*, 392 S.W.3d 24, 38 (Mo. App. 2012).
[70] Exhibit 39, Wills Direct, page 22.
[71] Exhibit 39, Wills Direct, pages 24-25.

39. Currently, all Ameren Missouri residential rate plans have $9.00 per month fixed monthly customer charge.[72]

40. Ameren Missouri's analysis of customer-related costs from its CCOSS suggests that $25.94 a month residential customer charge accurately reflects customer related costs.[73]

41. Ameren Missouri introduced time of use (TOU) rates in its 2019 general rate case.[74] Ameren Missouri currently offers five residential rate plans including TOU rate plans. Ameren Missouri's TOU plans include the Anytime plan, the Evening/Morning Saver plan, the Overnight Saver plan, the Smart Saver plan, and the Ultimate Saver plan.[75]

42. Ameren Missouri proposes establishing different customer charges for its different residential rate plans.[76]

43. Each of Ameren Missouri's residential rate plan has a different applicable time of use periods. Ameren Missouri's rate plans, time of use periods, peak/off-peak price differentials, and proposed customer charge are accurately represented in the following chart:[77]

Rate Plan	TOU Periods	Peak/Off-Peak Price Differential	Proposed Customer Charge
Anytime	None	None	$13.00
Evening/Morning Saver	Peak: 9 a.m. to 9 p.m. daily Off-Peak: 9 p.m. to 9 a.m. daily	Small	$13.00
Overnight Saver	Peak: 6 a.m. to 10 p.m. daily Off-Peak: 10 p.m. to 6 a.m. daily	Moderate	$13.00

[72] Exhibit 39, Wills Direct, page 24.
[73] Exhibit 39, Wills Direct, page 24.
[74] Exhibit 1, Wood Direct, page 5.
[75] Exhibit 39, Wills Direct, page 27.
[76] Exhibit 39, Wills Direct, page 27.
[77] Exhibit 39, Wills Direct, pages 4 and 27.

Rate Plan	TOU Periods	Peak/Off-Peak Price Differential	Proposed Customer Charge
Smart Saver	Summer Peak: 3 - 7 p.m. weekdays Non-summer Peak: 6 - 8 a.m. and p.m. weekdays Off-Peak: 10 p.m. to 6 a.m. daily Intermediate: All other hours	Large	$11.00
Ultimate Saver	Summer Peak: 3 - 7 p.m. weekdays Non-summer Peak: 6 - 8 a.m. and p.m. weekdays Off-Peak: All other hours	Large	$9.00

44. Rate differential refers to the difference between the per kWh charge during different defined time periods, such as on-peak and off-peak periods. For example, the current Smart Saver rate has a peak summer rate of approximately 33½ cents/kWh, and an off-peak rate of almost 6½ cents/kWh, for a peak to off-peak price ratio of approximately 5:1. This large price differential creates more savings when customers shift usage to the off-peak period, but could increase costs for a customer that has significant usage during the 33½ cents/kWh on-peak periods that they are unable or unwilling to shift.[78]

45. For the Ultimate Saver, in addition to the customer charge for this residential rate plan, Ameren Missouri proposes a demand charge.[79]

46. In support of its rate plans, Ameren Missouri contends that for the different customer charges some of the rate plans, specifically the Ultimate Saver and the Smart Saver are the most cost-reflective rate design. According to Ameren Missouri, The other three plans, Anytime, Evening/Morning Saver and Overnight Saver, are not as sophisticated and are more prone to outcomes where some customers may not contribute equitably to the minimum distribution system fixed costs. Ameren Missouri's witness Wills

[78] Exhibit 39, Wills Direct, page 5, Footnoe 3.
[79] Exhibit 39, Wills Direct, page 4

further states that the Company's new proposed rate structures, including the customer charge, are intended to send price signals to encourage customers to adopt technologies like battery storage, electric vehicle (EV) charging, smart thermostats and other home automation, and intermittent resources like solar.[80]

47. Ameren Missouri's proposed $13.00 customer charge for three of its rate plans results in a 44.44 percent increase over the current $9.00 customer charge.[81] Ameren Missouri is proposing lower customer charges on the TOU rate plans that have more risk or a higher peak to off-peak differential.[82]

48. Staff conducted an analysis based upon the annual average bills of 99 random customers. Staff's analysis of the Ultimate Saver plan showed that out of those 99 customers, 16 customers experienced a decrease, with an average value of six percent, but 83 customers experienced an increase, with an average size of 11 percent. The largest increase was 41 percent, and the largest decrease was 23 percent. As part of Staff's analysis, they reviewed the impact of the demand charge on these customers. The analysis shows that the customer with the lowest annual demand charge calculation would be billed $99.01 in demand charges, for an average of $4.52 per month. The average demand charge calculated was $33.00 per month, averaging $21.98 for non-summer months and $55.06 for summer months. Staff concludes that the inclusion of the demand charge with the Ultimate Saver plan is incredibly risky for ratepayers under the rate design proposed by Ameren Missouri in this case.[83]

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[80] Exhibit 39, Wills Direct, pages 27-28
[81] Exhibit 201, Marke Surrebuttal, page 30.
[82] Exhibit 201, Marke Surrebuttal, page 30.
[83] Exhibit 138, Lange Surrebuttal, pages 5-6.

49. Ameren Missouri's witness Steven Wills acknowledged that there are natural "winners" and "losers" on TOU rates without any customer behavioral changes.[84] Staff expressed concern that the lower customer charge will promote the riskiest TOU plans to customers least equipped to handle high bills.[85]

50. Increasing the customer charge positively impacts above-average use customers and negatively impacts below-average use customers. Conversely, a lower customer charge favors below-average use customers. Below-average use customers would include low-income customers, renters, and customers who have invested in energy efficiency or solar.[86]

51. Staff also studied the costs classifiable to the customer charge and its results indicated that the high end of the reasonable range for the residential customer charge is under $8.00 per month. Staff does not recommend reducing the customer charge and as a result recommended retaining the customer charge for all residential rate schedules at the current level of $9.00 per month.[87]

52. Public Counsel recommends maintaining the customer charge at $9.00 per month customer charge for all residential rate plans.[88]

53. Renew Missouri's witness disagrees with Ameren Missouri's position that different customer charges for the residential rate plans will encourage adoption of distributed generation (DG) technologies. To the contrary, James Owen believes that it will discourage adoption of DG technologies.[89]

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[84] Exhibit 39, Wills Direct, page 14.
[85] Transcript, pages 432-433.
[86] Exhibit 201, page 29 and Exhibit 450, Owen Rebuttal, page 15
[87] Exhibit 136, Lange Direct, pages 31-32
[88] Exhibit 201, Marke Surrebuttal, page 35
[89] Exhibit 450, Owen Rebuttal, page 15

54. Consumer Council of Missouri's witness recommends the customer charge remain at its current level of $9.00 per month. To promote affordability, rates should be based more on energy usage than on fixed amounts. Consumers Council would prefer that the rate design for residential customers include a fixed charge that is based on the cost of the meter, customer service, and the line to the dwelling.[90]

Conclusions of Law:

T. Sections 393.130 and 393.140, RSMo, mandate that the Commission ensure that all utilities are providing safe and adequate service and that all rates set by the Commission are just and reasonable.

Decision:

The Commission finds it appropriate to maintain the current $9.00 customer charge for all residential rate plans. Customers cannot avoid paying the customer charge because it is a fixed charge, and it is not dependent on energy usage or demand. Higher customer charges negatively affect a customer's ability to lower their utility bill through conservation and energy efficiency measures. This directly conflicts with one of the purposes of TOU rate options. TOU rate options provide customers with rate choice options and a means to save money on their utility bills and cut peak demand at the same time.

Ameren Missouri proposes instituting different customer charges for different TOU rate plans. Ameren Missouri theorizes that differentiated customer charges will send price signals to encourage customers to adopt energy efficient technologies. However, TOU rates provide price signals even without a differentiated customer charge through peak

[90] Exhibit 300, Hutchinson Direct, page 13

and off-peak pricing. An unavoidable fixed charge does little to inform customers to change usage patterns. Ameren Missouri's proposed lower customer charge for the Ultimate Saver plan makes it an attractive plan for customers wanting to maximize bill savings. However, the Ultimate Saver plan is a risky plan for customers who may not fully understand the risks of the TOU rate with its demand charge. Many Ultimate Saver customers will pay more than they would on the Smart Saver or Anytime plans. As Ameren Missouri acknowledged, TOU rates can be inherently confusing for customers, therefore differentiating the customer charge for different TOU rate plans merely adds to this confusion. The Commission finds it appropriate to maintain the current $9.00 customer charge for all of its Residential rate plans.

F. What changes should be made, if any, to the Residential rate plans offered by the Company?

a. Should Staff's proposal to eliminate the Anytime (flat) rate option for any Residential customers who have an AMI meter be approved?
b. What changes, if any, should be made to the deployment of residential TOU rate plans?
c. Should the Commission order Ameren Missouri to provide a study about offering TOU rates to customers with distributed generation?

These sub issues are related and the Commission will address them together.

Findings of Fact:

55. TOU residential rate plans are available for all customers with AMI meters.[91] Approximately two thirds of Ameren Missouri customers have AMI meters.[92]

[91] Exhibit 39, Wills Direct, page 5
[92] Transcript, pages 245 and 355.

56. Customers who do not affirmatively elect a rate plan six months after receiving their AMI meter, are transitioned to the Evening/Morning Saver rate plan, the current default TOU rate plan.[93]

57. As of July 20, 2022, 359,115 customers are on the Evening/Morning Saver plan, 522 customers are on the Overnight Saver plan, 366 customers on the Smart Saver plan and 302 customers on the Ultimate Saver plan. As of that date, 519,333 customers with AMI meters, have opted for, or switched from a residential TOU rate plans, to the Anytime plan.[94]

58. Customers on the Overnight Saver, Smart Saver and Ultimate Saver residential rate plans are allowed the option to participate in TOU pricing during the summer only.[95]

59. The Smart Saver and Ultimate Saver rate plans provide the greatest rate differential between peak and non-peak rates.[96]

60. Ameren Missouri presented results that indicate for Overnight Saver, Smart Saver and Ultimate Saver TOU rate plans, around 80 percent of the customer outcomes and individual bills are lower than they would be for the same customers on the Anytime rate plan.[97]

61. The Anytime rate plan and Evening/Morning Saver rate plan produce very similar bills for customers.[98]

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[93] Exhibit 39, Wills Direct, pages 5-6
[94] Exhibit 39, Wills Direct, page 7
[95] Exhibit 39, Wills Direct, page 4
[96] Exhibit 39, Wills Direct, page 4
[97] Exhibit 39, Wills Direct, page 8
[98] Exhibit 39, Wills Direct, page 8, Footnote 6

62. Ameren Missouri testified that TOU rates can be a valuable system planning tool to help reduce peak demand and capacity needs, as well as to help integrate increasing levels of intermittent renewable generation.[99]

63. Staff recommends the Evening/Morning Saver rate schedule be modified to eliminate the six-month lead-in period for changes to TOU rates so that customers can receive service under the Evening/Morning Saver plan from the first billing month after AMI meters are installed.[100]

64. Staff also recommends eliminating the Anytime rate schedule for customers with an AMI meter.[101]

65. Public Counsel agrees with Staff that the Evening/Morning Saver plan should be the default plan for customers with an AMI meter, but opposes eliminating the 6-month phase-in.[102]

66. Ameren Missouri provides reasons why Staff's recommendation to eliminate the 6-month transition period for the Evening/Morning Saver plan is problematic:

1) Allows time for Ameren Missouri to collect interval data from the AMI meter to provide customers with an accurate rate comparison information to empower their decision.
2) Customers receive specific communication on the rate options, along with personalized rate comparison data.[103]

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[99] Exhibit 39, Wills Direct, pages 9-10
[100] Exhibit 136, Lange Direct, page 34.
[101] Exhibit 136, page 32.
[102] Exhibit 201, Marke Surrebuttal, page 28
[103] Exhibit 40, Wills Rebuttal, pages 7 and 8

67. Ameren Missouri argues that the elimination of the Anytime rate would eliminate a popular rate and reduce customer choice.[104]

68. Renew Missouri asks the Commission to direct Ameren Missouri to provide a study about offering TOU rates to customers with distributed generation.[105]

69. Ameren Missouri allows customers with their own generation or with service under its net-metering tariff to participate in the Evening/Morning Saver rate plan. Ameren Missouri does not allow net-metering customers to participate in the Overnight Saver, Smart Saver, or Ultimate Saver rate plans.[106] Renew Missouri witness, James Owen, offers policy considerations for offering TOU rate options to distributed generation customers. Offering distributed generation customers the same rate options as other customers encourages the installation of distributed generation technologies, including rooftop solar and battery storage, and promotes electric vehicle adoption.[107]

70. Ameren Missouri expressed interest in making more TOU rates available to net metering customers, but does not believe that is as drafted under Section 386.890.3 RSMo, the Net Metering and Easy Connect Act, does not contemplate the application of TOU rates, and when applied as written, does not allow the billing of TOU rates in an economically-rational manner.[108]

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[104] Exhibit 40, Wills Rebuttal, page 4
[105] Exhibit 450, Owen Rebuttal, page 4.
[106] Exhibit 450, Owen Rebuttal, page 5.
[107] Exhibit 450, Owen Rebuttal, page 6.
[108] Exhibit 41, Wills Surrebuttal, page 21, and Section 386.890.3 RSMo.

71. For the Evening/Morning Saver rate plan, Ameren Missouri proposes to allow customers the option to request all other eligible rare options subject to the term of use and provisions of those rates and can return to this rate at any time.[109]

72. For the Anytime rate plan, customers would be able to switch to this rate plan at any time as an optional rate at the customer's election.[110]

73. The rate plan selected by the customer shall be applied to the customer's account for a period of not less than one year, unless customer elects to transfer to a different rate during the first ninety (90) days of service.[111]

74. Ameren Missouri has an existing process for providing rate education and a detailed bill comparison for each rate plan to customers after receiving the AMI meter.[112]

75. Making changes to the TOU rate structures would be disruptive to the education process and could potentially cause confusion or frustration with the TOU experience.[113]

Conclusions of Law:

U. There are no additional conclusions of law for these issues.

Decision:

The Commission finds it necessary to make several changes to the residential TOU rate plans Ameren Missouri offers. When determining just and reasonable rates for ratepayers and the Company, the Commission considers both Ameren Missouri's TOU

[109] Exhibit 32, Harding Direct, Schedule MWH-D1, Sheet No. 54.4.
[110] Exhibit 32, Harding Direct, Schedule MWH-D1, Sheet No. 54.
[111] Exhibit 32, Harding Direct, Schedule MWH-D1, Sheet No. 134.
[112] Exhibit 32, Harding Direct, Schedule MWH-D1, Sheet No. 134.
[113] Exhibit 39, Wills Direct, page 6.

rates and TOU rates throughout Missouri. TOU rates, as previously discussed, send price signals to customers by having different rates for peak and off-peak usage. Those price signals should relay a consistent message that the price of energy varies throughout the day.

Ameren Missouri's current default TOU rate plan for customers with an AMI meter is the Evening/Morning Saver plan. The Evening/Morning Saver plan has a small price differential between peak and off-peak pricing and produces similar bill outcomes to the Anytime plan, which is a non-TOU residential plan. The Smart Saver plan has a greater potential to reduce peak load than the Evening/Morning Saver plan and 81 percent of the smart saver customers saved on their bills when compared to the Anytime plan. The Commission finds the Smart Saver plan more appropriate as the default residential TOU plan for Ameren Missouri's customers with an AMI meter. The Smart Saver plan most closely aligns with other electric TOU default plans in Missouri. The Smart Saver plan has two options, a year-round option, and a summer-only option. The Commission finds that the Smart Saver year-round option is the appropriate default option.

Two thirds of Ameren Missouri's customers have AMI meters. Those customers have already defaulted into the Evening/Morning Saver plan, or have selected another TOU rate plan, or the Anytime plan. The Commission wishes to honor the choices of customers already in a TOU plan. The default Smart Saver plan only applies moving forward to customers who do not yet have an AMI meter or customers establishing a new account.

In order for Ameren Missouri to have sufficient time to institute an effective education program to inform customers about TOU rate impacts, to permit Ameren

Missouri time to engage with customers about the new default rate, and so customers have time to adjust their usage patterns before next summer, the Commission finds that the Smart Saver default rate must take effect no later than March 31, 2024. Ameren Missouri must take extra steps to educate space heating customers about the new default plan because those customers could experience greater impacts from the Smart Saver plan.

Staff has asked to eliminate the Anytime plan as an option for customers with an AMI meter. The Commission does not find it appropriate to eliminate the Anytime plan, as it would eliminate a choice available to customers. The Commission encourages customers to take control of their electric utility bills by adopting one of Ameren Missouri's TOU plans. However, certain customers may want to maintain the same rate for all hours of the day, without having to determine whether they are using electricity during a peak usage time. Therefore, the Commission will maintain the Anytime rate as an option for those customers.

Not every customer will reduce their bill and save money on a particular TOU rate plan. Inevitably, as customers endeavor to find the TOU plan that best suits their electric usage, customers may want to switch plans. The Commission does not want to discourage customers from finding the best plan for them, but the Commission does not want to overload Ameren Missouri with customers who may want to change plans frequently. Therefore, the Commission finds that customers must be allowed to change plans up to three times a year. Customers may not change between optional TOU plans more than once in a billing cycle. However, customers may switch to the default Smart Saver plan and the Anytime plan without limitation or restriction.

Renew Missouri's requests that the Commission direct Ameren Missouri to conduct a study on integrating distributed generation technologies and TOU rate plans is reasonable. In view of the forgoing, the Commission will direct Ameren Missouri to conduct such a study.

G. What changes should be made, if any, to the Non-Residential, Non-Lighting rate options offered by the Company?

- **a. Should Staff's proposal to introduce a time-based overlay for all Non-Residential, Non-Lighting classes for all customers who have an AMI meter and are not served on a time-based schedule be adopted?**
- **b. Should MECG's proposed shift to increase the demand component for Large General Service and Small Primary Service and decrease energy charges be adopted?**
- **c. Should the Commission approve MECG's proposed optional electric vehicle (EV) charging 3M/4M rate design?**
- **d. Should the Rider C factor be adjusted?**
- **e. Should the values for the monthly customer charge, Rider B credits, and Reactive Charge remain consistent for SPS and LPS customers because these costs are effectively the same regardless of the customer class?**

These sub-issues are related and the Commission will address them together.

Findings of Fact:

76. Staff recommends the Commission order that non–residential customers with AMI meters be billed time-based rates through the introduction of a revenue neutral TOU overlay to be introduced into a parallel rate structure for each non-residential non-lighting rate class. Essentially creating time based rates where, prior to Staff's overlay, they did not exist.[114]

77. Staff's desire to explore rate structure changes that would apply to non-residential large customers belongs in a separate proceeding, where staff could collaborate with Ameren Missouri and interested parties prior to the next rate case filing.

[114] Exhibit 136 Sarah Lange Direct, page 40

This approach (followed by Evergy) permits all participants to have an opportunity to consider impacts, solutions, and have their concerns heard.[115] Both MECG and MIEC recommend that Staff's non-residential rate design proposals be evaluated in a working docket.[116] MECG asks the Commission to reject Staff's TOU overlay and establish the non-residential working docket ordered in File No. ER-2021-0240. The non-residential working docket will give all interested parties a collaborative opportunity to fully examine relevant factors, inputs, and outputs to ensure that the resulting rates are cost-based, equitable, and just and reasonable.[117]

78. MECG's witness, Steve Chriss's analysis suggests that the LGS and SPS classes are paying rates in excess of their cost of service.[118]

79. MECG proposes that the Commission take steps to address an over-recovery of the demand charge for LGS and SPS customers through the energy charge by increasing the summer and winter demand charges for LGS and SPS by one and one-half times the percent of the approved class percentage increases.[119]

80. Allocation of fixed production plant costs on an energy basis can introduce shifts in cost responsibility from lower load factor classes to higher load factor classes.[120]

81. It would be directionally consistent with cost of service principles for the Commission to increase the proportion of revenues coming from the demand charge to the extent that the distribution demand related costs are not currently fully reflected by the level of the current demand charge.[121]

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[115] Exhibit 351, Brubaker Rebuttal, pages 12-13
[116] Exhibit 351, Brubaker Rebuttal, pages 12-13, and Exhibit 401, Chriss Rebuttal, page 12.
[117] Exhibit 401, Chriss Rebuttal, pages 4-5.
[118] Exhibit 400, Chriss Direct, page 25.
[119] Exhibit 400, Chriss Direct, page 5.
[120] Exhibit 400, Chriss Direct, page 11.
[121] Exhibit 40, Wills Rebuttal, pages 24-25.

82. Any amount of movement in the demand charge relative to the energy charge should be gradual to avoid any significant bill impacts on the customers in the class that might arise from significant changes in the relative weighting of the different charges.[122]

83. Any changes in the demand charge should be moderated to maintain gradualism in the way they impact all customers including those with EV charging applications.[123]

84. MECG proposes the Commission order Ameren Missouri to create alternative optional LGS and SPS rates for EV charging customers. MECG proposes to reallocate the summer demand charge revenue requirement to the first block of the summer energy rate, and reallocate the winter demand charge revenue requirement to the first block of the winter energy rate. MECG says this would reduce the barrier to entry for very low usage EV chargers versus LGS and SPS's demand charges, and it would recover the demand charge revenue requirements in the low load factor first blocks.[124]

85. A new EV rate would restrict the rate to only customers with significant EV charging applications, which would require additional administrative procedures to verify the eligibility of the customer for the optional rate.[125]

86. A new EV rate would potentially risk having every low load factor customer in these rate classes adopt the optional rate and reduce their bill as a "free rider" on the EV rate.[126]

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[122] Exhibit 40, Wills Rebuttal, page 25.
[123] Exhibit 40, Wills Rebuttal, page 25.
[124] Exhibit 400, Chriss Direct, pages 36-37.
[125] Exhibit 40, Wills Rebuttal, page 25.
[126] Exhibit 40, Wills Rebuttal, p. 25.

87. Staff opposes the creation of rate schedules for LGS and SPS EV charging customers. MECG's proposal would substantially reduce the accretive earnings assumed in justifying the Charge Ahead portfolio. MECG's EV proposal is also not cost based because it benefits customers with an assumed load shape regardless of cost-causation. Finally, this is a specialty end-use rate, which is contrary to Staff's proposed rate schedule modernization.[127]

88. The Rider C factor adjusts the usage billed to customers to account for energy losses where the meter is configured on the opposite side of a transformer than it would be in standard circumstances.[128]

89. Staff recommends an adjustment of the Rider C factor from 0.68 percent to 0.72 percent.[129] Staff recommends that the credits offered under Rider B and Rider C be held constant absent sufficient information to evaluate how reasonable they are.[130]

90. Rider B is used to credit customers that own their own substation equipment so that they do not pay for equipment they do not use.[131]

91. Staff witness Sarah Lange was unable to study the relationship of cost causation and revenue sufficiency associated with the discounts provided to certain customers under Rider C because Staff did not have the information to study the cost causation of these discounts or the reasonableness of the charges.[132]

92. SPS and LPS customers are not the same. Parties to a rate case often group these classes together in CCOSSs because customers can switch between these

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[127] Exhibit 137, Lange Rebuttal, pages 62-63.
[128] Exhibit 37, Hickman Surrebuttal, page 3.
[129] Exhibit 137, Lange Rebuttal, page 16.
[130] Exhibit 136, Lange Direct, page 51.
[131] Exhibit 35, Hickman Direct, page 27.
[132] Exhibit 136, Lange Direct, page 50.

rate schedules. Nevertheless, SPS and LPS are different rate schedules with different requirements. With the growth in the utility cost of service related to distribution rate base, it is necessary to undertake a more granular study of the costs caused by and allocated to customers on these rate schedules separately.[133]

93. Three charges need to remain consistent for SPS and LPS customers because these costs are essentially the same regardless of the customer class: 1) The monthly customer charge; 2) The Rider B credits (customer-owned substation discounts); and 3) The Reactive charge.[134]

Conclusions of Law:

V. There are no additional conclusions of law for this issue.

Decision:

The Commission determined to allocate any rate increase as an even percentage to the classes, and not based upon Staff's CCOSS or on its proposed rate modernization. Therefore, it does not make sense for the Commission to adopt Staff's overlay for non-residential non-lighting customers at this time. The Commission has similar concerns about authorizing Staff's overlay as it did with Staff's CCOSS. Mainly, that Staff couldn't obtain sufficient information from Ameren Missouri. The Commission does not find it reasonable to adopt Staff's proposed overlay.

The Commission does not find that a shift between demand charges and energy charges within the LGS and SPS rate classes is appropriate at this time. The Commission said as much in File No. ER-2021-0240. The Commission does find that this issue is

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[133] Exhibit 137, Lange Rebuttal, page 3.
[134] Exhibit 32, Harding Direct, pages 10-11.

appropriate for the non-residential working docket, where the parties can collaborate and look at ways to adjust these classes more toward their relative costs of service.

The Commission also finds it appropriate for MECG's proposed optional EV charging rate to be examined in the non-residential working docket. The Commission has concerns about allowing a special rate that, is potentially, not based upon causation. Likewise the Commission does not find it appropriate to adjust the Rider C factor or alter the Rider B values due to absent sufficient information to do so. All of these issues involve the non-residential classes. The Commission finds these sub-issues appropriate to address in the non-residential working docket ordered in File No. ER-2021-0240. Because Ameren Missouri filed this case before the Commission established a working docket via separate order, the Commission will issue an order opening a non-residential working docket within 30 days of the effective date of this order

H. Rate Structures – Information, Studies, and Working Docket

a. Should the cost-causation and rates of Riders B & C be fully evaluated?
b. Ordered Rider B Study - Did Ameren Missouri comply with the Report and Order in ER-2021-0240 at pages 31 – 34, where the Commission addressed whether it should require "Performance of a study of the reasonableness of the calculations and assumptions underlying Rider B to be filed as part of the Company's direct filing in its next general rate case?" The decision paragraph at pages 33-34 states "The Commission will not suspend the Rider B credits, but it believes the question of the proper calculation of those credits should be further addressed in Ameren Missouri's next rate case. Therefore, the Commission will direct Ameren Missouri to study the reasonableness of the calculations and assumption underlying Rider B and to file the results of that study as part of its direct filing in its next general rate case."
c. Should Ameren Missouri be ordered to record transmission assets related to maintenance of voltage support due to the retirement of large synchronous generators be recorded to new subaccounts?
d. Should Ameren Missouri be ordered to retain customer and rate schedule characteristics related to draws of reactive demand?

e. **Should Ameren Missouri be ordered to create subaccounts within distribution accounts and transmission accounts (plant and reserve) for recording infrastructure related to utility-owned generation?**
f. **Should Ameren Missouri be ordered to provide a study of the customer specific infrastructure, by account, by rate schedule, by voltage, in its next general rate case?**
g. **Should Ameren Missouri be ordered to provide data concerning the level of rate base and expense associated with radial transmission facilities including substation components, by customer?**
h. **What information should Ameren Missouri provide for any rate modernization workshop, or for its next general rate case?**
i. **Should Ameren Missouri be required to study potential rate structures and make available related determinants?**

These sub-issues are related and the Commission will address them together.

Findings of Fact:

94. Ameren Missouri performed a study of the reasonableness of Rider B.[135] The result of the study was a discount of $1.34 per kW.[136]

95. Ameren Missouri will consider the study's results in future ratemaking proposals, and it will look for opportunities to bring the discount more in line with CCOSS results consistent with other class adjustments.[137]

96. Due to the unavailability of reliable data, Staff was forced to rely on Ameren Missouri's allocations for many of its calculations.[138]

97. Ameren Missouri does not consider it appropriate to require the Company to undertake what it believes is unreasonable data collection processes to facilitate the further refinement of results of Staff's approach to CCOSS.[139] Ameren Missouri's biggest

[135] Exhibit 35, Hickman Direct, page 26.
[136] Exhibit 35, Hickman Direct, page 28.
[137] Exhibit 35, Hickman Direct, page 28.
[138] Exhibit 136, Lange Direct, pages 14, 16, 24, 38,
[139] Exhibit 36, Hickman Rebuttal, page 22.

problem with the data Staff seeks is that the Company believes it is driving a methodological change.[140]

98. To improve the reliability of CCOSSs, Staff recommends the ordered studies and reviews discussed in witness Sarah Lange's testimony, and that Ameren Missouri also retain data discussed in her testimony.[141] Staff's suggestions in the findings of fact below are related to the unavailability of data.

99. Staff suggests the Commission direct Ameren Missouri to record transmission assets related to maintenance of voltage support due to the retirement of large synchronous generators to new subaccounts.[142]

100. Staff suggests the Commission direct Ameren Missouri record customer and rate schedule characteristics related to draws of reactive demand for study for use in allocators, and for creation of determinants for customer billing.[143]

101. Staff suggests the Commission direct Ameren Missouri to retain a reasonable level of information for study for use in allocators, and for creation of determinants for customer billing.[144]

102. Staff suggests the Commission direct Ameren Missouri to create subaccounts within distribution accounts and transmission accounts (plant and reserve) for recording infrastructure related to utility-owned generation, or infrastructure related to generation other than net-metering or parallel generation.[145] Based upon Ameren Missouri's answers to specific data requests, Staff classified and segregated

[140] Transcript, page 255.
[141] Exhibit 136, Lange Direct, page 56.
[142] Exhibit 137, Lange Rebuttal, page 34.
[143] Exhibit 137, Lange Rebuttal, page 34.
[144] Exhibit 137, Lange Rebuttal, page 34.
[145] Exhibit 136, Lange Direct, page 14.

representative assets that are recorded to the distribution accounts but are within the exclusive use of individual customers. Based upon this Staff recommends in future cases, Ameren Missouri provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage.[146]

103. Based on existing data deficiencies, Staff suggests that Ameren Missouri provide data concerning the level of rate base and expense associated with radial transmission facilities including substation components, by customer.[147]

104. Staff has requested that Ameren Missouri provide the following for a rate modernization workshop.

1) Company to provide a study estimating costs of customer-specific infrastructure by class and by (1) HV, (2) Primary, (3) "average" LGS customer, (4) "average" SGS customer, (5) "average" residential customer. Residential may be broken down further by customers served at 3 phase, customers using in excess of 30kW in any hour, customers in apartments vs detached, etc.

   a. In distribution accounts 364-367 in total, and
   b. In substation accounts total.
   c. Two sets of estimates of each to be developed
      i. One set of estimates based on historic costs, supported by workpapers,
      ii. One set of estimates based on current installation costs, informed by ongoing line extension requests or similar data, supported by workpapers

2) Company to provide data concerning the level of rate base and expense associated with radial transmission facilities including substation components, by customer.

3) Company to provide a study to identify assets in distribution accounts that exist to support Company-owned distributed generation.

4) Company to provide a study of the costs associated with service under "Rider RDC, Reserve Distribution Capacity Rider."

[146] Exhibit 136, Lange Direct, page 14.
[147] Exhibit 138, Lange Rebuttal, page 42.

5) Company to provide a study estimating costs by mile of (1) HV, (2) Primary, (3) relatively high voltage secondary, (4) relatively low voltage secondary separately for overhead and underground,

   a. In distribution accounts 364-367 in total, and
   b. In substation accounts in total.
   c. Two sets of estimates of each to be developed
      i. One set of estimates based on historic costs, supported by workpapers,
      ii. One set of estimates based on current installation costs, informed by ongoing line extension requests or similar data, supported by workpapers.
   d. Miles by voltage and overhead/underground to be provided, with indication of whether or not customer-specific facilities are included.

6) Company to provide a study of the level of net metered generation supplied by each class, and to specifically identify the extent to which hourly load data provided for weather normalization, class allocations, etc reflects netting from net metered generation.

7) Company to provide a breakdown of the values recorded to Account 903 to review the extent to which those costs would be expected to vary with the addition of a new customer, or the discontinuance of service of an existing customer.[148]

105. Staff proposes that as Ameren Missouri completes its installation of AMI metering, it is reasonable to require Ameren Missouri to prepare information to develop modern rate structures for potential implementation in its next rate case.[149]

Conclusions of Law:

W. The Commission may prescribe uniform methods of keeping accounts and records to be observed by electric corporations.[150] The Commission may also prescribe by order, the accounts into which particular outlays and receipts shall be entered, charged, or credited.[151]

[148] Exhibit 138, Lange Surrebuttal, pages 42-43.
[149] Exhibit 136, Lange Direct, page 51.
[150] Section 393.140(4) RSMo.
[151] Section 393.140(8) RSMo.

Decision:

The Commission finds it reasonable, given the unavailability of information for Riders B and C, to direct an evaluation of the cost-causation and rates for those riders. So, Ameren will work with Staff to fully evaluate Riders B and C.

The Commission finds Ameren Missouri minimally complied with the Commission's Report and Order in File No. ER-2021-0240. However, in the range of compliance with a Commission order, this is in the low level of compliance. The reasonableness of the calculations and assumptions underlying Rider B seems an appropriate subject for the non-residential rate design working docket.

Much of the other information Staff requested Ameren Missouri provide is appropriate for the non-residential working docket. Some of Staff's proposals will make information and data more readily available for future rate cases. To that end, the Commission directs Ameren Missouri to record transmission assets related to maintenance of voltage support due to the retirement of large synchronous generators be recorded to new subaccounts. The Commission also directs Ameren Missouri to create subaccounts within distribution accounts and transmission accounts for recording infrastructure related to utility-owned generation.

So that sufficient information and data is available for analysis, The Commission finds it reasonable to direct Ameren Missouri to conduct and provide a study of the customer-specific infrastructure, by account, by rate schedule, by voltage, in its next general rate case. Additionally, the Commission finds it reasonable to direct Ameren Missouri to retain customer and rate schedule characteristics related to draws of reactive demand. Ameren Missouri is also directed to provide data concerning the level of rate base and expense associated with radial transmission facilities, including substation components by customer, for its next rate case.

Staff expressed multiple times that it was unable to complete analysis necessary for an exploration of rate modernization because the information that Staff requested was unavailable. Staff also stated that it did not know “the universe”[152] of what information exists. Staff supplied, at the hearing and in testimony[153], an extensive list of information that would assist its analysis in any rate modernization workshop. The Commission is reluctant to order Ameren Missouri to provide all the information that Staff requested, not because the Commission believes it unnecessary, but because the Commission does not know the full extent of information Ameren Missouri can provide, or the expense associated with collecting that information. The Commission finds it reasonable that Ameren Missouri provide more granular data for any rate modernization workshop, non-residential working docket, and the Company’s next rate case. Therefore, the Commission directs Ameren Missouri to provide the information Staff requested that it can provide at reasonable expense. Ameren Missouri shall also work with Staff to provide a better understanding of what information is available, so that Staff can better request information the Company can access.

Finally, Staff has requested that the Commission direct Ameren Missouri to study potential rate structures and make available related determinants. The Commission does not find this request reasonable and will not order Ameren Missouri to conduct such a study.

[152] Transcript, page 411.
[153] That list is also included above in the findings of fact for this issue.

I. Should the Commission authorize Ameren Missouri to track some valuation of estimated revenue changes that may arise from residential customer rate switching?

a. Is the Ameren Missouri requested method for calculating the tracker balance reasonable?
b. Are alternative approaches available to address what Ameren Missouri characterizes as an inherent disincentive for the utility to pursue a rapid transition toward broad adoption?

Findings of Fact:

106. A tracker is a deferral accounting mechanism.[154]

107. Ameren Missouri requests the Commission authorize it to track changes in revenue caused by residential customers adopting new TOU options.[155]

108. Ameren Missouri asserts that, unlike other demand side management measures under the Missouri Energy Efficiency Investment Act, there is an inherent disincentive for Ameren Missouri to pursue rapid transition and adoption of TOU rates. Ameren Missouri contends that a rate switching tracker would address that disincentive.[156]

109. Granting Ameren Missouri's two-way rate switching tracker would mitigate any revenue erosion and any excess revenues could be amortized and returned to customers in a future rate case.[157]

110. The rate switching tracker would be calculated for each customer that adopts an optional residential TOU rate. The customer's bill on the new rate would be compared to what their bill would have been on the Anytime User rate.[158]

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[154] Exhibit 39, Wills Direct, page 18, citing the Report and Order in File No. ET-2018-0132.
[155] Exhibit 39, Wills Direct, page 14.
[156] Exhibit 39, Wills Direct, page 12.
[157] Exhibit 39, Wills Direct, pages 16-17.
[158] Exhibit 39, Wills Direct, page 17.

111. A tracker is not necessary for the Commission to order a rate modernization plan in this and future cases consistent with the large capital investment made to enable TOU rates. Public Counsel believes it is premature to consider trackers based on the non-substantial costs and speculative information in this case.[159]

112. Ameren Missouri has done no analysis quantifying any changes in current residential load that it projects will be caused by its TOU rate plans. Lower bills for opt-in users do not benefit all ratepayer justifying a tracker.[160]

113. Ameren Missouri requested a two-way tracker in File No. ER-2019-0335 that the Company referred to as a "Rate Migration Tracker". Ameren Missouri's Rate Migration Tracker, similar to this case, was to authorize it to track changes in revenue arising from customers adopting new rate offerings (TOU rate plans).[161] Ameren Missouri expressed concern about revenue erosion from customers switching rates in that case.[162] The Commission did not authorize Ameren Missouri's Rate Migration Tracker.[163]

Conclusions of Law:

X. There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri asks the Commission for authority to implement a two-way tracker to quantify and track any changes in revenue caused by customers adopting TOU rate plans. A tracker would permit the Company to track changes in revenue for possible treatment by the Commission in a future rate case. The Company's rationale for

[159] Exhibit 201, Marke Surrebuttal, page 26.
[160] Exhibit 137, Lange Rebuttal, page 7.
[161] File No. ER-2019-0335, Direct Testimony of Steven Wills, page 65. The Commission took official notice of Wills direct testimony during the evidentiary hearing in this case.
[162] File No. ER-2019-0335, Direct Testimony of Steven Wills, page 66.
[163] Transcript, page 216.

requesting a tracker is that it wants to track any loss in its revenues, presumably, for recovery in a future rate case.

The Commission did not approve a rate switching tracker for Ameren Missouri in File No. ER-2019-0335. The Commission sees no benefit to approving this tracker. The tracker will not track all Ameren Missouri customers. The tracker will only track those customers adopting TOU rates and compare their bills to the Anytime rate plan to quantify revenue changes. There is insufficient analysis for a rate switching tracker. Ameren Missouri bears the burden of proof. The Commission finds that the Company failed to present sufficient evidence that its proposed two-way rate switching tracker is needed. The Commission denies Ameren Missouri's request for a two-way rate switching tracker.

2. Depreciation/Continuing Property Record (CPR).

A. Should the Company be ordered to change the manner that property retirements are recorded to its continuing property record (CPR)?

Findings of Fact:

114. A CPR is a record of plant assets that electric utilities are required to maintain by Commission Rule, 20 CSR 4240-20.030 (3)(A).[164]

115. The assets are segregated by individual retirement units or in some instances, groups of assets can be accounted for in mass property accounts. Each category of mass property requires the following information:

1) A general description of the property and quantity;
2) The quantity placed in service by vintage year;
3) The average cost; and

[164] Exhibit 117, Cunigan Direct, page 10.

4) The plant control account to which the costs are charged. [165]

116. Location information is not required for mass property asset CPRs while it is required of all plant assets (location property) not classified as mass property.[166]

117. For location property (non-mass property) the actual asset to be retired can be determined within Ameren Missouri's accounting records. Ameren Missouri's plant accounting group works with the business line to identify the continuing property record to be retired when the asset is taken out of service.167

118. Ameren Missouri maintains multiple databases of plant asset records. Its response to MPSC Data Request 565 was that accounting records are the recordkeeping system that maintains vintage information of plant assets. Ameren Missouri's operational recordkeeping system contains the location of all poles.168

119. Mass property assets are relatively homogeneous property units that tend to be retired individually. Ameren Missouri includes poles, meters, overhead conductors, underground conductors, conduit, towers, fixtures, and line transformers in its mass property accounting records.[169]

120. Depreciation rates estimate the reduction in an assets value of over time.[170]

121. Survivor curves are estimates based on statistical analysis.[171] Iowa curves represent common survival rates and patterns of assets, and are widely used to estimate

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[165] Exhibit 117, Cunigan Direct, page 10-11.
[166] Transcript, page 553 and Exhibit 117, Cunigan Direct, page 10..
[167] Transcript pages 518-519.
[168] Exhibit 01, Response to DR 565.
[169] Exhibit 47, Lansford Rebuttal, page 10, and Exhibit 122, Eubanks Rebuttal, Schedule CME-r1, page 11.
[170] Transcript, page 554.
[171] Transcript, page 554.

depreciation.[172] Iowa type curves contain the range of survivor characteristics usually experienced by utilities and other industrial companies.[173]

122. Ameren Missouri acknowledges that it is best to identify the actual vintage of an asset. Nevertheless, the Company states that realizing that goal is unrealistic. Additionally, Ameren Missouri asserts that its process and methods of retiring mass property assets is the same or similar to many other utilities. [174]

123. Ameren Missouri also acknowledges that vintage and location are not asset information that it collects for its mass asset CPRs. By way of example, if a 10-year old 40-foot (40') pole is retired, the information provided to the PowerPlan asset accounting system includes the unit (40' pole) and the quantity of that unit retired. The software uses the Iowa survivor curve for the account where 40' poles are recorded to determine what vintage year it will select for retirement. Poles typically are in service well beyond 10-years so the vintage selected by PowerPlan could be 70-years for the retirement of the pole.175

124. Ameren Missouri's example of the retirement of a 10-year-old pole using the mass property software, PowerPlan, applies the applicable survivor curve that may indicate that it is statistically more likely that the pole would have been older, say 70-years, hypothetically. Accounting records would be updated to reduce the number of 70-year-old poles by 1 as a result of this hypothetical retirement. In contrast the operational records would include the location of the retired pole and any available historical data on

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[172] Exhibit 117, Cunigan Direct, page 8.
[173] Exhibit 42, Spanos Direct, page 8.
[174] Exhibit 43, Spanos Rebuttal, pages 17-18.
[175] Exhibit 185, Response to DR 439 and Attachment.

that specific pole, which then allows the operational records to be updated for that specific 10-year-old pole's retirement.176

125. Mass property items to retire are provided to plant accounting. The specific asset being retired cannot be identified within Ameren Missouri's mass property accounting records. So, retirements are selected based on retirement curves and statistical analysis provided by the Company that performs Ameren Missouri's depreciation studies. For location property the actual asset to be retired can be determined within the Company's accounting records. [177]

126. The life characteristics of categories of mass property are influenced by statistical analysis. Commission ordered depreciation rates and the survivor curves underlying those depreciation rates determine the vintage of assets to be removed from Ameren Missouri's accounting records upon retirement.178

127. Ameren Missouri's witness Spanos used the straight line remaining life method of depreciation using the average service life procedure, applied on a remaining life basis. Ameren Missouri alleges these technology solutions and accompanying statistical analysis that supports the processing of retirements for mass property in a Company's CPR is a necessity for keeping the property records accurate and as current as possible.179

128. Staff accounts for depreciation by reducing the book value of the assets over the estimated useful life of the asset. The rate of reduction is the depreciation rate. The depreciation rate is determined by looking at historical data on asset lives, retirement

[176] Exhibit 185, Response to DR 439 and Attachment.
[177] Exhibit 184, Response to DR 209
[178] Exhibit 185, Response to DR 439 and Attachment.
[179] Exhibit 42, Spanos Direct, Schedule JJS-D2, p. iii.

costs, and salvage costs. The application of depreciation rates results in a depreciation expense that is the depreciation rate times the book value of the assets. This depreciation expense accumulates in a depreciation reserve, which offsets the original investment level for purposes of calculating rates.180

129. Staff utilized the straight-line method, broad group-averaging life procedure, and the remaining life technique for the depreciation of distribution accounts 364-371 and 373.181 The combined plant balance and book reserve for these accounts is $6,391,076,638 and $2,945,110,727, respectively.[182]

130. Ameren Missouri provided a copy of its accounting records for all plant assets. These records allegedly contain life characteristics as required under FERC USOA. Ameren Missouri maintains separate operational records for its energy delivery assets which document the vintage of those assets.[183]

131. Ameren Missouri's November 15, 2022 supplemental response to Staff data request 209.1 indicates that Ameren Missouri is not keeping all of the required records for their mass property accounts. Ameren Missouri stated, "Vintage, location, voltage, etc. are not a part of the asset information collected (which is by design because not collecting such information is the essence of and a key benefit of using mass property accounting)."[184]

132. Mass property items that are to be retired are provided to plant accounting through a work management system. Because the specific asset being retired cannot be

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[180] Exhibit 117, Cunigan Direct, page 2.
[181] Exhibit 117, Cunigan Direct, page 6 and TR, Page 551.
[182] Exhibit 118, Cunigan Rebuttal, Page 5-6.
[183] Exhibit 185, Response to DR 439 and Attachment.
[184] Exhibit 117, Cunigan Direct, page 11.

identified within Ameren Missouri's mass property accounting records, retirements are selected based on retirement curves and statistical analysis.[185]

133. Staff refutes that Ameren Missouri field personnel would need to label every foot of conduit so that it can be recorded in Ameren Missouri's work order system. Mass property is for homogenous high count low value assets. Ameren Missouri includes some items in mass property with values approaching $1 million. Therefore, it would be appropriate to review individual mass property asset groups or accounts.[186]

134. Tracking the actual mass property retired allows the curve shape to change. Using the retirements generated by the software only mimics the existing curve.[187]

135. Recording mass property retirements at the average cost of an older vintage selected by software rather than the average cost of the actual vintage would allow mass property assets to be overstated in rate base, assuming rising costs over time.[188]

136. Ameren Missouri's response to MPSC data request 440 indicates that Ameren Missouri maintains recordkeeping of maintenance, retirement and replacement of property assets, including mass property assets by age and vintage through its data collection systems.[189]

137. Staff is open to discussion with Ameren Missouri on how a new retirement process could be used for mass property accounts and assets.[190]

[185] Transcript, page 518.
[186] Transcript, pages 555-557.
[187] Transcript, page 561.
[188] Transcript, pages 568-569.
[189] Transcript pages573-575 and Exhibit. 186, Response to DR 440.
[190] Transcript, page 557.

138. The problem with Ameren Missouri's use of a program to select items for retirement based on Iowa survivor curves for mass property is that the retirement data does not match Ameren Missouri's plant in service.[191]

Conclusions of Law:

Y. Commission Rule 20 CSR 4240-3.175(1)(A)2A requires the CPR database include the annual dollar additions and dollar retirements by vintage year and year retired beginning with the earliest year of available data.

Z. Commission Rule 20 CSR 4240-20.030(3)(A) states that an electric corporation subject to the commission's jurisdiction must "Maintain plant records of the year of each unit's retirement as part of the continuing plant inventory records".

AA. Commission Rule 20 CSR 4240-20.030 (3)(G) states that when implementing section (1), regarding plant acquired or placed into service after 1993, that each electrical corporation subject to the Commission shall:

> Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 101 Electric Plant Instructions to 10.D and paragraph 15.060.10.F

BB. Federal Rule 18 CFR Part 101 definition eight requires a utility to record 1) a general description of the property and quantity; 2) The quantity placed in service by vintage year; 3) The average cost as set forth in Plant Instructions 2 and 3 of this part; and 4) The plant control account to which the costs are charged, for each category of mass property.

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[191] Exhibit 117, Cunigan Direct, page 8.

CC. Federal Rule 18 CFR Part 101, Electric Plant Instructions, 10.D provides:

> The book cost of electric plant retired shall be the amount at which such property is included in the electric plant accounts, including all components of construction costs. The book cost shall be determined from the utility's records and if this cannot be done it shall be estimated. Utilities must furnish the particulars of such estimates to the Commission, if requested. When it is impracticable to determine the book cost of each unit, due to the relatively large number or small cost thereof, an appropriate average book cost of the units, with due allowance for any differences in size and character, shall be used as the book cost of the units retired.

Decision:

By not tracking the actual vintage year of retirements, Ameren Missouri is also not tracking the actual dollars for those retirements. So, two of the pieces of information Ameren Missouri is required to track in its CPR are not being recorded correctly. The Commission finds that, by not tracking the correct vintage year of mass property retirements, Ameren Missouri is not recording information in its CPR as required by the Commission's rules.

Staff requests that the Commission direct Ameren Missouri to stop letting PowerPlan determine what vintages to retire for mass property assets, in order to comply with Commission Rules. It is not immediately clear how Ameren Missouri can most efficiently and effectively resolve this issue. Ameren Missouri may need to rely on its operational data base plant asset records for vintage information and its work management system. Ameren Missouri, upon the retirement of any mass property asset, should identify the actual vintage year that mass property asset was placed in service so that mass property asset retirements, removed from Ameren Missouri's CPRs result in more accurate recording of asset vintages and dollar values going forward.

Ameren Missouri proposes the Commission order the Company, Staff, Public Counsel and any other interested stakeholders, which may include other regulated Missouri utilities, to meet and discuss the mass property retirement process further. Staff's witness indicated that Staff would be open to discussions about mass property accounts and assets. The Commission finds Ameren Missouri's proposed solution reasonable. Ameren Missouri shall meet with Staff, Public Counsel, and other interested stakeholders to resolve Staff's concerns with how mass property assets are being recorded in the Company's CPR. Staff shall inform the Commission of any resolution by filing an appropriate pleading.

3. <u>Identification of Avoided Capital Investments for the Sioux and Labadie Coal Plants.</u>

A. Should the Company be required to identify avoided capital investments should the Sioux or Labadie Energy Centers retire earlier than currently planned as recommended by Sierra Club witness Comings?

a. Should Ameren Missouri be required to file a certificate of convenience and necessity prior to installing any new air controls in response to EPA regulations?

Findings of Fact:

139. Sierra Club recommends the Commission order Ameren Missouri to evaluate the costs of retiring the Sioux Energy Center (Sioux) and Labadie Energy Center (Labadie) coal powered generation plants early as compared to the costs of retrofits needed to comply with regulations proposed by the U.S. Environmental Protection Agency.[192]

140. Sierra Club argues that if avoidable costs are incurred, but the Company subsequently decides to retire the units earlier than currently planned, then ratepayers

[192] Exhibit 500, Comings Direct, pages 31-32.

will not realize savings from avoiding those costs because they were included in rates and these costs will then become stranded.[193]

141. The Michigan Public Service Commission has adopted a similar framework to identify potentially avoidable utility capital (environmental and non-environmental) and major maintenance generation plant expenditures due to the possibility of earlier retirement. Subsequent Michigan Public Service Commission rulings disallowed some avoidable costs from being recovered in rates.[194]

142. Ameren Missouri has currently scheduled the Sioux units to retire in 2030. The Labadie plant is currently scheduled to retire in 2042.[195]

143. The Sioux plant has operated at 50 percent of its capacity factor since 2019, because it is expensive to operate and is frequently offline due to forced outages.[196]

144. Ameren Missouri is retiring its Rush Island Energy Center coal generation facility early instead of installing flue gas desulfurization equipment to comply with a U.S. District Court decision.[197] Sierra Club points to Rush Island's early retirement by 2026 as a reason for the Commission to order Ameren Missouri to evaluate costs for its Sioux and Labadie plants.[198]

145. Ameren Missouri indicated in response to Sierra Club Data Request 1-11 that it plans to have capital expenditures at both its Sioux and Labadie generation plants over the next five years.[199]

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[193] Exhibit 500, Comings Direct, page 30.
[194] Exhibit 500, Comings Direct, pages 30-31.
[195] Exhibit 500, Comings direct, page 14.
[196] Exhibit 500, Comings direct, page 15.
[197] Exhibit 50, Michels Direct, page 2.
[198] Exhibit 500, Comings direct, page 23.
[199] Exhibit 500, Comings Direct, page 29.

146. In February 2022, the U.S. Environmental Protection Agency proposed the Good Neighbor Plan. The Good Neighbor Plan requires reductions in nitrogen oxide (NOx) emissions to reduce the formation of ground-level ozone.[200] NOx is a precursor to ozone.[201]

147. Missouri's generation plants emitted 20,388 tons of nitrogen oxide during ozone season in 2021. The Sioux and Labadie plants account for 29 percent of those emissions.[202]

148. The Sioux and Labadie plants may be affected by future environmental regulations.[203] The Good Neighbor Plan would result in a 73 to 76 percent reduction of NOx at the Sioux units and a 34 to 42 percent reduction at the Labadie units.[204]

149. Ameren Missouri believes this issue is not appropriate for a rate case. Ameren Missouri asserts that this issue is more appropriately handled within the Company's Integrated Resource Planning (IRP). The Commission's IRP rules allow Sierra Club and other stakeholders to suggest issues for Ameren Missouri to address in its IRP process. Both for the IRP's annual updates and Triennial filings.[205]

150. Sierra Club previously asked the Commission require Ameren Missouri, as part of its 2023 IRP analysis to analyze and document the net present value of continuing to operate its coal-burning generation units. The Commission did not include Sierra Club's request in its order concerning issues the Company must address in its 2023 IRP.[206]

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[200] Exhibit 500, Comings direct, pages 21-22.
[201] Exhibit 500, Comings direct, page 20.
[202] Exhibit 500, Comings direct, page 23.
[203] Exhibit 500, Comings direct, page 7.
[204] Exhibit 500, Comings direct, page 23.
[205] Exhibit 51, Michels Rebuttal, page 2.
[206] Exhibit 51, Michels Rebuttal, pages 2-3.

151. Sierra Club's filing in Ameren Missouri's 2023 IRP asked that Ameren Missouri be ordered to study whether retaining each unit in operation at its Sioux Energy Center and Labadie Energy Center benefits customers in comparison with an alternative suite of resources. No suggestion was made in that 2023 IRP filing to require the Company to track investments that could be avoided in conjunction with a decision to accelerate the retirement of coal-fired units, as Witness Comings is recommending in this case.[207]

152. An evaluation of avoidable costs for Sioux and Labadie is important for future rate cases because early retirement may affect Ameren Missouri's capital spending. If it is no longer cost-effective to continue to run those units Ameren Missouri may consider retiring them early.[208]

Conclusions of Law:

DD. Commission Rule 20 CSR 4240-20.045 provides that a utility must seek a certificate of convenience and necessity (CCN) prior to construction or operation of a new asset. "Construction" as defined in that rule includes "[T]he improvement, retrofit, or rebuild of an asset that will result in a ten percent increase in rate base as established in the electric utility's most recent rate case."

Decision:

The Sierra Club asks the Commission to order Ameren Missouri to identify avoided capital investments because of its concern that the Sioux or Labadie Energy Centers may retire earlier than currently planned, leading to the potential recovery of stranded costs in rates. While Ameren Missouri asserts that this issue is more appropriately addressed

[207] Exhibit 51, Michels Rebuttal, Pages 2-3.
[208] Exhibit 500, Comings direct, page 14.

within the Company's IRP process, Sierra Club argues that the IRP process is not a contested proceeding. There is no formal approval of Ameren Missouri's decisions in an IRP.

The Commission finds future environmental regulations may require costly retrofits that could prompt Ameren Missouri to retire the Sioux and Labadie plants early. Ultimately, ratepayers pay the costs of these plants. When generation plants cannot operate when needed, at the capacity needed, or when they require costly retrofitting, the ratepayers may be harmed if the benefits don't outweigh the costs. An early plant retirement may reduce the expected benefits of the capital expenditure that was to be realized over time. Ameren Missouri is not harmed by being ordered to identify avoidable costs for these plants.

Sierra Club also asks the Commission to order Ameren Missouri to file for a certificate of convenience and necessity prior to installing any new air controls in response to Environmental Protection Agency regulations. The Commission will not alter the existing threshold for seeking a CCN by ordering Ameren Missouri to apply for a certificate prior to installation of any new air controls. The Commission's rules already provide that Ameren Missouri must seek a CCN for any improvement, retrofit, or rebuild resulting in a ten percent increase in rate base.

The Commission finds that Ameren Missouri must identify avoidable capital investments when considering any early retirement of its Sioux and Labadie plants, from what is currently planned. Ameren Missouri shall include identification of avoidable capital investments with any future changes proposed for its Sioux and Labadie in its IRP filings.

Decision Summary

In making the decisions described above, the Commission has considered the positions and arguments of all of the parties. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the material was not dispositive of this decision. So that Ameren Missouri may expeditiously file tariff sheets as authorized below, and as contemplated by the Agreement, the Commission finds it reasonable to make this order effective in less than thirty days.

THE COMMISSION ORDERS THAT:

1. The Agreement filed on April 7, 2023, is approved. The signatories are ordered to comply with its terms. A copy of the Agreement is attached to this Report and Order.

2. Sierra Club's *Motion for Leave to Late File Initial Post-Hearing Briefs* is granted.

3. The tariff sheets submitted on August 1, 2022, by Ameren Missouri, assigned Tracking No. YE-2023-0031 are rejected.

4. Ameren Missouri is authorized to file tariff sheets sufficient to recover revenues approved in compliance with this order and the approved Stipulation and Agreement.[209]

5. Ameren Missouri must comply with all directives, conditions and other requirements as more fully described in the body of this order.

[209] Ameren Missouri must also file a redline version of any compliance tariff sheets.

6. Within 30 days of the effective date of this Report and Order the Commission will issue an order establishing a non-residential working docket.

7. This Report and Order shall become effective June 24, 2023.

BY THE COMMISSION

Nancy Dippell

Nancy Dippell
Secretary

Rupp, Chm., Coleman, Holsman
and Kolkmeyer, CC., concur and certify compliance
with the provisions of Section 536.080, RSMo (2016).
Hahn,C., abstains.

Clark, Senior Regulatory Law Judge

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 Increase Its Revenues for Electric Service.	)))	File No. ER-2022-0337

STIPULATION AND AGREEMENT

COME NOW Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "the Company"), the Staff of the Missouri Public Service Commission ("Staff"), the Office of the Public Counsel ("OPC"), Missouri Industrial Energy Consumers ("MIEC"), Midwest Energy Consumers Group ("MECG"), and Consumers Council of Missouri ("CCM") (collectively "Signatories"),[1] who present to the Missouri Public Service Commission ("Commission") for approval this Stipulation and Agreement ("*Stipulation*") commemorating an agreement between the Signatories resolving the issues in this case related to Ameren Missouri's revenue requirement and certain other issues enumerated herein. In support of this *Stipulation*, the Signatories respectfully state as follows:

BACKGROUND

1. On August 1, 2022, Ameren Missouri filed tariff sheets designed to implement a general rate increase for its electric service territory, together with supporting testimony. The Commission issued a procedural schedule in its September 28, 2022, *Order Setting Procedural Schedule and Adopting Test Year.* This procedural schedule ordered an evidentiary hearing to begin April 3, 2023, and to continue through April 14, 2023. It also scheduled a settlement conference to commence on March 6, 2023.

2. The Signatories began negotiations on the first day of the settlement conference and have

[1] Counsel for the remaining parties, Sierra Club, Missouri NAACP, Metropolitan Congregations United, and Renew Missouri have authorized the Signatories to state that they do not oppose the Stipulation.

continued to work to determine whether a resolution of issues could be mutually reached in advance of the evidentiary hearings. As a result of these discussions, the Signatories have agreed to a series of compromises to determine mutually acceptable resolutions to all issues relating to the revenue requirement and certain other issues as set forth in more detail below.[2] The Signatories agree that resolution of these issues will shorten the forthcoming hearing, and only certain issues (i.e., Issue 4 (and all subparts), 24.B, and 30) will require a hearing. The Signatories agreed to the settled "black box" revenue requirement increase amount using their own assumptions. The Signatories authorized the Company to file a Motion to Modify Procedural Schedule and Motion for Expedited Treatment asking the Commission to modify the procedural schedule to adjust the evidentiary hearing dates and to set the issues remaining for hearing on those adjusted dates, which Motion was granted on March 30, 2023.

SPECIFIC TERMS AND CONDITIONS

A. Revenue Requirement, W.A.C.C., Billing Determinants, and Net Base Energy Costs

3. Revenue Requirement Increase. The Signatories agree that Ameren Missouri should be authorized to file tariffs designed to increase the Company's annual revenues by $140 million, exclusive of any applicable license, occupation, franchise, gross receipts taxes, or similar fees or taxes, to become effective July 1, 2023.[3] If a customer's billing cycle covers days both before and after the effective date of the new rates, the new and old rates will be pro-rated on the customer's bill.

4. W.A.C.C. For purposes of calculating Plant-in-Service Accounting ("PISA") deferrals, the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") rates, and

[2] Referencing the Issues List filed by the Staff on behalf of the parties on March 22, 2023, this Stipulation resolves Issues 1 – 3, 5 – 24.A, 25 – 29, and 31-32.

[3] The Signatories support an effective date of July 1, 2023, but agree (without addressing the propriety of any such delay) that if the effective date were delayed beyond July 1, 2023, this *Stipulation* would remain effective.

the Allowance for Funds Used During Construction ("AFUDC"), the Signatories agree to a post-tax Weighted Average Cost of Capital ("W.A.C.C.") of 6.82%. The Signatories also agree that AFUDC shall be calculated in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts for Electric Utilities formula (short-term debt receives 100% weighting until Construction Work in Progress Balances exceed short-term debt balances).

5. Billing Determinants.

a. The Signatories agree that the billing determinants set forth in Exhibit A, which is incorporated herein by reference, shall be used to set the rates implemented from this case.

b. The Signatories agree that the level of cumulative kilowatt-hours ("kWh") to be rebased in the Missouri Energy Efficiency Investment Act ("MEEIA") Cycle 2 and MEEIA Cycle 3 Throughput Disincentive mechanisms to be used in Rider EEIC are set forth in Exhibit B, attached hereto and incorporated herein.

6. FAC Base Factors. The Signatories agree that for Ameren Missouri's fuel adjustment clause ("FAC") the summer base factor (BF_{SUMMER}) is \$0.01439 per kWh and the winter base factor (BF_{WINTER}) is \$0.01328 per kWh.

B. Tracking Mechanisms

7. The following trackers and respective base amounts shall be approved:[4]

a. Uncertain Tax Positions (a/k/a Fin. 48 Tracker), with its base set at \$0.
b. Pension Tracker, with its base level set at (\$88,252,272)
c. Other Post-Employment Benefits (a/k/a OPEB) Tracker, with its base level set at (\$30,968,640)
d. Renewable Energy Standard Compliance Cost Tracker, with its base level set at \$9,142,858.
e. Excess Deferred Tax Tracker, with its base set at (\$47,747,436), grossed up.

[4] The terms and conditions governing trackers approved in the Company's prior general rate proceedings shall continue to apply.

f. Inflation Reduction Act ("IRA") Tracker for IRA production tax credits and investment tax credits (subject to Internal Revenue Service normalization requirements) utilized to offset tax liabilities or sold, except as otherwise tracked in the Company's RESRAM. IRA Tracker has a $0 base.

g. Property Tax Tracker, with its base set at $161,446,770.

C. Amortizations

8. Timing Amortizations. The Signatories agree that the Company's regulatory assets and liabilities shall be amortized starting on the effective date of new rates, in the amounts set forth in the attached Exhibit C, "Summary of Amortizations," which is incorporated herein by reference.

9. Amortization Balances in Subsequent Rate Proceeding. The Signatories agree that in the Company's next electric general rate proceeding, the balance of each amortization relating to regulatory assets or liabilities that remain, after full recovery by Ameren Missouri (regulatory asset) or full credit to Ameren Missouri's customers (regulatory liability), shall be applied as offsets to other amortizations which do not expire before Ameren Missouri's new rates from that general rate proceeding take effect. If no other amortization expires before Ameren Missouri's new rates from that general rate proceeding take effect, then the remaining unamortized balance of any regulatory asset or liability that did not expire before new rates from that general rate proceeding take effect shall be a new regulatory liability or asset that is amortized over an appropriate period. Any over- or under-recovery of a regulatory asset or regulatory liability will

be treated in the same manner as the underlying regulatory asset or regulatory liability.[5]

D. FAC

10. FAC Tariff/Reporting.

a. The Signatories agree that the FAC tariff sheets attached as Exhibit D, incorporated herein by reference, should be approved and filed as compliance tariffs effective July 1, 2023.[6] The Signatories further agree that the Company shall continue to take the actions listed in the direct testimony of Staff witness Amanda Conner filed in this docket on January 10, 2023, that are listed in said testimony on p. 2, ll. 4 – 26 and on p. 3, starting at l. 6 – p. 4, l. 23. With respect to such actions, OPC shall have the same access to documents and receive the same notices as Staff.

b. The Company shall also provide hourly day ahead and real-time locational marginal prices for Ameren Missouri's load, and each generating resource, in its 20 CSR 4240-3.190(1)(B) monthly as-burned fuel report and shall include the information currently included for the High Prairie and Atchison Energy Centers in Tabs 5D p3 and 5d p4 for its other Energy Centers.

c. As part of its compliance tariff filing in this case the Company will cancel the following tariff sheets, which reflect prior iterations of Rider FAC no longer applicable to service, designating the cancelled tariff sheets as reserved for future use:

Sheet Nos. 70.1 – 70.7;

Sheet Nos. 72 – 72.9;

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[5] In other words, if the underlying regulatory asset or regulatory liability was included in rate base, the over- or under-recovery shall also be included in rate base; if the underlying regulatory asset or regulatory liability was not included in rate base, then the over- or under-recovery shall not be included in rate base.

[6] See footnote 3, supra. In addition, the Sheet numbers, issue and effective dates on Exhibit D shall be modified consistent with the terms of this *Stipulation* when the Company files compliance tariff sheets to reflect the agreed upon terms of Rider FAC.

Sheet Nos. 73 – 73.11; and

Sheet Nos. 74 – 74.13.

Also, as part of its compliance tariff filing in this case, the Company will eliminate the language currently contained in Sheet Nos 71-71.15 by overwriting and reusing these sheets so that they reflect the Rider FAC tariff sheets that took effect pursuant to the Commission's order in File No. ER-2021-0240, including 6th Revised Tariff Sheet No. 71.15.[7] Rider FAC tariff sheets to be approved in this case, on the terms reflected in Exhibit D to this *Stipulation*, will then start at Sheet No. 71.16 and continue for as many sheets as necessary to reflect the entirety of Rider FAC as approved in this case. The Company shall also include the appropriate title on the tariff sheets reflecting the Rider FAC approved in this case.

E. RESRAM

11. The Signatories agree that the Base Amount[8] in the Company's RESRAM shall be $7,205,895.[9]

F. Depreciation

12. Depreciation Rates. The Signatories agree that the depreciation rates set forth on Exhibit E attached hereto and incorporated herein by this reference shall be implemented effective July 1, 2023.

G. FERC Return on Equity ("ROE") Cases

13. The Signatories agree that Ameren Missouri shall continue its regulatory liability

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[7] Assuming that pending 3rd Revised Sheet No. 71.31 is approved in the pending File No. ER-2023-0338 docket, that FAC rate sheet will be replaced as part of the compliance tariffs filed in this case using the values from 3rd Revised Sheet No. 71.31, which will be reflected as 7th Revised Sheet No. 71.15, which will remain in effect until superseded by a subsequent FAC rate sheet.
[8] As defined in the RESRAM.
[9] Appropriate consideration will be given to any interaction between the application of PISA and the RESRAM to Renewable Energy Standard investments.

for the first FERC ROE case refunds, except that amortization of the first FERC ROE case refunds regulatory liability will not begin until the conclusion of the Company's next electric rate case assuming all litigation that may impact the final first FERC ROE case refunds is completed. If said litigation is not completed, amortization will start after the conclusion of the first Company electric rate case concluding after those refunds are finalized. The Company will continue the treatment for refunds attributable to the second FERC ROE case that was agreed upon in File No. ER-2021-0240.

H. Energy Delivery Investments.

14. Energy Delivery Projects

a. The Company will continue to submit in File No. EO-2019-0044, quarterly (e.g., information for the second quarter of 2023 shall be submitted by September 30, 2023, and so on), for those energy delivery projects falling within the six categories listed in Item I, Paragraph 18, Subparagraph A of the Unanimous Stipulation and Agreement approved by the Commission in File No. ER-2021-0240, with an investment of $1 million or greater and which went into service the prior year, the following information (as applicable, since not all the following items apply to all such projects):

i. Purchase orders;

ii. Change orders;

iii. Final project cost summaries;

iv. Project Notifications/Project Charters;

v. Oversight Committee review materials; and

vi. In-service dates.

b. The Company shall also submit in File No. EO-2019-0044, quarterly (e.g., results for the second quarter of 2023 shall be submitted by September 30, 2023, and so on), for so long as the Company continues to utilize Plant-in-Service-Accounting for energy delivery projects with an investment of $1 million or greater which went into service the prior quarter, the evaluation results for such projects consistent with the evaluation methodologies for the subject categories developed pursuant to Item I, Paragraph 18, Subparagraph A of the Stipulation and Agreement approved in File No. ER-2021-0240.

c. Company agrees to meet with Staff and OPC to discuss whether changes to the Smart Grid category evaluation methodology might be warranted given issues raised regarding Private LTE and Tripsavers.

I. Low-Income Programs.

15. Keeping Current and Keeping Cool Program.[10] The Keeping Current and Keeping Cool budget shall be increased to $4.25 million with funding provided 50% from customers and 50% from the Company. The Company agrees to meet as part of the Low-Income Collaborative Group, within 60 days of the order approving this *Stipulation*, to discuss methods for legally reducing disconnections in the zip codes with the highest percentage of customers being involuntarily disconnected, with the result of the meeting to be documented by the Collaborative and filed in this case. The following changes will also be made to the existing Keeping Current/Keeping Cool program:

a. Increase the Keeping Cool amount seniors receive to $50.

b. Allow for return check fees in amount that can be covered by a non-LIHEAP pledge, rather than customer being required to pay the return check fee.

[10] The portion of funding provided by customers shall be included in the Low-Income Pilot Program Charge, and is included in the revenue requirement upon which rates set in this case will be based.

c. Increase flexibility for enrollment criteria by allowing participants with up to two weeks of a past due balance.

d. Increase focus on non-LIHEAP agencies and consider marketing opportunities.

e. Institute automatic renewal rather than removing customers who complete 24 months following a needs assessment (phone call) by a participating agency employee.

f. The compensation for Keeping Current agencies shall be increased to $50 for each enrollment in the program, with the agencies' compensation for each successful completion in the program to remain at $25.

16. The Rehousing Program budget shall be $0.5 million annually, with funding provided 50% from customers and 50% from the Company.

17. The Critical Needs Program budget shall be $0.5 million annually, with funding provided 50% from customers and 50% from the Company.

18. The Low-income Weatherization Program budget shall be $1.2 million annually, which is reflected in the revenue requirement on which rates are based.

J. Other Non-Revenue Requirement Issues.

19. The Company will continue providing the High Prairie Energy Center reporting per Item H of the final Stipulation and Agreement in File No. ER-2021-0240, except that, as previously agreed, the seasonal reporting dates will be June 15, September 15, and November 30. The Company will also hold a meeting to discuss investments in mitigation projects at High Prairie with Staff, OPC, and MECG.

20. Company will meet at least twice with Staff and OPC to discuss how to align on the benchmarking recommended by OPC witness Seaver related to excavation coordination, and to discuss reporting and the annual workshop on the topic raised by OPC witness Seaver, all as outlined in Company witness Huss's rebuttal testimony.

21. The Company will continue to work collaboratively regarding the medical registry, per lines 16-19 on page 5 of Company witness Harding's rebuttal testimony.

22. The Company agrees to schedule guided tours for OPC and Staff regarding online account access per rebuttal testimony of Steve Wills.

23. The Company's Rider EEIC margin rate table will be updated consistent with the method in the direct testimony of Company witness Bowden adjusted to exclude MEEIA opt-out customers, as applied to the retail tariff rates established by this *Stipulation*.

24. Community Solar Pilot and Program: For the Community Solar Pilot and Program, the Solar Facilities Charge rate shall be adjusted per Stipulation in File No. EA-2016-0207.

25. The Company shall continue to provide the advertising materials for the test year to Staff within one month after filing a general rate proceeding. Company agrees that Blues PP Goals for Kids expenditures will be excluded from future revenue requirements.

26. The Company's Standby Service Rider rates will be updated consistent with the underlying class rate changes.

27. Ameren Missouri will submit tariff revision, along with its other compliance tariffs, regarding postcards to be sent to customers who do not have an AMI meter and have received more than three consecutive estimated bills so that the customer may provide meter readings to the company. Company agrees to send a letter via first class mail to all customers who have received more than three consecutive estimated bills.

28. The Company agrees to meet with Staff and OPC on a quarterly basis to discuss customer service billing and outreach updates.

29. The Company agrees to provide monthly reporting on the following: total number of customers with estimated bills for the month, and total customers with more than three consecutive estimated bills for the month and number of customers with "no bills", i.e., customers not billed within 30 days of the close of their billing period.

30. The Company agrees that paperless billing enrollment shall be opt-in as opposed to opt-out. The Company will no longer pre-check the customer enrollment box.

31. The Company also agrees in rate cases that it will identify, describe, and explain the reasoning for all proposed tariff changes in testimony. Miscellaneous tariff changes per Company witness Mike Harding's direct and surrebuttal testimony will be adopted (listed below):

a. Eliminate 12M rate schedule.
b. Sheet 55 - Removal of Unmetered CC from 2M TOU.
c. Sheet 59 - 6(M) E&M Lighting Updates - Phasing out the Energy and Maintenance option.
d. Sheet 63 - Updates to Misc. Charges - Add Tampering/Diversion Charge,
e. Sheet 84.2 - Accept various typo corrections and reference updates.
f. Sheets 88.9-88.13 – Eliminate old Solar Rebate (Rider SR).
g. Sheets 103 and 104.
h. Sheet No. 110: Eliminates outdated language in Section J., Non-Standard Service.
i. Sheet No. 115: Correction to Section reference, Overhead Extensions To Residential Subdivisions in Section 1.a.
j. Sheet No. 123: Correction to Special Facilities reference in Section 2.
k. Sheet No. 134: Updated language to Section 5 prohibiting eligibility for optional rates under 2(M) when a large customer requests a temporary transfer to the 2(M) rate class due to abnormal operations.
l. Sheet No. 137: Correction to Rent Inclusion section number reference.
m. Sheet No. 138: Correction to Missouri Code of State Regulations reference in Partial Payments Section & prospective removal of the Paperless Billing credit.

32. Customer Deposits: Ameren Missouri agrees that by the end of 2023, it will

implement a change to its policy on residential customer security deposits so that security deposits for residential customers are returned after 12 months of satisfactory bill payments regardless of whether the customer paid the deposit in installments. This policy change will also apply to Ameren Missouri's residential gas customers. These agreements regarding residential customer deposit policy changes resolve File Nos. EC-2023-0257 and GC-2023-0258, which shall be dismissed upon approval of this *Stipulation*.

33. Cape Girardeau Facility. The Signatories agree that the Cape Girardeau Solar Facility is in-service.

GENERAL PROVISIONS

33. This *Stipulation* is being entered into solely for the purpose of settling the issues listed in the Joint List of Issues filed on March 22, 2023, except for Issues 4 (and all subparts), 24.B, and 30, and unless otherwise specifically set forth herein represents a settlement on a mutually-agreeable outcome without resolution of specific issues of law or fact. This *Stipulation* is intended to relate *only* to the specific matters referred to herein; no Signatory waives any claim or right which it may otherwise have with respect to any matter not expressly provided for herein. No Signatory will be deemed to have approved, accepted, agreed, consented, or acquiesced to any substantive or procedural principle, treatment, calculation, or other determinative issue underlying the provisions of this *Stipulation* except as otherwise specifically set forth herein. Except as specifically provided herein, no Signatory shall be prejudiced or bound in any manner by the terms of this *Stipulation* in any other proceeding, regardless of whether this *Stipulation* is approved.

34. This *Stipulation* has resulted from extensive negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not approve this

Stipulation, or approves it with modifications or conditions to which a Signatory objects, then this *Stipulation* shall be null and void, and no Signatory shall be bound by any of its provisions.

35. If the Commission does not approve this *Stipulation* unconditionally and without modification, and notwithstanding its provision that it shall become void, neither this *Stipulation*, nor any matters associated with its consideration by the Commission, shall be considered or argued to be a waiver of the rights that any Signatory has for a decision in accordance with Section 536.090, RSMo 2016 or Article V, Section 18 of the Missouri Constitution, and the Signatories shall retain all procedural and due process rights as fully as though this *Stipulation* had not been presented for approval, and any suggestions or memoranda, testimony or exhibits that have been offered or received in support of this *Stipulation* shall become privileged as reflecting the substantive content of settlement discussions and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

36. If the Commission unconditionally accepts the specific terms of this *Stipulation* without modification, the Signatories waive, with respect only to the issues resolved herein: their respective rights (1) to call, examine and cross-examine witnesses pursuant to Section 536.070(2), RSMo 2016; (2) their respective rights to present oral argument and/or written briefs pursuant to Section 536.080.1, RSMo 2016; (3) their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2016; (4) their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2016; and (5) their respective rights to judicial review pursuant to Section 386.510, RSMo Supp. 2020. These waivers apply only to a Commission order respecting this *Stipulation* issued in this above-captioned proceeding, and do not apply to any matters raised in any prior or subsequent Commission proceeding, or any matters not explicitly addressed by this *Stipulation*.

37. The Signatories shall also have the right to provide, at any agenda meeting at

which this *Stipulation* is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that each Signatory shall, to the extent reasonably practicable, provide the other parties with advance notice of the agenda meeting for which the response is requested. Signatory's oral explanations shall be subject to public disclosure, except to the extent they refer to matters that are privileged or protected from disclosure pursuant to the Commission’s rules on confidential information.

38. This *Stipulation* contains the entire agreement of the Signatories concerning the issues addressed herein.

39. This *Stipulation* does not constitute a contract with the Commission and is not intended to impinge upon any Commission claim, right, or argument by virtue of the *Stipulation*'s approval. Acceptance of this *Stipulation* by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego the use of any discovery, investigative or other power which the Commission presently has or as an acquiescence of any underlying issue. Thus, nothing in this *Stipulation* is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right to access information, or any statutory obligation.

40. The Signatories agree that this *Stipulation*, except as specifically noted herein, resolves all issues related to these topics, and that the *Stipulation*, including its exhibits should be received into the record without the necessity of any witness taking the stand for examination. Further, contingent upon Commission approval of this *Stipulation* without modification, the Signatories hereby stipulate to the admission into the evidentiary record of the pre-filed written testimony of their witnesses except for those witnesses testifying on the remaining issues set for evidentiary hearing.

WHEREFORE, the Signatories respectfully request that the Commission approve this *Stipulation*, so that Ameren Missouri may move forward on these provisions, and grant any other and further relief as it deems just and equitable.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand-delivered, transmitted by e-mail or mailed, First Class, postage prepaid, this 7^{th} day of April 2023, to counsel for all parties on the Commission's service list in this case.

/s/James B. Lowery_______________
James B. Lowery

Residential - Anytime Users			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	7,656,624	9.00	68,909,616
Low Income Charge	7,656,624	0.14	1,071,927
Energy Charge			
Summer kWh	2,820,781,228	0.1296	365,573,247
Winter kWh			
First 750 kWh	3,041,866,111	0.0881	267,988,404
Over 750 kWh	2,410,305,625	0.0591	142,449,062
Total Anytime Users kWh	8,272,952,964		
Total Anytime Users Revenue			845,992,257

Residential - Anytime TOD			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	384	9.00	3,456
Low Income Charge	384	0.14	54
			0
Energy Charge			0
Summer kWh			0
Off Peak	231,819	0.0786	18,221
On Peak	43,916	0.3346	14,694
Winter kWh			0
First 750 kWh	272,801	0.0881	24,034
Over 750 kWh	195,719	0.0591	11,567
Total kWh	744,254		
Total Anytime TOD Revenue			72,026

Exhibit A

Residential - Evening Morning Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	5,333,904	9.00	48,005,136
Low Income Charge	5,333,904	0.14	746,747
Energy Charge			
Summer kWh	1,890,595,316	0.1263	238,782,188
Summer Peak kWh	1,159,782,600	0.005	5,798,913
Winter kWh			
First 750 kWh	1,819,301,574	0.0867	157,733,446
Over 750 kWh	1,277,180,781	0.0578	73,821,049
Winter Peak kWh	1,625,865,500	0.0025	4,064,664
Total kWh	4,987,077,672		
Total Anytime TOD Revenue			528,952,143

Residential - Overnight Savers			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Total Bills	9,276	9.00	83,484
Low Income Charge	9,276	0.14	1,299
Energy Charge			
Summer kWh			
Off Peak	1,098,207	0.0608	66,771
On Peak	2,236,209	0.1525	341,022
Winter kWh			
Off Peak	1,833,679	0.0524	96,085
On Peak	3,507,175	0.0858	300,916
First 750 kWh	194,308	0.0881	17,118
Over 750 kWh	142,898	0.0591	8,445
Total kWh	9,012,475		
Total R-TOU2 Revenue			915,140

Residential - Smart Savers			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	6,012	9.00	54,108
Low Income Charge	6,012	0.14	842
Energy Charge			
Summer kWh			
Off Peak	654,942	0.0637	41,720
Intermediate Peak	1,152,812	0.1008	116,203
On Peak	315,171	0.3359	105,866
Winter kWh			
Off Peak	990,238	0.0526	52,087
Intermediate Peak	1,737,674	0.0645	112,080
On Peak	337,528	0.1798	60,687
First 750 kWh	283,309	0.0881	24,960
Over 750 kWh	211,845	0.0591	12,520
Total kWh	5,683,519		
Total R-SmartSavers Revenue			581,072

Residential - Ultimate Savers			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	5,736	9.00	51,624
Low Income Charge	5,736	0.14	803
Energy Charge			
Summer kWh			
Off Peak	1,840,041	0.0479	88,138
On Peak	256,049	0.2831	72,488
Winter kWh			
Off Peak	3,341,897	0.0423	141,362
On Peak	414,759	0.1539	63,831
Demand Charge			
Summer Demand	10,456	7.71	80,617
Winter Demand	20,021	3.18	63,668
Total kWh	5,852,746		
Total kW	30,477		
Total R-SmartSavers Revenue			562,531

Community Solar Revenue	446,671
Total Residential Revenue	1,377,521,840

Small General Service Class			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
One-phase	1,151,879	11.33	13,050,789
Three-phase	466,994	21.68	10,124,432
Limited Unmetered Service	85,843	6.01	515,919
TOD Bills			
One-phase	18,155	21.72	394,323
Three-phase	1,907	42.42	80,877
Low Income Charge	1,724,778	0.18	310,460
Total Bills	1,724,778		
Energy Charge			
Summer kWh	1,061,022,584	0.1135	120,426,063
Off Peak	26,896,276	0.0688	1,850,464
On Peak	15,403,254	0.1687	2,598,529
Winter kWh			
Base	1,472,287,916	0.0848	124,850,015
Seasonal	472,118,529	0.0488	23,039,384
Off Peak	56,611,937	0.0507	2,870,225
On Peak	30,919,851	0.1111	3,435,195
kWh Lighting Rate	2,267,734	0.0490	111,119
Total kWh	3,137,528,082		
Total Revenue			303,657,795

Community Solar Revenue	9,341
Total SGS Revenue	303,667,136

Large General Service			
	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	128,484	102.8	13,208,155
TOD Bills	608	21.08	12,817
Low Income Charge	128,484	2.06	264,677
Demand Charge (kW)			
Summer	8,031,915	5.87	47,147,340
Winter	14,900,672	2.18	32,483,465
Energy Charge			
Summer kWh			
First 150HU	1,026,819,252	0.1054	108,226,749
Next 200HU	1,116,149,646	0.0793	88,510,667
Over 350HU	462,377,333	0.0534	24,690,950
Off Peak	12,591,571	-0.0065	-81,845
On Peak	6,886,236	0.0114	78,503
Winter kWh			
Base Energy Charge			
First 150HU	1,681,552,401	0.0662	111,318,769
Next 200HU	1,779,794,640	0.0492	87,565,896
Over 350HU	736,041,388	0.0387	28,484,802
Seasonal Energy	441,258,649	0.0387	17,076,710
Off Peak	25,981,234	-0.0019	-49,364
On Peak	13,292,749	0.0035	46,525
Total kWh	7,243,993,310		
Total EDI Discount			-482,414
Total Revenue			558,502,401

Small Primary Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	7,992	352.19	2,814,702
TOD Bills	227	21.08	4,785
Low Income Charge	7,992	2.06	16,464
Demand Charge (kW)			
Summer	2,862,027	5.06	14,481,854
Winter	5,123,628	1.84	9,427,476
Energy Charge			
Summer kWh			
First 150HU	405,242,682	0.1023	41,456,326
Next 200HU	488,010,630	0.0769	37,528,017
Over 350HU	365,100,927	0.0517	18,875,718
Off Peak	29,400,321	-0.0048	-141,122
On Peak	14,260,787	0.0084	119,791
Winter kWh			
Base Energy Charge			
First 150HU	662,509,337	0.0644	42,665,601
Next 200HU	800,634,751	0.0479	38,350,405
Over 350HU	600,790,969	0.0374	22,469,582
Seasonal Energy	187,865,226	0.0374	7,026,159
Off Peak	49,884,974	-0.0018	-89,793
On Peak	25,671,992	0.0031	79,583
Reactive Power (kvar)	1,266,631	0.38	481,320
Rider B 34.5/69 kV Discount	832,926	-1.24	-1,032,828
Rider B 138 kV Discount	6,085	-1.47	-8,944
Total kWh	3,510,154,524		
Total EDI Discount			-179,990
Total Revenue			234,345,107

Large Primary Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	756	352.19	266,256
TOD	60	21.08	1,265
Low Income Charge	756	220.99	167,068
Demand Charge (kW)			
Summer	2,373,150	21.00	49,836,153
Winter	4,223,011	9.34	39,442,923
Energy Charge			
Summer kWh			
Energy	1,294,347,606	0.0357	46,208,210
Off Peak	84,700,789	-0.0035	-296,453
On Peak	42,549,210	0.0064	272,315
Winter kWh			
Energy	2,261,638,474	0.0326	73,729,414
Off Peak	152,367,049	-0.0018	-274,261
On Peak	74,778,019	0.0029	216,856
Reactive Power (kvar)	285,420	0.38	108,459
Rider B 34.5/69 kV Discount	1,589,995	-1.24	-1,971,593
Rider B 138 kV Discount	656,209	-1.47	-964,627
Total kWh	3,555,986,080		
Total EDI Discount			-61,598
Total Revenue			206,680,387

Company Owned Lighting 5M			
	Billing Units	**Current Rates**	**Current Revenue**
100000 MH Direct	361	74.26	321,694
11000 MV Open Btm	75	10.56	9,504
140000 HPS Direct	4	74.88	3,594
20000 MV Direct	191	22.83	52,326
20000 MV Enclosed	1,702	17.39	355,173
25500 HPS Direct	2,242	23.75	638,970
25500 HPS Enclosed	4,450	18.29	976,686
27500 HP Enclosed	207	18.29	45,432
3300 MV Open Btm	1,054	10.54	133,310
3300 MV Post Top	73	23.39	20,490
34000 MH Direct	606	22.87	166,311
34200 HPS Direct	4	23.75	1,140
36000 MH Direct	2,045	22.87	561,230
47000 HPS Direct	85	37.58	38,332
50000 HPS Direct	2,152	37.58	970,466
50000 HPS Enclosed	1,122	33.04	444,851
54000 MV Direct	13	33.89	5,287
54000 MV Enclosed	46	29.35	16,201
5800 HPS Open Btm	46	10.89	6,011
6800 MV Enclosed	3,298	12.7	502,615
6800 MV Open Btm	5,581	11.09	742,719
6800 MV Post Top	6,547	24.3	1,909,105
9500 HPS Enclosed	4,486	13.23	712,197
9500 HPS Open Btm	12,003	11.62	1,673,698
9500 HPS Post Top	34,071	24.84	10,155,884
LED 100 W EQ Bracket	78,268	10.68	10,030,827
LED 250 W EQ Bracket	11,854	17.24	2,452,356
LED 400 W EQ Bracket	1,967	31.67	747,539
LED Direct-Large	526	71.72	452,697
LED Direct-Medium	3,499	35.98	1,510,728
LED Direct-Small	2,905	22.44	782,258
LED Post Top - All	14,060	23.71	4,000,351
Municipal Discount		-0.0392	-1,583,470
Total Revenue			38,856,513

Customer Owned Lighting 6M

	Billing Units	Current Rates	Current Revenue
100W LED Energy Only	45	1.66	896
11000 MV Energy Only	24	4.67	1,345
11000 MV Enrg&Maint	26	7.1	2,215
12900 MH Enrg&Maint	53	7.06	4,490
162W LED Energy Only	8	2.6892	258
180W LED Energy Only	9	2.988	323
196W LED Energy Only	28	3.2536	1,093
20000 MV Energy Only	88	7.21	7,614
20000 MV Enrg&Maint	38	9.33	4,254
25500 HPS Enrg&Maint	425	7	35,700
25500 HPS Enrgy Only	26	4.87	1,519
25W LED Energy Only	2	0.415	10
26W LED Energy Only	29	0.4316	150
27W LED Energy Only	10	0.4482	54
3300 MV Enrg&Maint	3	4.08	147
3300 MV Enrgy Only	84	2.02	2,036
36W LED Energy Only	43	0.5976	308
40W LED Energy Only	25	0.664	199
44W LED Energy Only	1	0.7304	9
45W LED Energy Only	47	0.747	421
50000 HPS Enrg&Maint	65	10.04	7,831
50000 HPS Enrgy Only	1	7.65	92
54000 MV Energy Only	11	17.17	2,266
54000 MV Enrg&Maint	4	19.8	950
54W LED Energy Only	33	0.8964	355
5500 MH Enrg&Maint	169	5.96	12,087
57W LED Energy Only	7	0.9462	79
60W LED Energy Only	4	0.996	48
6800 MV Enrg&Maint	1,445	5.25	91,035
6800 MV Enrgy Only	121	3.28	4,763
6M Ltd LED 100 W EQ	9,467	3.07	348,764
6M Ltd LED 250 W EQ	106	3.98	5,063
6M Ltd LED 400 W EQ	8	7.03	675
70W LED Energy Only	13	1.162	181
72W LED Energy Only	19	1.1952	273
75W LED Energy Only	182	1.245	2,719
80W LED Energy Only	249	1.328	3,968
85W LED Energy Only	50	1.411	847
9500 HPS Enrg&Maint	8,526	4.08	417,433
9500 HPS Enrgy Only	116	1.9	2,645
Fixture Revenue			965,117
Municipal Discount		-0.0392	-37,790
Total Revenue			927,326

Customer Owned Lighting 6M Metered			
	Billing Units	**Current Rates**	**Current Revenue**
Bills	20,051	7.75	155,395
Energy	42,066,286	0.049	2,061,248
Billed Revenue			2,216,643
Municipal Discount		-0.0641	-142,129
Total Revenue			2,074,515

Total Lighting Revenue	41,858,354

MSD Horsepower Service			
	Billing Units	**Current Rates**	**Current Revenue**
	36,900	0.1842	81,564

Rebasing Summary (kWh)

Actual savings through Dec 2022

	MEEIA 3 PY2021 Non-Low-Income	MEEIA 3 PY2022 Non-Low-Income	MEEIA 3 PY2021 Low-Income	MEEIA 3 PY2022 Low-Income
1M kWh				
Building Shell	38,542,274.30	1,226,552.01	358,771.88	78,525.25
Cooling	37,486,482.12	27,215,488.97	1,172,737.69	1,299,165.73
Freezer	187,232.77	-	-	-
Heating	17,633,237.35	14,294,279.87	3,456,395.66	883,301.98
HVAC	1,961,942.13	880,542.95	1,153,610.92	6,238,463.15
Lighting	102,276,618.65	3,269.78	2,896,338.86	2,450,800.44
Miscellaneous	179,713.11	113,492.66	175,169.89	137,127.42
Pool Spa	1,149,596.05	-	-	-
Refrigeration	1,548,649.24	-	34,939.39	23,151.06
Water Heating	3,151,068.64	541,721.32	1,215,960.93	217,999.60
Motors(uses bus. load shape)				
Total	**204,116,814.36**	**44,275,347.56**	**10,463,925.22**	**11,328,534.63**
2M kWh				
Air Comp	-	-	-	-
Building Shell	19,265.54	-	-	17,894.54
Cooking	-	-	-	-
Cooling	629,214.56	294,303.63	-	1,511.00
Ext Lighting	108,177.24	-	209,510.69	48,962.64
Heating	15,112.44	1,824.66	-	-
HVAC	1,253,913.54	448,011.00	2,188.62	102,704.63
Lighting	30,167,214.60	16,500,791.79	462,059.79	3,440,640.87
Miscellaneous	98,167.33	61,832.00	-	-
Motors	116,473.27	-	13,102.50	-
Process	-	-	-	-
Refrigeration	50,976.94	33,646.00	-	-
Water Heating	-	21,156.00	-	-
Total	**32,458,515.46**	**17,361,565.08**	**686,861.60**	**3,611,713.67**
3M kWh				
Air Comp	2,593,813.30	2,190,761.00	-	-
Building Shell	297,667.20	-	375.99	-
Cooking	6,783.20	12,294.00	-	-
Cooling	9,288,713.09	4,618,820.00	58,033.89	-
Ext Lighting	9,582.97	-	34,065.31	63,588.12
Heating	-	-	-	-
HVAC	41,013,265.90	11,260,587.38	-	-
Lighting	64,391,984.50	34,670,479.00	602,065.37	772,312.04
Miscellaneous	297,426.42	956,712.00	-	-
Motors	128,451.36	113,148.00	-	-
Process	-	-	-	-
Refrigeration	191,335.40	2,686,558.00	-	-
Water Heating	-	-	-	-
Total	**118,219,023.33**	**56,509,359.38**	**694,540.57**	**835,900.16**
4M kWh				
Air Comp	731,198.96	779,335.00	-	-
Building Shell	-	-	-	-
Cooking	-	41,970.00	-	-
Cooling	3,777,869.33	3,679,793.00	-	-
Ext Lighting	-	-	-	-
Heating	-	-	-	-
HVAC	4,213,862.52	511,347.00	-	-
Lighting	13,460,846.83	6,167,827.00	-	-
Miscellaneous	250,047.03	-	-	-
Motors	-	635,135.00	-	-
Process	46,341.08	200,529.00	-	-
Refrigeration	24,775.87	109,535.00	-	-
Water Heating	-	-	-	-
Total	**22,504,941.62**	**12,125,471.00**	**-**	**-**
11M kWh				
Air Comp	750,492.92	446,768.00	-	-
Building Shell	-	-	-	-
Cooking	-	-	-	-
Cooling	475,231.41	1,133,933.00	-	-
Ext Lighting	-	-	-	-
Heating	-	-	-	-
HVAC	129,602.80	-	-	-
Lighting	1,141,939.03	555,745.00	-	-
Miscellaneous	-	-	-	-
Motors	-	136,288.00	-	-
Process	-	-	-	-
Refrigeration	-	-	-	-
Water Heating	-	-	-	-
Total	**2,497,266.16**	**2,272,734.00**	**-**	**-**

Notes from each PY TD file, used Dec 2022 cumulative savings as rebasing values in July 2023 to zero out savings reported through Dec 2022

M3 PY21	M3 PY22
Post-true-up	Mid-PY (does not include year-end reporting); not trued-up
rebasing based on eval kWh	based on deemed kWh
will fully zero TD	will not fully zero TD

Exhibit B

File No. ER-2022-0337
Summary of Amortizations

Callaway Post Op Amortization	3,687,468
PISA Amortization (2019)	2,573,051
PISA Amortization (2021)	9,950,377
PISA Amortization (2022)	9,046,172
PAYS (2021)	16,188
PAYS (2022)	59,172
Pension Tracker Amortization	(13,044,905)
OPEB Tracker Amortization	(4,293,736)
Sioux Scrubber Construction Accounting	2,536,759
Fukushima Study Costs	92,656
RES Tracker Amortization (2021)	(363,620)
RES Tracker Amortization (2022)	366,516
Expired & Expiring Amortizations – Non-Rate Base	(4,371,579)
Expired & Expiring Amortizations – Rate Base	53,712
Callaway Life Extension	103,877
COVID Cost Amortization	1,747,232
Customer Affordability Study	2,177,445
Property Tax Tracker Amortization	1,121,852
Charge Ahead Corridor Amortization (2021)	615,671
Charge Ahead Corridor Amortization (2022)	288,964
Equity Issuance Costs	255,447
Excess Deferred Tax Tracker (2021)	(3,362,196)
Excess Deferred Tax Tracker (2022)	(3,054,533)
Meramec Inventory Write-off	960,052
Meramec Retirement	12,183,619
Federal and State Excess Deferred Tax Amortization	(85,452,744)[1]

[1] This amount reflects the impact on tax expense and is not grossed up for the effect on revenues.

Exhibit C

factors

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the calendar months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage. Notwithstanding that each RP covers a period of eight months, when an extraordinary event has occurred that results in an increase to actual net energy costs in an accumulation period, for good cause shown, subject to Commission approval after an opportunity for any party to be heard, the Company shall defer recovery beyond eight months over a period determined by the Commission upon a finding that the magnitude of the increase on customers of recovering the difference between actual net energy costs and net base energy costs for that accumulation period should be mitigated. The difference not recovered within the eight-month recovery period applicable to the accumulation period at issue will be added to subsequent recovery periods until recovered with a true-up at the end of the Commission approved extended recovery period.

The Company will make a FAR filing no later than sixty (60) days prior to the first day of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm TUP]/S_{RP}$$

Where:

ANEC = FC + PP + E ± R – OSSR

FC = Fuel costs and revenues associated with the Company's in-service generating plants, but excluding decommissioning and retirement costs, consisting of the following:

1) For fossil fuel plants:

   A. the following costs and revenues (including applicable taxes) arising from steam plant operations recorded in FERC Account 501: coal commodity, gas, alternative fuels, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, fuel additive costs included in commodity or transportation costs, oil costs, ash disposal costs and revenues, and expenses resulting from fuel and transportation portfolio optimization activities;~~; provided that costs otherwise included in the foregoing associated with coal remaining at a coal plant after the coal plant ceases coal-fired generation shall be excluded from Factor FC and instead deferred on the Company's books to a regulatory asset for consideration of recovery in a general rate prodeeding over a reasonable amortization period as determined by the Commission~~;

   B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone, and powder activated carbon; and

   C. the following costs and revenues (including applicable taxes) arising from non-steam plant operations recorded in FERC Account 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities, but excluding fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center; and

2) The following costs and revenues (including applicable taxes) arising from nuclear plant operations, recorded in FERC Account 518: nuclear

fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

PP = Purchased power costs and revenues and consists of the following:

1) The following costs and revenues for purchased power reflected in FERC Account 555, excluding (a) all charges under Midcontinent Independent System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and (b) generation capacity charges for contracts with terms in excess of one (1) year~~, provided that the cost of capacity acquired from a jointly owned entity, whose Factors PP, OSSR, or T costs and revenues assigned by the entity to the Company are included in this Rider FAC, will be included in Factor PP regardless of the term~~. Such costs and revenues include:

A. MISO costs or revenues for MISO’s energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:

i. Energy;

ii. Losses;

iii. Congestion management:
   a. Congestion;
   b. Financial Transmission Rights; and
   c. Auction Revenue Rights;

iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;

v. Revenue sufficiency guarantees;

vi. Revenue neutrality uplift;

vii. Net inadvertent energy distribution amounts;

viii. Ancillary Services:
   a. Regulating reserve service (MISO Schedule 3, or its successor);
   b. Energy imbalance service (MISO Schedule 4, or its successor);
   c. Spinning reserve service (MISO Schedule 5, or its successor);
   d. Supplemental reserve service (MISO Schedule 6, or its successor); and
   e. Short-term reserve service;

ix. Demand response:
   a. Demand response allocation uplift; and
   b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

x. System Support Resource:
   a. MISO Schedule 43K.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;

   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided ~~that either~~ such capacity is ~~acquired from a jointly owned entity, whose Factors PP, OSSR, or T costs and revenues assigned by the entity to the Company are included in this Rider FAC, orsuch capacity is~~ acquired for a term of one (1) year or less; and

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist.

2) Six and 84/100~~Four and 97/100~~ percent (~~4~~6.84~~.97~~%) of transmission service costs reflected in FERC Account 565 and Six and 84/100 percent (6.84%)~~Four and 97/100 percent (4.97%)~~ of transmission revenues reflected in FERC Account 456.1 (excluding costs or revenues under MISO Schedule 10, or any successor to that MISO Schedule). Such transmission service costs and revenues included in Factor PP include:

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

3) A. MISO costs and revenues associated with:

i. Network transmission service (MISO Schedule 9 or its successor);

ii. Point-to-point transmission service (MISO Schedules 7 and 8 or their successors);

iii. System control and dispatch (MISO Schedule 1 or its successor);

iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);

v. MISO Schedules 26, 26A, 26C, 26D, 26E, 26F, 37 and 38 or their successors;

vi. MISO Schedule 33; and

vii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs and revenues associated with:

i. Network transmission service;

ii. Point-to-point transmission service;

iii. System control and dispatch; and

iv. Reactive supply and voltage control.

E = Costs and revenues for SO_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

R = Net insurance recoveries for costs/revenues included in this Rider FAC (and the insurance premiums paid to maintain such insurance), and subrogation recoveries and settlement proceeds related to costs/revenues included in this Rider FAC.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

OSSR = Costs and revenues in FERC Account 447 for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   - A. Regulating reserve service (MISO Schedule 3, or its successor);
   - B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   - C. Spinning reserve service (MISO Schedule 5, or its successor);
   - D. Supplemental reserve service (MISO Schedule 6, or its successor);
   - E. Ramp capability service; and
   - F. Short-term reserve service;
4. Make-whole payments, including:
   - A. Price volatility; and
   - B. Revenue sufficiency guarantee; ~~and~~
5. Hedging; and
6. System Support Resource:
   - A. MISO Schedule 43K.

For purposes of factors FC, E, and OSSR, “hedging” is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company’s cost of fuel, off-system sales and emission allowances, including but not limited to, the Company’s use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors PP and OSSR shall not include costs and revenues for any undersubscribed portion of a permanent Community Solar Program resource allocated to shareholders under the approved stipulation in File No. ER-2021-0240.

Notwithstanding anything to the contrary contained in the tariff sheets for Rider FAC, factors FC, PP and OSSR shall not include costs and revenues for (a) amounts associated with portions of Power Purchase Agreements dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (b) amounts associated with generation assets dedicated, as of the date BF was determined, to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factor OSSR, (c) amounts associated with generation assets that began commercial operation after the date BF was determined and that were dedicated to specific customers under the Renewable Choice Program tariff or any subsequent renewable subscription program that is approved by the Commission in an order that acknowledges that such program's impacts should be excluded from Factors FC, PP, and OSSR when it began commercial operation, (d) for Renewable Energy Standard compliance included in Rider RESRAM, (e) amounts associated with energy purchased from the MISO market to serve digital currency mining by the Company, and (f) those amounts specified by Commission Order approving any tariff, rider or program, to be excluded from Rider FAC. Moreover, if a research and development (“R&D”) project would impact the amounts for Factors FC, PP, or OSSR in an upcoming FAR filing, the Company shall file, in the docket in which this Rider FAC was approved, a notice outlining what the research and development project consists of, and how it will impact such factors in the upcoming FAR filing. The Company will bear the burden of proof to show that the impacts of the subject project should be included in Factors FC, PP, or OSSR, as the case may be. Such notice shall be filed no fewer than 60 days prior to the date of the subject FAR filing. Parties shall have thirty days after the filing of the notice to challenge the inclusion of the impacts of such project on such Factors in the determination of the FAR by stating the reasons for the challenge. If a party challenges the inclusion of a cost/revenue, the costs/revenue will be removed from the FAR until the Commission makes a determination regarding the inclusion of the cost/revenue. If the Commission orders a challenged cost be included in the FAC, the costs will be refunded or the revenues returned along with interest in the next periodic adjustment. For purposes of this Rider FAC, a “research and development project” is defined the same as “Research, Development, and Demonstration (RD&D)” as defined in 18 CFR Chapter 1, subchapter C, Part 101, Federal Power Act Definition 32.B, provided that if the project at issue consumes electricity only incidentally, it will not constitute a research and development project.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP}

BF = The Base Factor, which is equal to the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR) divided by corresponding normalized retail kWh as adjusted for applicable losses. The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company’s most recent rate case. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.~~8~~01439 per kWh. The BF applicable to October through May calendar months (BF_{WINTER}) is $0.01328~~12~~ per kWh.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company’s load settled at its MISO CP node (AMMO.UE or successor node), but excluding kWh for research and development projects, the impact of which are challenged or ordered to be excluded by the Commission, ~~digital currency mining operations by the Company,~~ plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) but excluding kWh for research and development projects, the impact of which are challenged or ordered to be excluded by the Commission, ~~digital currency mining operations by the Company,~~ plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

I = Interest applicable to

(i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered;

(ii) refunds due to prudence reviews (“P”), if any; and

(iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“TUP”) provided for herein.

Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

TUP = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

FAR = The lower of (a) PFAR and (b) RAC.

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under– or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

PFAR = The Preliminary FAR, which is the sum of FAR_{RP} and $FAR_{(RP-1)}$

RAC = Rate Adjustment Cap: applies to the FAR rate and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the rate as determined under Section 393.1655.4 by the 2.85% Compound Annual Growth Rate compounded for the amount of time in days that has passed since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655, and dividing that result by the weighted average voltage adjustment factor 1.0455%.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

The Initial Rate Component For the Individual Service Classifications shall be determined by multiplying the FAR determined in accordance with the foregoing by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0539
Primary Voltage Service (VAF_{PRI})	1.0222
High Voltage Service (VAF_{HV})	1.0059
Transmission Voltage Service (VAF_{TRANS})	0.9928

Customers served by the Company under Service Classification No. 11(M), Large Primary Service, shall have their rate capped such that their FAR_{LPS} does not exceed RAC_{LPS}, where

RAC_{LPS} = Rate Adjustment Cap Applicable to LPS Class: applies to the FAR rate applicable to customers in the LPS class and shall apply so long as the rate caps provided for by Section 393.1655, RSMo. are in effect, and shall be calculated by multiplying the class average overall rate as determined under Section 393.1655.6 by the 2.00% Compound Annual Growth Rate compounded for the amount of time that has passed in days since the effective date of rate schedules published to effectuate the Commission's Order that approved the Stipulation and Agreement that resolved File No. ER-2016-0179, and subtracting the then-current RESRAM rate under Rider RESRAM and the class average base rate determined from the most recent general rate proceeding as calculated pursuant to Section 393.1655.

FAR_{LPS} = The lesser of (a) the Combined Initial Rate Component for RAC_{LPS} Comparison or (b) RAC_{LPS}.

Combined Initial Rate Component for RAC_{LPS} Comparison = The sum of the products of each of the Primary, High Voltage, and Transmission Initial Rate Components for the Individual Service Classifications and the applicable LPS Weighting Factors(WF):

Primary Voltage LPS Weighting Factor (WF_{PRI})	0.1587
High Voltage LPS Weighting Factor (WF_{HV})	0.3967
Transmission Voltage LPS Weighting Factor (WF_{TRANS})	0.4446

The Weighting Factors are the ratios between each voltage's annual kWh and total annual LPS kWh. The above Combined Initial Rate Component is developed for the purposes of determining if the statutory RAC_{LPS} has been exceeded, and if it has, calculating the FAR Shortfall Adder to be applied across all non-LPS service classifications in the immediately concluded AP.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

Where the Combined Initial Rate Component for RAC_{LPS} Comparison is greater than FAR_{LPS}, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

Per kWh FAR Shortfall Adder = (((Combined Initial Rate Component For RAC_{LPS} Comparison – FAR_{LPS}) x SLPS) / (SRP – SRP-LPS))

Where:

SLPS = Estimated Recovery Period LPS kWh sales at the retail meter
SRP-LPS = Estimated Recovery Period LPS kwh sales at the Company's MISO CP Node (AMMO.UE or successor node)

The FAR Applicable to the Non-LPS Individual Service Classifications shall be determined as follows:

FARSEC = Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAFSEC)
FARPRI = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAFPRI)
FARHV = Initial Rate Component For High Voltage Customers + (Per kWh FAR Shortfall Adder x VAFHV)
FARTRANS = Initial Rate Component For Transmission Customers + (Per kWh FAR Shortfall Adder x VAFTRANS)

The FAR Applicable to the LPS Individual Service Classifications shall be determined as follows:

LPSFARPRI = Initial Rate Component For Primary Customers x LPS RAC Cap Multiplier
LPSFARHV = Initial Rate Component For High Voltage Customers x LPS RAC Cap Multiplier
LPSFARTRANS = Initial Rate Component For Transmission Customers x LPS RAC Cap Multiplier

Where the LPS RAC Cap Multiplier is the FAR_{LPS} divided by the Combined Initial Rate Component for RAC_{LPS} Comparison.

The FAR applicable to the individual Service Classifications, including the calculations on Lines 24 through 29 of Rider FAC, shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in TUP above. Interest on the true-up adjustment will be included in I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

GENERAL RATE CASE/PRUDENCE REVIEWS
The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE

MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Short-term Reserve Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;

RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Schedule 49 Distribution;
RT Short-term Reserve Amount;
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;
Short-term Reserve Cost Distribution Amount;
Short-term ~~Rerserve~~ Reserve Deployment Failure Charge Amount;

MISO Transmission Service Settlement Schedules

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
~~MISO Schedule 11 (Wholesale Distribution)~~
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedules 26-C & 26-D - (TMEP Cost Recovery);
MISO Schedules 26-E & 26-F (IMEP Cost Recovery);
MISO Schedule 33 (Black Start Service);

MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
RT Market Administration Amount;

DA Schedule 24 Allocation Amount; RT Schedule 24 Allocation Amount;

FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
FAC CHARGE TYPE TABLE (Cont'd.)

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;
Reactive Services;

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE (Cont'd.)

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

SPP Market Settlement Charge Types

DA Asset Energy Amount;
DA Non-Asset Energy Amount;
DA Make-Whole Payment Distribution;
DA Make-Whole Payment;;
DA Virtual Energy;
DA Virtual Energy Transaction Fee;
DA Demand Reduction Amount;
DA Demand Reduction Distribution Amount;
DA GFA Carve-Out Daily Amount;
DA GFA Carve-Out Monthly Amount;
DA GFA Carve-Out Yearly Amount;
GFA Carve Out Distribution Daily Amount;
GFA Carve Out Distribution Monthly Amount;
GFA Carve Out Distribution Yearly Amount;
RT Asset Energy Amount
RT Over Collected Losse;s Distribution;
RT Miscellaneous Amount;
RT Non-Asset Energy;
RT Revenue Neutrality Uplift;
RT Joint Operating Agreement;
RUC Make Whole Payment Distribution;
RUC Make Whole Payment;
RT Virtual Energy Amount;
RT Demand Reduction Amount;
RT Demand Reduction Distribution Amount;
Transmission Congestion Rights Daily Uplift;
Transmission Congestion Rights Monthly Payback;
Transmission Congestion Rights Auction Transaction;
Transmission Congestion Rights Annual Payback;
Transmission Congestion Rights Funding;
Auction Revenue Rights Annual Closeout;
Auction Revenue Rights Funding;
DA Remp Capability Up Amount;
DA Ramp Capability Down Amount;
DA Ramp Capability Up Distribution Amount;
DA Ramp Capability Down Distribution Amount;

RT Ramp Capability Non-Performance Amount;

Transmission Congestion Rights Annual Closeout
Auction Revenue Rights Uplift
Auction Revenue Rights Monthly Payback
Auction Revenue Rights Annual Payback
DA Regulation Up
DA Regulation Down
DA Regulation Up Distribution
DA Regulation Down Distribution
DA Spinning Reserve
DA Spinning Reserve Distribution
DA Supplemental Reserve
DA Supplemental Reserve Distribution
RT Regulation Up
RT Regulation Up Distribution
RT Regulation Down
RT Regulation Down Distribution
RT Regulation Out of Merit
RT Spinning Reserve Amount
RT Supplemental Reserve Amount
RT Spinning Reserve Cost Distribution Amount
RT Supplemental Reserve Distribution Amount
RT Regulation Non-Performance
RT Regulation Non-Performance Distribution
RT Regulation Deployment Adjustment;
RT Contingency Reserve Deployment Failure
RT Contingency Reserve Deployment Failure Distribution;
RT Reserve Sharing Group;
RT Reserve Sharing Group Distribution;
RT Pseudo-Tie Congestion Amount;
RT Pseudo-Tie Losses Amount;
RT Unused Regulation -Up Mileage Make Whole Payment;
RT Ramp Capability Up Amount;
RT Ramp Capability Down Amount;
RT Ramp Capability Up Distribution Amount;
RT Ramp Capability Down Distribution Amount;
RT Ramp Capability Non-Performance Distribution Amount;

RT Unused Regulation -Down Mileage Make Whole Payment;

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

FAC CHARGE TYPE TABLE (Cont'd.)

SPP Transmission Service Charge Types

Schedule 1 – Scheduling, System Control & Dispatch Service;
Schedule 2 – Reactive Voltage;
Schedule 7 – Zonal Firm Point-to-Point;
Schedule 8 – Zonal Non-Firm Point-to-Point;
Schedule 11 – Base Plan Zonal and Regional;

SPP charge types representing administrative charges specifically excluded from the FAC

Schedule 1A – Tariff Administrative Fee;
Schedule 1A2 – Transmission Congestion~~k~~ Rights Administrat~~oin~~ion
Schedule 1A3 – Integrated Marketplace Clearing Administration
Schedule 1A4 – Integrated Marketplace Facilitation Administration
Schedule 12 – FERC Assessment;

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED NET SALVAGE PERCENT AND ANNUAL DEPRECIATION RATES

ACCOUNT	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	NET SALVAGE PERCENT	DEPRECIATION RATE
	STEAM PRODUCTION PLANT			
	MERAMEC STEAM PRODUCTION PLANT			
311	STRUCTURES AND IMPROVEMENTS	12-2022	0	10.90
312	BOILER PLANT EQUIPMENT	12-2022	0	10.37
314	TURBOGENERATOR UNITS	12-2022	0	5.92
315	ACCESSORY ELECTRIC EQUIPMENT	12-2022	0	13.75
316	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2022	0	27.91
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		0	5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		0	6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		0	20.00
	SIOUX STEAM PRODUCTION PLANT			
311.00	STRUCTURES AND IMPROVEMENTS	12-2030	(1)	5.89
312.00	BOILER PLANT EQUIPMENT	12-2030	(2)	7.00
314.00	TURBOGENERATOR UNITS	12-2030	(1)	6.27
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2030	(1)	7.09
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2030	0	8.50
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE			5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT			6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS			20.00
	LABADIE STEAM PRODUCTION PLANT			
311.00	STRUCTURES AND IMPROVEMENTS	12-2042	(1)	3.33
312.00	BOILER PLANT EQUIPMENT	12-2042	(5)	3.90
312.03	BOILER PLANT EQUIPMENT - ALUMINUM COAL CARS		25	0.14
314.00	TURBOGENERATOR UNITS	12-2042	(2)	2.97
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2042	(2)	3.08
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2042	(1)	4.12
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE			5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT			6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS			20.00
	RUSH ISLAND STEAM PRODUCTION PLANT			
311.00	STRUCTURES AND IMPROVEMENTS	12-2039	(1)	3.56
312.00	BOILER PLANT EQUIPMENT	12-2039	(4)	4.12
314.00	TURBOGENERATOR UNITS	12-2039	(2)	3.46
315.00	ACCESSORY ELECTRIC EQUIPMENT	12-2039	(2)	3.58
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	12-2039	(1)	5.61
316.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE			5.00
316.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT			6.67
316.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS			20.00
	COMMON - ALL STEAM PLANTS			
311.00	STRUCTURES AND IMPROVEMENTS	05-2025	0	15.07
312.00	BOILER PLANT EQUIPMENT	05-2025	(2)	13.13
315.00	ACCESSORY ELECTRIC EQUIPMENT	05-2025	(1)	14.91
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	05-2025	0	16.07
	NUCLEAR PRODUCTION PLANT			
	CALLAWAY NUCLEAR PRODUCTION PLANT			
321.00	STRUCTURES AND IMPROVEMENTS	10-2044	(1)	1.37
322.00	REACTOR PLANT EQUIPMENT	10-2044	(3)	2.51
323.00	TURBOGENERATOR UNITS	10-2044	(4)	2.45
324.00	ACCESSORY ELECTRIC EQUIPMENT	10-2044	(1)	1.57
325.00	MISCELLANEOUS POWER PLANT EQUIPMENT	10-2044	0	5.32
325.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE			5.00
325.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT			6.67
325.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS			20.00
	HYDRAULIC PRODUCTION PLANT			
	OSAGE HYDRAULIC PRODUCTION PLANT			
331.00	STRUCTURES AND IMPROVEMENTS	06-2047	(2)	3.49
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2047	(1)	2.94

Exhibit E

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED NET SALVAGE PERCENT AND ANNUAL DEPRECIATION RATES

ACCOUNT	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	NET SALVAGE PERCENT	DEPRECIATION RATE
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2047	(7)	2.86
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2047	(1)	2.97
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2047	0	4.27
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		0	5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		0	6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		0	20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2047	0	-
	KEOKUK HYDRAULIC PRODUCTION PLANT			
331.00	STRUCTURES AND IMPROVEMENTS	06-2055	(2)	2.71
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2055	(1)	2.25
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2055	(9)	2.76
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2055	(1)	2.53
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2055	0	2.97
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		0	5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		0	6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		0	20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2055	0	1.14
	TAUM SAUK HYDRAULIC PRODUCTION PLANT			
331.00	STRUCTURES AND IMPROVEMENTS	06-2089	(5)	1.38
332.00	RESERVOIRS, DAMS, AND WATERWAYS	06-2089	(3)	2.40
333.00	WATER WHEELS, TURBINES, AND GENERATORS	06-2089	(23)	1.98
334.00	ACCESSORY ELECTRIC EQUIPMENT	06-2089	(3)	1.70
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT	06-2089	0	2.05
335.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		0	5.00
335.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		0	6.67
335.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		0	20.00
336.00	ROADS, RAILROADS, AND BRIDGES	06-2089	0	1.25
	WIND PRODUCTION PLANT			
	HIGH PRAIRIE WIND PRODUCTION PLANT			
341.40	STRUCTURES AND IMPROVEMENTS	06-2050	0	3.48
344.40	GENERATORS - WIND	06-2050	(1)	3.66
345.40	ACCESSORY ELECTRIC EQUIPMENT - WIND	06-2050	(1)	3.66
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND	06-2050	0	2.63
	ATCHISON WIND PRODUCTION PLANT			
341.40	STRUCTURES AND IMPROVEMENTS	06-2051	0	3.37
344.40	GENERATORS - WIND	06-2051	(1)	3.58
345.40	ACCESSORY ELECTRIC EQUIPMENT - WIND	06-2051	(1)	3.54
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND	06-2051	0	2.36
	SOLAR PRODUCTION PLANT			
341.20	STRUCTURES AND IMPROVEMENTS - SOLAR		0	4.03
344.20	GENERATORS - SOLAR		0	5.13
345.20	ACCESSORY ELECTRIC EQUIPMENT - SOLAR		0	4.03
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT - SOLAR		0	4.95
	OTHER PRODUCTION PLANT			
341.00	STRUCTURES AND IMPROVEMENTS		(5)	2.43
342.00	FUEL HOLDERS, PRODUCERS, AND ACCESSORIES		(5)	2.04
	GENERATORS			
344.00	OTHER CTS		(5)	1.64
344.10	MARYLAND HEIGHTS LANDFILL CTG		40	0.83
345.00	ACCESSORY ELECTRIC EQUIPMENT		(5)	1.68
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT		0	1.68
346.21	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE FURNITURE		0	5.00
346.22	MISCELLANEOUS POWER PLANT EQUIPMENT - OFFICE EQUIPMENT		0	6.67
346.23	MISCELLANEOUS POWER PLANT EQUIPMENT - COMPUTERS		0	20.00
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT - WIND - OTHER		0	2.60

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED NET SALVAGE PERCENT AND ANNUAL DEPRECIATION RATES

ACCOUNT	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	NET SALVAGE PERCENT	DEPRECIATION RATE
	TRANSMISSION PLANT			
352.00	STRUCTURES AND IMPROVEMENTS		(5)	1.59
353.00	STATION EQUIPMENT		(10)	1.88
354.00	TOWERS AND FIXTURES		(50)	2.78
355.00	POLES AND FIXTURES		(100)	3.39
356.00	OVERHEAD CONDUCTORS AND DEVICES		(40)	1.82
359.00	ROADS AND TRAILS		0	-
	DISTRIBUTION PLANT			
361.00	STRUCTURES AND IMPROVEMENTS		(5)	1.74
362.00	STATION EQUIPMENT		(10)	1.83
364.00	POLES AND FIXTURES		(150)	3.78
365.00	OVERHEAD CONDUCTORS AND DEVICES		(50)	2.26
366.00	UNDERGROUND CONDUIT		(50)	2.12
367.00	UNDERGROUND CONDUCTORS AND DEVICES		(40)	2.58
368.00	LINE TRANSFORMERS		0	1.98
369.01	OVERHEAD SERVICES		(170)	3.28
369.02	UNDERGROUND SERVICES		(90)	2.43
370.00	METERS	12-2024	(5)	23.80
370.01	AMI METERS		(5)	5.35
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES		0	1.23
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		(30)	2.47
	GENERAL PLANT			
390.00	STRUCTURES AND IMPROVEMENTS			
	MISCELLANEOUS STRUCTURES - OLD		(10)	4.07
	LARGE STRUCTURES		(10)	2.32
390.05	STRUCTURES AND IMPROVEMENTS - TRAINING ASSETS		0	-
391.00	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		0	5.00
391.20	OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS		0	20.00
391.30	OFFICE FURNITURE AND EQUIPMENT - EQUIPMENT		0	6.67
392.00	TRANSPORTATION EQUIPMENT		15	5.88
392.05	TRANSPORTATION EQUIPMENT - TRAINING ASSETS		0	-
393.00	STORES EQUIPMENT		0	5.00
394.00	TOOLS, SHOP, AND GARAGE EQUIPMENT		0	5.00
394.05	TOOLS, SHOP, AND GARAGE EQUIPMENT - TRAINING ASSETS		0	-
395.00	LABORATORY EQUIPMENT		0	5.00
396.00	POWER OPERATED EQUIPMENT		15	6.45
397.00	COMMUNICATION EQUIPMENT		0	6.67
397.05	COMMUNICATION EQUIPMENT - TRAINING ASSETS		0	-
398.00	MISCELLANEOUS EQUIPMENT		0	5.00

NOTES: **NEW ADDITIONS FOR LARGE WIND FARM FACILITIES WILL HAVE THE FOLLOWING RATES:**

ACCOUNT	DESCRIPTION		NET SALVAGE PERCENT	ACCRUAL RATE
341.40	STRUCTURES AND IMPROVEMENTS		0	3.47
344.40	GENERATORS		0	3.67
345.40	ACCESSORY ELECTRIC EQUIPMENT		0	3.67
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT		0	3.63

NEW ADDITIONS FOR SMALLER WIND FARM FACILITIES WILL HAVE THE FOLLOWING RATES

ACCOUNT	DESCRIPTION		NET SALVAGE PERCENT	ACCRUAL RATE
341.40	STRUCTURES AND IMPROVEMENTS		0	4.15
344.40	GENERATORS		0	4.34
345.40	ACCESSORY ELECTRIC EQUIPMENT		0	4.32
346.40	MISCELLANEOUS POWER PLANT EQUIPMENT		0	4.22

AMEREN MISSOURI

ELECTRIC DIVISION

SUMMARY OF ESTIMATED NET SALVAGE PERCENT AND ANNUAL DEPRECIATION RATES

ACCOUNT	DEPRECIABLE GROUP	PROBABLE RETIREMENT YEAR	NET SALVAGE PERCENT	DEPRECIATION RATE
	NEW ADDITIONS FOR LARGE SOLAR GENERATION FACILITIES WILL HAVE THE FOLLOWING			
ACCOUNT	**DESCRIPTION**		**NET SALVAGE PERCENT**	**ACCRUAL RATE**
341.20	STRUCTURES AND IMPROVEMENTS		0	3.47
344.20	GENERATORS		0	3.89
345.20	ACCESSORY ELECTRIC EQUIPMENT		0	3.83
346.20	MISCELLANEOUS POWER PLANT EQUIPMENT		0	3.82
	NEW ADDITIONS FOR ENERGY STORAGE EQUIPMENT AND SURGE PROTECTORS WILL HAV			
ACCOUNT	**DESCRIPTION**		**NET SALVAGE PERCENT**	**ACCRUAL RATE**
348.00	ENERGY STORAGE EQUIPMENT		0	10.00
351.00	ENERGY STORAGE EQUIPMENT		0	10.00
363.00	STORAGE BATTERY EQUIPMENT		0	10.00
370.20	METERS - SURGE PROTECTION DEVICES		0	6.85

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 14th day of June, 2023.

Nancy Dippell

Nancy Dippell
Secretary

MOPSC Digitally signed by MOPSC
Date: 2023.06.14
15:23:58 -05'00'

MISSOURI PUBLIC SERVICE COMMISSION

June 14, 2023

File/Case No. ER-2022-0337

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Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Nancy Dippell

Nancy Dippell
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.