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Working Capital  
Witness: Stephen J. Hipkiss  
Type of Exhibit: Direct Testimony  
Sponsoring Party: Union Electric Company  
File No.: ER-2026-0291  
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**MISSOURI PUBLIC SERVICE COMMISSION**

**FILE NO. ER-2026-0291**

**DIRECT TESTIMONY**

**OF**

**STEPHEN J. HIPKISS**

**ON**

**BEHALF OF**

**UNION ELECTRIC COMPANY**

**D/B/A AMEREN MISSOURI**

**St. Louis, Missouri  
June, 2026**

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**DIRECT TESTIMONY**  
**OF**  
**STEPHEN J. HIPKISS**  
**FILE NO. ER-2026-0291**

**I. INTRODUCTION**

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**Q. Please state your name and business address.**

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

**Q. What is your position with Ameren Missouri?**

A. I am employed by Ameren Missouri as Senior Manager, Regulatory Accounting.

**Q. Please describe your educational background and employment experience.**

A. I received a Bachelor of Science in Accounting and Finance from Truman State University in 2010 and a Master's degree in Accounting from Truman State University in 2011. I am a Certified Public Accountant (CPA), licensed to practice in the state of Missouri. From 2011 to 2014, I worked for Ernst and Young LLP in its assurance practice, first as an Audit Staff and then as an Audit Senior. From 2014 to 2016, I worked for SunEdison, Inc., a major solar and wind energy developer and operator, in its Financial Reporting group, first as a Senior Accountant and then as a manager. From 2016 to April 2024, I worked for Ameren Services Company, first as a supervisor and then as a manager in the Accounting Research, Policy, and Internal Controls group. My primary duties and

1 responsibilities included accounting analysis for non-standard transactions, overseeing the  
2 implementation of new accounting guidance, implementation of new accounting policies,  
3 and assessments of the internal control environment. From May 2024 to present, I have  
4 been working for Ameren Missouri as Senior Manager, Regulatory Accounting.

5 **Q. What are your responsibilities in your current position?**

6 A. In my current position, my primary duties and responsibilities include  
7 preparation of the revenue requirement for Ameren Missouri rate filings, preparing written  
8 testimony for rate, regulatory, and audit proceedings, and testifying before the Missouri  
9 Public Service Commission ("MPSC").

10 **II. PURPOSE OF TESTIMONY**

11 **Q. What is the purpose of your direct testimony?**

12 A. The primary purpose of my Direct Testimony is to develop the revenue  
13 requirement (cost of service) for the electric operations of Ameren Missouri. The revenue  
14 requirement determines the level of electric revenues required to cover operating expenses,  
15 provide for depreciation and taxes, and give investors an opportunity to earn a fair and  
16 reasonable return on their investment. Company witness Thomas Hickman uses this data  
17 as the starting point for his class cost of service study. I will also provide an update on the  
18 status of the Company's securitization cost tracker. In addition, I will provide testimony on  
19 the calculation of net base energy costs, which are used in the formula appearing in the  
20 Company's fuel adjustment clause ("FAC", i.e., Rider FAC), as well as the rate values  
21 reflected in the FAC, i.e., the summer and winter values for Factor BF as defined in the  
22 FAC tariff. Finally, I will discuss the lead/lag study prepared for the Company's electric  
23 business that I used to develop cash working capital ("CWC") factors. The CWC factors

1 were used to calculate the Company's cash working capital requirements included in the  
2 rate base.

3 **Q. Are you sponsoring any schedules?**

4 A. Yes. I am sponsoring Schedules SJH-D1 through SJH-D18.

5 **Q. What is the subject matter of these schedules?**

6 A. Schedules SJH-D1 through SJH-D16 develop the various elements of the  
7 revenue requirement to be considered in arriving at the proper level of rates for the  
8 Company's electric service based on the test year of the twelve months ended March 31,  
9 2026, with pro forma adjustments and updates for known and measurable changes to be  
10 tried-up through December 31, 2026. Schedule SJH-D17 reflects the calculation of net  
11 base energy costs ("NBEC") and the seasonal values for Factor BF in Rider FAC. Schedule  
12 SJH-D18 reflects the results of the cash working capital lead/lag study prepared as of the  
13 twelve months ended March 31, 2026.

14 **Q. Will you please briefly summarize the information provided on each of**  
15 **the schedules you are presenting?**

16 A. Each schedule provides the following information:

- 17 • Schedule SJH-D1 – Original Cost of Electric Plant by Functional  
18 Classification at March 31, 2026, per book and pro forma.
- 19 • Schedule SJH-D2 – Electric Plant Reserves for Depreciation and  
20 Amortization by Functional Classification at March 31, 2026, per book  
21 and pro forma.

- 1                   • Schedule SJH-D3 – Average Fuel Inventories and Average Materials  
2                   and Supplies Inventories at March 31, 2026, per book and pro forma  
3                   applicable to electric operations.
- 4                   • Schedule SJH-D4 – Average Prepayments at March 31, 2026, per book  
5                   and pro forma applicable to electric operations.
- 6                   • Schedule SJH-D5 – Total Electric Cash Working Capital (per the  
7                   Company’s lead/lag study) for the twelve months ended March 31,  
8                   2026, applicable to electric operations.
- 9                   • Schedule SJH-D6 – Interest Expense Cash Requirement, Federal  
10                  Income Tax Cash Requirement, State Income Tax Cash Requirement,  
11                  and City of St. Louis Earnings Tax Cash Requirement applicable to  
12                  electric operations (per the Company's lead/lag study) for the twelve  
13                  months ended March 31, 2026.
- 14                  • Schedule SJH-D7 – Average Electric Customer Advances for  
15                  Construction and Average Electric Customer Deposit reductions to rate  
16                  base at March 31, 2026.
- 17                  • Schedule SJH-D8 – Regulatory Asset and Liability balances included in  
18                  rate base at March 31, 2026, per book and pro forma.
- 19                  • Schedule SJH-D9 – Total Electric Accumulated Deferred Income Taxes  
20                  at March 31, 2026, per book and pro forma.
- 21                  • Schedule SJH-D10 – Total Electric Operating Revenues for the twelve  
22                  months ended March 31, 2026, per book and pro forma.

- 1                   • Schedule SJH-D11 – Total Electric Operations and Maintenance  
2                   Expenses, by functional classification, for the twelve months ended  
3                   March 31, 2026, updated for certain known items, per book and pro  
4                   forma. A description of each pro forma adjustment is included.
- 5                   • Schedule SJH-D12 – Depreciation and Amortization Expenses  
6                   applicable to electric operations, by functional classification, for the  
7                   twelve months ended March 31, 2026, per book and pro forma. A  
8                   description of each pro forma adjustment is included.
- 9                   • Schedule SJH-D13 – Taxes Other Than Income Taxes, for the twelve  
10                  months ended March 31, 2026, per book and pro forma for the electric  
11                  operations of the Company. A description of each pro forma adjustment  
12                  is included.
- 13                 • Schedule SJH-D14 – Income Tax Calculation at the proposed rate of  
14                  return and statutory tax rates for the total electric operations of the  
15                  Company for the twelve months ended March 31, 2026.
- 16                 • Schedule SJH-D15 – The pro forma Electric Net Original Cost Rate  
17                  Base at March 31, 2026, and Electric Revenue Requirement including  
18                  the pro forma adjustments.
- 19                 • Schedule SJH-D16 – The annual revenue increase required at a 7.506%  
20                  return on Net Original Cost Electric Rate Base, including pro forma  
21                  adjustments.
- 22                 • Schedule SJH-D17 – Calculation of NBEC and seasonal values of  
23                  Factor BF in Rider FAC.

- 1                   • Schedule SJH-D18 – Cash Working Capital Factors.

2   **III. REVENUE REQUIREMENT**

3           **Q.     What do you mean by "revenue requirement"?**

4           A.     The revenue requirement of a utility company is the sum of operations and  
5 maintenance expenses, depreciation and amortization expenses, taxes, and a fair and  
6 reasonable return on the net value of property used and useful in serving its customers (and  
7 other rate base amounts). The revenue requirement is based on a test year, and it is  
8 necessary to make certain pro forma adjustments in order to reflect conditions existing at  
9 the end of the trued-up test year, as well as significant changes that are known or reasonably  
10 certain to occur closer to when new rates would take effect.

11           The revenue requirement represents the total funds (revenues) that must be  
12 collected by the Company if it is to pay employees and suppliers, satisfy tax liabilities, and  
13 provide a fair return to investors. To the extent that current revenues are less than the  
14 revenue requirement, as is true in this case, a rate increase is required.

15           **Q.     What test year is the Company proposing to use to establish the revenue**  
16 **requirement in this proceeding?**

17           A.     The Company is proposing a test year consisting of the twelve months  
18 ending March 31, 2026 ("test year"), with pro forma adjustments to account for the true-  
19 up of various items through December 31, 2026 ("true-up date"), consistent with the  
20 approach used in the Company's previous rate reviews. The Company is proposing to true-  
21 up the following items: plant-in-service, depreciation reserve, materials and supplies  
22 (including fuel inventories), prepayments, cash working capital (excluding CWC factors),  
23 customer advances for construction, customer deposits, accumulated deferred income taxes

1 ("ADIT"), pension and other post-employment benefits ("OPEB"), tracked regulatory  
2 asset/liability balances, customer growth revenues, Missouri Energy Efficiency Investment  
3 Act ("MEEIA") revenues, behind-the-meter solar revenues, Renewable Solutions Program  
4 ("RSP") revenues, net energy costs (as defined in Rider FAC), payroll, employment levels,  
5 other employee benefits, Renewable Energy Standard ("RES") costs, bad debt expense,  
6 Callaway refueling expenses, non-labor scheduled outage maintenance expenses at the  
7 Labadie and Sioux Energy Centers, storm costs, vegetation management, infrastructure  
8 inspection expenses, Circuit & Device Inspection System expenses, locates expenses,  
9 software maintenance, cybersecurity expenses, Renewable Energy Standard Rate  
10 Adjustment Mechanism ("RESRAM") costs, insurance expenses, Pay as You Save  
11 ("PAYS") amounts, regulatory assessments, Nuclear Regulatory Commission ("NRC")  
12 fees, rate case expense, depreciation study expense, meter reading fees, customer  
13 convenience charges, operations and maintenance costs resulting from new solar energy  
14 centers, capital structure, capital costs, depreciation expense, income taxes, non-income  
15 taxes, sales tax overcollections due to Senate Bill 872, and various amortization amounts  
16 (such as the pension & OPEB tracker amortization). The Company will also true-up coal  
17 prices, Midcontinent Independent System Operator, Inc. ("MISO") transmission revenues  
18 and expenses, and any wage increases that become effective on or before January 1, 2027.  
19 Finally, the Company proposes that other significant items that may arise through the true-  
20 up date, both increases and decreases, should be trued-up through December 31, 2026.

1           **Q.     Why is it necessary to make pro forma adjustments to the test year data**  
2           **and to true-up certain revenue requirement components?**

3           A.     In ratemaking, rates are set for the future. It is often necessary to adjust the  
4 test year data to be more representative of future operating conditions. Pro forma  
5 adjustments allow for newly authorized rates that will provide a greater likelihood of  
6 producing the allowed rate of return during the period they are in effect. This requires pro  
7 forma adjustments to reflect known and measurable changes from historical test year  
8 levels.

9           **Q.     Please explain Schedule SJH-D1.**

10          A.     Schedule SJH-D1 shows the recorded original cost of electric plant by  
11 functional classification at March 31, 2026, along with the estimated plant additions and  
12 other adjustments through December 31, 2026, which is the end of the Company's proposed  
13 true-up period. The Company's plant accounts are recorded on the basis of original cost as  
14 defined by the Federal Energy Regulatory Commission ("FERC") Uniform System of  
15 Accounts and prescribed by the MPSC.

16          **Q.     Please explain Adjustment 1, the elimination of the plant balances**  
17 **related to Accounting Standards Codification ("ASC") 410-20 *Asset Retirement***  
18 ***Obligations* ("ARO") and ASC 842 *Leases* shown as the first adjustment on Schedule**  
19 **SJH-D1.**

20          A.     An ARO is a legal obligation associated with the retirement of a tangible,  
21 long-lived asset that results from the acquisition, construction, development, and/or normal  
22 operation of that asset. ASC 410-20<sup>1</sup> requires the Company to record both an asset and a

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<sup>1</sup> ASC 410-20 superseded Financial Accounting Standard (FAS) 143, *Asset Retirement Obligations*.

1 corresponding liability for such asset retirement costs. ASC 842 is an accounting  
2 requirement that all leases are recorded on the balance sheet in the form of both an asset  
3 and an equivalent offsetting liability. Adjustment 1 to plant, in the amount of  
4 (\$281,450,000) eliminates both the ARO and lease assets for ratemaking purposes.

5 **Q. For Adjustment 2, why is the Company including plant additions**  
6 **through December 31, 2026?**

7 A. The Company continues to make targeted investments across its system as  
8 part of our core strategy to provide safe and reliable service to our customers. In order to  
9 provide the Company with an opportunity to earn a fair and reasonable return on its total  
10 investment, it is necessary for the cost of service to reflect, as closely as possible, the level  
11 of the Company's investment that exists at the time new rates become effective. Adjustment  
12 2 adds the estimated plant-in-service additions of \$2,324,428,000 from March 31, 2026,  
13 through December 31, 2026, which is the end of the proposed true-up period.

14 **Q. Please explain Adjustment 3, the elimination of items in General and**  
15 **Intangible Plant applicable to gas operations.**

16 A. General and Intangible Plant assets, such as general office buildings, the  
17 central warehouse, the central garage, software, computers, and office equipment, are used  
18 in both the electric and gas operations. For convenience, such investments are presented as  
19 electric plant in our accounting records. Adjustment 3 eliminates the portion of the multi-  
20 use General Plant and Intangible Plant allocated to the Company's gas operations of  
21 \$59,665,000 and \$8,246,000, respectively.

1           **Q.     Please explain Adjustment 4, the reduction to electric plant-in-service**  
2 **for incentive compensation.**

3           A.     In past Ameren Missouri rate reviews, a portion of the Company's incentive  
4 compensation paid has not been requested for recovery by the Company. Within the  
5 accounting records of the Company, a portion of that incentive compensation was  
6 capitalized and added to plant-in-service. Adjustment 4 reduces the plant-in-service  
7 balance by \$59,862,000 for the accumulated portion of such capitalized incentive  
8 compensation.

9           **Q.     After reflecting the above four pro forma adjustments, what amount of**  
10 **electric plant-in-service is the Company proposing to include in rate base?**

11          A.     As shown in Schedule SJH-D1, the total electric plant-in-service is  
12 \$28,995,077,000.

13          **Q.     What pro forma adjustments were made to the accumulated reserve**  
14 **for depreciation on Schedule SJH-D2?**

15          A.     Similar adjustments were made to the accumulated reserve balance of plant-  
16 in-service. Adjustment 1 eliminates \$19,627,000 from the depreciation reserve related to  
17 ASC 410-20 *ARO* and ASC 842 *Leases*. This adjustment corresponds to Adjustment 1  
18 made to plant-in-service on Schedule SJH-D1.

19          Adjustment 2 increases the depreciation reserve by \$697,891,000 to reflect  
20 depreciation through the true-up date on plant-in-service investments existing at March 31,  
21 2026.

1           Adjustment 3 increases the depreciation reserve by \$41,810,000 to reflect the  
2 depreciation related to pro forma net additions to plant-in-service from March 31, 2026,  
3 through December 31, 2026, the proposed true-up period.

4           Adjustment 4 reduces the depreciation reserve by \$499,000 to remove the  
5 remaining depreciation reserve associated with the Rush Island Energy Center ("Rush  
6 Island"). Recovery of any remaining net plant balance at the time of the retirement of the  
7 Rush Island in October 2024 occurs outside of base rates through the Company's  
8 Securitized Utility Tariff Rider<sup>2</sup> (Rider SUR).

9           Adjustment 5 eliminates the accumulated depreciation reserve of \$23,240,000 for  
10 the multi-use General Plant applicable to gas operations and the accumulated amortization  
11 of \$1,604,000 for Intangible Plant applicable to gas operations. This adjustment totals  
12 \$24,844,000 and corresponds to Adjustment 3 made to plant-in-service on Schedule SJH-  
13 D1.

14           Accumulated depreciation and amortization reserve is reduced by \$23,394,000 in  
15 Adjustment 6 to reflect the accumulated depreciation and amortization applicable to a  
16 portion of capitalized incentive compensation reflected in Adjustment 4 in Schedule SJH-  
17 D1.

18           The pro forma accumulated provision for depreciation and amortization, as shown  
19 in Schedule SJH-D2, applicable to total plant-in-service is \$10,859,045,000.

20           **Q.     Please explain Schedule SJH-D3.**

21           A.     Schedule SJH-D3 shows the average investment in fuel inventories and  
22 materials and supplies inventories at March 31, 2026. Fuel inventory consists of nuclear

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<sup>2</sup> Established in File No. EF-2024-0021.

1 fuel, coal, minor amounts of oil and stored natural gas used for electric generation,  
2 emissions allowances, and renewable energy credits. The nuclear fuel balances include the  
3 nuclear fuel in the reactor as well as the nuclear fuel on site at the Callaway Energy Center.  
4 General materials and supplies inventory includes items such as poles, cross arms, wire,  
5 cable, line hardware, and general supplies. A thirteen-month average is used for all these  
6 items, except nuclear fuel. An eighteen-month average is used for nuclear fuel since the  
7 Callaway Energy Center is re-fueled every eighteen months.

8 Adjustment 1 shown in Schedule SJH-D3 increases coal inventory included in rate  
9 base by \$2,959,000 to remove Rush Island coal inventories<sup>3</sup> and to adjust the thirteen-  
10 month average inventory levels to January 2027 coal prices.

11 Adjustment 2 shown in Schedule SJH-D3 reduces general materials and supplies  
12 included in rate base by \$3,239,000 for the portion of the average general materials and  
13 supplies inventories applicable to the Company's gas operations.

14 **Q. What is the amount of pro forma materials and supplies applicable to**  
15 **electric operations?**

16 A. The pro forma materials and supplies applicable to total electric operations,  
17 as shown in Schedule SJH-D3, is \$641,685,000.

18 **Q. Please explain the average prepayments shown in Schedule SJH-D4.**

19 A. Certain costs for items such as rent, insurance, medical and dental voluntary  
20 employee beneficiary association contributions, memberships, and service agreements  
21 related to software maintenance are paid in advance. After elimination of amounts

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<sup>3</sup> Recovery of estimated remaining coal inventories at the time of the retirement of the Rush Island in October 2024 occurs outside of base rates through the Company's Rider SUR.

1 applicable to gas operations, the thirteen-month average balance of total electric  
2 prepayments at March 31, 2026, is \$47,266,000.

3 **Q. Please explain Schedule SJH-D5.**

4 A. Schedule SJH-D5 shows the calculation of the electric cash working capital  
5 requirement as a negative net cash requirement of (\$8,548,000), which is based on a  
6 lead/lag study for the twelve months ended March 31, 2026, and including pro forma  
7 adjustments to operating expenses. I will explain the details of the lead/lag study later in  
8 this testimony.

9 **Q. What appears on Schedule SJH-D6?**

10 A. The interest expense, federal income tax, state income tax, and St. Louis  
11 City earnings tax cash requirements applicable to the Company's electric operations (per  
12 the Company's lead/lag study) are shown in Schedule SJH-D6. The payment lead times for  
13 these items are based on actual or statutory due dates. I will explain the details of the  
14 lead/lag study later in this testimony.

15 **Q. What is the cash requirement for interest expense, federal income  
16 taxes, state income taxes and St. Louis City earnings tax?**

17 A. Reflecting the payment lead times for each of these items compared to the  
18 revenue lag results in negative cash requirements of (\$57,056,000) for interest expense,  
19 (\$787,000) for federal income taxes, (\$290,000) for state income taxes, and \$116,000 for  
20 St. Louis City earnings tax.

21 **Q. What items are shown in Schedule SJH-D7?**

22 A. The thirteen-month average balances at March 31, 2026, for electric  
23 customer advances for construction and electric customer deposits are shown in Schedule

1 SJH-D7. These items represent cash provided by customers that can be used by the  
2 Company until they are refunded. Therefore, the average balances for customer advances  
3 for construction and customer deposits are reductions to the Company's rate base.

4 Customer advances for construction are cash advances made by customers that are  
5 subject to refund to the customers in whole or in part. These advances provide the Company  
6 with cash that offsets the cost of the construction until they are refunded. The thirteen-  
7 month average balance of electric customer advances for construction was \$2,546,000 at  
8 March 31, 2026.

9 Customer deposits are cash deposits made by customers, which are subject to  
10 refund to the customer under the terms set out in Ameren Missouri's tariffs. The Company  
11 pays interest on the deposits, which is shown as a customer accounts expense in Schedule  
12 SJH-D11. The thirteen-month average balance of electric customer deposits was  
13 \$30,235,000 at March 31, 2026.

14 **Q. What is shown in Schedule SJH-D8?**

15 A. Schedule SJH-D8 shows regulatory assets and liability balances included in  
16 rate base, including the pension and OPEB regulatory liability balances, the PAYS  
17 regulatory asset, the plant-in-service accounting ("PISA") regulatory asset, a regulatory  
18 asset for expired & expiring amortizations, and the property tax tracker regulatory liability  
19 balance.

20 The pension and OPEB regulatory asset balances of \$69,814,000 and (\$2,659,000),  
21 respectively, reflect amortization of the tracked balances established in File No. ER-2024-  
22 0319 through the true-up date and accumulation through the true-up date for the current  
23 accumulation period. The Company proposes that the remaining balances as of the true-up

1 date for all pension and OPEB deferrals established prior to File No. ER-2024-0319 be  
2 combined into the expired & expiring amortizations regulatory asset included in rate base  
3 and to be amortized as part of the expired & expiring amortizations discussed in  
4 Adjustment 10 on Schedule SJH-D12. Additionally, the Company proposes to refund the  
5 remaining regulatory liability balance from File No. ER-2024-0319 over 2 years and the  
6 most recent accumulation period, from January 1, 2025, through the true-up date, over a  
7 period of 5 years, consistent with the approach agreed to and approved in File No. ER-  
8 2024-0319.

9 In the Unanimous Stipulation and Agreement in File No. EO-2018-0211, the  
10 Company agreed to include the PAYS regulatory asset in rate base in future rate reviews.  
11 The \$5,741,000 PAYS regulatory asset reflects the total deferrals made under the PAYS  
12 program, less any amortization recorded or expected to be recorded by the true-up date.

13 Schedule SJH-D8 also includes the PISA regulatory asset balance included in rate  
14 base. PISA is the name commonly given to the deferrals of 85% of the depreciation expense  
15 and return on "qualifying electric plant" as required by Section 393.1400 RSMo., under  
16 legislation adopted by the Missouri General Assembly in 2018 and amended in 2022 and  
17 2025. The total PISA regulatory asset balance of \$889,935,000 reflects the deferral made,  
18 and estimated, under PISA on or after September 1, 2018, through the true-up date, net of  
19 amortization. The statute also provides that in each general rate proceeding, the balance of  
20 the PISA regulatory asset as of the rate base cutoff date (i.e., December 31, 2026) shall be  
21 included in the participating utility's rate base.

22 Beginning with the Unanimous Stipulation and Agreement in File No. ER-2016-  
23 0179, the Company has combined and netted the true-up date balances of regulatory assets

1 and liabilities that have expired (and over-amortized) since the Company's last rate review  
2 or are expected to expire soon after the true-up date. Any over- or under-recovery of a  
3 regulatory asset/liability is treated in the same manner as the underlying regulatory  
4 asset/liability, meaning that if the underlying regulatory asset/liability was included in rate  
5 base the over-/under-recovery shall also be included in rate base, but if the underlying  
6 regulatory asset/liability was not included in rate base neither shall the over-/under-  
7 recovery be. The Company proposes to continue that approach in this case.

8 In accordance with this approach, a regulatory asset of \$12,862,000 increases the  
9 Company's rate base for the combined effect of regulatory assets and liabilities that were  
10 previously included in rate base, but which will expire prior to the true-up date in this case  
11 (or soon after). The combined over- or under-recovery of such regulatory assets and  
12 liabilities expected through December 31, 2026, has also been included in this adjustment.  
13 Refer to Adjustment 10 from the discussion of Schedule SJH-D12 below for the inventory  
14 of regulatory assets and liabilities that are expected to expire prior to the true-up date in  
15 this case (or soon after) and, therefore, have been combined.<sup>4</sup>

16 In the Stipulation and Agreement in File No. ER-2024-0319, an electric property  
17 tax tracker was memorialized with a base amount of \$166,486,906. Line 6 of Schedule  
18 SJH-D8 includes a \$2,570,000 property tax tracker regulatory liability balance,  
19 representing actual and estimated deferrals (expense levels below the established base  
20 amount) under the property tax tracker through the true-up date. In this case, the Company  
21 proposes to set the base level for the property tax tracker at \$162,034,000.

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<sup>4</sup> As proposed by Staff and agreed to by the Company in File No. ER-2022-0337, the Company has measured this regulatory liability balance (as well as other amortizations) as of the true-up date in this case.

1           **Q.     Please explain Schedule SJH-D9.**

2           A.     Schedule SJH-D9 lists the ADIT applicable to total electric operations at  
3     March 31, 2026, and the pro forma adjustments required to project the balances forward to  
4     December 31, 2026, the end of the proposed true-up period. ADIT is the net result of  
5     normalizing the tax benefits resulting from timing differences between the periods in which  
6     transactions affect taxable income and the period in which such transactions affect the  
7     determination of pre-tax income.

8           Currently, the Company has deferred income taxes in FERC Accounts 190, 281,  
9     282, and 283. As shown in Schedule SJH-D9, the total electric pro forma ADIT balance is  
10    a net liability balance of \$3,014,263,000. Net deferred income tax liabilities are a deduction  
11    from rate base.

12           **Q.     What is the Company's pro forma net original cost electric rate base at**  
13    **December 31, 2026?**

14           A.     The Company's total electric rate base as shown in Schedule SJH-D15 is  
15    \$16,684,497,000.

16           **Q.     Please explain Schedule SJH-D10.**

17           A.     Schedule SJH-D10 shows total electric operating revenues per book and pro  
18    forma for the twelve months ended March 31, 2026, with customer growth and other pro  
19    forma adjustments through December 31, 2026, the end of the proposed true-up period.

1           **Q.     Please explain the pro forma adjustments to the electric operating**  
2 **revenues shown in Schedule SJH-D10.**

3           A.     The following pro forma adjustments are shown in Schedule SJH-D10:

4           Adjustment 1 eliminates revenue add-on taxes of \$182,038,000, as they are directly  
5 passed through to customers by the Company.

6           Adjustment 2 eliminates the MEEIA revenues of \$59,637,000, as they are collected  
7 through the MEEIA Rider rather than through base rates.

8           Adjustment 3 eliminates FAC revenues of \$101,168,000, as they are collected  
9 through the FAC Rider rather than base rates.

10          Adjustment 4 eliminates the effect of unbilled revenues and decreases revenues by  
11 \$16,878,000. After the unbilled revenue adjustment, book revenues are reflected on a bill  
12 cycle basis.

13          Because new retail rates (resulting from File No. ER-2024-0319) were effective  
14 June 1, 2025, Adjustment 5 increases revenues by \$54,643,000 to annualize the effect of  
15 those new rates to the full test year.

16          Adjustment 6 removes \$16,001,000 of revenues as a result of the economic  
17 development incentive ("EDI") adjustment, an adjustment made to account for pro forma  
18 base rate revenues that will not otherwise be collected due to discounts on base rates  
19 granted under the Company's economic development incentive provisions under Rider EDI  
20 approved pursuant to Section 393.1640 RSMo.

21          Adjustment 7 increases revenues by \$16,212,000 to remove the EDI discounts  
22 provided during the test year.

1 Adjustment 8 increases revenues by \$1,619,000 to reflect revenues expected to be  
2 received as part of the Company's Community Solar Program.

3 Adjustment 9 increases revenues by \$14,538,000 to reflect estimated customer  
4 growth through December 31, 2026.

5 Adjustment 10 reduces revenues by \$54,940,000 to remove revenues recovered  
6 under the RESRAM.

7 To annualize the impact of energy efficiency efforts and customer-owned solar  
8 installations, most of which were incentivized through Company rebate programs,  
9 revenues are being reduced by \$3,160,000 in Adjustment 11.

10 Since the Company uses cycle and window billing, revenues are increased by  
11 \$8,293,000 to reflect the twelve-month billing year as a twelve-month, 365-day, calendar  
12 year in Adjustment 12.

13 Adjustment 13 decreases revenues by \$3,113,000 to synchronize the book revenues  
14 with the Company's billing unit rate analysis.

15 Revenues were decreased in Adjustment 14 by \$17,122,000 to reflect normal  
16 weather. Revenue adjustments 5, 6, 8, 9, 11, 12, 13, and 14 are further discussed by  
17 Company witness Nicholas Bowden in his direct testimony.

18 Adjustment 15 removes test year RSP revenues, reducing revenues by \$9,293,000.

19 Adjustment 16 increases revenues by \$12,670,000<sup>5</sup> to reflect revenues expected to  
20 be received as part of the Company's RSP. Adjustment 16 is further discussed by Company  
21 witness Steven Wills in his Direct Testimony.

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<sup>5</sup> The \$12,670,000 in pro forma revenues includes \$9,390,000 in pro forma revenues for the RSP and \$3,280,000 in pro forma revenues for the RSP-LLC associated with large load service.

1           Adjustment 17 increases revenues by \$10,087,000 to reflect a discrete adjustment  
2 to the requested revenue requirement calculation in this case to reflect known and  
3 measurable large load revenues that will start after the true-up date but roughly  
4 commensurately with the dates rates take effect in this case. Adjustment 17 is further  
5 discussed by Company witness Wills in his Direct Testimony.

6           The provision for rate refunds of \$286,000, applicable to the operation of the  
7 Company's FAC, is eliminated in Adjustment 18.

8           The "other electric revenues" in Schedule SJH-D10 were increased by \$3,460,000  
9 in Adjustment 19 for estimated transmission revenues through December 31, 2026, the  
10 proposed true-up date.

11           Adjustment 20 increases revenue by \$8,334,000 to reflect expected additional  
12 intercompany facility rental revenue.

13           Adjustment 21 decreases revenue by \$1,200,000 to remove a waiver payment  
14 received by the Company in exchange for waiving certain contractual build-out restrictions  
15 in the area surrounding the Atchison Renewable Energy Center. As the Atchison  
16 Renewable Energy Center is a RES compliance project whose costs and benefits are  
17 required to be included in the RESRAM, this waiver payment is being passed through to  
18 customers via the RESRAM rather than via base rates.

19           Adjustment 22 increases revenue by \$129,000 for annual revenues expected at the  
20 true-up date under the PAYS program.

21           Adjustment 23 eliminates add-on taxes of \$775,000 applicable to other revenues,  
22 as they are directly passed through to customers by the Company.

1           **Q.    Are the revenues from off-system energy sales included in Schedule**  
2 **SJH-D10?**

3           A.    Yes, Adjustment 24 in Schedule SJH-D10 increases the actual off-system  
4 sales revenues from energy by \$170,965,000 to reflect a normal level of off-system sales  
5 calculated using the current normalized market price for energy and the annualized power  
6 and ancillary services market revenues from MISO, as discussed in the Direct Testimony  
7 of Company witness Andrew Meyer. Adjustment 25 decreases sales of capacity by  
8 \$173,769,000, to reflect a normal level of capacity sales, as is also addressed in Company  
9 witness Meyer's Direct Testimony. The production cost model ("PowerSIMM"), explained  
10 in the Direct Testimony of Company witness Michael Flanagan, was used to develop the  
11 normal off-system sales volumes and revenues from energy sales.

12           **Q.    What are the pro forma electric operating revenues for the twelve**  
13 **months ending December 31, 2026?**

14           A.    The pro forma electric operating revenues for the twelve months ending  
15 December 31, 2026, are \$4,230,694,000, including the off-system sales revenues.

16           **Q.    Please describe what is shown in Schedule SJH-D11.**

17           A.    Total electric operating and maintenance ("O&M") expense for the twelve  
18 months ended March 31, 2026 (per books by functional classification), the pro forma  
19 electric operations and maintenance expenses by functional classification, and a listing of  
20 the pro forma adjustments are shown in Schedule SJH-D11.

1           **Q.    Please explain the pro forma adjustments to electric O&M expense for**  
2 **the twelve months ended March 31, 2026.**

3           A.    A summary of the pro forma adjustments to O&M expense appears in  
4 Schedule SJH-D11. Adjustment 1 reflects the increased labor expenses related to union  
5 and management wage increases at January 1, 2026, and January 1, 2027. A 3.0% wage  
6 increase for union employees was effective January 1, 2026, per the labor contracts. A  
7 3.35% wage increase for management employees was effective January 1, 2026. In  
8 addition, the Company expects management employees to receive average wage increases  
9 of 3.75%, effective January 1, 2027. The current union contracts expire prior to the true-  
10 up date in this case. The Company is currently in the process of negotiating contract  
11 extensions with its primary unions and expects to have such contracts in place prior to the  
12 true-up date in this case. For the purposes of the direct filing, the Company will utilize the  
13 actual contract wage increases effective January 1, 2026, as a proxy for the upcoming  
14 negotiated January 1, 2027 increase. The Company will true-up this assumption to the  
15 actual negotiated wage increases as part of its true-up filing in this case. The annualized  
16 increase in the total electric operating labor expense resulting from wage increases is  
17 \$18,770,000. These wage increases reflect known and measurable changes that either have  
18 occurred or will occur subsequent to the test year. Incentive compensation was excluded  
19 from the calculation of the wage increases, as wage increases only apply to base wages.

20           Adjustment 2 reduces O&M expenses by \$3,068,000 to eliminate the short-term  
21 incentive compensation that is based on the achievement of earnings-per-share goals of the  
22 Company and, for the remaining incentive compensation not eliminated, adjust from  
23 expenses recognized to payments made under the plans during the test year.

1           Consistent with prior cases, Adjustment 3 reduces O&M expenses by \$7,820,000  
2 to eliminate the portion of long-term incentive compensation that is based on total  
3 shareholder return ("TSR")<sup>6</sup>, including the allocated Ameren Services Company amount.

4           Adjustment 4 increases O&M expenses by \$47,428,000 for an increase in fuel  
5 expense, while Adjustment 5 decreases O&M by \$277,759,000 for a decrease in purchased  
6 power expense. Adjustments 4 and 5 were calculated by Company witness Flanagan using  
7 the PowerSIMM production cost model. His Direct Testimony details the inputs and  
8 assumptions used in the PowerSIMM production cost model. The purchased power  
9 expenses also include the power market and ancillary services charges from MISO.

10           Adjustment 6 reduces O&M expenses by \$116,000 to reflect an adjustment  
11 ordered by the MPSC in its Report and Order in File No. EO-2011-0128, issued April 19,  
12 2012, as modified by the Commission's Order Modifying Report and Order issued  
13 December 22, 2014. The referenced orders require that the Company make certain  
14 adjustments for ratemaking purposes for transmission charges from MISO for regionally  
15 allocated transmission facilities constructed by an Ameren Missouri affiliate in the service  
16 territory of Ameren Missouri. Ameren Missouri has received MISO transmission charges  
17 arising from such projects and thus has adjusted its revenue requirement in this case for  
18 charges received on the projects through December 31, 2025. The Company will true-up  
19 this adjustment to include charges through the true-up date in this case of December 31,  
20 2026.

21           Adjustment 7 decreases O&M expenses by \$2,681,000 to normalize non-labor  
22 scheduled outage maintenance expenses over the Company's planned six-year maintenance

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<sup>6</sup> TSR is a measure of how well a publicly traded company is performing financially. TSR measures returns from both changes in the Company's stock price and from the dividends it pays over any given period.

1 cycle at the Labadie and Sioux Energy Centers. Given the six-year maintenance cycle, a  
2 specific test year is not representative of the normal scheduled outage maintenance expense  
3 levels incurred. Adjustment 7 reflects an adjustment of scheduled outage maintenance  
4 expenses to the six-year average of historical costs, which is consistent with the  
5 maintenance cycle at these plants.

6 Adjustment 8 decreases O&M expenses by \$1,506,000 to adjust non-labor O&M  
7 expenses at Rush Island to expected amounts necessary for post-closure activities. Ongoing  
8 amounts include costs for ash pond closure maintenance and groundwater monitoring.

9 Adjustment 9 increases O&M expenses by \$102,923,000 to eliminate the FAC  
10 recovery during the test year, as these costs are recovered under the FAC Rider rather than  
11 base rates.

12 Adjustment 10 is an increase to O&M expenses to include two-thirds of the  
13 average of the last three Callaway Nuclear Energy Center refueling expenses. This  
14 adjustment is required because the outage cycle at the Callaway Nuclear Energy Center  
15 occurs every 18 months and the test year partially excluded the cost of a refueling outage,  
16 as related refueling costs are deferred and amortized in accordance with the Commission's  
17 Order in File No. EU-2020-0114. Therefore, in order to reflect an annualized amount of  
18 O&M expenses, it is necessary to include two-thirds (twelve-month annual period for  
19 setting rates as compared to the eighteen-month outage cycle) of Callaway Energy Center  
20 refueling expenses. Additionally, to address the variability in the level of expenses incurred  
21 during a refueling outage, this adjustment also reflects the normalization of costs by  
22 averaging the costs of the past three Callaway refueling outages. Production expenses must

1 be increased by \$26,418,000 for non-labor maintenance expense and \$6,395,000 for  
2 incremental overtime expenses. Adjustment 10 results in a total increase of \$32,813,000.

3 Adjustment 11 is a decrease in O&M expenses of \$30,569,000 to eliminate the  
4 Callaway Energy Center refueling amortization recorded in accordance with the  
5 Commission's order in File No. EU-2020-0114 from the test year. The net impact of  
6 adjustments 10 and 11 is an increase in O&M expenses of \$2,244,000.

7 Adjustment 12 decreases O&M expenses by \$2,008,000 to eliminate amortization  
8 of the RES tracker regulatory balances established in prior cases and recover current  
9 accumulated costs over a three-year period. The remaining regulatory balances established  
10 in File No. ER-2024-0319 as of the true-up date have been added to the expired & expiring  
11 amortizations discussed in Schedule SJH-D12.

12 Adjustment 13 decreases O&M expenses by \$4,163,000 to rebase expenses related  
13 to the RES tracker, including the Maryland Heights Renewable Energy Center fuel costs.<sup>7</sup>

14 Adjustment 14 decreases O&M expenses by \$223,000 to eliminate pre-RESRAM  
15 solar rebate costs and amortization from the test year.

16 Adjustment 15 increases O&M expenses by \$598,000 for an increase in  
17 depreciation that is charged to O&M for transportation and heavy-duty equipment.  
18 Depreciation expense charged to O&M was updated for investment levels at December 31,  
19 2026.

20 Adjustment 16 increases O&M expenses by \$2,047,000 to normalize storm costs  
21 to reflect a five-year average. Variability exists in the level of storm costs experienced in  
22 any given test year. This normalization adjustment is consistent with past practice.

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<sup>7</sup> The Company proposes to set the base level for the RES tracker at \$2,150,000, subject to true-up.

1           Adjustment 17 increases O&M expenses by \$12,785,000 to update vegetation  
2 management and infrastructure inspection expenses to the most recent levels expected in  
3 the proposed true-up period.

4           Adjustment 18 is an increase of \$2,419,000 to O&M expenses to reflect interest  
5 expense at 8.0% on the thirteen-month average customer deposit balance as of March 31,  
6 2026. The average customer deposit balance is deducted from rate base.

7           Adjustment 19 is an increase of \$5,269,000 to update Circuit & Device Inspection  
8 System ("CDIS") expenses to the levels expected in the proposed true-up period. The  
9 Company is proposing to true-up CDIS expenses in order to appropriately reflect the  
10 annualized level of costs necessary to complete the repairs identified through recent  
11 inspections.

12           Adjustment 20 decreases O&M expenses by \$45,195,000 to eliminate program  
13 costs related to MEEIA, which are included in the MEEIA Rider.

14           Adjustment 21 increases O&M expenses by \$327,000 for the annual amortization  
15 of the PAYS regulatory assets expected at the true-up date. This adjustment includes  
16 annualization of the amortization authorized in File Nos. ER-2021-0240, ER-2022-0337  
17 and ER-2024-0319, and amortization of incremental deferrals expected through the true-  
18 up date. The amortization period relating to the incremental deferrals will be calculated  
19 based on the remaining weighted useful life of measures installed under the program at the  
20 proposed true-up date.

21           Adjustment 22 is an increase of \$2,887,000 to update locates expenses to the most  
22 recent levels expected in the proposed true-up period. Locate costs are increasing due to  
23 higher contractor pricing, elevated levels of new construction activity within the

1 Company's service territory, and the implementation of a 21-day expiration period for  
2 locate requests under Missouri Senate Bill 133 (2025) amending provisions of Chapter 319  
3 of the Missouri Revised Statutes.

4 Adjustment 23 decreases O&M expenses by \$1,483,000 to adjust bad debt expense  
5 to the level of bad debt net write-offs from the test year.

6 Adjustment 24 increases O&M expenses by \$10,524,000 to annualize salaries and  
7 benefits expenses based on expected staffing levels as of the true-up date. This adjustment  
8 is consistent with the past practice of adjusting for the on-going employment levels  
9 experienced through the true-up date and allows for newly authorized rates to most closely  
10 align with the Company's costs.

11 The various insurance policies of the Company are renewable at different times  
12 during the year. Adjustment 25 increases O&M expenses by \$5,186,000 to annualize the  
13 premiums of the various insurance policies in effect, or expected to be in effect, at the time  
14 new rates are expected to be implemented in this case.

15 Adjustment 26 increases O&M expenses by \$3,059,000 to reflect annualized other  
16 employee benefits expenses through the proposed true-up date.

17 Adjustment 27 decreases O&M expenses by \$28,000 to reflect current cost levels  
18 for the non-qualified pension plan.<sup>8</sup>

19 Adjustment 28 increases O&M expenses by \$34,777,000 to rebase the pension and  
20 OPEB trackers to reflect applicable annualized calendar year 2025 expense levels.<sup>9</sup>

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<sup>8</sup> The non-qualified pension plan is no longer included in the pension tracker.

<sup>9</sup> In this case, the Company proposes to set the base levels for the pension and OPEB trackers at (\$36,183,000) and (\$28,265,000), respectively.

1           Adjustment 29 increases O&M expenses by \$25,653,000 to remove test year  
2 pension and OPEB tracker amortization, to amortize the remaining liability balances from  
3 File No. ER-2024-0319 as of the true-up date over 2 years, and to amortize the regulatory  
4 asset balance from the most recent accumulation period, from January 1, 2025, through the  
5 true-up date, over a period of 5 years. As discussed above in Schedule SJH-D8, the  
6 Company proposes that the remaining balances as of the true-up date for all pension and  
7 OPEB tracker deferrals established prior to File No. ER-2024-0319 be combined into the  
8 expired & expiring amortizations regulatory asset included in rate base. Amortization of  
9 these remaining balances is included in the expired & expiring amortizations discussed in  
10 Schedule SJH-D12.

11           Adjustment 30 increases O&M expenses by \$1,322,000 for non-labor O&M  
12 expenses included in the RESRAM base amount.<sup>10</sup> This rebasing adjustment reflects the  
13 expected annual O&M expenses at the Company's wind energy centers and the Huck Finn  
14 Renewable Energy Center as of the true-up date.

15           O&M expenses are increased in Adjustment 31 by \$360,000 to reflect the average  
16 rate case expenses incurred by the Company in the last three general rate reviews and  
17 recovery of these costs over a two-year period.

18           Adjustment 32 increases O&M expenses by \$2,497,000 to annualize the most  
19 recent Ameren Missouri electric operations MPSC Regulatory Assessment and to update  
20 Office of Public Counsel ("OPC") and FERC regulatory expenses to the levels expected  
21 during the proposed true-up period.

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<sup>10</sup> The Company proposes to set the base amount for the RESRAM at (\$23,145,000), subject to true-up.

1           In Adjustment 33, the Company reduced O&M expenses by \$288,000 to remove  
2 certain Ameren Corporation Board of Directors travel, meal, and entertainment expenses  
3 from the test year.

4           Adjustment 34 increases O&M expenses by \$3,465,000 to annualize the increase  
5 in building rent expenses allocated to Ameren Missouri from Ameren Services Corporation  
6 and Ameren Illinois Transmission Company.

7           Adjustment 35 increases O&M expenses by \$34,000 to reflect a normalized level  
8 of depreciation study expenses incurred by the Company, based on the depreciation study  
9 expenses incurred as part of its most recent electric rate review in File No. ER-2024-0319,  
10 and recovery of these costs over a two-year period.

11           Adjustment 36 decreases O&M expenses by \$1,497,000 to normalize severance  
12 costs to reflect a three-year average. Variability exists in the level of severance costs  
13 experienced in any given test year due to variations in the amount and timing of employee  
14 terminations.

15           Adjustment 37 increases O&M expenses by \$616,000 to annualize applicable  
16 expenses based on current allocation factors.

17           Adjustment 38 decreases O&M expenses by \$370,000 to remove Automated  
18 Meter Reading ("AMR") costs due to deployment of the Company's Advanced Metering  
19 Infrastructure ("AMI").

20           Adjustment 39 increases O&M expenses by \$4,000 for identified electric costs  
21 which were allocated to gas operations in the test year.

22           Adjustment 40 decreases O&M expenses by \$1,014,000 for customer convenience  
23 charges (e.g., credit card fees) that are included in the Company's revenue requirement in

1 accordance with File No. ER-2021-0240. This adjustment removes customer convenience  
2 fees attributable to gas operations and annualizes the level of customer convenience fees  
3 based on current customer payment volumes and fee rates.

4 Adjustment 41 increases O&M expenses by \$952,000 for expected annual  
5 cybersecurity costs through December 31, 2026, the proposed true-up period.  
6 Cybersecurity costs are generally expected to increase over time as the Company responds  
7 to an expanding threat landscape.

8 Adjustment 42 decreases O&M expenses by \$1,910,000 for expected annual  
9 software maintenance expenses through December 31, 2026, the proposed true-up period.

10 Adjustment 43 decreases O&M expenses by \$226,000 to annualize fees assessed  
11 by the NRC.

12 Adjustment 44 increases O&M expenses by \$1,665,000 to include an annualized  
13 level of land lease expenses for the new Split Rail solar energy center, which is scheduled  
14 to be placed in service by the proposed true-up date.

15 Adjustment 45 decreases O&M expenses by \$514,000 to remove expenditures for  
16 the St. Louis Blues Power Play Goals for Kids campaign and other similar initiatives, in  
17 accordance with the Stipulation and Agreement in File No. ER-2021-0240.

18 Adjustment 46 increases O&M expenses by \$8,000,000 to remove an adjustment  
19 to the expense reserve associated with the Rush Island New Source Review litigation from  
20 the test year.

21 Adjustment 47 decreases O&M expenses by \$32,000 to remove certain Chamber  
22 of Commerce dues from the test year.

1           **Q.     What is the impact on total electric operations and maintenance**  
2 **expense from the above pro forma adjustments?**

3           A.     As shown in Schedule SJH-D11, the total electric O&M expenses are  
4 decreased from \$2,282,020,000 to \$2,225,930,000, or a total net decrease of \$56,090,000,  
5 by the above pro forma adjustments.

6           **Q.     What is shown in Schedule SJH-D12?**

7           A.     Schedule SJH-D12 shows the total electric depreciation and amortization  
8 expenses by functional classifications for the twelve months ended March 31, 2026, per  
9 book and pro forma through the true-up date.

10          **Q.     What pro forma adjustments apply to the depreciation and**  
11 **amortization expense?**

12          A.     Schedule SJH-D12 details the following pro forma adjustments to the  
13 depreciation and amortization expenses:

14                 Adjustment 1 increases depreciation and plant amortization by \$108,049,000 to  
15 reflect the book depreciation annualized for the plant-in-service depreciable balances at  
16 March 31, 2026, and plant additions through the true-up period, based on the depreciation  
17 rates approved in File No. ER-2024-0319.

18                 Adjustment 2 increases depreciation and plant amortization by \$40,409,000 to  
19 eliminate PISA deferrals and amortization from the test year ended March 31, 2026.

20                 Depreciation for coal cars (Account 312), transportation equipment (Account 392),  
21 and heavy-duty equipment (Account 396) are charged to O&M rather than depreciation  
22 expense. Adjustment 3 reduces depreciation expense by \$17,990,000 to remove the  
23 depreciation expense on these accounts.

1           Adjustment 4 decreases amortization expense by \$615,000 to eliminate  
2 amortization of the Callaway Post Operational Regulatory Asset. The over-amortized  
3 balance as of the true-up date has been included in the expired & expiring amortizations  
4 regulatory asset included in rate base, discussed earlier in Schedule SJH-D8, and will be  
5 amortized as part of Adjustment 10 discussed below.

6           Adjustment 5 decreases amortization expense by \$15,000 to eliminate amortization  
7 of the Callaway Fukushima Study Costs regulatory asset. The remaining Callaway  
8 Fukushima Study Costs regulatory asset balance was included in the expired & expiring  
9 amortizations regulatory balances in File No. ER-2024-0319.

10          Adjustment 6 increases amortization expense by \$790,000 to eliminate annual  
11 amortization of the construction accounting contra regulatory asset for the Sioux Scrubbers  
12 and to reflect the updated 2032 retirement date for the Sioux Energy Center established as  
13 part of File No. ER-2024-0319. The contra regulatory asset account is recorded for  
14 Generally Accepted Accounting Principles purposes and has no impact on ratemaking.

15          Adjustment 7 decreases amortization expense by \$2,177,000 to eliminate  
16 amortization of costs of a customer affordability opportunities study. The remaining  
17 unamortized balance as of the true-up date will be amortized along with other expired &  
18 expiring regulatory balances as part of Adjustment 10 discussed below.

19          Adjustment 8 decreases amortization by \$2,569,000 to eliminate MEEIA deferrals  
20 and amortizations that are considered under the MEEIA Rider, including MEEIA ordered  
21 adjustments.

1 Adjustment 9 decreases amortization expense by \$2,854,000 to remove the  
2 customer-funded portion of the Keeping Current and Keeping Cool Program as further  
3 discussed by Company witnesses Page Selby and Bowden in their Direct Testimonies.

4 As previously referenced, the Company has combined and netted the true-up date  
5 balances of regulatory assets and liabilities that have expired (and over-amortized) since  
6 the Company's last rate review or are expected to expire soon after the true-up date. Any  
7 over or under-recovery that will exist as of the true-up date will be tracked, combined, and  
8 netted for the following balances:

<b>Balance Description</b>	<b>December 31, 2026 Balance (Projected)</b>	
<b>Included in rate base</b>	<b>(Over) / Under Recovered Amt.</b>	
Expired & Expiring Amortizations (ER-2024-0319)	\$	(887,000)
Property Tax Tracker (ER-2024-0319)		7,810,000
Pension Tracker (tranches prior to ER-2024-0319)		1,530,000
OPEB Tracker (tranches prior to ER-2024-0319)		419,000
Meramec Retirement		2,030,000
Meramec Inventory Write Off		3,326,000
Meramec Coal Inventory Write Off		170,000
Callaway Post Operations Regulatory Asset		(1,536,000)
<b>Included in rate base total</b>	<b>\$</b>	<b>12,862,000</b>
<b>Non-rate base</b>		
Expired & Expiring Amortizations (ER-2024-0319)	\$	1,333,000
RES Tracker (ER-2024-0319)		(1,716,000)
COVID AAO		291,000
Customer Affordability Study		3,266,000
Rush Island Deferral		(18,344,000)
Excess Deferred Tax Tracker ER-2024-0319		6,893,000
Federal Excess Deferred Income Taxes (Unprotected Plant)		(17,353,000)
Federal Excess Deferred Income Taxes (Unprotected Non-Plant)		(715,000)
State Excess Deferred Income Taxes		4,612,000
Solar Rebate Program (ER-2021-0240)		(557,000)
<b>Non-rate base total</b>	<b>\$</b>	<b>(22,290,000)</b>
<b>Net projected over-recovered amount as of the true-up date</b>	<b>\$</b>	<b>(9,428,000)</b>

9

1           These tracked, combined, and netted balances will be amortized over a three-year  
2 period. Adjustment 10 decreases amortization by \$1,650,000 to amortize the combined and  
3 netted over- and under-collections associated with expired & expiring regulatory asset and  
4 liability balances and to remove test year amortization associated with the expired &  
5 expiring regulatory asset and liability balances established in File No. ER-2024-0319.

6           Adjustment 11 increases amortization by \$50,244,000 to reflect the amortization of  
7 PISA deferrals over twenty-year periods.

8           Adjustment 12 increases amortization by \$407,000 to eliminate amortization of the  
9 excess deferred tax tracker regulatory liability balances established in prior cases, eliminate  
10 test year deferrals, and amortize the current accumulation period balance over a three-year  
11 period.<sup>11</sup> The remaining unamortized regulatory asset balance established in File No. ER-  
12 2024-0319 as of the true-up date has been added to the expired & expiring amortizations  
13 discussed in Adjustment 10 above.

14           Adjustment 13 decreases amortization by \$9,355,000 to eliminate deferrals made  
15 under the RESRAM and to eliminate amortization associated with amounts recovered  
16 through the associated RESRAM rider.

17           Adjustment 14 increases amortization by \$123,000 to recover the Charge Ahead  
18 Corridor Program regulatory asset over a seven-year period.

19           Adjustment 15 increases amortization by \$1,256,000 to reflect amortization of the  
20 remaining unamortized costs associated with the issuance of equity for the funding of the  
21 High Prairie and Atchison renewable energy centers over a period of 5 years.

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<sup>11</sup> In this case, the Company proposes to set the base level for the excess deferred tax tracker at (\$37,950,000), grossed up.

1           Adjustment 16 decreases amortization by \$12,184,000 to eliminate amortization  
2 of the Meramec Retirement Cost regulatory asset. The under-amortized balance as of the  
3 true-up date has been included in the expired & expiring amortizations regulatory asset  
4 included in rate base, discussed earlier in Schedule SJH-D8, and will be amortized as part  
5 of Adjustment 10 discussed above.

6           Adjustment 17 decreases amortization by \$1,854,000 to eliminate amortization of  
7 the Meramec Inventory and Coal Inventory regulatory assets. The under-amortized balance  
8 as of the true-up date has been included in the expired & expiring amortizations regulatory  
9 asset included in rate base, discussed earlier in Schedule SJH-D8, and will be amortized as  
10 part of Adjustment 10 discussed above.

11           Adjustment 18 increases amortization by \$1,806,000 to eliminate amortization of  
12 the Rush Island Deferral.<sup>12</sup> The remaining unamortized balance of the Rush Island Deferral  
13 as of the true-up date will be amortized along with other expired & expiring regulatory  
14 balances as part of Adjustment 10 discussed above.

15           Adjustment 19 decreases amortization by \$986,000 to eliminate amortization  
16 related to the COVID-19 Accounting Authority Order. The remaining unamortized balance  
17 as of the true-up date will be amortized along with other expired & expiring regulatory  
18 balances as part of Adjustment 10 discussed above.

19           Adjustment 20 decreases amortization by \$857,000 to amortize the expected  
20 property tax tracker regulatory liability balance as of the true-up date for the current  
21 accumulation period over a period of 3 years. The remaining unamortized balance

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<sup>12</sup> The Rush Island Deferral relates to the requirement established by the Commission in File No. EF-2024-0021 to track Rush Island related costs recovered in rates after the facility's retirement for future refund to customers.

1 established in File No. ER-2024-0319 as of the true-up date will be amortized along with  
2 other expired & expiring regulatory balances as part of Adjustment 10 discussed above.

3 Adjustment 21 decreases amortization by \$3,373,000 to eliminate deferrals made  
4 under the RSP.

5 Adjustment 22 decreases amortization by \$3,258,000 to reflect amortization of  
6 RSP tracker deferrals over 2 years.

7 Adjustment 23 decreases amortization by \$339,000 to eliminate deferrals of sales  
8 tax overcollections due to Senate Bill 872 and to amortize the accumulated overcollection  
9 balance over 3 years.

10 Adjustment 24 decreases amortization by \$2,998,000 to reflect the amortization of  
11 Nuclear Production Tax Credits over 5 years, consistent with the approach agreed to and  
12 approved in File No. ER-2024-0319.

13 Adjustment 25 decreases amortization by \$263,000 to reflect the amortization of  
14 a remaining regulatory liability balance associated with a legacy electric energy efficiency  
15 program over 2 years.

16 Adjustment 26 decreases amortization by \$250,000 to remove the customer-  
17 funded portion of the Rehousing Low-Income Pilot (New Start Energy Relief) Program, as  
18 further discussed by Company witnesses Selby and Bowden in their Direct Testimonies.

19 **Q. Is the Company submitting a full depreciation study as part of this**  
20 **case?**

21 A. No. The Commission's rules call for submission of a full depreciation study  
22 no less often than every five years.<sup>13</sup> As the Company last submitted a full depreciation

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<sup>13</sup> Section 20 CSR 4240-3.175 - Submission Requirements for Electric Utility Depreciation Studies.

1 study only two years ago in 2024 as part of File No. ER-2024-0319, it is not required to  
2 submit a full depreciation study as part of this case.

3 While the Company is not submitting a full depreciation study as part of this case,  
4 the Company is seeking Commission approval of forecasted depreciation rates for certain  
5 future generating facilities, specifically, for its new simple cycle combustion turbine  
6 facilities (currently under construction) and for battery energy storage systems. The  
7 combustion turbine facilities and at least one energy storage system is expected to go in to  
8 service before the Company's next electric general rate proceeding. Refer to the Direct  
9 Testimony of Company witness John J. Spanos for the development of these forecasted  
10 depreciation rates.

11 **Q. What are the total electric pro forma depreciation and amortization**  
12 **expenses?**

13 A. As reported in Schedule SJH-D12, the total electric pro forma depreciation  
14 and amortization expenses are \$1,028,936,000.

15 **Q. Please explain Schedule SJH-D13.**

16 A. Schedule SJH-D13 shows taxes other than income taxes for the twelve  
17 months ended March 31, 2026, per book and pro forma.

18 **Q. Please list the pro forma adjustments required to arrive at the total**  
19 **electric pro forma taxes other than income taxes as detailed in Schedule SJH-D13.**

20 A. The following pro forma adjustments detailed in Schedule SJH-D13 are  
21 required to arrive at the total electric pro forma taxes other than income taxes. Adjustment  
22 1 increases Federal Insurance Contributions Act ("FICA") taxes by \$1,765,000 to reflect  
23 pro forma wage adjustments.

1            Adjustment 2 decreases property taxes by \$3,451,000 to reflect property taxes  
2 expected to be paid in December 2026.

3            Adjustment 3 decreases property taxes by \$4,939,000 to eliminate the deferrals  
4 under the property tax tracker.

5            Property taxes of \$231,000 applicable to plant held for future use are eliminated  
6 in Adjustment 4. This adjustment is required as the investment in plant held for future use  
7 is not currently serving customers.

8            Adjustment 5 adjusts taxes other than income taxes to remove Missouri gross  
9 receipts taxes of \$183,362,000, as they are add-on taxes that are directly passed through to  
10 customers. The pro forma book revenues also reflect the removal of the add-on revenue  
11 taxes.

12            **Q.    What are the total electric pro forma taxes other than income taxes?**

13            A.    As reflected in Schedule SJH-D13, the total electric pro forma taxes other  
14 than income taxes are \$194,161,000.

15            **Q.    What is shown in Schedule SJH-D14?**

16            A.    Schedule SJH-D14 shows the derivation of the income tax calculation at the  
17 requested 7.506% rate of return for total electric operations reflecting the statutory tax  
18 rates. Refer to the Direct Testimony of Company witness Mitchell J. Lansford for the  
19 development of the 7.506% rate of return.

1           **Q. As shown in Schedule SJH-D14, what are the income taxes at the**  
2 **requested rate of return for electric operations?**

3           A. Total current federal, state, and city earnings income taxes using the  
4 statutory tax rates at the requested rate of return are \$113,815,000<sup>14</sup> for electric operations,  
5 as shown in Schedule SJH-D14. Deferred income taxes for electric operations, also shown  
6 in Schedule SJH-D14, are (\$241,603,000). The net current and deferred income taxes for  
7 electric operations included in the revenue requirement are (\$127,788,000).

8           Deferred income taxes for electric operations consist of amortization of excess  
9 ADIT (\$30,218,000) and investment tax credits (\$211,385,000).

10           **Q. Deferred income taxes for electric operations include what amount of**  
11 **unprotected excess ADIT amortization?**

12           A. None. The unprotected excess ADIT related to the 2017 Tax Cuts and Jobs  
13 Act that the Company agreed to return to customers as part of a stipulation and agreement  
14 in File No. ER-2018-0362<sup>15</sup> will become fully amortized in May 2027. As this amortization  
15 will expire soon after the true-up date in this case, the Company is proposing that the  
16 remaining unamortized balance as of the true-up date be amortized along with other expired  
17 & expiring regulatory balances discussed in Adjustment 10 on Schedule SJH-D12. The  
18 excess ADIT amortization component of deferred income taxes instead consists entirely of  
19 protected plant-related excess ADIT amortization that utilizes the Average Rate  
20 Assumption Method and is subject to the excess deferred tax tracker.

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<sup>14</sup> Current income taxes reflect a reduction of \$77,909,000 for Production Tax Credits ("PTCs") relating to the High Prairie, Atchison, and Huck Finn renewable energy centers, which are subject to the RESRAM. Production levels used to calculate PTC amounts are those produced by Company witness Flanagan.

<sup>15</sup> The amortization period for this balance was subsequently adjusted in File No. ER-2024-0319.

1           **Q.     What is the impact to deferred income taxes from the unprotected**  
2 **excess ADIT balance becoming fully amortized prior to new rates being established**  
3 **in this case?**

4           A.     The Company's current revenue requirement, established in File No. ER-  
5 2024-0319, reflects approximately \$73 million<sup>16</sup> in annual customer refunds from the  
6 amortization of unprotected excess ADIT. As such, the expiring unprotected excess ADIT  
7 amortization represents the end of a significant benefit stream that has been reducing  
8 customer rates for nearly a decade.

9           **Q.     Has the Company taken any proactive steps to mitigate the impact that**  
10 **the end of this income tax benefit will have on customers?**

11          A.     Yes. The Company's past practice has been to amortize proceeds from  
12 transferring Investment Tax Credits ("ITCs") subject to the Company's Inflation Reduction  
13 Act ("IRA") tracker into customer rates over a three-year period.<sup>17</sup> In this case, the  
14 Company is proposing to accelerate amortization of such ITC proceeds over a two-year  
15 period in order to pass these benefits through to customers more quickly to help offset other  
16 cost increases that our customers are facing, including the expiration of unprotected excess  
17 ADIT amortization benefits discussed above and the inclusion of the investments in the  
18 Split Rail, Vandalia, and Bowling Green renewable energy centers in the Company's rate  
19 base. This voluntary, customer-centric change reduces the Company's revenue requirement  
20 by approximately \$92 million.<sup>18</sup>

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<sup>16</sup> Unprotected excess ADIT amortization balance established in File No. ER-2024-0319 of approximately \$56 million, grossed up for the effect on revenues.

<sup>17</sup> IRC Section 6418 Transfer of Certain Credits, a provision of the IRA, allows eligible taxpayers to transfer all, or a portion of tax credits, including PTCs and ITCs, to unrelated taxpayers for cash.

<sup>18</sup> ITC amortization increase grossed up for the effect on revenues.

1           **Q. Has the Company taken any other actions in order to mitigate the size**  
2 **of the rate increase request in this case?**

3           A. Yes. In recent years, customers have benefitted from substantially lower  
4 rates due to the Company's revenue requirement being reduced by the impact of changes  
5 in actuarial assumptions for the Company's pension and OPEB plans and differences  
6 between expected returns on plan assets and actual market returns. In fact, in the  
7 Company's two most recent electric general rate cases, File Numbers ER-2022-0337 and  
8 ER-2024-0319, the combined pension and OPEB tracker base amounts actually  
9 represented a net decrease to the Company's revenue requirement of (\$119 million) and  
10 (\$95 million), respectively. Unfortunately, most of these items will have become fully  
11 amortized to the benefit of customers prior to the true-up date in this case, resulting in an  
12 expected large one-time increase in the net pension and OPEB tracker base amounts.<sup>19</sup>

13           If the Company were to rebase its pension and OPEB costs in this case based on  
14 the most current information available as of the true-up date, annualized calendar year 2026  
15 expense levels, it would represent an increase in the pension and OPEB tracker base  
16 amounts of over \$70 million versus amounts reflected in current rates. In order to minimize  
17 the customer rate shock from reflecting this entire one-time net cost increase as part of the  
18 present case, the Company is proposing to instead rebase its pension and OPEB costs in  
19 this case based on the annualized 2025 expense levels that cover the majority of the test  
20 year. This approach is intended to spread this significant one-time net cost increase roughly  
21 evenly across both the present case and the Company's next electric general rate review,  
22 spreading the customer rate impact out over a longer period.

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<sup>19</sup> Or, more accurately, a decrease in the size of the reduction to the revenue requirement from the pension and OPEB tracker base amounts.

1           **Q.    Please explain Schedule SJH-D15.**

2           A.    Schedule SJH-D15 shows the total electric rate base of \$16,684,497,000  
3 and the total electric revenue requirement of \$4,573,577,000 at the requested return of  
4 7.506%.

5           **Q.    What does Schedule SJH-D16 reflect?**

6           A.    Schedule SJH-D16 compares the total electric revenue requirement of  
7 \$4,573,577,000 with the total electric pro forma operating revenues under the present rates  
8 of \$4,230,694,000, including off-system energy sales revenues. It shows that the revenue  
9 requirement is \$342,883,000 more than the pro forma operating revenues at present rates.  
10 \$4,573,577,000 is the amount of revenues used to set the rates filed in this case and is the  
11 level of revenues needed to provide the Company an opportunity to collect and recover its  
12 cost of service, including an opportunity to recover its cost of capital.

13                           **IV.    SECURITIZATION COST TRACKER UPDATE**

14           **Q.    What is the securitization cost tracker?**

15           A.    Per the below excerpt from the Commission's Financing Order in File No.  
16 EF-2024-0021, the Company was ordered to track the estimated Rush Island retirement  
17 costs<sup>20</sup> included in the Securitized Utility Tariff Bonds against the actual costs incurred by  
18 the Company, so that any differences, either higher or lower, can be reconciled and  
19 included through an amortization in a future general rate case.

20                           Most of the amounts authorized for securitization in this  
21 order are estimates. Those estimates must be reconciled with  
22 actual amounts in a future general rate case. The  
23 Commission finds that a tracker would be an appropriate  
24 mechanism to track actual costs for any of the estimated  
25 costs included in the Securitized Utility Tariff Bonds so that

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<sup>20</sup> The estimated Rush Island retirement costs included in the Securitized Utility Tariff Bonds included both Energy Transition Costs and Upfront Financing Costs.

1                   the amounts, either higher or lower can be reconciled and  
2                   included through an amortization in a future general rate  
3                   case.<sup>21</sup>

4                   **Q. Does the Company's revenue requirement in this case include an**  
5                   **amortization to recover or refund any differences between the estimated Rush Island**  
6                   **retirement costs included in the Securitized Utility Tariff Bonds and the actual costs**  
7                   **incurred by the Company?**

8                   A. No, it does not. The safe closure and decommissioning of Rush Island  
9                   remains ongoing and the final decommissioning costs needed to perform the estimate-to-  
10                  actual cost reconciliation are not yet known. The Company will continue to track its actual  
11                  costs incurred against the estimated costs included in the Securitized Utility Tariff Bonds  
12                  and expects that any over- or under-recovery will be evaluated as part of its next general  
13                  rate case.

14                  **V. DETERMINATION OF NET BASE ENERGY COSTS**

15                  **Q. Did you determine the "net base energy costs" utilized in the**  
16                  **Company's FAC, as addressed in the Direct Testimony of Company witnesses Meyer**  
17                  **and Flanagan?**

18                  A. Yes. I calculated the net base energy costs and the seasonal values for Factor  
19                  BF in Rider FAC for both the summer and winter, which are 1.600 cents per kilowatt-hour  
20                  ("kWh") for the summer and 1.375 cents per kWh for the winter. Schedule SJH-D17 shows  
21                  the calculation of total net base energy costs, and the calculation of the Factor BF values  
22                  for the summer and winter periods. The net base energy costs calculation starts with the  
23                  fuel and purchased power costs determined by PowerSIMM, as discussed in Company

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<sup>21</sup> File No. EF-2024-0021, *Amended Report and Order*, p. 120, issued August 7, 2024.

1 witness Flanagan's Direct Testimony. There are other costs for fuel and purchased power  
2 that are not modeled by PowerSIMM, including net fly ash revenues and expenses, fixed  
3 gas supply costs, fuel additives, MISO Day 2 expenses, capacity expenses, replacement  
4 power insurance costs, Account 565 transmission expenses, the cost of purchasing ancillary  
5 services, and the cost of purchased power to serve common boundary customers. This total  
6 cost of fuel and purchased power is then offset or reduced by off-system energy sales  
7 revenues calculated via PowerSIMM. There are additional revenues not included in  
8 PowerSIMM, including the MISO Day 2 revenues, capacity sales, real-time load and  
9 generation deviation, and revenues from sales of ancillary services. All of the above  
10 expenses and revenues are then divided between the summer and winter periods to develop  
11 two separate values under Rider FAC. Per Schedule SJH-D17, the summer net base energy  
12 cost of \$194,955,558 was then divided by the normalized Ameren Missouri summer load  
13 at the MISO Node AMMO.UE of 12,182,615,450 kWhs to arrive at a summer value  
14 expressed in cents per kWh of 1.600 cents. The winter net base energy cost of \$285,893,924  
15 was then divided by the normalized Ameren Missouri winter load at the MISO Node  
16 AMMO.UE of 20,791,181,810 kWhs to arrive at a winter value expressed in cents per kWh  
17 of 1.375 cents.

## 18 VI. CASH WORKING CAPITAL ANALYSIS

19 **Q. For what period was the cash working capital lead/lag study**  
20 **performed?**

21 A. The lead/lag study analyzed the Company's cash transactions and invoices  
22 for the twelve months ending March 31, 2026.

1           **Q.    Please define what you mean by the phrase "cash working capital."**

2           A.    Cash working capital is the amount of funds required to finance the day-to-  
3 day operations of the Company.

4           **Q.    What is a lead/lag study?**

5           A.    A lead/lag study is an analysis of revenue lags and expense leads. CWC  
6 requirements are generally determined by lead/lag studies that are used to analyze the lag  
7 time between the date customers receive service and the date that customers' payments are  
8 available to the Company (i.e., the revenue lag). This lag is offset by a lead time during  
9 which the Company receives goods and services but pays for them at a later date (i.e., the  
10 expense lead). The "lead" and "lag" are both measured in days. The dollar-weighted lead  
11 and lag days are then divided by 365 to determine a daily CWC factor. This CWC factor  
12 is then multiplied by the annual test year cash expenses to determine the amount of cash  
13 working capital required for operations. The resulting amount of cash working capital is  
14 then included in the Company's rate base.

15          **Q.    Please explain the revenue lag in more detail.**

16          A.    As noted, the revenue lag refers to the elapsed time between the delivery of  
17 the Company's product (i.e., electricity) and its ability to use the funds received as payment  
18 for the delivery of the product. The revenue lag actually consists of three components as  
19 follows: the service lag, which is the number of days from the mid-point of the service  
20 period to the meter reading date; the billing lag, which is the time between when the meter  
21 is read and the bill is sent; and the collections lag, which is the time between when the bill  
22 is sent to the customer and when the customer's payment is received by the Company.

1           **Q.    Please explain the expense lead in more detail.**

2           A.    An expense lead refers to the elapsed time from when a good or service is  
3 provided to the Company to the point in time when the Company pays for the good or  
4 service and the funds are no longer available to the Company. There are a number of  
5 different expense leads, since the Company acquires goods and services from a number of  
6 different sources.

7           **Q.    What sources of information are employed to determine the leads  
8 and lags in a CWC analysis for the Company?**

9           A.    Information from the Accounts Payable, Customer Service, Human  
10 Resources, Payroll, Treasury Management, and Tax systems are utilized. The information  
11 derived from these sources, together with analyses of specific invoices, is used to determine  
12 the appropriate number of lead/lag days for the Company's electric business.

13           **Q.    How should the results of the CWC analysis be treated for ratemaking  
14 purposes?**

15           A.    The CWC requirement should be included as part of Ameren Missouri's  
16 rate base for ratemaking purposes, and I have included it in my calculation of the revenue  
17 requirement as previously discussed.

18           **Q.    Was one revenue lag applied to all of the Company's revenues?**

19           A.    No. The Company calculated a base revenue lag that was then weighted for  
20 relevant components applicable to retail and interchange sales revenues. This weighted  
21 revenue lag was applied to all cash operating revenues with the exception of pass-through  
22 taxes. A separate revenue lag was calculated and applied to all revenues associated with  
23 pass-through taxes.

1           **Q.    How was the base revenue lag applicable to retail sales determined?**

2           A.    The base revenue lag measures the average number of days from the date  
3 service was rendered by the Company until the date payment was received from customers  
4 and such funds were deposited by the Company. In the calculation, the base revenue lag  
5 was divided into three distinct components: 1) service lag; 2) billing lag; and 3) collections  
6 lag. Considered together, these three components of the base revenue lag for retail revenues  
7 totaled 39.32 lag days. An explanation of each component of the base revenue lag follows.  
8 Additionally, I will discuss how a total weighted revenue lag, incorporating interchange  
9 sales revenues, was calculated.

10          **Q.    What is meant by service lag?**

11          A.    The service lag refers to the number of days from the mid-point of the  
12 service period to the meter reading date for that service period. Using the mid-point  
13 methodology, the average service lag applicable to retail sales was 15.21 days (365 days  
14 in the year divided by 12 months divided by 2).

15          **Q.    What is meant by billing lag?**

16          A.    Billing lag refers to the average number of days from the date on which the  
17 meter was read until the customer was billed. The billing lag was determined by analyzing  
18 the Company's monthly billing schedules and meter reading records. The average billing  
19 lag applicable to retail sales was determined to be 0.97 days.

20          **Q.    What is meant by collections lag?**

21          A.    The collections lag refers to the average amount of time from the date when  
22 the customer received a bill to the date that the Company received payment from its

1 customers. Based on weighted average data from the Company's Customer Service System,  
2 the average collection lag applicable to retail sales was determined to be 23.14 days.

3 **Q. What data was used to calculate the collections lag?**

4 A. The Company used data from the bill payment report which was created to  
5 support the calculation of the collections lag.

6 **Q. Please describe the bill payment report used in the collections lag  
7 calculation.**

8 A. The Company developed a bill payment report to aggregate actual customer  
9 payments. This allows us to better understand customer payment behavior. The bill  
10 payment report compares the date a customer is billed to the date the bill was paid to arrive  
11 at the lag days. The bill payment report summarizes the dollar amounts collected per lag  
12 day. The lag days for each line item are capped at 150 days. Each line item is then weighted  
13 to calculate the weighted lag days. The bill payment report was run monthly for the period  
14 from April 2025 to March 2026.

15 **Q. How were uncollectible revenues treated in your analysis?**

16 A. The bill payment report aggregates actual customer payments. Therefore,  
17 an adjustment for uncollectible revenues is not needed in the analysis.

18 **Q. Please summarize the calculation of base revenue lag applicable to  
19 retail sales.**

20 A. The calculation of the overall base revenue lag, by lag component, is  
21 summarized in the following table. Please note that the base revenue lag pertains to revenue  
22 lag for items other than off-system sales, which I will address below.

Base Revenue Lag Component	Lag Days
Service	15.21
Billing	0.97
Collections	23.14
<b>Total Base Revenue Lag</b>	<b>39.32</b>

1           **Q. You mentioned that the above figures do not include the revenue lag**  
2 **for off-system sales. What is the overall revenue lag once off-system sales are**  
3 **included?**

4           A. Revenues from off-system sales were collected, on average, within 14.30  
5 days. The proposed total retail revenues and off-system sales revenues were used to arrive  
6 at a weighted-average revenue lag for tariffed revenues and off-system sales. The resulting  
7 weighted revenue lag to be used in this filing was determined to be 34.43 days.

8           **Q. How does the revenue lag applied to pass-through taxes differ from the**  
9 **base revenue lag applicable to retail sales?**

10          A. The only difference between the base revenue lag applicable to retail sales  
11 and the revenue lag applied to pass-through taxes is that the revenue lag applied to pass-  
12 through taxes excludes the service lag. Therefore, the revenue lag applied to pass-through  
13 taxes is 24.11 days.

1           **Q.    Why should a different revenue lag be applied to the pass-through tax**  
2 **revenues?**

3           A.    In prior cases, the Commission Staff has argued that pass-through taxes are  
4 not generated as a result of the provisioning of a service by the utility.<sup>22</sup> Therefore, in these  
5 proceedings a revenue lag which excludes a lag associated with the provision of utility  
6 service has been applied to the pass-through tax revenues.

7           **Q.    Are the revenues attributable to pass-through taxes collected in the**  
8 **same manner and at the same time as all other revenues?**

9           A.    Yes. The Company's customers pay one bill. That bill (and thus the  
10 payment) includes both operating revenues associated with the provision of electric service  
11 as well as revenues associated with pass-through taxes.

12           **Q.    What impact does the exclusion of the service lag from the revenue lag**  
13 **associated with pass-through taxes have on the CWC calculation?**

14           A.    The service lag represents the period of time during which the Company has  
15 provided a service for which it has not yet been compensated. Since the Company serves  
16 primarily as a collect and remit agent for the various taxing bodies, by excluding the service  
17 lag from the revenue lag applied to the pass-through taxes, the Company is reflecting that  
18 it has no out-of-pocket expense for which it is awaiting payment.

19           **Q.    What expense-related leads were considered in the lead/lag analysis?**

20           A.    Lead times associated with the following expense categories were  
21 considered in the lead/lag study: a) employee pensions and benefits; b) base payroll; c)

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<sup>22</sup> Such proceedings include File Nos. ER-2010-0036 (AmerenUE), ER-2008-0318 (AmerenUE), ER-2007-0291 (Kansas City Power & Light Company), ER-2008-0093 (The Empire District Electric Company), GR-2007-0208 (Laclede Electric Company), and GR-2006-0422 (Missouri Gas Energy).

1 payroll taxes (i.e., FICA, Medicare) and other withholdings; d) other operations and  
2 maintenance expenses; e) cost of fuel – nuclear, coal, oil, and gas; f) purchased power; g)  
3 general taxes other than income taxes, excluding pass-through taxes; h) pass-through taxes;  
4 i) federal income taxes; j) state income taxes; k) interest on long-term debt; and l) incentive  
5 compensation.

6 **Q. What types of leads associated with the Company's employee benefit**  
7 **programs were considered in the analysis?**

8 A. The estimated lead times associated with the following major categories of  
9 the Company's employee benefit programs were considered: a) group life insurance; b)  
10 group health insurance including claims processing, claims payment, and administration  
11 costs; c) the Company's 401-K plan; d) contributions to the Company's pension fund; and  
12 e) OPEB costs. Taken together, these employee pensions and benefit costs had a dollar-  
13 weighted lead time of 19.91 days.

14 **Q. Provide an explanation of the leads associated with the Company's**  
15 **payroll expenses.**

16 A. Payroll lead days were determined by calculating the nominal and weighted  
17 lead time by pay period and weighting the resulting lead days by the amounts paid by the  
18 Company to cover its payroll obligations. The resulting total on a dollar-weighted basis  
19 was 9.77 days.

20 **Q. Please explain the lead effects associated with payroll taxes.**

21 A. The Company has outsourced its payroll tax processing to a third-party  
22 provider, ADP. The payroll taxes outsourced to ADP include: a) Federal and State  
23 Withholding Taxes; b) Federal and State Unemployment Taxes; c) FICA (Social Security)

1 Taxes and Medicare Taxes for both employee and employer; and d) City of St. Louis  
2 Employee Withholding Tax and St. Louis City Employer Expense. ADP pulls all payroll  
3 taxes out of the Company's bank account on the same date as the employees are paid.  
4 Therefore, the payroll taxes lead time is equal to the base payroll lead time of 9.01 days.

5 **Q. What are the lead times associated with other operations and**  
6 **maintenance expenses?**

7 A. The Company engages in transactions with other vendors (not associated  
8 with pensions, benefits, payroll, fuel, or taxes) for a variety of purposes including facility  
9 maintenance, system maintenance, and customer service. Invoices from providers of such  
10 services were analyzed in order to estimate a lead time associated with payment for services  
11 related to other operations and maintenance activities. The analysis indicates that on  
12 average, invoices were paid by the Company 36.40 days after receipt of goods or services.

13 **Q. What is the lead time applicable to expenses associated with the**  
14 **Company's nuclear fuel?**

15 A. The Company purchases and owns all of its current nuclear fuel. At the time  
16 the nuclear fuel is purchased, it is included in construction work in progress and accrues  
17 an Allowance for Funds Used During Construction ("AFUDC"). The nuclear fuel accrues  
18 AFUDC until it arrives at the reactor site. At that time, the nuclear fuel is in stock and the  
19 AFUDC ceases. When the nuclear fuel assemblies are loaded into the reactor, they are  
20 moved from stock to in service. The nuclear fuel is then amortized to expense each month  
21 as it is burned. The average unburned nuclear fuel is included in the materials and supplies  
22 inventory in rate base. Therefore, the only lag is between the monthly burn charged to

1 expense and when this expense is recovered in revenue. Thus, a service lag of 15.21 days  
2 is used for the expense lead.

3 **Q. How did you determine the expense lead time associated with the**  
4 **Company's purchase of coal and related services?**

5 A. Invoices related to purchases of coal were examined to determine the  
6 expense lead time associated with the Company's coal purchases. When weighted by the  
7 dollar amounts shown in the invoices examined, a weighted average expense lead time of  
8 14.55 days was determined.

9 **Q. What is the expense lead time associated with the Company's purchase**  
10 **of oil to support its electric operations?**

11 A. Based on an examination of invoices from the suppliers of oil to the  
12 Company, a weighted average lead time of 16.09 days was determined.

13 **Q. What is the expense lead time associated with the Company's purchase**  
14 **of natural gas to support its electric operations?**

15 A. Based on an examination of invoices from commodity and pipeline  
16 suppliers to the Company, a weighted average lead time of 39.88 days was determined.

17 **Q. What type of leads were associated with the Company's purchase of**  
18 **electricity?**

19 A. The Company purchases electricity from MISO as well as other sources.  
20 Based on an examination of the service periods and payment dates for the Company's  
21 sources of purchased power, a weighted lead time of 14.30 days was determined.

1           **Q.    What are the various general taxes considered in the analysis?**

2           A.    The following general taxes were considered in the study: a) Real Estate  
3 and Property Taxes; b) Missouri Sales Tax; c) Missouri Use Tax; d) Iowa Use Tax e)  
4 Illinois Use Tax; f) St. Louis Corporate Earnings Taxes; g) Federal Excise Heavy Use Tax;  
5 h) Self Procured Insurance Tax; i) Corporate Franchise Tax; and j) Gross Receipts Taxes.  
6 When taxes were required to be paid to a single taxing authority pursuant to a set schedule,  
7 the statutory payment dates were considered in the analysis.

8           **Q.    Explain the leads that were calculated for each type of general taxes**  
9 **considered in the analysis.**

10          A.    The treatment of each category of general taxes in the study is described  
11 below:

12           1) Real Estate and Property Taxes: All current-year property taxes in Missouri are  
13 due on December 31st of the current year. Taking this schedule into consideration, a dollar-  
14 weighted expense lead of 182.50 days was calculated.

15           2) Missouri Use Tax: Missouri use tax is payable to the Missouri Department of  
16 Revenue on the last day of the month following the end of the quarter. Taking this  
17 information into account, the expense lead time associated with the Missouri use taxes was  
18 determined to be 76.33 days.

19           3) Iowa Use Tax: Iowa use tax is payable to the Iowa Department of Revenue  
20 monthly, due on the last day of the month. Taking this information into account, the  
21 expense lead time associated with the Iowa use taxes was determined to be 45.46 days.

22           4) Illinois Use Tax: Illinois use tax is payable to the Illinois Department of  
23 Revenue on the 20th of the month following the end of the month. Taking this information

1 into account, the expense lead time associated with the Illinois use taxes was determined  
2 to be 35.78 days.

3 5) St. Louis Corporate Earnings Tax: The Company pays corporate earnings taxes  
4 to the City of St. Louis. This tax is paid by check to the City of St. Louis annually on April  
5 1st for the previous year. Taking this information into account, the expense lead time  
6 associated with corporate earnings taxes was determined to be 273.50 days.

7 6) Federal Heavy Use Tax: The federal heavy use tax is paid annually to the federal  
8 government at the beginning of the tax period. Additional payments are made as heavy  
9 vehicles are added. Taking this information into account, the expense lead time associated  
10 with the federal heavy use tax was determined to be -138.28 days.

11 7) Self Procured Insurance Tax: The self-procured insurance tax for 2025 was paid  
12 to the State of Missouri in February 2026. Taking this information into account, the  
13 expense lead time associated with self-procured insurance taxes was determined to be  
14 238.50 days.

15 8) Corporate Franchise Tax – The Company had one corporate franchise tax  
16 payment to the State of Illinois in the test period that resulted in an expense lead time of  
17 213.50 days.

18 **Q. What pass-through taxes are included in the CWC analysis?**

19 A. Pass-through taxes considered in the CWC analysis were gross receipts  
20 taxes and Missouri sales taxes.

21 **Q. Please describe the timing of the payment of Missouri sales tax.**

22 A. Missouri sales tax is payable to the Missouri Department of Revenue and  
23 was calculated as a percent of billings, less a 2 percent timely payment allowance.

1 Estimated payments were made weekly with the remaining balance due by the end of the  
2 subsequent month. Based on the above, the Company calculated a weighted expense lead  
3 time of 16.37 days.

4 **Q. Please describe the timing of the payment of gross receipts taxes.**

5 A. Gross receipts taxes are payable to municipalities and counties and are paid  
6 as a percent of billings to customers within the taxing authority. These taxes are paid on  
7 the last day of the month following the end of a month with the exception of Arnold,  
8 Brentwood, Cape Girardeau, Chesterfield, Clayton, Dexter, Fenton, Florissant, Jefferson  
9 City, Jennings, Kirksville, Ladue, Maryland Heights, Moberly, St. Louis County, and  
10 Wentzville that are paid on the 20th day of the month. Based on the specific tax periods of  
11 the various taxing authorities, a dollar-weighted gross receipts tax expense lead time of  
12 26.35 days was calculated.

13 **Q. Do the lead times for gross receipts taxes or Missouri sales taxes include**  
14 **a service lead?**

15 A. No. Since no service lag was included in the revenue lag assigned to pass-  
16 through taxes, there has been no service lead attributed to either gross receipts taxes or  
17 Missouri sales taxes.

18 **Q. Please explain.**

19 A. Both the service lag and the service lead are associated with the timing of  
20 the provision of service. If there is no service lag on the revenue side, there can be no  
21 service lead on the expense side. Therefore, for consistency purposes, I have excluded both  
22 the service lag and service lead from the analysis of the pass-through taxes.

1           **Q.    How did your study address federal income taxes?**

2           A.    The lead time associated with federal income tax payments was based on  
3 the provisions of the Internal Revenue Code that require estimated tax payments of 25  
4 percent of total income taxes due on April 15, June 15, September 15, and December 15 of  
5 the current year. Taking this schedule into consideration a lead time of 37.88 days for  
6 federal income tax payments made by the Company was determined.

7           **Q.    How did the study address Missouri state income taxes?**

8           A.    Missouri state income taxes follow a pattern similar to federal taxes. Thus,  
9 assuming quarterly payments due on April 15, June 15, September 15, and December 15  
10 of the current year, an expense lead time of 37.88 days was determined.

11          **Q.    Were income taxes paid to any state other than Missouri during the**  
12 **study period?**

13          A.    No.

14          **Q.    Provide a description of how lead times associated with the Company's**  
15 **interest expenses were addressed by the study.**

16          A.    The Company's interest payments on its long-term bonds were made from  
17 current revenues. Thus, there was a lead (or lag) between the date the interest payments  
18 were collected from customers and the date when such amounts were paid to financial  
19 institutions. The Company generally made interest payments on its fixed rate long-term  
20 debt twice a year at varying times. Using actual due dates on interest payments, a dollar-  
21 weighted lead of 92.27 days for interest payments was determined.



Direct Testimony of  
Stephen J. Hipkiss

1 amortization of existing regulatory assets and liabilities. As summarized in Schedule  
2 SJH-D16, the Company's total electric revenue requirement, including the Company's  
3 proposed 7.506% return on rate base, is more than the pro forma operating revenues at  
4 the present rates by \$342,883,000. Consequently, rates should be designed to increase  
5 revenues by \$342,883,000, subject to the true-up in this case. Finally, the seasonal values  
6 of Factor BF in Rider FAC should be set at the values shown in Schedule SJH-D17,  
7 reflecting a rebase of net base energy costs.

8 **Q. Does this conclude your Direct Testimony?**

9 **A. Yes, it does.**



**AMEREN MISSOURI**  
**ORIGINAL COST OF ELECTRIC PLANT**  
**BY FUNCTIONAL CLASSIFICATION FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>FUNCTIONAL CLASSIFICATION</u> (A)	<u>TOTALS</u> <u>PER</u> <u>BOOKS</u>	<u>PRO FORMA</u> <u>ADJUSTMENTS</u>	<u>PRO FORMA</u> <u>ELECTRIC</u> <u>TOTALS</u>
		(B)	(C)	(D)
	<b>INTANGIBLE PLANT</b>			
1	FRANCHISES	\$ 153,652	\$ -	\$ 153,652
2	CALLAWAY LIFE EXTENSION DEFERRAL	2,812	-	2,812
3	MISC INTANGIBLE	58,916	146,310	205,226
4	<b>TOTAL INTANGIBLE PLANT</b>	<u>215,380</u>	<u>146,310</u>	<u>361,690</u>
	<b>PRODUCTION PLANT</b>			
5	NUCLEAR	3,874,825	39,718	3,914,543
6	CALLAWAY POST OPERATIONAL	-	-	-
7	STEAM	3,650,940	173,987	3,824,927
8	HYDRAULIC	720,841	43,745	764,586
9	WIND	1,221,748	(39,456)	1,182,292
10	SOLAR	1,292,553	549,428	1,841,981
11	OTHER RENEWABLE	57,063	517	57,580
12	OTHER PRODUCTION	1,204,134	180,459	1,384,593
13	<b>TOTAL PRODUCTION PLANT</b>	<u>12,022,104</u>	<u>948,398</u>	<u>12,970,502</u>
14	<b>TRANSMISSION PLANT</b>	2,521,533	215,738	2,737,271
15	<b>DISTRIBUTION PLANT</b>	10,343,771	616,096	10,959,867
16	<b>GENERAL PLANT</b>	1,977,084	48,525	2,025,609
17	<b>INCENTIVE COMPENSATION CAPITALIZED</b>	<u>-</u>	<u>(59,862)</u>	<u>(59,862)</u>
18	<b>TOTAL PLANT IN SERVICE</b>	<u>\$ 27,079,872</u>	<u>\$ 1,915,205</u>	<u>\$ 28,995,077</u>

**PRO FORMA ADJUSTMENTS**

19	(1) Eliminate plant in service related to ASC 410-20 Asset Retirement Obligations and ASC 842 Leases.			
20	NUCLEAR		\$ (92,750)	
21	STEAM		(25,268)	
22	WIND		(52,681)	
23	SOLAR		(104,578)	
24	GENERAL		(6,173)	
25	TOTAL		<u>                    </u>	\$ (281,450)
26	(2) Plant additions for the true-up period.			
27	MISC INTANGIBLE		154,556	
28	NUCLEAR		132,468	
29	STEAM		199,255	
30	HYDRAULIC		43,745	
31	WIND		13,225	
32	SOLAR		654,006	
33	OTHER RENEWABLE		517	
34	OTHER PRODUCTION		180,459	
35	TRANSMISSION		215,738	
36	DISTRIBUTION		616,096	
37	GENERAL		114,363	
38	TOTAL		<u>                    </u>	2,324,428
39	(3) Eliminate portions of plant in service for multi use general assets which are applicable to gas			
40	operations. For convenience, such assets are recorded as electric plant but are commonly used for			
41	both electric and gas.			
42	MISC INTANGIBLE		(8,246)	
43	GENERAL		(59,665)	
44	TOTAL		<u>                    </u>	(67,911)
45	(4) Reduce plant in service for specified incentive compensation capitalized.			
46	GENERAL			<u>(59,862)</u>
47	<b>TOTAL PRO FORMA ADJUSTMENTS</b>			<u>\$ 1,915,205</u>

**AMEREN MISSOURI**  
**TOTAL ELECTRIC RESERVES FOR DEPRECIATION AND AMORTIZATION**  
**BY FUNCTIONAL CLASSIFICATION FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>FUNCTIONAL CLASSIFICATION</u> (A)	<u>TOTALS PER BOOKS</u> (B)	<u>PRO FORMA ADJUSTMENTS</u> (C)	<u>PRO FORMA ELECTRIC TOTALS</u> (D)
<b>INTANGIBLE PLANT</b>				
1	FRANCHISES	\$ 50,467	\$ 3,955	\$ 54,422
2	CALLAWAY LIFE EXTENSION DEFERRAL	884	78	962
3	MISC INTANGIBLE	4,134	10,831	14,965
4	<b>TOTAL INTANGIBLE PLANT</b>	<u>55,485</u>	<u>14,864</u>	<u>70,349</u>
<b>PRODUCTION PLANT</b>				
5	NUCLEAR	2,086,590	60,268	2,146,858
6	STEAM	1,790,902	130,074	1,920,976
7	HYDRAULIC	190,805	14,820	205,625
8	WIND	225,785	22,491	248,276
9	SOLAR	60,439	47,307	107,746
10	OTHER RENEWABLE	11,375	871	12,246
11	OTHER PRODUCTION	718,089	17,528	735,617
12	<b>TOTAL PRODUCTION PLANT</b>	<u>5,083,985</u>	<u>293,359</u>	<u>5,377,344</u>
13	<b>TRANSMISSION PLANT</b>	645,237	54,064	699,301
14	<b>DISTRIBUTION PLANT</b>	3,733,447	233,909	3,967,356
15	<b>GENERAL PLANT</b>	669,554	98,535	768,089
16	<b>INCENTIVE COMPENSATION CAPITALIZED</b>	<u>-</u>	<u>(23,394)</u>	<u>(23,394)</u>
17	<b>TOTAL DEPRC. &amp; AMORT RESERVE</b>	<u>\$ 10,187,708</u>	<u>\$ 671,337</u>	<u>\$ 10,859,045</u>
<b>PRO FORMA ADJUSTMENTS</b>				
18	(1) Eliminate reserve related to ASC 410-20 Asset Retirement Obligations and ASC 842 Leases.			
19	NUCLEAR		\$ (11,292)	
20	STEAM		1,875	
21	WIND		(9,161)	
22	SOLAR		468	
23	GENERAL		(1,517)	
24	<b>TOTAL</b>			\$ (19,627)
25	(2) Reserve at March 31, 2026 adjusted to reflect reserve at December 31, 2026.			
26	FRANCHISES		3,955	
27	CALLAWAY LIFE EXTENSION DEFERRAL		78	
28	MISC INTANGIBLE		1,439	
29	NUCLEAR		70,313	
30	STEAM		125,423	
31	HYDRAULIC		14,438	
32	WIND		31,472	
33	SOLAR		33,266	
34	OTHER RENEWABLE		868	
35	OTHER PRODUCTION		16,358	
36	TRANSMISSION		52,033	
37	DISTRIBUTION		227,000	
38	GENERAL		121,248	
39	<b>TOTAL</b>			697,891
40	(3) Adjustment to reserve for the additions to plant in service for the true-up period of			
41	April 1, 2026 through December 31, 2026.			
42	MISC INTANGIBLE		10,996	
43	NUCLEAR		1,247	
44	STEAM		3,275	
45	HYDRAULIC		382	
46	WIND		180	
47	SOLAR		13,573	
48	OTHER RENEWABLE		3	
49	OTHER PRODUCTION		1,171	
50	TRANSMISSION		2,030	
51	DISTRIBUTION		6,909	
52	GENERAL		2,044	
53	<b>TOTAL</b>			41,810
54	(4) Rush Island Energy Center adjustment.			
55	STEAM		(499)	
				(499)
56	(5) Eliminate portions of reserve for multi use general assets which are applicable to			
57	gas operations. For convenience, such assets are recorded as electric plant but			
58	are commonly used for both electric and gas operations.			
59	MISC INTANGIBLE		(1,604)	
60	GENERAL		(23,240)	
61	<b>TOTAL</b>			(24,844)
62	(6) Reduce reserve for specified incentive compensation capitalized.			
63	GENERAL			(23,394)
64	<b>TOTAL PRO FORMA ADJUSTMENTS</b>			<u>\$ 671,337</u>

**AMEREN MISSOURI**  
**AVERAGE FUEL AND MATERIALS & SUPPLIES INVENTORIES**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTALS PER BOOKS</u> (B)	<u>PRO FORMA ADJUSTMENTS</u> (C)	<u>PRO FORMA ELECTRIC TOTALS</u> (D)
1	<b>AVERAGE NUCLEAR FUEL</b>	\$ 144,889	\$ -	\$ 144,889
	<b>AVERAGE FOSSIL FUEL:</b>			
2	COAL	89,551	2,959	92,510
3	OIL	10,519	-	10,519
4	STORED GAS FOR CTG'S	<u>1,290</u>	<u>-</u>	<u>1,290</u>
5	<b>TOTAL FOSSIL FUEL</b>	101,360	2,959	104,319
6	<b>EMISSION ALLOWANCES AND RECS</b>	702	-	702
7	<b>GENERAL MATERIALS AND SUPPLIES</b>	<u>395,014</u>	<u>(3,239)</u>	<u>391,775</u>
8	<b>TOTAL</b>	<u>\$ 641,965</u>	<u>\$ (280)</u>	<u>\$ 641,685</u>
	<b>PRO FORMA ADJUSTMENTS</b>			
9	(1) Adjust coal supply to remove Rush Island coal inventories and to reflect 13-month average inventory levels			\$ 2,959
10	priced at the January 2027 coal prices.			
11	(2) Eliminate portions of average fuel and general materials and supplies which are applicable to gas operations.			<u>(3,239)</u>
12	<b>TOTAL PRO FORMA ADJUSTMENTS</b>			<u>\$ (280)</u>

**AMEREN MISSOURI  
AVERAGE PREPAYMENTS  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026  
(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u>	<u>TOTALS PER BOOKS (1)</u>	<u>PRO FORMA ADJUSTMENTS</u>	<u>PRO FORMA ELECTRIC TOTALS</u>
	(A)	(B)	(C)	(D)
1	RENTS (2)	\$ 5	\$ -	\$ 5
2	INSURANCE (2)	13,119	(966)	12,153
3	SOFTWARE MAINTENANCE PREPAYMENTS (3)	25,639	(685)	24,954
4	GAS SOFTWARE MAINTENANCE PREPAYMENTS (2)	47	(47)	-
5	MEMBERSHIP DUES (3)	1,548	(41)	1,507
6	GAS MBP INSURANCE (2)	19	(19)	-
7	ELECTRIC MBP INSURANCE (2)	127	-	127
8	POWER/CAPACITY PREPAID (2)	994	-	994
9	MEDICAL AND DENTAL VEBA (3)	4,618	(123)	4,495
10	GAS MEMBERSHIP DUES (2)	69	(69)	-
11	PREPAID INVENTORY MILESTONE PMTS (2)	1,019	-	1,019
12	SOLAR LAND LEASES (2)	1,529	-	1,529
13	LOW INCOME WEATHERIZATION (2)	491	(8)	483
14	<b>TOTAL AVERAGE PREPAYMENTS</b>	<b>\$ 49,224</b>	<b>\$ (1,958)</b>	<b>\$ 47,266</b>

- 15 (1) Reflects 13-month average.  
16 (2) Directly assigned to electric or gas.  
17 (3) Allocated to gas based on operating expenses excluding fuel and purchased power.

**PRO FORMA ADJUSTMENT**

18	(1) Eliminate portions of prepayments which are applicable to gas operations. Amounts	\$	(1,958)
19	were either directly assigned to gas operations or were allocated between electric and		
20	gas operations based on operating expenses excluding fuel and purchased power.		

**AMEREN MISSOURI**  
**TOTAL ELECTRIC CASH WORKING CAPITAL**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

LINE	DESCRIPTION (A)	REVENUE	EXPENSE	NET	FACTOR (E)	TEST YEAR	CASH WORKING
		LAG (B)	LEAD (C)	LEAD/LAG (D)		EXPENSE (F)	CAPITAL REQUIREMENT (G)
1	PENSIONS AND BENEFITS	34.43	(19.91)	14.52	0.039781	\$ (9,408)	\$ (374)
2	PAYROLL & WITHHOLDINGS	34.43	(9.77)	24.66	0.067562	356,543	24,089
3	FUEL						
4	NUCLEAR	34.43	(15.21)	19.22	0.052658	63,955	3,368
5	COAL	34.43	(14.55)	19.88	0.054466	378,502	20,615
6	OIL	34.43	(16.09)	18.34	0.050247	2,968	149
7	NATURAL GAS	34.43	(39.88)	(5.45)	(0.014932)	49,280	(736)
8	PURCHASED POWER	34.43	(14.30)	20.13	0.055151	651,384	35,924
9	INCENTIVE COMPENSATION	34.43	(252.98)	(218.55)	(0.598767)	34,173	(20,462)
10	UNCOLLECTIBLE ACCOUNTS	34.43	(34.43)	0.00	-	14,510	-
11	OTHER OPERATING EXPENSES	34.43	(36.40)	(1.97)	(0.005397)	684,024	(3,692)
12	TOTAL O&M EXPENSES					2,225,932	
13	<b>TOTAL CASH WORKING CAPITAL REQUIREMENT</b>						<b>\$ 58,881</b>
14	FICA - EMPLOYER'S PORTION	34.43	(9.01)	25.42	0.069644	21,338	1,486
15	ST. LOUIS PAYROLL EXPENSE TAXES	34.43	(9.01)	25.42	0.069644	381	27
16	FEDERAL UNEMPLOYMENT TAXES	34.43	(9.01)	25.42	0.069644	168	12
17	STATE UNEMPLOYMENT TAXES	34.43	(9.01)	25.42	0.069644	58	4
18	CORPORATE FRANCHISE TAXES	34.43	(213.50)	(179.07)	(0.490603)	184	(90)
19	REAL ESTATE AND PROPERTY TAXES	34.43	(182.50)	(148.07)	(0.405671)	171,748	(69,673)
20	SALES TAXES	24.11	(16.37)	7.74	0.021205	99,078	2,101
21	MO USE TAXES	34.43	(76.33)	(41.90)	(0.114795)	702	(81)
23	IA USE TAXES	34.43	(45.46)	(11.03)	(0.030219)	13	-
22	IL USE TAXES	34.43	(35.78)	(1.35)	(0.003699)	74	-
24	FED EXCISE HEAVY USE TAX	34.43	138.28	172.71	0.473178	66	31
25	SELF PROCURED INS TAX	34.43	(238.50)	(204.07)	(0.559096)	217	(121)
26	GROSS RECEIPTS TAXES	24.11	(26.35)	(2.24)	(0.006137)	183,362	(1,125)
27	TOTAL TAXES AND OTHER EXPENSES					477,389	
28	<b>NET CUSTOMER SUPPLIED FUNDS</b>						<b>\$ (67,429)</b>
29	<b>NET CASH WORKING CAPITAL REQUIREMENT</b>						<b>\$ (8,548)</b>

**AMEREN MISSOURI**  
**TOTAL ELECTRIC FEDERAL AND STATE INCOME TAX AND CITY EARNINGS TAX CASH REQUIREMENTS**  
**AND INTEREST EXPENSE CASH REQUIREMENT**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>REVENUE</u> <u>LAG</u> (B)	<u>EXPENSE</u> <u>LEAD</u> (C)	<u>NET</u> <u>LEAD/LAG</u> (D)	<u>FACTOR</u> (E)	<u>TEST YEAR</u> <u>EXPENSE</u> (F)	<u>CASH WORKING</u> <u>CAPITAL</u> <u>REQUIREMENT</u> (G)
1	FEDERAL INCOME TAX CASH REQUIREMENT	34.430	(37.880)	(3.450)	(0.009452)	\$ 83,257	\$ (787)
2	MO STATE INCOME TAX CASH REQUIREMENT	34.430	(37.880)	(3.450)	(0.009452)	\$ 30,734	\$ (290)
3	CITY EARNINGS TAX CASH REQUIREMENT	34.430	(273.500)	(239.070)	(0.654986)	\$ (177)	\$ 116
4	INTEREST EXPENSE CASH REQUIREMENT	34.430	(92.270)	(57.840)	(0.158466)	\$ 360,051	\$ (57,056)

**AMEREN MISSOURI**  
**TOTAL ELECTRIC AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION AND**  
**AVERAGE CUSTOMER DEPOSITS**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTAL ELECTRIC</u> (B)
1	AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION	<u>\$ (2,546)</u>
2	AVERAGE CUSTOMER DEPOSITS	<u>\$ (30,235)</u>

**AMEREN MISSOURI  
OTHER REGULATORY ASSETS  
AND REGULATORY LIABILITIES  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026  
(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTAL ELECTRIC (1)</u> (B)
1	PENSIONS	\$ 69,814
2	OTHER POST-EMPLOYMENT BENEFITS	\$ (2,659)
3	PAYS REGULATORY ASSET	\$ 5,741
4	PISA REGULATORY ASSET	\$ 889,935
5	EXPIRED & EXPIRING AMORTIZATIONS IN RATE BASE	\$ 12,862
6	PROPERTY TAX TRACKER	\$ (2,570)
7	(1) A positive balance is a Regulatory Asset and a negative balance is a	
8	Regulatory Liability.	

**AMEREN MISSOURI**  
**ACCUMULATED DEFERRED INCOME TAXES**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTAL ELECTRIC PER BOOKS</u> (B)	<u>PRO FORMA ADJUSTMENTS</u> (C)	<u>PRO FORMA ELECTRIC TOTAL</u> (D)
1	ACCOUNT 190	\$ 165,700	\$ (3,242)	\$ 162,458
2	ACCOUNT 281	(37,891)	-	(37,891)
3	ACCOUNT 282	(2,916,785)	(13,754)	(2,930,539)
4	ACCOUNT 283	<u>(204,653)</u>	<u>(3,638)</u>	<u>(208,291)</u>
5	<b>TOTAL ACCUMULATED DEFERRED INCOME TAXES</b>	<b><u>\$ (2,993,629)</u></b>	<b><u>\$ (20,634)</u></b>	<b><u>\$ (3,014,263)</u></b>

**PRO FORMA ADJUSTMENT:**

- 6 Changes in balances from March 31, 2026 to December 31, 2026, which is the end of the true-up period.

**AMEREN MISSOURI**  
**TOTAL ELECTRIC PER BOOK AND PRO FORMA OPERATING REVENUES**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

LINE	DESCRIPTION (A)	TOTAL ELECTRIC (B)	PRO FORMA ADJUSTMENTS (C)	ADJUSTED TOTAL ELECTRIC (D)
	<b>OPERATING REVENUES</b>			
1	RETAIL REVENUES	\$ 3,651,997	\$ (345,288)	\$ 3,306,708
2	PROVISION FOR RATE REFUNDS	286	(286)	-
3	OTHER ELECTRIC REVENUES	110,040	9,948	119,988
4	<b>TOTAL REVENUES</b>	<b>3,762,323</b>	<b>(335,626)</b>	<b>3,426,696</b>
5	DISPOSITION OF ALLOWANCES	-	-	-
6	OFF-SYSTEM SALES - ENERGY	100,984	170,965	271,949
7	OFF-SYSTEM SALES - CAPACITY	705,818	(173,769)	532,049
8	<b>TOTAL REVENUES</b>	<b>\$ 4,569,125</b>	<b>\$ (338,430)</b>	<b>\$ 4,230,694</b>
	<b>PRO FORMA ADJUSTMENTS:</b>			
9	(1) REMOVE ADD ON REVENUE TAX	\$ (182,038)		
10	(2) ELIMINATE REVENUE FROM MEEIA RECOVERIES	(59,637)		
11	(3) ELIMINATE REVENUE FROM FAC RECOVERIES	(101,168)		
12	(4) ELIMINATE UNBILLED REVENUE	(16,878)		
13	(5) ANNUALIZE RATE CHANGE	54,643		
14	(6) ADJUST FOR PRO FORMA EDI	(16,001)		
15	(7) ADJUST TO REMOVE TEST YEAR EDI	16,212		
16	(8) ADJUST FOR COMMUNITY SOLAR	1,619		
17	(9) ADJUST FOR GROWTH	14,538		
18	(10) ADJUST FOR RESRAM REVENUES	(54,940)		
19	(11) ADJUST FOR ENERGY EFFICIENCY AND SOLAR ANNUALIZATION	(3,160)		
20	(12) DAYS ADJUSTMENT	8,293		
21	(13) ADJUST FOR BILLING UNITS	(3,113)		
22	(14) ADJUST FOR NORMAL WEATHER	(17,122)		
23	(15) REMOVE TEST YEAR RSP REVENUE	(9,293)		
24	(16) ADJUST FOR PRO FORMA RSP REVENUES	12,670		
25	(17) LARGE LOAD PRO FORMA REVENUES	10,087		
26	TOTAL RETAIL REVENUES	\$ (345,288)		
27	(18) ELIMINATE PROVISION FOR RATE REFUNDS		(286)	
28	(19) ADJUST TRANSMISSION REVENUES	3,460		
29	(20) ADJUST LEASE REVENUE FROM RENT	8,334		
30	(21) REMOVE ATCHISON WIND ENERGY CENTER PAYMENT	(1,200)		
31	(22) ADJUST FOR PAYS REVENUES	129		
32	(23) REMOVE ADD ON REVENUE TAX	(775)		
33	TOTAL OTHER ELECTRIC REVENUES		9,948	
34	(24) ADJUST OFF-SYSTEM SALES - ENERGY		170,965	
35	(25) ADJUST OFF-SYSTEM SALES - CAPACITY		(173,769)	
36	<b>TOTAL PRO FORMA ADJUSTMENTS</b>		<b>\$ (338,430)</b>	

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION (A)	TOTAL PER BOOKS (B)	#1	#2	#3	#4	#5	#6	#7	#8
			LABOR ADJUSTMENT (C)	INCENTIVE COMPENSATION ADJUSTMENT (D)	LONG TERM INCENTIVE COMPENSATION ADJUSTMENT (E)	CHANGE IN FUEL EXPENSE FOR TU CHANGE (F)	ADJUST PURCHASED POWER FOR TU CHANGE (G)	AFFILIATE TRANSMISSION ADJUSTMENT (H)	STEAM PLANT OUTAGE MAINTENANCE (I)	RUSH ISLAND MAINTENANCE ADJUSTMENT (J)
<b>PRODUCTION:</b>										
INCREMENTAL COSTS:										
1	LABOR	\$ 195,977	\$ 10,459	\$ (1,640)	\$ (1,446)	\$ -	\$ -	\$ -	\$ -	\$ -
	FUEL									
2	BASE LOAD	424,824	-	-	-	(7,512)	-	-	-	-
3	INTERCHANGE	31,344	-	-	-	55,909	-	-	-	-
4	FUEL ADDITIVES	15,706	-	-	-	(969)	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	238,045	-	-	-	-	(87,312)	-	-	-
6	INTERCHANGE	17,678	-	-	-	-	(17,678)	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	681,526	-	-	-	-	(180,876)	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	61,574	-	-	-	-	-	-	(2,681)	(1,506)
10	TOTAL PRODUCTION EXPENSES	1,666,674	10,459	(1,640)	(1,446)	47,428	(285,866)	-	(2,681)	(1,506)
<b>TRANSMISSION EXPENSES:</b>										
11	LABOR	7,682	402	(64)	(106)	-	-	-	-	-
12	OTHER	137,358	-	-	-	-	8,107	(116)	-	-
13	TOTAL TRANSMISSION EXPENSES	145,040	402	(64)	(106)	-	8,107	(116)	-	-
<b>REGIONAL MARKET EXPENSES:</b>										
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	5,824	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	5,824	-	-	-	-	-	-	-	-
<b>ENERGY STORAGE EXPENSES</b>										
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>										
20	LABOR	59,847	2,973	(501)	(940)	-	-	-	-	-
21	OTHER	103,809	-	-	-	-	-	-	-	-
22	TOTAL DISTRIBUTION EXPENSES	163,656	2,973	(501)	(940)	-	-	-	-	-
<b>CUSTOMER ACCOUNTS EXPENSES:</b>										
23	LABOR	16,987	906	(142)	(57)	-	-	-	-	-
24	OTHER	41,455	-	-	-	-	-	-	-	-
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	58,442	906	(142)	(57)	-	-	-	-	-
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>										
26	LABOR	9,237	480	(77)	(214)	-	-	-	-	-
27	OTHER	52,271	-	-	-	-	-	-	-	-
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	61,508	480	(77)	(214)	-	-	-	-	-
<b>SALES EXPENSES:</b>										
29	LABOR	435	24	(4)	-	-	-	-	-	-
30	OTHER	333	-	-	-	-	-	-	-	-
31	TOTAL SALES EXPENSES	768	24	(4)	-	-	-	-	-	-
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>										
32	LABOR	76,497	3,526	(640)	(5,057)	-	-	-	-	-
33	OTHER	103,611	-	-	-	-	-	-	-	-
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	180,108	3,526	(640)	(5,057)	-	-	-	-	-
35	<b>TOTAL OPERATIONS &amp; MAINTENANCE EXPENSES</b>	<b>\$ 2,282,020</b>	<b>\$ 18,770</b>	<b>\$ (3,068)</b>	<b>\$ (7,820)</b>	<b>\$ 47,428</b>	<b>\$ (277,759)</b>	<b>\$ (116)</b>	<b>\$ (2,681)</b>	<b>\$ (1,506)</b>

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-1

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION	#9	#10	#11	#12	#13	#14	#15	#16	#17
		REMOVE	CALLAWAY	REMOVE	OTHER	REBASE	ELIMINATE	DEPRECIATION	NORMALIZE	VEG MGMT &
		MEMBERSHIP	ELIMINATE	CALLAWAY	RES	RES	SOLAR REBATE	TO O&M	STORM	INFRA INSPEC
	DUES	FAC	REFUELING	REFUELING	ADJUSTMENT	AMORTIZATIONS	ADJUSTMENT	COSTS	COSTS	
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
<b>PRODUCTION:</b>										
INCREMENTAL COSTS:										
1	LABOR	\$ -	\$ 6,395	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	FUEL									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	102,923	26,418	(30,569)	(2,008)	(4,163)	-	-	-	-
10	TOTAL PRODUCTION EXPENSES	102,923	32,813	(30,569)	(2,008)	(4,163)	-	-	-	-
<b>TRANSMISSION EXPENSES:</b>										
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	-	-
<b>REGIONAL MARKET EXPENSES:</b>										
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
<b>ENERGY STORAGE EXPENSES</b>										
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>										
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	-	-	-	-	-	598	2,047	12,785
22	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	598	2,047	12,785
<b>CUSTOMER ACCOUNTS EXPENSES:</b>										
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	-	-	-	-	-	-	-
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	-	-	-	-	-	-	-
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>										
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	(223)	-	-	-
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	(223)	-	-	-
<b>SALES EXPENSES:</b>										
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	-	-	-	-	-	-	-	-
31	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>										
32	LABOR	-	-	-	-	-	-	-	-	-
33	OTHER	-	-	-	-	-	-	-	-	-
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	-	-	-	-	-	-	-	-	-
35	TOTAL OPERATIONS & MAINTENANCE EXPENSES	\$ 102,923	\$ 32,813	\$ (30,569)	\$ (2,008)	\$ (4,163)	\$ (223)	\$ 598	\$ 2,047	\$ 12,785

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-2

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION (A)	#18	#19	#20	#21	#22	#23	#24	#25	#26
		ADD INTEREST ON CUSTOMER DEPOSITS (B)	CDIS ADJUSTMENT (C)	ENERGY EFFICIENCY PROGRAM COST RECOVERY ADJUSTMENT (D)	PAYS PROGRAM AMORTIZATION (E)	LOCATES ADJUSTMENT (F)	ANNUALIZE BAD DEBT EXPENSE (G)	STAFFING ANNUALIZATION ADJUSTMENT (H)	INSURANCE ADJUSTMENT (I)	PRO FORMA MEDICAL & BENEFIT ADJUSTMENT (J)
<b>PRODUCTION:</b>										
INCREMENTAL COSTS:										
1	LABOR	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	FUEL									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS	-	-	-	-	-	-	-	-	-
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	-	-	-	-	-	-	-	-	-
10	TOTAL PRODUCTION EXPENSES	-	-	-	-	-	-	-	-	-
<b>TRANSMISSION EXPENSES:</b>										
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	-	-
<b>REGIONAL MARKET EXPENSES:</b>										
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
<b>ENERGY STORAGE EXPENSES</b>										
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>										
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	5,269	-	-	2,887	-	-	-	-
22	TOTAL DISTRIBUTION EXPENSES	-	5,269	-	-	2,887	-	-	-	-
<b>CUSTOMER ACCOUNTS EXPENSES:</b>										
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	2,419	-	-	-	(1,483)	-	-	-	-
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	2,419	-	-	-	(1,483)	-	-	-	-
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>										
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	(45,195)	327	-	-	-	-	-
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	(45,195)	327	-	-	-	-	-
<b>SALES EXPENSES:</b>										
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	-	-	-	-	-	-	-	-
31	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>										
32	LABOR	-	-	-	-	-	-	9,778	-	-
33	OTHER	-	-	-	-	-	-	746	5,186	3,059
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	-	-	-	-	-	-	10,524	5,186	3,059
35	TOTAL OPERATIONS & MAINTENANCE EXPENSES	\$ 2,419	\$ 5,269	\$ (45,195)	\$ 327	\$ 2,887	\$ (1,483)	\$ 10,524	\$ 5,186	\$ 3,059

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

SCHEDULE SJH-D11-3

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION (A)	#27 NON-QUALIFIED PENSION ADJUSTMENT (B)	#28 REBASE PENSION AND OPEB TRACKER (C)	#29 AMORTIZE PENSION AND OPEB TRACKER (D)	#30 RESRAM BASE EXPENSE (E)	#31 RATE CASE EXPENSES (F)	#32 REGULATORY ASSESSMENTS (G)	#33 BOARD OF DIRECTORS EXPENSE ADJUSTMENT (H)	#34 BUILDING RENT FROM AMS & ITC (I)	#35 NORMALIZE DEPR. STUDY EXPENSE (J)
<b>PRODUCTION:</b>										
INCREMENTAL COSTS:										
1	LABOR	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	FUEL									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER									
	ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	-	-	-	1,322	-	-	-	-	-
10	TOTAL PRODUCTION EXPENSES	-	-	-	1,322	-	-	-	-	-
<b>TRANSMISSION EXPENSES:</b>										
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	(170)	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	(170)	-
<b>REGIONAL MARKET EXPENSES:</b>										
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
<b>ENERGY STORAGE EXPENSES</b>										
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>										
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	-	-	-	-	-	-	-	-
22	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	-	-	-
<b>CUSTOMER ACCOUNTS EXPENSES:</b>										
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	-	-	-	-	-	-	-
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	-	-	-	-	-	-	-
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>										
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-	-
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	-	-	-	-
<b>SALES EXPENSES:</b>										
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	-	-	-	-	-	-	-	-
31	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>										
32	LABOR	-	-	-	-	-	-	-	-	-
33	OTHER	(28)	34,777	25,653	-	360	2,497	(288)	3,635	34
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	(28)	34,777	25,653	-	360	2,497	(288)	3,635	34
35	TOTAL OPERATIONS & MAINTENANCE EXPENSES	\$ (28)	\$ 34,777	\$ 25,653	\$ 1,322	\$ 360	\$ 2,497	\$ (288)	\$ 3,465	\$ 34

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION (A)	#36	#37	#38	#39	#40	#41	#42	#43	#44
		NORMALIZE SEVERANCE COSTS (B)	ALLOCATION FACTOR ADJUSTMENT (C)	METER READS ADJUSTMENT (D)	ELECTRIC COSTS ALLOC. TO GAS (E)	CUSTOMER CONVENIENCE FEES ADJUSTMENT (F)	CYBERSECURITY COSTS ADJUSTMENT (G)	SOFTWARE MAINTENANCE ADJUSTMENT (H)	NRC FEE ANNUALIZATION (I)	ANNUALIZE NEW SOLAR FACILITY O&M (J)
<b>PRODUCTION:</b>										
INCREMENTAL COSTS:										
1	LABOR	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	FUEL									
2	BASE LOAD	-	-	-	-	-	-	-	-	-
3	INTERCHANGE	-	-	-	-	-	-	-	-	-
4	FUEL ADDITIVES	-	-	-	-	-	-	-	-	-
	PURCHASED POWER ENERGY									
5	BASE LOAD	-	-	-	-	-	-	-	-	-
6	INTERCHANGE	-	-	-	-	-	-	-	-	-
	CAPACITY COSTS									
7	BASE LOAD	-	-	-	-	-	-	-	-	-
8	INTERCHANGE	-	-	-	-	-	-	-	-	-
9	OTHER	-	-	-	-	-	-	-	(5)	1,665
10	TOTAL PRODUCTION EXPENSES	-	-	-	-	-	-	-	(5)	1,665
<b>TRANSMISSION EXPENSES:</b>										
11	LABOR	-	-	-	-	-	-	-	-	-
12	OTHER	-	-	-	-	-	-	-	-	-
13	TOTAL TRANSMISSION EXPENSES	-	-	-	-	-	-	-	-	-
<b>REGIONAL MARKET EXPENSES:</b>										
14	LABOR	-	-	-	-	-	-	-	-	-
15	OTHER	-	-	-	-	-	-	-	-	-
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	-	-	-	-	-
<b>ENERGY STORAGE EXPENSES</b>										
17	LABOR	-	-	-	-	-	-	-	-	-
18	OTHER	-	-	-	-	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>										
20	LABOR	-	-	-	-	-	-	-	-	-
21	OTHER	-	-	-	-	-	-	-	-	-
22	TOTAL DISTRIBUTION EXPENSES	-	-	-	-	-	-	-	-	-
<b>CUSTOMER ACCOUNTS EXPENSES:</b>										
23	LABOR	-	-	-	-	-	-	-	-	-
24	OTHER	-	-	(370)	-	(1,014)	-	-	-	-
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	(370)	-	(1,014)	-	-	-	-
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>										
26	LABOR	-	-	-	-	-	-	-	-	-
27	OTHER	-	-	-	-	-	-	-	-	-
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	-	-	-	-	-	-	-	-	-
<b>SALES EXPENSES:</b>										
29	LABOR	-	-	-	-	-	-	-	-	-
30	OTHER	-	-	-	-	-	-	-	-	-
31	TOTAL SALES EXPENSES	-	-	-	-	-	-	-	-	-
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>										
32	LABOR	-	-	-	-	-	-	-	-	-
33	OTHER	(1,497)	616	-	4	-	952	(1,910)	(221)	-
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	(1,497)	616	-	4	-	952	(1,910)	(221)	-
35	TOTAL OPERATIONS & MAINTENANCE EXPENSES	\$ (1,497)	\$ 616	\$ (370)	\$ 4	\$ (1,014)	\$ 952	\$ (1,910)	\$ (226)	\$ 1,665

SCHEDULE SJH-D11-5

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

**AMEREN MISSOURI**  
**ELECTRIC OPERATING AND MAINTENANCE EXPENSES**  
**PER BOOK AND PRO FORMA**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026 UPDATED THROUGH DECEMBER 31, 2026**  
**(\$000)**

LINE	FUNCTIONAL CLASSIFICATION (A)	#45	#46	#47	TOTAL	PRO FORMA
		ADVERTISING (B)	NSR RESERVE (C)	MEMBERSHIP DUES ADJUSTMENT (D)	PRO FORMA ADJUSTMENT (E)	PRO FORMA ELECTRIC TOTALS (F)
<b>PRODUCTION:</b>						
INCREMENTAL COSTS:						
1	LABOR	\$ -	\$ -	\$ -	\$ 13,768	\$ 209,745
	FUEL	-	-	-	-	-
2	BASE LOAD	-	-	-	(7,512)	417,312
3	INTERCHANGE	-	-	-	55,909	87,253
4	FUEL ADDITIVES	-	-	-	(969)	14,737
	PURCHASED POWER	-	-	-	-	-
	ENERGY	-	-	-	-	-
5	BASE LOAD	-	-	-	(87,312)	150,733
6	INTERCHANGE	-	-	-	(17,678)	-
	CAPACITY COSTS	-	-	-	-	-
7	BASE LOAD	-	-	-	(180,876)	500,650
8	INTERCHANGE	-	-	-	-	-
9	OTHER	-	-	-	91,396	152,970
10	TOTAL PRODUCTION EXPENSES	-	-	-	(133,274)	1,533,400
<b>TRANSMISSION EXPENSES:</b>						
11	LABOR	-	-	-	232	7,914
12	OTHER	-	-	-	7,821	145,179
13	TOTAL TRANSMISSION EXPENSES	-	-	-	8,053	153,093
<b>REGIONAL MARKET EXPENSES:</b>						
14	LABOR	-	-	-	-	-
15	OTHER	-	-	-	-	5,824
16	TOTAL REGIONAL MARKET EXPENSES	-	-	-	-	5,824
<b>ENERGY STORAGE EXPENSES</b>						
17	LABOR	-	-	-	-	-
18	OTHER	-	-	-	-	-
19	TOTAL ENERGY STORAGE EXPENSES	-	-	-	-	-
<b>DISTRIBUTION EXPENSES:</b>						
20	LABOR	-	-	-	1,532	61,379
21	OTHER	-	-	(1)	23,585	127,394
22	TOTAL DISTRIBUTION EXPENSES	-	-	(1)	25,117	188,773
<b>CUSTOMER ACCOUNTS EXPENSES:</b>						
23	LABOR	-	-	-	707	17,694
24	OTHER	-	-	-	(448)	41,007
25	TOTAL CUSTOMER ACCOUNTS EXPENSES	-	-	-	259	58,701
<b>CUSTOMER SERV. &amp; INFO. EXPENSES:</b>						
26	LABOR	-	-	-	189	9,426
27	OTHER	(514)	-	(1)	(45,606)	6,665
28	TOTAL CUSTOMER SERV. & INFO. EXPENSES	(514)	-	(1)	(45,417)	16,091
<b>SALES EXPENSES:</b>						
29	LABOR	-	-	-	20	455
30	OTHER	-	-	(26)	(26)	307
31	TOTAL SALES EXPENSES	-	-	(26)	(6)	762
<b>ADMINISTRATIVE &amp; GENERAL EXPENSES:</b>						
32	LABOR	-	-	-	7,607	84,104
33	OTHER	-	8,000	(4)	81,571	185,182
34	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	-	8,000	(4)	89,178	269,286
35	TOTAL OPERATIONS & MAINTENANCE EXPENSES	\$ (514)	\$ 8,000	\$ (32)	\$ (56,090)	\$ 2,225,930

36 NOTE: See SCHEDULE SJH-D11-7 for explanation of the pro forma adjustments.

**AMEREN MISSOURI  
ELECTRIC OPERATING AND MAINTENANCE EXPENSE  
PRO FORMA ADJUSTMENTS  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026  
(\$000)**

LINE	PRO FORMA ITEM NO. (A)	DESCRIPTION (B)	TOTAL AMOUNT (C)
1	(1)	Increase labor expense from annualizing the average 3.35% wage increase for management employees effective January 1, 2026, the 3% wage increase for the Company's union employees effective January 1, 2026 per the labor contracts, annualizing an estimated 3.75% wage increase for management employees effective January 1, 2027, and the estimated 3% wage increase for the Company's union employees effective January 1, 2027.	\$ 18,770
2			
3			
4			
5	(2)	Decrease incentive compensation expense for the incentive compensation applicable to AMS and Ameren Missouri officers that is based on the achievement of earnings-per-share (EPS) goals of the Company.	(3,068)
6			
7	(3)	Eliminate the long-term incentive compensation expense that is based on the achievement of total shareholder return (TSR) goals of the Company.	(7,820)
8			
9	(4)	Increase in fuel expense to reflect the normalized sales and customer growth through December 31, 2026 reflecting January 2027 fuel prices.	47,428
10			
11	(5)	Decrease in purchased power expense to reflect normalized sales and customer growth through December 31, 2026 and normalized power prices.	(277,759)
12			
13	(6)	Decrease in transmission expense related to regionally-allocated transmission facilities constructed by a Company affiliate in the service territory of the Company.	(116)
14			
15	(7)	Decrease in production expense to normalize non-labor scheduled outage maintenance expenses over the Company's planned six-year maintenance cycle at the Labadie and Sioux Energy Centers.	(2,681)
16			
17	(8)	Decrease in production expense to remove a portion of production expense related to Rush Island Energy Center.	(1,506)
18	(9)	Eliminate test year FAC recovery.	102,923
19	(10)	Increase in nuclear production expense to include the average annualized cost from the last 3 Callaway Nuclear Energy Center refueling outages.	32,813
20			
21	(11)	Decrease in nuclear production expense to eliminate the Callaway Nuclear Energy Center refueling amortization.	(30,569)
22	(12)	Decrease in production expense for amortization of RES cost regulatory liability.	(2,008)
23	(13)	Decrease in production expense for rebase of RES expenses.	(4,163)
24	(14)	Decrease in production expense to eliminate Solar Rebate amortizations in the test year.	(223)
25	(15)	Increase in distribution expenses for increase in depreciation charged to O&M.	598
26	(16)	Increase in distribution expense to normalize storm costs.	2,047
27	(17)	Increase in distribution expense to annualize vegetation management and infrastructure inspection costs.	12,785
28	(18)	Increase in customer accounts expenses to reflect interest expense at 8% on the average customer deposit balance.	2,419
29	(19)	Increase in distribution expense to annualize CDIS costs based on current cost levels in the true up period.	5,269
30	(20)	Decrease in customer service expense to eliminate test year MEEIA program costs.	(45,195)
31	(21)	Increase in customer service expense from PAYS program amortization.	327
32	(22)	Increase in distribution expense to annualize locates costs based on current cost levels in the true up period.	2,887
33	(23)	Decrease in customer accounts expense to adjust bad debt expense to actual test year write offs.	(1,483)
34	(24)	Increase in administrative and general expense for staffing annualization of salary and benefits.	10,524
35	(25)	Annualize insurance expense based upon current and expected insurance premiums.	5,186
36	(26)	Increase in administrative and general expense to reflect annualized major medical and other employee benefit expenses through December 31, 2026.	3,059
37			
38	(27)	Decrease non-qualified pension expense to reflect current level of expense.	(28)
39	(28)	Rebase Pension and OPEB Tracker to 2025 actuarial expense levels.	34,777
40	(29)	Increase in administrative and general expense to reflect an increase in the amortization of the net regulatory liabilities for the Pension and OPEB Tracker.	25,653
41			
42	(30)	Increase in production expense for base level expenses related to RESRAM.	1,322
43	(31)	Increase in administrative and general expense to reflect the 3-case average of expenses to prepare and litigate a rate filing and to normalize this amount.	360
44			
45	(32)	Increase in administrative and general expense to annualize current level of regulatory assessments.	2,497
46	(33)	Decrease in administrative and general expense to remove certain Board of Director meeting expenses.	(288)
47	(34)	Increase in administrative and general expense for building rent from AMS and ITC.	3,465
48	(35)	Increase in administrative and general expense to normalize depreciation study expense.	34
49	(36)	Decrease in administrative and general expense to normalize severance costs.	(1,497)
50	(37)	Increase in administrative and general expense to utilize 2026 allocation factors.	616
51	(38)	Decrease in customer accounts expense to reflect AMR cost savings due to deployment of AMI.	(370)
52	(39)	Increase in administrative and general expense for electric costs allocated to gas.	4
53	(40)	Decrease in customer accounts expense to remove customer convenience fees attributable to gas operations and to reflect current customer payment volumes and fee rates.	(1,014)
54			
55	(41)	Increase in administrative and general expense for an increase in cybersecurity costs.	952
56	(42)	Decrease in administrative and general expense for a decrease in software maintenance costs.	(1,910)
57	(43)	Decrease in administrative and general and production expense for NRC fee annualization.	(226)
58	(44)	Increase in production expense to reflect an annualized level of land lease expense for the Split Rail solar energy center.	1,665
59	(45)	Decrease in administrative and general expense to remove certain advertising expenses.	(514)
60	(46)	Increase in administrative and general expense to remove adjustment to NSR reserve.	8,000
61	(47)	Decrease in administrative and general expense to remove certain membership dues.	(32)
62		<b>Total Pro Forma Adjustments to Electric Operating and Maintenance Expenses</b>	<b>\$ (56,090)</b>

**AMEREN MISSOURI**  
**DEPRECIATION & AMORTIZATION EXPENSE**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTALS</u> <u>PER</u> <u>BOOKS</u> (B)	<u>PRO FORMA</u> <u>ADJUSTMENTS (1)</u> (C)	<u>PRO FORMA</u> <u>ELECTRIC</u> <u>TOTALS</u> (D)
<b>DEPRECIATION EXPENSE:</b>				
1	STEAM	\$ 164,685	\$ 7,267	\$ 171,952
2	NUCLEAR	94,725	(2,154)	92,571
3	CALLAWAY DECOMMISSIONING	1,133	(1,133)	-
4	HYDRAULIC	17,953	2,117	20,070
5	OTHER	102,455	35,636	138,091
6	TRANSMISSION PLANT	65,558	7,088	72,646
7	DISTRIBUTION PLANT	289,933	24,898	314,831
8	GENERAL PLANT	168,367	(100,039)	68,328
9	CLOUD IMPLEMENTATION - DISTRIBUTION	150	(150)	-
10	CLOUD IMPLEMENTATION - GENERATION	142	(142)	-
11	CLOUD IMPLEMENTATION - GENERAL	9,739	(9,739)	-
12	PISA	(26,704)	26,704	-
13	ICC DEPRECIATION	-	(1,868)	(1,868)
14	TOTAL DEPRECIATION EXPENSE	<u>888,136</u>	<u>(11,515)</u>	<u>876,621</u>
<b>PLANT AMORTIZATION:</b>				
15	INTANGIBLE PLANT	(8,683)	128,278	119,595
16	HYDRAULIC PLANT	756	-	756
17	TRANSMISSION PLANT	445	-	445
18	GENERAL PLANT	-	-	-
19	PISA	(13,705)	13,705	-
20	TOTAL PLANT AMORTIZATION	<u>(21,187)</u>	<u>141,983</u>	<u>120,796</u>
<b>MISC AMORTIZATION:</b>				
21	CALLAWAY POST OPERATIONAL	615	(615)	-
22	CALLAWAY LIFE EXTENSION	104	-	104
23	FUKUSHIMA STUDY COSTS	15	(15)	-
24	SIOUX SCRUBBER CONSTRUCTION ACCOUNTING	1,113	790	1,903
25	CUSTOMER AFFORDABILITY STUDY	2,177	(2,177)	-
26	ENERGY EFFICIENCY REG ASSETS AND MEEIA ORDERED ADJ.	2,569	(2,569)	-
27	LOW INCOME SURCHARGE	2,854	(2,854)	-
28	EXPIRED & EXPIRING REGULATORY BALANCES	(1,492)	(1,650)	(3,142)
29	PISA AMORTIZATION	-	50,244	50,244
30	EXCESS DEFERRED TAX TRACKER AMORTIZATION	1,508	407	1,915
31	RESRAM ADJUSTMENTS	9,355	(9,355)	-
32	CHARGE AHEAD CORRIDOR	1,342	123	1,465
33	EQUITY ISSUANCE COSTS	-	1,256	1,256
34	MERAMEC RETIREMENT	12,184	(12,184)	-
35	MERAMEC INVENTORY WRITE-OFF	1,854	(1,854)	-
36	RUSH ISLAND DEFERRAL	(1,806)	1,806	-
37	COVID AAO	986	(986)	-
38	CRITICAL NEEDS LOW INCOME PROGRAM	250	-	250
39	NEW START LOW INCOME PROGRAM	250	(250)	-
40	PROPERTY TAX TRACKER	-	(857)	(857)
41	RENEWABLE SOLUTIONS PROGRAM	3,373	(6,631)	(3,258)
42	OVERCOLLECTION OF SALES TAX - SB872	220	(339)	(119)
43	NUCLEAR PTC	(14,990)	(2,998)	(17,988)
44	LEGACY ELECTRIC ENERGY EFFICIENCY PROGRAM	-	(263)	(263)
45	KERSTING ESTATES REGULATORY ASSET	9	-	9
46	TOTAL MISC AMORTIZATION	<u>22,490</u>	<u>9,029</u>	<u>31,519</u>
47	TOTAL DEPRECIATION & AMORTIZATION EXPENSE	<u>\$ 889,439</u>	<u>\$ 139,497</u>	<u>\$ 1,028,936</u>
48	(1) See SCHEDULE SJH-D12-2 for explanation of the pro forma adjustments.			

**AMEREN MISSOURI**  
**ELECTRIC DEPRECIATION & AMORTIZATION EXPENSE PRO FORMA ADJUSTMENTS**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

LINE	ITEM NO.	DESCRIPTION	PRO FORMA ADJUSTMENTS
	(A)	(B)	(C)
1	(1)	To reflect the book depreciation annualized for the plant in service depreciable balances at	
2		March 31, 2026 and additions to plant in service from April 2026 through December 2026 to	
3		reflect the true-up.	
4		Change in Depr. Exp. - Steam	\$ 9,080
5		Change in Depr. Exp. - Nuclear	(2,154)
6		Change in Depr. Exp. - Decommissioning	(1,133)
7		Change in Depr. Exp. - Hydro	2,117
8		Change in Depr. Exp. - Other Prod.	35,636
9		Change in Depr. Exp. - Transmission	7,088
10		Change in Depr. Exp. - Distribution	24,898
11		Change in Depr. Exp. - General Plant	(83,862)
12		Change in Depr. Exp. - Cloud Implementation - Distribution	(150)
13		Change in Depr. Exp. - Cloud Implementation - Generation	(142)
14		Change in Depr. Exp. - Cloud Implementation - General	(9,739)
15		Change in Depr. Exp. - Incentive Comp Capitalized	(1,868)
16		Change in Amort. Exp. - Intangible Plant	128,278
17		Total Increase in Depreciation and Amortization Expense	<u>108,049</u>
18	(2)	To eliminate test year PISA deferrals and amortization.	
19		Depreciation	26,704
20		Amortization	13,705
21		Total Increase in Depreciation and Amortization Expense	<u>40,409</u>
22	(3)	To reduce depreciation expense charged to O&M.	
23		Decrease in Depr. Exp. - Steam	(1,813)
24		Decrease in Depr. Exp. - General Plant	(16,177)
25		Total Decrease in Depreciation Expense	<u>(17,990)</u>
26	(4)	To eliminate the amortization of the Callaway Post Operational regulatory asset.	(615)
27	(5)	To eliminate the amortization of the Fukushima Study Costs.	(15)
28	(6)	To eliminate the amortizations of the Sioux Scrubber Construction Accounting contra	790
29		regulatory assets and change amortization consistent with updated plant retirement.	
30	(7)	To reflect annualization of the amortization of the Customer Affordability regulatory asset and	(2,177)
31		eliminate set-up of the regulatory asset.	
32	(8)	To eliminate the amortizations and deferrals made under the MEEIA Rider, including MEEIA	(2,569)
33		ordered adjustments.	
34	(9)	To remove customer-funded portion of the Keeping Current and Keeping Cool Program.	(2,854)
35	(10)	To amortize expired & expiring regulatory balances.	(1,650)
36	(11)	To reflect amortization of PISA.	50,244
37	(12)	To eliminate accumulation and reflect annualized amortization of Excess Deferred Tax Tracker.	407
38	(13)	To eliminate RESRAM activity.	(9,355)
39	(14)	To reflect Charge Ahead Corridor amortization.	123
40	(15)	To reflect amortization of the Equity Issuance Costs regulatory asset.	1,256
41	(16)	To eliminate Meramec Retirement Cost amortization.	(12,184)
42	(17)	To eliminate Meramec Inventory amortization.	(1,854)
43	(18)	To eliminate amortization of the Rush Island Deferral.	1,806
44	(19)	To eliminate COVID AAO amortization.	(986)
45	(20)	To reflect Property Tax Tracker amortization.	(857)
46	(21)	To eliminate Renewable Solutions Program tracker deferrals.	(3,373)
47	(22)	To reflect amortization of Renewable Solutions Program tracker deferrals.	(3,258)
48	(23)	To eliminate sales tax deferrals due to SB872 and amortize the deferred balance.	(339)
49	(24)	To amortize Nuclear PTCs.	(2,998)
50	(25)	To amortize legacy electric energy efficiency program regulatory liability balance.	(263)
51	(26)	To remove customer-funded portion of the Rehousing Low-Income Pilot (New Start Energy	(250)
52		Relief) Program.	
53		<b>TOTAL PRO FORMA ADJUSTMENTS: DEPRECIATION &amp; AMORTIZATION</b>	<u>\$ 139,497</u>

**AMEREN MISSOURI**  
**TAXES OTHER THAN INCOME TAXES**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>TOTAL PER BOOKS</u> (B)	<u>PRO FORMA ADJUSTMENTS (1)</u> (C)	<u>PRO FORMA ELECTRIC TOTALS</u> (D)
<b>PAYROLL TAXES</b>				
1	F.I.C.A.	\$ 19,573	\$ 1,765	\$ 21,338
2	FEDERAL UNEMPLOYMENT	168	-	168
3	MISSOURI UNEMPLOYMENT	-	-	-
4	ILLINOIS UNEMPLOYMENT	57	-	57
5	IOWA UNEMPLOYMENT	1	-	1
6	OTHER STATES UNEMPLOYMENT	1	-	1
7	ST. LOUIS EMPLOYMENT TAX	381	-	381
8	TOTAL PAYROLL TAXES	<u>20,181</u>	<u>1,765</u>	<u>21,946</u>
<b>PROPERTY TAXES</b>				
9	MISSOURI R.E. & P.P.	193,856	4,049	197,905
10	ILLINOIS R.E. & P.P.	6,768	(92)	6,676
11	IOWA R.E. & P.P.	1,330	70	1,400
12	OTHER STATES R.E. & P.P.	7	7	14
13	R.E. TAXES CAPITALIZED	(21,082)	(12,655)	(33,737)
14	TRANSFER TO GAS	(326)	-	(326)
15	TRANSFER TO NON UTILITY	(184)	-	(184)
16	TOTAL R.E., P.P. & CORP FRANCHISE	<u>180,369</u>	<u>(8,621)</u>	<u>171,748</u>
17	<b>MUNICIPAL GROSS RECEIPTS</b>	183,362	(183,362)	-
<b>CORP FRANCHISE AND MISCELLANEOUS</b>				
18	ILLINOIS CORP FRANCHISE	184	-	184
19	FED. EXCISE TAX-HEAVY VEH. USE TAX	66	-	66
20	MISCELLANEOUS	217	-	217
21	TOTAL MISCELLANEOUS	<u>467</u>	<u>-</u>	<u>467</u>
22	<b>TOTAL TAXES OTHER THAN INCOME TAXES</b>	<u>\$ 384,379</u>	<u>\$ (190,218)</u>	<u>\$ 194,161</u>

23 (1) See SCHEDULE SJH-D13-2 for explanation of the pro forma adjustments.

**AMEREN MISSOURI  
TAXES OTHER THAN INCOME  
PRO FORMA ADJUSTMENTS  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026  
(\$000)**

<u>LINE</u>	<u>ITEM NO.</u>	<u>DESCRIPTION</u>	<u>PRO FORMA AMOUNT</u>
	(A)	(B)	(C)
1	(1)	Increase F.I.C.A. taxes to reflect the pro forma wage adjustments.	\$ 1,765
2	(2)	Property tax true-up adjustment.	(3,451)
3	(3)	Eliminate property tax tracker.	(4,939)
4	(4)	Eliminate the property taxes on future use plant, as this investment is	(231)
5		excluded from rate base.	
6	(5)	Eliminate gross receipts taxes as they are a pass through tax.	(183,362)
7		<b>Total Pro Forma Adjustments to Taxes Other Than Income</b>	<u>\$ (190,218)</u>

**AMEREN MISSOURI**  
**TOTAL ELECTRIC INCOME TAXES AT THE PROPOSED RETURN**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

LINE	DESCRIPTION (A)	(B)	TOTAL ELECTRIC (C)
1	TOTAL ELECTRIC NET INCOME FROM OPERATIONS		\$ 1,252,338
	ADD		
2	CURRENT INCOME TAXES		113,814
3	DEFERRED INCOME TAXES		
4	EXCESS DEFERRED INCOME TAX EXPENSE		(30,218)
5	I.T.C. AMORTIZATION		<u>(211,385)</u>
6	TOTAL ELECTRIC NET INCOME BEFORE INCOME TAX		1,124,549
	ADDITIONS TO NET INCOME BEFORE INCOME TAX		
7	BOOK DEPRECIATION		876,621
8	BOOK DEPRECIATION CHARGED TO O&M		5,787
9	INTANGIBLE AMORTIZATIONS		119,595
10	HYDRAULIC AMORTIZATIONS		756
11	TRANSMISSION AMORTIZATIONS		445
12	NONDEDUCTIBLE PARKING LOT EXPENSE		861
13	RSU PERM ITEM		<u>1,465</u>
14	TOTAL ADDITIONS		<u>1,005,530</u>
	SUBTRACTIONS TO NET INCOME BEFORE INCOME TAX		
15	INTEREST ON DEBT (1)		360,051
16	TAX STRAIGHT LINE		959,534
17	NUCLEAR DECOMMISSIONING		-
18	PREFERRED DIVIDEND DEDUCTION		<u>692</u>
19	TOTAL SUBTRACTIONS		1,320,277
20	<b>TOTAL ELECTRIC NET TAXABLE INCOME</b>		<b>809,802</b>
	<b>FEDERAL INCOME TAX</b>		
21	NET TAXABLE INCOME		809,802
22	DEDUCT MISSOURI INCOME TAX		30,734
23	DEDUCT CITY EARNINGS TAX		<u>(177)</u>
24	FEDERAL TAXABLE INCOME		779,245
25	<b>FEDERAL INCOME TAX</b>	<b>21.00%</b>	163,641
	LESS TAX CREDITS		
26	RESEARCH CREDIT		2,475
27	PRODUCTION TAX CREDIT		<u>77,909</u>
28	<b>TOTAL ELECTRIC FEDERAL INCOME TAX</b>		<b>83,257</b>
	<b>STATE INCOME TAXES</b>		
29	NET TAXABLE INCOME		809,802
30	DEDUCT 50% OF FEDERAL INCOME TAX		41,629
31	DEDUCT CITY EARNINGS TAX		<u>(177)</u>
32	MISSOURI TAXABLE INCOME		768,350
33	<b>TOTAL ELECTRIC MISSOURI INCOME TAX</b>	<b>4.00%</b>	<b>30,735</b>
	<b>CITY EARNINGS TAX</b>		
34	NET TAXABLE INCOME		809,802
35	LESS TAX ADJUSTMENTS TO INCOME		<u>(1,047,314)</u>
36	CITY TAXABLE INCOME		(237,512)
37	CITY EARNINGS TAX	<b>0.0993%</b>	(236)
38	LESS: TAX CREDIT		<u>(59)</u>
39	<b>TOTAL ELECTRIC NET CITY EARNINGS TAX</b>		<b>(177)</b>
40	<b>TOTAL ELECTRIC CURRENT INCOME TAXES</b>		<b>113,815</b>
	<b>DEFERRED INCOME TAXES:</b>		
41	EXCESS DEFERRED INCOME TAX EXPENSE		(30,218)
42	I.T.C. AMORTIZATION		<u>(211,385)</u>
43	<b>TOTAL ELECTRIC DEFERRED INCOME TAX</b>		<b>(241,603)</b>
44	<b>TOTAL ELECTRIC CURRENT &amp; DEFERRED INCOME TAX</b>		<b>\$ (127,788)</b>
45	(1) RATE BASE X EMBEDDED		
46	COST OF DEBT.	<b>2.158%</b>	

**AMEREN MISSOURI**  
**TOTAL ELECTRIC NET ORIGINAL COST RATE BASE AND REVENUE REQUIREMENT**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**  
**(\$000)**

<u>LINE</u>	<u>DESCRIPTION</u> (A)	<u>REFERENCE</u> (B)	<u>TOTAL ELECTRIC AMOUNT</u> (C)
<b>A. TOTAL ELECTRIC NET ORIGINAL COST RATE BASE</b>			
1	ORIGINAL COST OF PLANT IN SERVICE	SCHEDULE SJH-D1	\$ 28,995,077
2	LESS: RESERVES FOR DEPRECIATION & AMORTIZATION	SCHEDULE SJH-D2	10,859,045
3	NET ORIGINAL COST OF PLANT		<u>18,136,032</u>
4	AVERAGE FUEL AND MATERIALS AND SUPPLIES	SCHEDULE SJH-D3	641,685
5	AVERAGE PREPAYMENTS	SCHEDULE SJH-D4	47,266
6	CASH WORKING CAPITAL (LEAD/LAG)	SCHEDULE SJH-D5	(8,548)
7	FEDERAL INCOME TAX CASH REQUIREMENT	SCHEDULE SJH-D6	(787)
8	STATE INCOME TAX CASH REQUIREMENT	SCHEDULE SJH-D6	(290)
9	CITY EARNINGS TAX CASH REQUIREMENT	SCHEDULE SJH-D6	116
10	INTEREST EXPENSE CASH REQUIREMENT	SCHEDULE SJH-D6	(57,056)
11	AVERAGE CUSTOMER ADVANCES FOR CONSTRUCTION	SCHEDULE SJH-D7	(2,546)
12	AVERAGE CUSTOMER DEPOSITS	SCHEDULE SJH-D7	(30,235)
13	PENSION TRACKER REG ASSET	SCHEDULE SJH-D8	69,814
14	OPEB TRACKER REG LIABILITY	SCHEDULE SJH-D8	(2,659)
15	PAYS REGULATORY ASSET	SCHEDULE SJH-D8	5,741
16	PISA REGULATORY ASSET	SCHEDULE SJH-D8	889,935
17	EXPIRED & EXPIRING AMORTIZATIONS IN RATE BASE	SCHEDULE SJH-D8	12,862
18	PROPERTY TAX TRACKER	SCHEDULE SJH-D8	(2,570)
19	ACCUMULATED DEFERRED INCOME TAXES	SCHEDULE SJH-D9	<u>(3,014,263)</u>
20	<b>TOTAL ELECTRIC NET ORIGINAL COST RATE BASE</b>		<b><u><u>16,684,497</u></u></b>
<b>B. TOTAL ELECTRIC REVENUE REQUIREMENT</b>			
TOTAL ELECTRIC OPERATING EXPENSES:			
21	PRODUCTION	SCHEDULE SJH-D11-1	\$ 1,533,400
22	TRANSMISSION	SCHEDULE SJH-D11-1	153,093
23	REGIONAL MARKET EXPENSES	SCHEDULE SJH-D11-1	5,824
24	DISTRIBUTION	SCHEDULE SJH-D11-1	188,773
25	CUSTOMER ACCOUNTS	SCHEDULE SJH-D11-1	58,701
26	CUSTOMER SERVICE	SCHEDULE SJH-D11-1	16,091
27	SALES	SCHEDULE SJH-D11-1	762
28	ADMINISTRATIVE AND GENERAL	SCHEDULE SJH-D11-1	269,286
29	TOTAL ELECTRIC OPERATING EXPENSES		<u>2,225,930</u>
30	DEPRECIATION AND AMORTIZATION	SCHEDULE SJH-D12-1	1,028,936
31	TAXES OTHER THAN INCOME TAXES	SCHEDULE SJH-D13-1	194,161
INCOME TAXES-BASED ON PROPOSED RATE OF RETURN			
32	FEDERAL	SCHEDULE SJH-D14	83,257
33	STATE	SCHEDULE SJH-D14	30,735
34	CITY EARNINGS	SCHEDULE SJH-D14	(177)
35	TOTAL INCOME TAXES		<u>113,815</u>
DEFERRED INCOME TAXES			
36	EXCESS DEFERRED INCOME TAX EXPENSE	SCHEDULE SJH-D14	(30,218)
37	I.T.C. AMORTIZATION	SCHEDULE SJH-D14	<u>(211,385)</u>
38	TOTAL DEFERRED INCOME TAXES		<u>(241,603)</u>
39	RETURN (RATE BASE * 7.506%)	<b>7.506%</b>	<u>1,252,338</u>
40	<b>TOTAL ELECTRIC REVENUE REQUIREMENT</b>		<b><u><u>\$ 4,573,577</u></u></b>

**AMEREN MISSOURI**  
**INCREASE REQUIRED TO PRODUCE 7.506% RETURN ON**  
**TOTAL ELECTRIC NET ORIGINAL COST RATE BASE**  
**FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**

LINE	DESCRIPTION (A)	TOTAL ELECTRIC AMOUNT (B)
1	<b>TOTAL ELECTRIC NET ORIGINAL COST RATE BASE</b>	<b>\$ 16,684,497</b>
	<b>TOTAL ELECTRIC REVENUE REQUIREMENT:</b>	
2	RETURN AT PROPOSED RATE (7.506%)	1,252,338
3	OPERATING AND MAINTENANCE EXPENSES	2,225,930
4	DEPRECIATION AND AMORTIZATION	1,028,936
5	TAXES OTHER THAN INCOME	194,161
6	FEDERAL AND STATE INCOME AND CITY EARNINGS TAXES AT CLAIMED RETURN	113,815
7	DEFERRED INCOME TAXES	(241,603)
8	<b>TOTAL ELECTRIC REVENUE REQUIREMENT</b>	<b>4,573,577</b>
9	<b>PRO FORMA TOTAL ELECTRIC OPERATING REVENUE AT PRESENT RATES</b>	<b>4,230,694</b>
10	<b>DEFICIENCY IN TOTAL ELECTRIC OPERATING REVENUE</b>	<b>\$ 342,883</b>

**AMEREN MISSOURI  
CALCULATION OF NET BASE ENERGY COST (BF)  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**

LINE	DESCRIPTION (A)	TOTAL (B)	SUMMER (D)	WINTER (E)
<b>A FUEL &amp; PURCHASED POWER COSTS</b>				
BASE LOAD				
1	FUEL FOR LOAD	\$ 409,157,536	\$ 153,331,000	\$ 255,826,536
2	FLY ASH (1)	(690,866)	(256,475)	(434,391)
3	FIXED GAS SUPPLY COSTS FOR LOAD (2)	8,845,302	3,268,017	5,577,285
4	FUEL ADDITIVES (2)	12,189,139	4,503,442	7,685,697
5	PURCHASED POWER FOR LOAD	95,526,497	37,527,000	57,999,497
6	TOTAL BASE LOAD	525,027,608	198,372,984	326,654,624
OSS				
7	FUEL FOR LOAD	85,548,247	34,010,000	51,538,247
8	FLY ASH (1)	(144,449)	(53,625)	(90,824)
9	FIXED GAS SUPPLY COSTS FOR LOAD (2)	1,849,410	683,290	1,166,120
10	FUEL ADDITIVES (2)	2,548,552	941,597	1,606,955
11	PURCHASED POWER FOR LOAD	-	-	-
12	TOTAL OSS	89,801,760	35,581,262	54,220,498
13	<b>TOTAL FUEL AND PURCHASED POWER</b>	<b>614,829,367</b>	<b>233,954,246</b>	<b>380,875,121</b>
<b>B TRANSMISSION COSTS AND REVENUES</b>				
14	TRANSMISSION BY OTHERS (ACCT. 565 @9.22%) (2)	7,337,193	2,711,093	4,626,100
15	TRANSMISSION REVENUES (ACC 456.1) (2)	(4,152,038)	(1,534,178)	(2,617,860)
16	<b>TOTAL TRANSMISSION COSTS AND REVENUES</b>	<b>3,185,155</b>	<b>1,176,915</b>	<b>2,008,240</b>
<b>C ADDITIONAL FUEL &amp; PP COSTS</b>				
17	MISO DAY 2 EXCLUDING ADMIN (ACCT 555) (2)	42,009,779	15,521,081	26,488,698
18	COMMON BOUNDARY (2)	171,001	63,179	107,822
19	CAPACITY EXPENSE (2)	500,650,893	184,972,245	315,678,648
20	ANCILLARY SERVICES PURCHASED (ACCT. 555) (2)	11,028,338	4,074,971	6,953,367
21	PJM EXCLUDING ADMIN (ACCT. 555) (2)	-	-	-
22	REPLACEMENT POWER INSURANCE (ACC 925) (2)	858,281	317,135	541,146
23	<b>TOTAL ADDITIONAL FUEL &amp; PP COSTS</b>	<b>554,718,293</b>	<b>204,948,611</b>	<b>349,769,682</b>
<b>D SALES</b>				
24	OFF-SYSTEM ENERGY SALES REVENUES (ACCT. 447)	159,194,179	48,315,000	110,879,179
25	MAKE WHOLE PAYMENT MARGINS (ACCT 447) (2)	1,913,730	707,053	1,206,677
26	CAPACITY SALES REVENUES (ACCT. 447) (2)	517,489,094	191,193,346	326,295,748
27	BILATERAL ENERGY SALES MARGINS (447) (2)	-	-	-
28	FINANCIAL SWAPS (ACCT 447) (2)	(185,826)	(68,656)	(117,170)
29	ANCILLARY SERVICES REVENUE (ACCT. 447) (2)	12,913,720	4,771,149	8,142,571
30	<b>TOTAL SALES</b>	<b>691,324,896</b>	<b>244,917,892</b>	<b>446,407,004</b>
<b>E OTHER ADJUSTMENTS</b>				
31	REAL-TIME LOAD AND GENERATION DEVIATION (2)	558,437	206,322	352,115
32	<b>TOTAL OTHER ADJUSTMENTS</b>	<b>558,437</b>	<b>206,322</b>	<b>352,115</b>
33	<b>A + B + C - D - E NET BASE ENERGY COSTS</b>	<b>\$ 480,849,482</b>	<b>\$ 194,955,558</b>	<b>\$ 285,893,924</b>
34	LOAD AT MISO CP NODE AMMO.UE (KWH)	32,973,797,260	12,182,615,450	20,791,181,810
35	BASE FACTOR (BF) (\$ PER MWH)	14.58	16.00	13.75
36	<b>BASE FACTOR (BF) (CENTS PER KWH)</b>	<b>1.458</b>	<b>1.600</b>	<b>1.375</b>

37 MONTHS IN EACH PERIOD:  
38 SUMMER: JUNE THROUGH SEPTEMBER  
39 WINTER: OCTOBER THROUGH MAY

40 (1) ALLOCATED BETWEEN SUMMER AND WINTERS BASED ON COAL FROM FUEL MODEL.  
41 (2) ALLOCATED BETWEEN SUMMER AND WINTERS BASED ON LOAD.

**AMEREN MISSOURI  
CASH WORKING CAPITAL REQUIREMENT  
FOR THE TWELVE MONTHS ENDED MARCH 31, 2026**

Line No.	Description (A)	Revenue Lag (B)	Expense Lead (C)	Net Lag (D)	CWC Factor (E)
1	Pensions & Benefits	34.43	(19.91)	14.52	0.0398
2	Payroll and Withholdings	34.43	(9.77)	24.66	0.0676
3	Payroll Taxes	34.43	(9.01)	25.42	0.0696
4	Other Operations and Maintenance Expenses	34.43	(36.40)	(1.97)	(0.0054)
5	Fuel - Nuclear	34.43	(15.21)	19.22	0.0527
6	Fuel - Coal	34.43	(14.55)	19.88	0.0545
7	Fuel - Oil	34.43	(16.09)	18.34	0.0502
8	Fuel - Gas	34.43	(39.88)	(5.45)	(0.0149)
9	Purchased Power	34.43	(14.30)	20.13	0.0552
10	Real Estate and Property Taxes	34.43	(182.50)	(148.07)	(0.4057)
11	Missouri Use Tax	34.43	(76.33)	(41.90)	(0.1148)
12	Iowa Use Tax	34.43	(45.46)	(11.03)	(0.0302)
13	Illinois Use Tax	34.43	(35.78)	(1.35)	(0.0037)
14	St Louis Corporate Earnings Tax	34.43	(273.50)	(239.07)	(0.6550)
15	Fed Excise Heavy Use Tax	34.43	138.28	172.71	0.4732
16	Self Procured Insurance Tax	34.43	(238.50)	(204.07)	(0.5591)
17	Corporate Franchise Tax	34.43	(213.50)	(179.07)	(0.4906)
18	Missouri Sales Tax	24.11	(16.37)	7.74	0.0212
19	Gross Receipts Taxes	24.11	(26.35)	(2.24)	(0.0061)
20	Federal Income Tax	34.43	(37.88)	(3.45)	(0.0095)
21	State Income Tax	34.43	(37.88)	(3.45)	(0.0095)
22	Interest Expense	34.43	(92.27)	(57.84)	(0.1585)
23	Incentive Compensation	34.43	(252.98)	(218.55)	(0.5988)
24	Uncollectible Expense	34.43	(34.43)	-	-