

In the Matter of Evergy Metro, Inc. d/b/a)
Evergy Missouri Metro's Request for Authority) File No. ER-2026-0143
to Implement a General Rate Increase for)
Electric Service)

COMES NOW, Evergy Metro, Inc. d/b/a Evergy Missouri Metro (“EMM” or the “Company”) and, pursuant to the Missouri Public Service Commission’s (“Commission”) Order Setting Procedural Schedule and Directing the Filing of Dates for Local Public Hearings issued March 18, 2026, submits its Statement of Positions, as follows:

1. Cost of Capital

EMM POSITION: EMM’s actual capital structure at the June 30, 2026, true-up date should be used. Mr. Ley’s pro forma estimate was 52.07% common equity and 47.93% long-term debt; Staff’s true-up analysis found 52.19% common equity and 47.81% long-term debt as of June 30, 2026, and Staff agrees EMM’s standalone capital structure is appropriate for ratemaking; the rate of return (“ROR”) used in Ron Klote’s true-up direct used the same capital structure as Staff. (Ley Direct at p. 8, l. 20; Won Surrebuttal/True-Up Direct at pp. 62, 66; Klote at RAK-6) EMM agrees with Staff’s true-up capital structure. (Ley True-Up Rebuttal at p. 2, ll. 10–11) Mr. Murray’s 45% common equity and 55% long-term debt, built on Evergy, Inc.’s consolidated capital structure rather than EMM’s own, should be rejected, as Staff also concludes. (Ley Surrebuttal at pp. 3–4; Ley True-Up Rebuttal at p. 2, ll. 13–15; Won True-Up Rebuttal at p. 2)

EMM POSITION: The embedded cost of long-term debt at the June 30, 2026, true-up date, 4.54%, should be used; Staff and EMM agree on that figure. (Won Surrebuttal/True-Up Direct at p. 66; Ley True-Up Rebuttal at p. 2, ll. 18–20)

1

C. What return on common equity should be used for determining rate of return?

EMM POSITION: EMM's return on common equity should be set at 10.50%, at the conservative lower end of the 10.25% to 11.25% range supported by Ms. Bulkley's constant-growth DCF, CAPM, ECAPM, and bond yield plus risk premium analyses, a range her updated analysis through June 30, 2026, did not change. (Bulkley Direct at p. 5; Bulkley Rebuttal at p. 8; Ley Direct at p. 3) Capital market conditions, including elevated long-term Treasury yields, have changed since EMM's currently authorized 9.50% was set, and both Ms. Bulkley and Dr. Won conclude the authorized ROE should be higher than 9.50%. (Bulkley Surrebuttal at p. 23) Dr. Won's 9.73% and Mr. Murray's 9.25% are below the 9.85% average authorized for vertically integrated electric utilities in 2026 to date, and well below the approximately 10.04% historically authorized for vertically integrated utilities with nuclear operations. EMM faces moderately higher business and regulatory risk than its peers from its capital expenditure program, plant-in-service accounting, nuclear operations, and a 95% pass-through fuel adjustment clause. (Ley Rebuttal at p. 9; Ley Surrebuttal at p. 4; Won Surrebuttal/True-Up Direct at p. 3) Since June 30, 2026, the 30-year Treasury yield has risen 45 basis points, from 4.91% to 5.36% as of September 15, 2026, and on September 16, 2026, the Federal Open Market Committee raised the federal funds rate 25 basis points; neither Dr. Won nor Mr. Murray changed his recommendation. (Bulkley True-Up Rebuttal at p. 2, ll. 12–17; id. at p. 3, ll. 10–13) Rising long-term rates indicate a rising cost of equity, and updating Dr. Won's own DCF, CAPM, and bond yield plus risk premium analyses through August 31, 2026, raises every result. (Bulkley True-Up Rebuttal at p. 4, ll. 15–16; id. at p. 5, ll. 7–12)

D. What is the appropriate rate of return to use for ratemaking in this proceeding?

EMM POSITION: The rate of return produced by the capital structure, cost of debt, and 10.50% ROE stated above. With the 52.19% equity ratio and 4.54% cost of debt, that return is 7.651%, the return on rate base in Mr. Klote's true-up direct testimony. (Ley True-Up Rebuttal at p. 2, ll. 10–12; id. at p. 2, ll. 18–20)

2. Revenues and Billing Determinants

A. What level of billing units and normalized revenues should be used in calculating rates?

- i. What update period adjustment should be used in calculating normalized billing units, revenues, and rates?
- ii. What rate switcher and Large Power Service customer annualization adjustment should be used?
- iii. What weather normalization adjustment should be applied?
- iv. Should the blocking percentage for the actual blocks and the weather normalized blocks be the same?
- v. What 365-day adjustment should be used?
- vi. What energy efficiency adjustment should be used?
- vii. What growth adjustment should be used, and what counts should be used to calculate normal use per customer and customer growth?
- viii. What non-Missouri kilowatt hour (“kWh”) adjustment should be used in calculating normalized billing units?
- ix. Should the definitions of bill count and customer charge counts be added to EMM’s tariff?
- x. For normalization of retail revenues and billing determinants, should customer charge count or bill count be utilized?
- xi. Should the Company be compelled to provide both bill count and customer charge count in future rate cases.
- xii. What is the normalized revenue and kWh for Large Power Service (“LPS”) customers?
- xiii. What Economic Development Rider discount annualization should be applied?
- xiv. What amount of gross up for revenue requirement should be applied to Economic Development Rider discount amount.

EMM POSITION: The weather-normalized and customer-annualized billing determinants developed by Mr. Bass and the normalized revenues developed by Mr. Jaynes, updated through the true-up, should be used. (Bass Direct at pp. 3–5, 17; Jaynes Direct at pp. 3–4; Jaynes Surrebuttal/True-Up Direct at pp. 26–27)

(i) The Company’s update-period adjustment, which repeats the direct-filing steps through the update period, should be used. (Bass Direct at p. 17, ll. 11–14)

(ii) The Company’s rate switcher and customer growth adjustment should be used. (Bass Direct at p. 12, ll. 8–14) Customer B should be normalized, not annualized as Staff now proposes (A. Rucker True-Up Rebuttal at pp. 2–3). The Company normalized Customer B to its activity for the twelve months ending June 2026; Customer B is a Large Power Service customer without observable LLPS behavior or commitments, and at this early point of service it is appropriately handled through the typical customer normalization process. (Jaynes Surrebuttal/True-Up Direct at p. 27, ll. 6–8; Lutz Rebuttal at p. 34, ll. 17–19)

(iii) The Company’s weather normalization adjustment should be applied. In the direct case it increased test-year sales by 153,623 MWh, or 1.9%. (Bass Direct at pp. 3–10)

(iv) Yes. EMM’s method uses twelve months of actual rate code data and applies the same blocking percentages to actual and weather-normalized usage and applies normalized sales and customer levels to the observed block relationships. (Jaynes Direct at pp. 3–4; Jaynes Surrebuttal/True-Up Direct at pp. 2–3)

(v) The Company’s 365-day adjustment, which uses the same method Staff has historically used, should be applied. (Bass Rebuttal at p. 4)

(vi) The Company’s energy efficiency adjustment, calculated under the Commission’s Amended Report and Order in No. EO-2019-0132, should be used. (Bass Direct at p. 14, ll. 21–23; id. at pp. 15–16)

(vii) Customer charge count should be used wherever the rate has a customer charge. Staff uses bill count for normal use per customer and customer charge count for growth; whichever count is used, the definition should be the same for both purposes. (Jaynes Direct at pp. 7–9; Lutz Surrebuttal at pp. 2–5) Staff’s annualization of the SGS Primary growth that reflects temporary construction power for Customer A should be rejected; that load is not expected to continue. (Bass Surrebuttal at p. 3, ll. 12–18; id. at p. 5, ll. 3–7)

(viii) No adjustment to non-Missouri kWh should be made. Normalization occurs after jurisdictional allocation

(ix) No. Customer counts are used only in determining revenues in rate cases; defining them in the tariff would not help customers or others who rely on the tariff, and the definitions section of the Rules and Regulations defines terms used in those rules. No other Missouri electric utility defines customer counts in its tariff. (Lutz Surrebuttal at p. 5)

(x) Customer charge count should be utilized for rates that include that billing component, and bill count should be used only as the fallback where a customer charge is not available, which occurs most often in the lighting rates. (Jaynes Direct at p. 9, ll. 6–9). The customer charge count is the count tied directly to billing and revenues, and it is the count the Company proposed for all ratemaking purposes. (Jaynes Direct at p. 7). Both counts were

furnished in this case, and the monthly differences between them for the residential class during the test year are small. (Jaynes Direct at pp. 7–8). Because the two counts are essentially the same, there is no inherent benefit to one count over the other, and a single agreed count would allow the case and future cases to proceed more efficiently. (Lutz Surrebuttal at p. 5). Adopting the customer charge count here would resolve the disagreement that has persisted across the Company's Missouri rate cases. (Lutz Surrebuttal at pp. 2–3).

(xi) No. Producing both counts in every future case creates additional work and further opportunity for disagreement, without any offsetting benefit. (Lutz Surrebuttal at p. 4). A standing requirement to furnish both counts for EMM is also inconsistent with the commitment to cooperate in evaluating the counts and to determine the single appropriate count for use in the Company's rate cases going forward, and it is unreasonable to entrench both counts here while that commitment remains pending in a future Missouri West case. (Lutz Surrebuttal at pp. 4–5). The recommendation to provide both counts does not resolve the issue that produced the commitment; it perpetuates the existing inefficiency and could impede the determination of the appropriate count. (Lutz Surrebuttal at p. 4). The related recommendation to define the counts in the Company's tariff should also be rejected, because the counts are used only in determining revenues, adding the definitions provides no value to customers or others outside the rate case process, and placing them in the definitions section of the General Rules and Regulations would not aid anyone referencing the tariffs. (Lutz Surrebuttal at p. 5).

(xii) The individually annualized Large Power Service kWh developed by Mr. Bass and the normalized Large Power revenue developed by Mr. Jaynes should be used. (Bass Direct at pp. 12–13; Jaynes Direct at pp. 4–6; Jaynes Surrebuttal/True-Up Direct at pp. 26–27)

(xiii) The Economic Development Rider discounts should be grossed up so that the approved revenue requirement is recovered after the discounts. Test-year EDR credits were \$651,723 and the gross-up at the requested revenue requirement is approximately \$99,000. (Jaynes Direct at pp. 50–52)

(xiv) A gross up of \$99,022 should be applied. When the requested increase is applied to current rates, a proof of revenue confirms that the billing determinants provided will recover the revenue requirement. (Jaynes Direct at p. 52, ll. 3–6). Because the discounts provided under the Economic Development Rider are a reduction in recovered revenue, the amount of those discounts must be grossed up to reflect the new revenue requirement. (Jaynes Direct at p. 52, ll. 5–7). That gross up supplies the additional revenue that must be applied to the final determinants so that application of the new rates nets back to the requested increase of \$140,353,035. (Jaynes Direct at p. 52, ll. 7–10; Schedule GAJ-09; Schedule GAJ-10). EDR credits are applied top side, so revenues must be grossed up to the level before the reduction in order to price the determinants to recover the allowed revenue requirement. (Jaynes Direct, Schedule GAJ-09). Without the gross up, the pricing would be set on determinants that understate recoverable revenue by the amount of the discount, and EMM would not recover the revenue requirement the Commission approves. (Jaynes Direct at p. 52, ll. 4–10).

3. Other Revenues

A. What is the appropriate level of net revenue to reflect in the cost of service and other models for Large Load Power Service (“LLPS”) and other large customers?

i. What is the appropriate revenue adjustment for expected future revenues from Schedule LLPS customers in the cost of service model?

EMM POSITION: In its direct case the Company voluntarily reduced its revenue requirement by approximately \$25 million of projected LLPS revenue: a \$16.1 million pro forma adjustment and a further \$9.1 million revenue-only adjustment for anticipated LLPS growth. (Jaynes Direct at pp. 5–6) At true-up, the Company annualizes Customer A’s revenues to twelve months at the June 2026 level, using known and measurable information as of June 2026, which reflects the increased activity observed during the true-up period. (Jaynes Surrebuttal/True-Up Direct at p. 27, ll. 3–5; id. at p. 21) The Company bears the risk if those revenues fall short until its next rate case, and revenues above forecast become part of its operating results. Mr. Meyer’s one-way tracker, which records excess revenue as a regulatory liability but denies a regulatory asset for any shortfall, should be rejected; differences between forecast and actual should be addressed in the next general rate case under traditional ratemaking. OPC’s \$117 million adjustment should be rejected. (Gunn Rebuttal at pp. 2–3, 6, 8, 27) Mr. Nelson’s surrebuttal adjustment to LLPS revenues is not supported by any calculation or analysis, and extending the adjustment beyond the Customer A revenues observed at true-up would rely on forecasted operating conditions for years after rates take effect. (Jaynes True-Up Rebuttal at p. 2, ll. 6–8; id. at p. 2, ll. 10–16) Google likewise opposes MECG’s tracker, noting that a regulatory liability for net revenues above \$25 million would double count revenues if the trued-up LLPS revenues in this case exceed that amount. (Berry True-Up Rebuttal at pp. 5–6)

B. What level of forfeited discount, commonly referred to as late payment revenue, should be included in the cost of service?

EMM POSITION: The forfeited discount revenue reflected in the Company’s true-up, calculated by applying the Company’s ratio to normalized revenue and to the revenue increase, should be used. (Kramer Direct at p. 11; Kramer Rebuttal at pp. 2–4).

C. Should late payment fee revenue be increased by a proportionate amount of the revenue requirement increase authorized by the Commission in this case, commonly referred to as a “late payment fee factor-up”?

EMM POSITION: Yes. If bad debt expense is factored up for the revenue requirement change, late payment revenue should be factored up for the same reason; the two move together. (Kramer Rebuttal at pp. 2–4)

4. Wholesale Transmission Revenue Credit

- A. Should the Commission accept EMM's revenue reduction to adjust utility transmission revenues in its cost of service to reflect Commission-authorized versus Federal Energy Regulatory Commission ("FERC") authorized returns on equity?

EMM POSITION: Yes. Adjustment R-80 corrects the mismatch between the ROE the Commission authorizes for retail service, and the ROE FERC authorizes for the transmission facilities whose revenue is credited against retail cost of service. Without the adjustment, crediting wholesale transmission revenue at the FERC-authorized return allows wholesale customers to subsidize retail rates beyond the Commission's authorized return. (Reuter Direct at pp. 5–6; Reuter Rebuttal at pp. 3, 7)

5. Fuel and Purchased Power

- A. What should be adopted as the variable fuel and purchased power cost for this case?

EMM POSITION: The variable fuel and purchased power cost produced by the Company's PROMOD production cost model, updated through the true-up, should be adopted. The model normalizes system load, fuel prices, maintenance schedules, and resource availability and solves simultaneously for market prices, dispatch, and the resulting fuel, purchased power, and off-system sales values, so those values are internally consistent. Staff's model relies on historically low natural gas and market price inputs that do not reflect conditions expected while rates are in effect. (Foo Direct at pp. 7–8; Foo Rebuttal at pp. 7–8; Foo True-Up Direct at pp. 2–4)

- B. What fuel prices should be included in the cost of service?

EMM POSITION: The fuel prices in the Company's true-up model should be used. Coal prices increased two to seven percent from the direct filing, driven by diesel surcharges on transportation; natural gas prices decreased about six percent. The Company agrees that coal prices should be updated to the most current contract terms at true-up. (Foo True-Up Direct at pp. 2–3; Foo Rebuttal at p. 8) At true-up, the Company's natural gas prices use actual prompt-month prices from January 2025 through June 2026 and forward market prices as of July 1, 2026, for the remaining eighteen months of the normalization period; forward prices are observable market prices, not speculation. (Meitner True-Up Rebuttal at p. 2, ll. 12–21; id. at p. 3, ll. 10–16) Coal prices should be the actual June 2026 delivered prices under the contracts in effect at the true-up date; Staff's twelve-month composite blends in lower-priced earlier deliveries. (Meitner True-Up Rebuttal at p. 5, ll. 15–22; id. at p. 6, ll. 1–8)

- C. What normalized market prices should be used to determine the revenue requirement in this case?

EMM POSITION: The market prices generated within the Company's PROMOD simulation should be used. Because the model dispatches the regional system on fuel prices, load, and unit characteristics, its prices preserve the economic relationship between gas-

fired generation costs and locational marginal prices; Staff's independently supplied historical prices do not, and rest on historically low levels. (Foo Rebuttal at pp. 7–8) Staff's twelve-month historical average of natural gas prices is backward-looking, and Staff itself excludes Winter Storm Fern prices as unrepresentative. (Meitner True-Up Rebuttal at p. 4, ll. 1–17)

- D. What level of Transmission Congestion Rights (“TCR”) revenue, not TCR margin, should be included in the cost of service?

EMM POSITION: Normalized TCR revenue, not historical TCR margin, should be included. The Company derives a recovery factor from three years of actual TCR margin and congestion costs and applies it to the congestion costs its production cost model produces, so TCR revenue reflects the same market conditions as the fuel and purchased power costs. (Foo Rebuttal at pp. 17–18) Staff's historical TCR margin already contains historical congestion costs, so adding it to production cost model results that embed normalized congestion in locational marginal prices counts congestion twice; the Company's recovery-factor method keeps TCR revenue matched to the modeled congestion. (Foo True-Up Rebuttal at p. 2, ll. 5–10; id. at p. 3, ll. 1–7; id. at p. 5, ll. 2–9)

6. Transmission Expense

- A. Should the requirement for the Transource adjustment be discontinued?

EMM POSITION: Yes. The Company agrees with Staff that Adjustment CS-108 should be eliminated. (Reuter Surrebuttal at pp. 1–2) The adjustment was established through prior proceedings in Case Nos. EO-2012-0367 and EA-2013-0098, and Staff has expressed concern that the parties to those cases should have an opportunity to be heard before it is removed. (Reuter Surrebuttal at pp. 1–2). The Company recognizes that concern and commits to pursuing an amended stipulation in those dockets, which will provide the original parties, including Staff, OPC, and MIEC, an opportunity to review and comment on the proposed change. (Reuter Surrebuttal at p. 2). The adjustment is highly complex, requires numerous assumptions and manual inputs, and now produces an immaterial increase to the revenue requirement that will continue to decline as the projects depreciate. (Reuter Rebuttal at pp. 3, 7; Reuter Direct at pp. 5–6).

7. Payroll, Benefits, and Incentive Compensation

- A. What is the appropriate ratio of Operations and Maintenance (“O&M”) expense to be used in calculating payroll, benefits, and payroll tax expense?

EMM POSITION: The capitalization ratio should be based on a multi-year average rather than a single year. The ratio fluctuates with the availability of internal labor for capital work, storm restoration, and contractor use; a single low year would artificially reduce the cost of service. The Company's three-year average ratio is 57.34%. (Kramer Rebuttal at pp. 9–10)

- B. What level, if any, of long-term stock-based incentive compensation should be included in the cost of service?

EMM POSITION: The long-term equity compensation remaining in the Company's revenue requirement, about \$2.3 million on a total Evergy Metro basis, should be included. The Company already removed all performance-based long-term equity compensation for executive-level employees and 50% of time-based long-term equity compensation for officers and the board of directors; what remains is director-level performance-based restricted stock units and 50% of director, executive, and board time-based units. Staff does not contend that the Company's compensation is excessive or imprudent and would remove these costs only because they are paid in equity; restricted stock units are part of a competitive total compensation package that attracts and retains the employees who provide safe and reliable service. (Klote Rebuttal at pp. 21–28)

- C. What level of capitalized short-term incentive compensation based on earnings should be removed from plant in service?

EMM POSITION: The Company agrees with Staff that capitalized short-term incentive compensation tied to EMM's financial performance should be removed from plant in service. The remaining difference is Staff's estimate of the amount; the actual amounts through the true-up date should be used. (Klote Rebuttal at pp. 38–39)

- D. What level of severance payments should be included in the cost of service?

EMM POSITION: The Company has included only non-executive severance in the cost of service. Severance is a recurring cost of employing a workforce and should be included. Non-executive severance paid in the test year should be amortized over four years; executive severance has been excluded. Severance recurs every year as a category of workforce expense even though each payment is specific to an employee, and Staff's regulatory-lag rationale looks only at the favorable side of payroll-related lag. (Klote Direct at pp. 15–16; Klote Rebuttal at pp. 33–38)

- E. What level of pension and other post-employment benefit ("OPEB") expense should be included in the cost of service?

EMM POSITION: Following the reconciliation, Staff and EMM agree on pension and OPEB expense except as affected by the capitalization ratio addressed in A above.

- F. What level of supplemental executive retirement plan ("SERP") expense should be included in the cost of service?

EMM POSITION: Following the reconciliation, Staff and EMM agree on SERP expense except as affected by the capitalization ratio addressed in A above.

8. Maintenance and Operating Expense

- A. What level of meter replacement O&M costs should be included in the cost of service?

EMM POSITION: The Company disagrees with Staff's allocation of command center cost within meter replacement O&M. The Company's adjustment, which annualizes the AMI meter reading contract cost using the composite meter count for January through June 2025 and the estimated 2026 per-meter price, should be used. (Kramer Direct at p. 20)

- B. What level of outside services expense should be included in the cost of service?

EMM POSITION: EMM believes this number has not been identified within the docket and are not at issue.

- C. What level of affiliate transaction expenses should be included in the cost of service?

EMM POSITION: EMM believes this number has not been identified within the docket and are not at issue.

9. Amortizations and Expired Amortization Tracker

- A. What level of Demand Side Management pre-MEEIA opt-out amortization should be included in the cost of service?

EMM POSITION: The pre-MEEIA opt-out costs deferred after the May 31, 2022 true-up date in the 2022 case, together with the expected unamortized balance of Vintage 4 after the January 1, 2027 effective date of new rates, should be combined as Vintage 5, the final vintage, and amortized over six years, consistent with previous vintages, with no rate base treatment. (Kramer Direct at pp. 9–10)

- B. What level of prospective tracking amortization should be included in the cost of service?

EMM POSITION: Following the reconciliation, Staff and EMM agree except on the gross margin interest rate, a difference of approximately \$7,000. The Company's adjustment amortizes over four years the net balance of the prospectively tracked regulatory assets and liabilities through June 2026, including carrying costs through true-up on the Renewable Energy Standard regulatory liability. (Kramer True-Up Direct at p. 3; Kramer Direct at pp. 23–25)

10. Advertising, Dues, and Donations

- A. What level of Edison Electric Institute ("EEI") dues should be included in the cost of service?

EMM POSITION: EEI dues should be included. The Company records the portion of EEI dues attributable to lobbying below the line, and the remaining dues provide operational and customer benefits. Staff's disallowance should be rejected. (Kramer Rebuttal at pp. 7–8)

11. Customer Accounts Expense

- A. Should bad debt expense be increased by a proportionate amount of the revenue requirement increase authorized by the Commission in this case, commonly referred to as a “bad debt factor-up”?

EMM POSITION: Yes. Bad debt expense varies with revenue and should be adjusted for the revenue requirement change ordered in this case. (Kramer Rebuttal at pp. 2–4)

12. Regulatory Assessments, Rate Case Expense, and Local Taxes

- A. What level of rate case expense, if any, should be allowed in the revenue requirement?

EMM POSITION: Rate case expense should be recovered in full. The Company agrees with averaging over recent cases but disagrees with Staff’s proposal to recover only 50% of the averaged amount. Rate case expense is a necessary cost of operating as a regulated utility. (Kramer Rebuttal at pp. 4–6)

13. Common Use Billings

- A. Should the Uplight software be billed to Evergy’s Kansas regulated entities?

EMM POSITION: Not the Phase 1 implementation costs. Kansas customers now receive benefits from Uplight, but the Phase 1 implementation costs were incurred before Kansas customers had access to or could use the platform, and Staff’s customer-count reallocation ignores the separate implementation phases. (Branson Rebuttal at p. 6, ll. 3–11) See the response to B.

- B. What Uplight costs, including plant, reserve, amortization expense, and common use billings, should be included in the revenue requirement, and how should those costs be allocated and recovered?

EMM POSITION: Uplight Phase 1 implementation costs were incurred to create and deploy Uplight functionality for Missouri customers, at a time when Kansas customers could not access the platform without further implementation work; those costs were caused by and incurred for Missouri operations and should remain allocated to Missouri. Phase 2 enabled Kansas participation and expanded the platform across Evergy’s regulated jurisdictions and is allocated across all benefiting jurisdictions by customer count. Staff’s proposal to allocate all Uplight costs across jurisdictions ignores the distinction between the phases. (Kramer Rebuttal at p. 11; Branson Rebuttal at pp. 6–7)

14. Property Tax

- A. What is the appropriate level of Missouri property tax to be included in rates?

EMM POSITION: The Company’s property tax tracker balance as of June 30, 2026, is \$31,626,790, which includes \$4,052,953 in deferrals from August 28, 2022, through

January 8, 2026, to be amortized over four years at approximately \$7,906,698 per year. (Hardesty True-Up Rebuttal at pp. 3–4, 8).

B. What base level of property taxes should the Commission approve for tracking purposes?

EMM POSITION: The base level for tracking should equal the property tax expense included in the revenue requirement as stated in A above. That base level is EMM’s 2025 actual property taxes, its last known annual amount, the same measure Staff has recommended for every regulated Missouri utility since the tracker legislation took effect and will be used for tracking with the effective day of new rates. The deferrals from January 9, 2023, through the effective day of new rates in this case will be tracked against the base set in the 2022 rate case. (Hardesty True-Up Rebuttal at p. 6)

C. What level of property tax tracker rate base amount and amortization should be included in the cost of service?

EMM POSITION: The Commission should include in rate base the unamortized property tax tracker deferral balance of \$31,626,790 as of June 30, 2026, and authorize amortization of that balance over four years, producing an annual amortization of approximately \$7,906,698 (Hardesty True-Up Rebuttal at pp. 3-4, 8). EMM has deferred property tax expense incurred in excess of the amount included in base rates in accordance with Missouri Revised Statute § 393.400, which requires that the unamortized regulatory asset or liability balance be included in rate base and recovered through amortization in the subsequent general rate proceeding. (Hardesty Direct at pp. 15–18). Section 393.400² measures property tax expenses “actually incurred,” not paid, and the Company’s approach is consistent with Staff’s own methodology in the 2024 Evergy Missouri West rate case (Hardesty True-Up Rebuttal at pp. 5–6). The tracker balance reflects cumulative deferrals from the statute’s August 28, 2022, effective date through June 30, 2026, including \$4,052,953 for the stub period from August 28, 2022, through January 8, 2023, based on the property tax level determinable from the 2018 rate case (Klote Rebuttal at pp. 40–41; Hardesty True-Up Rebuttal at p. 3).

15. Income Taxes

A. How much income tax expense should be included in rates?

i. Should income tax expense be reduced by a normalized disposition loss deduction?

EMM POSITION: No, The disposition loss is a timing difference in the tax calculation and not necessary as the current and deferred taxes would offset each other if included.

ii. What amount of research and development tax credits should be included in income tax expense?

EMM POSITION: Yes, The company used the latest estimate of research and development tax credits based on the 2026 amounts recorded through June 30, 2026.

² All citations are to the Revised Statutes of Missouri (2016), as amended.

iii. What amount of ongoing nuclear production tax credit benefits realized should be included in income tax expense?

EMM POSITION: The revenue requirement should include \$0 of assumed ongoing nuclear production tax credit (“PTC”) benefits. No nuclear PTC sale had occurred by the June 30, 2026, true-up date, and the credits’ value depends on unresolved calculation guidance and market prices, so Staff’s assumed level is not known and measurable; the tracker returns to customers the benefit actually realized. (Hardesty True-Up Rebuttal at p. 8-9; Ives True-Up Rebuttal at p. 2-3).

B. Should the Commission approve a tracker for Inflation Reduction Act tax benefits?

i. If a tax tracker should be approved, should the differences between actual tax benefits and tax benefits included in income tax expense be subject to carrying costs, and if so, what is the appropriate carrying cost to accrue?

EMM POSITION: Yes. The tracker compares the Inflation Reduction Act tax credit benefits reflected in customer rates against the benefits actually monetized through utilization or sale, so that customers receive the actual benefit and the Company is not exposed to benefits assumed in rates but never realized. (Hardesty Direct at pp. 13–14; Hardesty Rebuttal at pp. 6–8)

C. What amount of net operating loss deferred tax assets should be included in rate base?

EMM POSITION: The net operating loss deferred tax asset should be included in rate base as calculated by the Company. OPC’s position misreads the nature of the balance. (Hardesty Rebuttal at pp. 11–13)

D. Should an Accounting Authority Order (“AAO”) be issued to defer the sale of tax benefits after the true-up date but prior to the effective date of rates?

EMM POSITION: Yes. EMM agrees the Commission should issue an AAO deferring, for customers, the proceeds of Inflation Reduction Act tax benefit sales realized after the true-up date and before new rates take effect; Staff understands EMM intends to pass all such benefits to customers. (Young Surrebuttal/True-Up Direct at p. 30, ll. 6–14)

16. Income-Eligible Programs

A. What level of Critical Medical Needs and Rehousing Programs expense should be included in the revenue requirement?

EMM POSITION: The Critical Medical Needs Program should continue at its existing \$300,000 funding level, and the Rehousing Program at its existing \$250,000 annual level, each funded equally by customers and shareholders. (Kramer Direct at p. 17; McDonald Rebuttal at pp. 9–10; McDonald Surrebuttal at p. 7)

B. What level of economic relief pilot program (“ERPP”) expense should be included in the revenue requirement?

EMM POSITION: The existing level should continue. The ERPP is funded at \$1,260,000 a year, half by shareholders, with the \$630,000 ratepayer-funded portion included in the revenue requirement, as the Commission ordered in the 2016 rate case and as settled without change in the 2018 and 2022 cases. (Kramer Direct at p. 17; McDonald Rebuttal at p. 9) The tariff changes that would broaden enrollment are addressed in G below.

C. Should the pilot designation be removed from EMM’s ERPP tariff?

EMM POSITION: Yes. EMM continues to support removing the pilot designation; the ERPP has operated for many years and is no longer new or experimental. Staff supports removal as well. (McDonald Surrebuttal at pp. 4–5)

D. Should EMM be required to provide a summary of the Rehousing Program administration, reporting, and evaluation by email to Staff and the Office of the Public Counsel at the conclusion of each year of the Program as described in its currently approved tariff?

EMM POSITION: Yes. EMM will continue to provide the year-end reporting its current tariff requires and will assess the program at the conclusion of its initial three-year pilot period. (McDonald Surrebuttal at pp. 5–6)

E. Should the Commission approve the creation of a low-income rate or assistance program that waives EMM’s customer charge for qualifying customers in this case, or should such a program continue to be developed in the Affordability Workshop?

i. If such a program is approved, should late fees be waived for qualifying customers?

ii. If such program is approved, how should the waived revenues be recovered?

EMM POSITION: Such a program should not be approved in this case; it should continue to be developed in the Affordability Workshop. Consideration is premature while the Affordability Workshop is actively examining these issues; EMM anticipates developing recommendations informed by that process and the Commission’s report. (McDonald Rebuttal at pp. 10–11)

(i) The Commission need not reach this question, because no such program should be approved in this case.

(ii) The Commission need not reach this question, because no such program should be approved in this case.

F. Should EMM be required to file quarterly Rehousing Program reports in EFIS in addition to the existing year-end report?

EMM POSITION: No. EMM already files an annual Rehousing Program report and provides program updates at the quarterly customer service meetings. Quarterly EFIS filings would add cost without adding information the parties do not already receive. EMM should continue administering its income-eligible programs as currently designed, without additional program requirements. (Gunn Rebuttal at p. 27, ll. 7–8; McDonald Surrebuttal at p. 6)

G. What changes, if any, should be made to the ERPP tariff to permit broader enrollment or to allow unused program funding to be transferred to other income-eligible programs?

EMM POSITION: EMM is evaluating a tariff adjustment to address ERPP enrollment barriers and is taking additional steps to improve participation. EMM opposes broad fungibility of ERPP funding with other income-eligible programs, which have different purposes, eligibility requirements, funding mechanisms, administrative structures, and reporting requirements. (McDonald Surrebuttal at pp. 3–4)

H. What level of Low-Income Weatherization Program expense, if any, should be included in the revenue requirement?

EMM POSITION: The existing \$573,888 annual funding level, recovered through base rates, should continue; the Company has recently spent the full budget, and the current level is appropriate. The projected regulatory liability balance at June 30, 2026, should be amortized over four years. Evergy’s separate Weatherization Ready initiative addresses the home-repair barriers that cause otherwise eligible homes to be passed over, which lets the program remain focused on energy efficiency. (Kramer Direct at p. 10; McDonald Rebuttal at pp. 10–11; McDonald Surrebuttal at p. 8)

17. Depreciation

A. Which depreciation rates should be used?

EMM POSITION: The depreciation and amortization rates in Schedule JJS-1 proposed by Mr. Spanos, together with the rates for the two account and location combinations that arose after the direct filing, 7.82% for Plant Account 312002 at Iatan 1 and 3.14% at Iatan 2, should be adopted. (Spanos Direct at p. 18; Branson Rebuttal at p. 2; Branson True-Up Direct at pp. 2–3)

B. Should terminal net salvage be included in depreciation rates?

EMM POSITION: Yes. Terminal net salvage for production plant should be included in depreciation rates as the Uniform System of Accounts defines net salvage and as the Commission’s Laclede order contemplates. The costs are not speculative: they were calculated in the Decommissioning Cost Study prepared by 1898 & Co., and Evergy has retired Hawthorn, Montrose, and Sibley in recent years and incurred the costs of shutting

those facilities down. Excluding terminal net salvage shifts those costs to future customers. (Spanos Rebuttal at pp. 2, 25–31)

C. What general plant amortization reserve deficiency adjustment should be made?

EMM POSITION: The Company agrees that a reserve adjustment for the general plant amortization accounts is appropriate and identified the issue itself during the case; the dispute is the calculation. The book reserve for those accounts is \$71,411,595 and the reserve required for proper amortization rates is \$80,493,572, leaving an unrecovered reserve of \$9,081,977 to be amortized over five years at \$1,816,034 annually. Staff ignored that reclassification and instead adjusted the book reserve to a theoretical reserve of \$84,859,579 that does not reflect the ages of the assets in each account. (Branson Rebuttal at pp. 7–8; Spanos Rebuttal at p. 20)

D. Should rates reflect the ongoing amortization of a cost of removal asset?

EMM POSITION: Yes. Both interim and terminal net salvage should be included in depreciation rates.

E. Should EMM recover future retirement costs in current rates?

EMM POSITION: Yes. This is the terminal net salvage question stated from the other direction; see the response to B above. (Spanos Rebuttal at pp. 25–31)

18. Plant in Service Accounting

A. What projects should be reflected as eligible for plant in service accounting (“PISA”)?

EMM POSITION: The projects reflected in the Company’s PISA calculation are eligible under Section 393.1400 RSMo. The Company removed \$8,751 of direct-assigned large-load costs that were inadvertently included; the remaining \$518,571 of broader-system costs Staff identified serves the system generally and is PISA-eligible. (Kramer Direct at p. 6; Kramer Rebuttal at pp. 12–14)

B. What amount of PISA deferral should be reflected in rate base?

EMM POSITION: The PISA deferral balance calculated by the Company should be reflected in rate base. (Kramer Direct at p. 6)

C. What amount of PISA amortization should be included in expense?

EMM POSITION: The PISA amortization calculated by the Company should be included. (Kramer Direct at pp. 6–7; Kramer True-Up Direct at pp. 1–3)

D. Should EMM's plant-in-service reporting requirements be modified from those in the Stipulation and Agreement approved in Commission Case No. ER-2022-0129, and if so, what modifications should be made?

EMM POSITION: No. The existing reporting under the Stipulation and Agreement, including the \$5 million project threshold, should be maintained. (Klote Rebuttal at p. 12)

19. Distribution Investment

A. What level of distribution capital investment should be reflected in rate base?

EMM POSITION: The level of distribution capital investment reflected in the Company's true-up rate base should be included. Prudent asset management is evaluated prospectively, on what was known when the decision was made, not with hindsight. (Mulvany Rebuttal at p. 7) OPC's criticisms do not show that the Company's AssetLens prioritization was unreasonable or imprudent, and the \$21.806 million of lateral improvement disallowances OPC recommends is 2.9% of the \$747.9 million of distribution investment planned for 2022 through 2026. (Alexander Rebuttal at pp. 12–13, 20–21) OPC treats a project-specific benefit-cost analysis as a prerequisite to prudence, which is not a complete or reliable basis for finding an investment imprudent. (De Stigter Rebuttal at p. 21, ll. 12–19; id. at p. 24, ll. 3–5) The absence of a particular economic screen does not establish imprudence; OPC's \$29.424 million of substation disallowances should be rejected. (Rietcheck Rebuttal at pp. 3–8) Under Missouri's prudence standard, a utility's costs are presumed prudent, and its decisions are judged on what was reasonably known when they were made, not with hindsight; OPC has not raised a serious doubt. (Ives True-Up Rebuttal at p. 7, ll. 12–16; id. at p. 9, ll. 11–20)

B. Is EMM's asset prioritization methodology a reasonable basis for the investment reflected in this case?

EMM POSITION: Yes. AssetLens uses condition, failure probability, consequence, and customer impact data to prioritize potential projects; final decisions also apply engineering judgment, field verification, and project-specific considerations. (Mulvany Rebuttal at pp. 8–9; Mulvany Surrebuttal at pp. 6–7; De Stigter Rebuttal at p. 5, ll. 18–21; id. at p. 6, ll. 13–17; id. at p. 16, ll. 4–6)

C. Is EMM in compliance with the Commission's vegetation management rule, and if not, what should the Commission order?

EMM POSITION: Yes. EMM complies with the Commission's vegetation management rule, and no order is needed. Evergy administers and reports its Missouri vegetation management activities as a single, integrated program covering EMM and EMW, and its annual vegetation management reports to the Commission since 2009 have reflected that combined operation. The rule sets minimum requirements but does not prohibit integrated planning and deployment of vegetation management resources across affiliated Missouri service territories, and Staff has not recommended that Evergy change its reporting

practices. Staff's contrary conclusion reflects a different reading of how the rule applies to EMM and EMW, not a newly discovered practice; the same practice was explained in response to a similar Staff concern in No. ER-2024-0189. (Mulvany Surrebuttal at pp. 2–5)

- D. Should EMM be required to compare the benefit of increased vegetation management against additional investment in its lateral improvement program?

EMM POSITION: No. EMM does not need to evaluate increased vegetation management spending as a means of improving reliability before making further lateral investment. Vegetation management and lateral replacement address different reliability risks and are complementary, not interchangeable: equipment-related outages, which vegetation management cannot prevent, are the largest outage category Staff identifies, and Staff neither recommends disallowing any of the investments nor identifies a project that failed to provide reliability benefits. (Mulvany Surrebuttal at pp. 5–9) Staff's recommendation for a comparative cost-benefit analysis (Bowman Rebuttal at pp. 3–14) should be rejected.

20. Rate Base Components

- A. What level of EEI prepayments should be included in rate base?

EMM POSITION: EEI prepayments should be included in rate base for the reasons EEI dues should be included in expense. The underlying EEI dues are properly recoverable and benefit customers through improved operations, reliability, emergency preparedness, and cybersecurity, so the prepaid balance should remain in rate base. (Branson Rebuttal at p. 9, ll. 1–9) See the response under Advertising, Dues, and Donations.

- B. What amount of construction work in progress is appropriate to reflect in rate base?

EMM POSITION: Qualifying construction work in progress for Mullin Creek No. 2 should be included in rate base under Section 393.135. Staff's objection that CWIP is premature while the CCN in EA-2026-0154 is pending (Young True-Up Rebuttal at pp. 1–2) is procedural, not substantive; nothing in the CCN proceeding prevents the Commission from granting CWIP here. Denying CWIP does not eliminate costs but defers them through AFUDC, which increases the plant balance customers ultimately pay depreciation and return on; including CWIP reduces AFUDC accumulation and the long-term revenue requirement. Direct assignment of the plant's costs to LLPS customers is inconsistent with cost causation and SPP's market design. OPC did not question the amount. (Klote Direct at pp. 13–15; Gunn Rebuttal at pp. 3, 18–21) The CWIP in the Company's true-up rate base is \$64,389,129. (Klote Surrebuttal/True-Up Direct, Schedule RAK-7, l. 22) The turbine reservation fees are project-specific costs incurred to secure manufacturing capacity and delivery slots for the project's generating equipment, not preliminary studies; the amount is an early-stage portion of a multi-year project well below its anticipated budget; and Section 393.135 provides refund protection with interest if costs are later found imprudent or the project is not placed in service within a reasonable time. (Klote Rebuttal at pp. 5–11).

C. How much of EMM's current rate base has been retired, and should a rate of return be applied to this amount?

EMM POSITION: None of EMM's rate base should be removed as retired plant. Staff's proposal to remove about \$43.9 million of Missouri-jurisdictional plant from rate base should be rejected. Replacement before average service life is expected under group depreciation; the replacement facilities are used and useful and are not alleged to be imprudent; and retirement experience is addressed through service lives, survivor curves, and depreciation rates in the depreciation study, which Mr. Young does not challenge and under which Staff's own depreciation witness continues to support long lives for the same asset classes. Staff's analysis also contains errors: correcting an incorrect depreciation rate on 135 line items and the seven largest items alone reduces the adjustment from \$43.9 million to \$23.9 million. The investment should continue to earn a return; Staff's proposal would allow return of the investment through depreciation while denying a return on it. (Ives Rebuttal at pp. 13–18; Klote Rebuttal at pp. 15–21; Mulvany Rebuttal at pp. 10–19)

D. What treatment should apply to the pension asset in rate base?

EMM POSITION: The pension asset, representing prepaid pension cost funded by the Company, should be included in rate base consistent with prior Commission treatment. (Klote Rebuttal at pp. 41–42)

E. If construction work in progress is included in rate base, what rate of return should be applied to it?

EMM POSITION: The Commission-authorized rate of return should apply to all rate base, including CWIP. Section 393.135.2 RSMo authorizes CWIP in rate base in lieu of AFUDC and says nothing about a separate, reduced return. (Ley True-Up Rebuttal at p. 5, ll. 16–21; id. at p. 7, ll. 1–4) Mr. Murray's 5.08% rests on a net present value comparison that discounts customer impacts at EMM's weighted average cost of capital, which is already reflected in both revenue requirements; customer impacts should be compared in nominal dollars or, at most, at a societal discount rate. (Ley True-Up Rebuttal at p. 3, ll. 14–22; id. at p. 4, ll. 3–11) Neither of his alternatives, a bond-yield return or a 6.16% return from the AFUDC formula, achieves the customer neutrality he offers as the basis for the 5.08%. (Ley True-Up Rebuttal at p. 6, ll. 11–16) Staff likewise rejects Mr. Murray's alternative CWIP capital structure and agrees that any return on CWIP should reflect EMM's actual cost of capital. (Won True-Up Rebuttal at pp. 3, 5)

F. What amount of transmission investment since EMM's last rate case should be included in rate base?

EMM POSITION: The transmission investment placed in service since EMM's last rate case should be included in rate base. OPC first recommended its transmission disallowances in Mr. Shapley's and Mr. Alvarez's surrebuttal testimony, and EMM has moved to strike that material as improper surrebuttal; the plant Mr. Shapley addresses was in service before the end of the test year and in rate base in EMM's direct case. (Ives True-Up Rebuttal at p. 6, ll. 6–16) If the Commission considers the recommendations, they

should be rejected under the prudence standard. (Ives True-Up Rebuttal at p. 7, ll. 8–16; id. at p. 9, ll. 9–20) Mr. Rietcheck’s sur-surrebuttal (tendered with EMM’s motion to strike) shows that Mr. Shapley’s \$73.110 million in disallowances for the Wolf Creek transformers, the Leeds–Winchester and Brunswick–Carrollton line rebuilds, and the Claycomo substation rest on incomplete or incorrect condition, age, inspection, and net book value facts. (Rietcheck Sur-Surrebuttal at p. 3, ll. 7–9; id. at pp. 3–19)

G. What level of coal inventory should be included in rate base?

EMM POSITION: The coal inventory at the true-up date should be included in rate base at the levels produced by the Company’s Utility Fuel Inventory Model, which sets targets that balance the cost of holding inventory against the cost of running out, valued at June 2026 pricing, with burns updated for actual July 2025 through June 2026 experience. (Tucker Direct at pp. 12–13, 17, 20; Meitner True-Up Direct at p. 10) Staff’s true-up sets coal inventory from modeled burns, which yields a much lower ending inventory than actual; the target inventory levels in RB-74, which EMM plans and manages to maintain for reliability, should be used. (Meitner True-Up Rebuttal at p. 6, ll. 10–20; id. at p. 7, ll. 11–15)

H. Should rate base be reduced to remove Evergy Kansas Central’s investment in transmission to serve Panasonic allocated to EMM?

EMM POSITION: No. OPC first recommended this disallowance in Mr. Alvarez’s surrebuttal testimony, and EMM has moved to strike that material as improper surrebuttal. (Motion to Strike Portions of the Surrebuttal Testimony of OPC Witnesses Shapley and Alvarez and Motion for Expedited Treatment (Sep. 23, 2026); Rietcheck Sur-Surrebuttal at p. 3, ll. 7–20) If the Commission considers the recommendation, it should be rejected. Mr. Alvarez’s 50% proxy for a transmission-level contribution in aid of construction (“CIAC”) treats regionally allocated transmission investment as though it were a distribution line extension serving only Panasonic. (Reuter Sur-Surrebuttal at p. 2, ll. 11–16) The distribution facilities serving Panasonic were directly assigned to it. Panasonic reimbursed their actual cost, including some costs at transmission voltage, through a one-time payment completed at the end of 2025. (Reuter Sur-Surrebuttal at pp. 2–3) The transmission facilities are SPP Base Plan upgrades built under SPP Notifications to Construct. Their revenue requirement is recovered from all transmission customers on a load-ratio-share basis through Schedule 11 of the SPP Open Access Transmission Tariff. The West Gardner–Atlantic–Craig 345 kV project that includes them is an SPP-approved regional reliability Network Upgrade recovered entirely through the regional Schedule 11 charge. (Reuter Sur-Surrebuttal at p. 3, ll. 5–23) The gross investment Mr. Alvarez uses is therefore not the cost EMM bears. The EMM load-ratio share is about 6.86% of the approximately \$3.4 million 2026 Schedule 11 amount for the project. That share changes with regional loads and cannot be equated to the full project cost or reduced by an assumed 50% transmission CIAC. (Reuter Sur-Surrebuttal at p. 4, ll. 3–10)

21. Jurisdictional Allocations

A. What jurisdictional demand and energy allocation factors should be used?

EMM POSITION: Jurisdictional demand should be allocated using the arithmetic average of the 4 CP and 12 CP allocators, except for transmission, which should use 12 CP. (Wolfram Direct at p. 9, ll. 5–10) The result differs from Staff’s 4 CP allocator by only 45 basis points. (Wolfram Surrebuttal at p. 9, ll. 8–11) Staff’s adherence to 4 CP looks only to past Missouri practice and does not address the Company’s inability to recover its full cost of service when Missouri and Kansas allocate the same integrated system differently. (Ives Surrebuttal at pp. 11–12) The jurisdictional energy allocator should be updated with data through the June 30, 2026, true-up date under the existing methodology; updating revenues and rate base through true-up while allocating costs on older usage data creates an inconsistency. (Klote True-Up Rebuttal at p. 2, ll. 10–21; id. at p. 3, ll. 13–18; id. at p. 4, ll. 20–23)

B. How should the allocations be determined for the various elements of the cost of service?

EMM POSITION: The jurisdictional allocators for the other elements of the cost of service, including the customer, distribution, and energy storage situs allocators, should be those updated through the true-up. (Branson True-Up Direct at p. 2, ll. 8–13)

C. Should a portion of plant, reserve, and depreciation expense of the Greenwood solar facility be allocated to EMM?

EMM POSITION: No. The Greenwood solar facility is connected to a single distribution circuit on Evergy Missouri West’s system and serves only customers on that circuit; allocating any portion of its cost to EMM is inconsistent with cost causation. If the Commission nonetheless orders an allocation, no more than \$100,000 should be assigned to EMM. (Ives Rebuttal at pp. 18–21)

22. Fuel Adjustment Clause — Structure and Base Factor

A. Should the Commission authorize EMM to continue its FAC?

EMM POSITION: Yes. The Commission should authorize EMM to continue its FAC under Section 386.266 RSMo, with full reconciliation of eligible costs and with LLPS customers retained in it. (Gunn Rebuttal at p. 2, ll. 20–22; id. at p. 27, ll. 3–6; Nunn True-Up Rebuttal at p. 2, ll. 9–14)

B. Should the general construct of EMM’s FAC be changed?

EMM POSITION: No. The FAC should continue in its current construct with Large Load Power Service customers included. EMM supports Staff’s Option 1, which keeps LLPS customers in the existing FAC and adjusts the single base factor for annualized LLPS load and net base energy costs, and opposes Option 2, which removes them. EMM also opposes the separate LLPS mechanism Staff later indicated it would not oppose. (Nunn Rebuttal at pp. 3–5; Nunn Surrebuttal/True-Up Direct at pp. 10–13)

C. What value should the FAC base factor be set at the conclusion of this case?

EMM POSITION: The base factor derived from the Company's true-up model, \$0.01931 per kWh, should be used. (Nunn Surrebuttal/True-Up Direct at p. 14)

D. What sharing ratio between EMM and its customers should the Commission order as an incentive mechanism in EMM's FAC?

EMM POSITION: The Commission should adopt full reconciliation of eligible costs without sharing. The 95/5% mechanism was adopted to give the Company an incentive to control costs; sharing functions only where the utility can affect the outcome, and the variances now flowing through the FAC are driven by large load energization timing, ramp schedules, and SPP resource adequacy requirements the Company cannot control. In those circumstances sharing operates as a risk transfer rather than an incentive, and customers remain protected by the Commission's prudence review. In an organized market, efficiency is already enforced by SPP's economic dispatch. If the Commission nonetheless determines that a sharing mechanism is appropriate, the 95/5% ratio should be maintained. (Gunn Rebuttal at pp. 14–17)

23. Fuel Adjustment Clause — Included Costs

A. What SPP transmission costs should be included in the FAC?

EMM POSITION: The share of SPP transmission service costs flowing through the FAC should be updated from the currently tariffed 28.50% to 27.78%, the percentage in the Company's true-up FAC tariff sheets. (Nunn Direct at p. 4; Nunn Surrebuttal/True-Up Direct, Schedule LJN-8, Sheet No. 50.3)

B. What SPP charge types should be included in the FAC?

EMM POSITION: The SPP charge types proposed by Ms. Nunn should be included. The Integrated Marketplace Clearing and Facilitation Administrative Service charges recorded in Account 555070 vary with load in the same manner as other FAC costs and are appropriately recovered through the FAC. (Nunn Rebuttal at pp. 21–23; Nunn Surrebuttal/True-Up Direct at pp. 2–4)

C. What FAC subaccounts should be included in the FAC?

EMM POSITION: The subaccounts proposed by Ms. Nunn should be included. Staff does not oppose the additional uncertainty-reserve and market charge types, the emissions and environmental-credit account updates, subaccount 501310 for glycol additives, or the storage-and-transportation language in Account 501000. (Nunn Direct at pp. 4–6; Henderson Rebuttal at pp. 2–4)

D. Should EMM include long-term capacity purchases and sales for recovery in its FAC?

EMM POSITION: Yes. Long-term capacity purchase costs should be recovered through the FAC. (Nunn Rebuttal at pp. 23–25) An Interim Capacity Agreement has a limited role and is not a substitute. (Nunn Surrebuttal/True-Up Direct at pp. 4–5) Prudently incurred long-term capacity costs and revenues should be eligible for FAC treatment when such

transactions occur, which recognizes both sides of the transactions consistently; costs charged to specific LLPS customers under an Interim Capacity Agreement would remain excluded. (Nunn True-Up Rebuttal at p. 7, ll. 17–24; id. at p. 8, ll. 13–16)

24. Fuel Adjustment Clause — Tariff Language

- A. Should EMM include a new definition in the FAC tariff sheets for retail revenue and accounts 440 through 444?

EMM POSITION: Yes. The retail revenue definition covering FERC Accounts 440-444 revenues under the Alternative Energy Credit, Renewable Energy Program, and Green Solutions Connection Riders should be adopted. Staff does not oppose it. (Nunn Direct at pp. 4–5; Henderson Rebuttal at pp. 3–4)

- B. Should the definition of fuel residuals under FERC subaccount 501400 in the FAC tariff sheets be changed?

EMM POSITION: No. The surrounding tariff language already limits miscellaneous expenses under subaccount 501400 to legitimate fuel-residual costs, and the prudence review provides oversight. (Nunn Rebuttal at pp. 16–17)

- C. Should the extraordinary costs language proposed by Staff be reflected in EMM’s FAC tariff?

EMM POSITION: Yes, in substance. EMM agrees that the FAC tariff should address extraordinary events, and its true-up tariff sheets include language, similar to Ameren Missouri’s FAC tariff, which allows the Commission, for good cause shown and after an opportunity for any party to be heard, to extend recovery beyond twelve months to mitigate the effect on customers of an extraordinary increase in net energy costs. (Nunn Rebuttal at p. 17; Nunn Surrebuttal/True-Up Direct, Schedule LNJ-8, Sheet No. 50)

- D. Should EMM change the Emissions definition Factor R to Emissions and Environmental credit accounts, subaccounts 411.8, 411.9, 411.12 and 411.13?

EMM POSITION: Yes. EMM proposed the change, and Staff does not oppose the emissions and environmental credit account updates. (Nunn Direct at pp. 4–6; Henderson Rebuttal at pp. 2–4)

- E. Should language be added to the FAC tariff sheets to address fuel hedging?

EMM POSITION: Yes. Staff agrees that the fuel hedging language should be included in the FAC tariff. (Meitner Surrebuttal at p. 2, ll. 16–18; Poudel Rebuttal at p. 6, ll. 1–13)

25. Fuel Adjustment Clause — Large Load Power Service

A. Should changes be made to the FAC to address LLPS customers?

EMM POSITION: No. LLPS customers should remain in the existing FAC with their annualized usage and costs reflected in the common base factor. (Nunn Rebuttal at pp. 4–6; Ives Surrebuttal at pp. 8–9) Removing LLPS customers from the FAC, or isolating them in a separate FAC, would create mismatches among FAC costs, revenues, load determinants, and base factors; if Customer A revenues are annualized, the associated fuel and purchased power costs should be reflected consistently. (Nunn True-Up Rebuttal at p. 4, ll. 19–24; id. at p. 5, ll. 3–9)

B. What, if any, new FAC reporting requirements should the Commission order?

EMM POSITION: None. EMM should continue its existing FAC reporting and provide those reports to OPC as well as Staff (Nunn Rebuttal at p. 17, ll. 19–20); the Commission should reject Staff’s recommended annual hedging report (Poudel Rebuttal at pp. 6–7; Poudel Surrebuttal at p. 3, ll. 15–20), whose forward-looking projections of hedge ratios and price variability are inherently uncertain and could be read as prescriptive targets that limit the flexibility the natural gas fuel supply plan needs. (Meitner Surrebuttal at p. 4, ll. 9–18; id. at p. 7, ll. 14–16) Ms. Nunn agrees to continue the existing monthly FAC reporting requirements. (Nunn Rebuttal at p. 17). The Commission should reject Staff’s recommendation for additional reporting if changes are made to the FAC. There is no accounting record that can be used to accurately separate actual LLPS net energy costs from the costs incurred to serve the remainder of Evergy’s retail load. (Nunn Surrebuttal at p. 12, ll. 18–23)

C. Should EMM have a separate FAC base factor for LLPS customers?

EMM POSITION: No. A separate mechanism would require separate cost tracking, base levels, accumulation balances, and true-up calculations, fragmenting the reconciliation without improving accuracy. (Nunn Rebuttal at pp. 25–27; Nunn Surrebuttal/True-Up Direct at pp. 10–13; Nunn True-Up Rebuttal at p. 5, ll. 15–18)

26. Rules and Regulations Tariff

A. Should the Commission approve EMM’s proposed tariff changes regarding its Rules and Regulations inclusive of modifications identified in the error log?

EMM POSITION: Yes. The Company’s proposed changes reorganize and update the Rules and Regulations tariff, add a grid interconnection section, and clarify redistribution and customer support provisions. (Lutz Direct at pp. 17–30; Lutz Surrebuttal at pp. 29–32)

27. Estimated Billing and Interval Data

A. What updates, if any, to EMM’s tariffs should occur to address energy interval estimation?

EMM POSITION: Section 6.06 of EMM’s General Rules and Regulations should be revised to add the interval estimation procedure in Schedule BDL-1. Under that procedure, a missing interval is estimated from the same day and time one week prior, then the same

day and time two weeks prior, then similar days and times; interval-based totals are compared to non-interval meter readings for the month, with differences investigated manually where practical; and the entire monthly bill is designated as estimated when the number of estimated intervals exceeds quality-control levels the Company sets. No other tariff change is needed. The tariff should not fix numeric thresholds, which would not improve estimation and would constrain the Company's control of costs. (Lutz Rebuttal at pp. 55–56, 58; Lutz Rebuttal, Schedule BDL-1; Lutz Surrebuttal at p. 20)

- B. What interval estimation threshold is appropriate for designation of an estimated bill and how should intervals be estimated?

EMM POSITION: Missing interval data should be held for up to 48 hours to allow a corrected meter read file to arrive, then estimated from the same day and time one week prior, then the same day and time two weeks prior, then similar day types and times (weekday, weekend, or holiday). The interval total for the billing period is then compared to the scalar reading for the same period. This follows the historical data approach 20 CSR 4240-13.020 contemplates and keeps estimated usage aligned with the time periods of time-based rates. (Lutz Rebuttal at pp. 52–54; Lutz Surrebuttal at p. 17)

- C. What records should be retained for missing or estimated interval data?

EMM POSITION: The records 20 CSR 4240-13.020 requires: the reasons for an estimated bill and the efforts made to obtain an actual reading, which EMM maintains through its operational systems. Under EMM's AMI system the reason is a lack of communication with the meter, and the effort is continued attempts to obtain the read, which the meter keeps trying to send. The additional records Staff proposes, covering each missing interval, each inserted estimate, the data supporting it, and the circumstances, go beyond the rule, would add cost, and would not reduce estimations or make estimates more accurate. (Lutz Surrebuttal at pp. 16–17, 19)

- D. What reporting requirements should be implemented for missing or estimated interval data?

EMM POSITION: None. Staff's proposal to identify bills containing estimated usage and report the usage and revenue estimated goes beyond 20 CSR 4240-13.020 and would not improve billing; the Company produces more than 99% of its bills without estimation or correction. (Lutz Surrebuttal at pp. 16, 19)

- E. Should EMM's estimation procedure defined in the EMM tariff include thresholds for automated and manual reviews of estimations?

EMM POSITION: EMM's procedure already includes both. A monthly bill is flagged as estimated when one-third of its intervals have been estimated, and a variance of more than 33 kWh between the interval total and the scalar reading is reviewed manually. The 33 kWh threshold keeps manual review where it is cost-justified; of the sum checks below it in the twelve months ending June 2026, 98.55% had variances of less than 1 kWh. These thresholds should remain within the Company's discretion rather than be fixed in the tariff. (Lutz Rebuttal at pp. 53–54; Lutz Surrebuttal at pp. 18–20)

28. Residential Rate Design

A. What should the residential customer charge be set at in this case?

EMM POSITION: The residential customer charge should be set at \$13.82 per month, an increase of \$1.82 from the current \$12.00. The purely cost-based charge from the class cost of service study is \$18.33; the proposal moves toward that level while moderating customer impact. (Jaynes Direct at p. 53; Jaynes Surrebuttal/True-Up Direct at p. 11)

B. Should EMM be required to inform customers on specified Time-of-Use rate schedules of billing issues and remove customers from such specified rate schedules if EMM has estimated their monthly billing?

EMM POSITION: No. Removing customers from a time-of-use rate they chose because of meter-reading issues they cannot control, with a notice asserting billing-system programming errors and metering deficiencies that are untrue, would harm those customers and increase customer dissatisfaction, particularly after the recent residential time-of-use implementation. EMM's interval estimation process is reasonable, and the appropriate step is to add it to the Rules and Regulations (Issue 27). If the Commission believes there is a chronic estimation problem, it should be taken up in a separate investigation. (Lutz Rebuttal at pp. 56–57)

29. Non-Residential Rate Design

A. Should the rates of the non-residential non-lighting customers be restructured in this case?

- i. What are the appropriate periods for each time-related element?
- ii. Should the Large General Service ("LGS") and Medium General Service ("MGS") classes be subject to reactive demand charges?
- iii. What are the appropriate charges for each rate element for each class?
- iv. Should EMM be ordered to promptly conduct a billing determinants and customer impact study?
- v. What customer education is appropriate?
- vi. What date should restructured rates take effect?

EMM POSITION: No. Staff's restructuring should not be adopted; the Company's proposed structures should be used. (Jaynes Rebuttal at pp. 1–2, 23) Reactive demand should be removed for MGS and LGS. (Jaynes Rebuttal at p. 33) The Company's summer on-peak period of 3:00 to 7:00 p.m. should be used rather than Staff's 10:00 a.m. to midnight summer and 6:00 a.m. to midnight non-summer windows. (Jaynes Rebuttal at pp. 23–25) The charges in Schedule GAJ-04 should be adopted. (Jaynes Rebuttal at p. 26) The

rates should be implemented on the ordinary schedule; Staff's proposed November 1, 2027, delayed implementation should be rejected. (Jaynes Rebuttal at pp. 27–33) Targeted education and outreach may be appropriate, but customer education does not justify a one-year delay. (Jaynes Rebuttal at pp. 29–32, 45)

- B. Should the non-residential non-lighting opt-in time based rates proposed by EMM be implemented?

EMM POSITION: Yes. The proposed three-period, four-part optional time-of-use rate for SGS, MGS, LGS, and LPS customers should be implemented. (Jaynes Direct at pp. 25–27)

- C. How should standby service rates be modified to include a minimum demand alternative or modified as appropriate?

EMM POSITION: Standby service should be modified as proposed by Mr. Lutz to provide an alternative minimum demand approach under Schedule SSR, with the minimum demand approximating at least 50% of the expected customer load if no customer generation were present. (Lutz Direct at pp. 37–38)

30. Other Rate Schedules

- A. How should all other applicable rates in this case be increased, including lighting, Large Load Power Service, Electric Vehicle Charging, and Time Related Pricing, if applicable?

- i. Should the TRP (Time Related Pricing) rate schedule be eliminated?
- ii. Should Schedule LLPS rates be increased in this proceeding, and if so, by how much?

EMM POSITION: Lighting rates should receive a weighted increase applied to non-LED components rather than an equal increase across components, to align lighting price signals with technological efficiency. Rates not set in a general rate case are not intended to receive the equal increase. (Jaynes Direct at p. 52; Jaynes Surrebuttal/True-Up Direct at p. 12)

(i) Yes. The Time Related Pricing rate has three active service agreements, two under the same account, and the optional time-of-use rate provides a replacement. (Jaynes Direct at pp. 28–29; Jaynes Surrebuttal/True-Up Direct at pp. 19–20) If the Commission instead keeps the rate for its current participants, it should be recalibrated to recover 4.73% more revenue than the jurisdictional increase, distributed across energy pricing, to move it toward its optional time-of-use equivalent. (Jaynes Surrebuttal/True-Up Direct at p. 20)

(ii) Yes. Schedule LLPS rates should increase by the same percentage as the Schedule LPS rates and the other classes (Issue 32), which preserves the relationship to the LPS rates on which the LLPS pricing was built; the LLPS rates are higher than the LPS rates because of an identifiable demand adder that replaced the proposed System Support Rider acceleration component. Freezing LLPS rates while LPS rates increase would break that relationship. (Jaynes Surrebuttal/True-Up Direct at p. 22; Lutz Rebuttal at pp. 46–49)

- B. Should obsolete residential rate schedules and the Underutilized Infrastructure Rider be removed from the EMM tariff book?

EMM POSITION: Yes. (Jaynes Direct at pp. 9, 27–29; Lutz Rebuttal at pp. 58–59)

31. Large Load Power Service Tariff and Reporting

- A. What tariff changes or clarifications, if any, should be made to the Large Load Power Service tariff?

EMM POSITION: None. The safeguards Dr. Marke urges on Schedule LLPS are the proposals the Commission considered and rejected in No. EO-2025-0154, and nothing has changed to warrant a different result; the Commission should decline to modify the Schedule LLPS terms approved there. (Gunn Rebuttal at p. 2, ll. 10–12; id. at p. 27, ll. 3–4)

- B. What reporting requirements are appropriate concerning new large loads and load growth?

EMM POSITION: No new reporting should be ordered. The approved LLPS framework already provides for reporting, stakeholder review, and a full cost allocation and rate design review in the first rate case with a qualifying LLPS customer in the test year. (Gunn Rebuttal at p. 2, ll. 17–19)

32. Revenue Apportionment and Implementation

- A. How should revenue responsibility, including any net revenues from LLPS customers and any reduction to revenues from any income-eligible customer discounts, be apportioned among the customer classes, if at all?
- i. What is the appropriate classification of customer-classified distribution system cost of service for any class cost of service study relied upon in this case?
- ii. What is the appropriate allocation of production-related cost of service for any class cost of service study relied upon in this case?

EMM POSITION: The revenue increase should be applied as an equal percentage to every customer class, as Mr. Jaynes proposes, with the LLPS revenue credit allocated among the other classes. In the direct case that was 15.19%, or \$140,353,035, with a pro forma LLPS credit of \$3,834,861. (Jaynes Direct at pp. 47–50) An equal increase is appropriate in this transitional case: no LLPS customer was active in the test year, LLPS costs, revenues, and usage are still developing, and the non-residential class structure is being restructured. (Jaynes Surrebuttal/True-Up Direct at pp. 5–6, 21, 25) The Company’s class cost of service study uses the same methods the Company has used in prior cases, relies on appropriate data, and is reliable to inform ratemaking in this case. Staff’s assertion that a reliable study

is not feasible should be rejected. (Jaynes Rebuttal at pp. 9–10; Jaynes Surrebuttal/True-Up Direct at pp. 6–12; Lutz Rebuttal at pp. 2–7)

(i) The Minimum System method should continue to be used to classify distribution plant in FERC Accounts 364 through 368 between customer-related and demand-related costs. OPC’s Basic Customer method ignores the customer-driven component of the distribution system. (Jaynes Rebuttal at pp. 20–21)

(ii) The Average and Excess method with a four coincident peak component, which the Company has used since 2018 and which is a method named in Missouri statute, should be used. OPC’s Probability of Dispatch method, which would shift the residential production allocation from 46.3% to 32.9%, should be rejected. (Jaynes Rebuttal at pp. 10–14)

B. How should customer affordability, including for low- and moderate-income households, be reflected in the rates ordered in this case?

EMM POSITION: Customer affordability is addressed through the apportionment described in A above and through the income-eligible programs addressed under that heading. Targeted programs deliver significantly more affordability benefit per dollar than across-the-board rate reductions and complement existing state and federal assistance. (Gunn Rebuttal at p. 3, ll. 11–13; id. at p. 26, ll. 8–23)

C. Should EMM’s surrebuttal proposal to implement the rate increase by bill cycle in this case be permitted?

EMM POSITION: Yes. EMM’s proposal to implement the rate increase by bill cycle should be permitted. (Lutz Surrebuttal at p. 8)

D. How should revenue responsibility for construction work in progress be assigned or allocated among the customer classes?

EMM POSITION: CWIP should not be directly assigned to LLPS customers. Direct assignment of generation costs to large load customers is inconsistent with cost causation, least-cost planning, and SPP’s market design. (Gunn Rebuttal at p. 3, ll. 8–10; id. at p. 23, ll. 3–17)

33. Critical Peak Rate

A. Should the Critical Peak Rate recommended by Staff be implemented?

i. If not implemented, are other accommodations needed to address high market cost events and establish offsetting revenues to be applied through the FAC?

EMM POSITION: No. The Critical Peak Rate would impose a mandatory weather-event surcharge without demonstrated, quantifiable load-reduction benefits, and Staff’s added treatment for AMI opt-out customers shows the design is not sufficiently developed. A mandatory time-based surcharge that falls on customers when they are most vulnerable

runs counter to Senate Bill 4, which requires that residential customers placed on mandatory time-of-use rates be allowed to opt out, and administering it would require daily review of day-ahead prices, customer notice with less than a day's lead time, and continuing customer education. Other mechanisms can offset high-cost events in the FAC without those burdens; any critical peak design should be developed through a separate, fuller process. (Jaynes Rebuttal at pp. 38–41; Jaynes Surrebuttal/True-Up Direct at pp. 23–24; Lutz Rebuttal at pp. 61–66; Lutz Surrebuttal at pp. 24–25)

- B. Should EMM have a separate line on its fuel adjustment rate tariff to account for critical peak pricing?

EMM POSITION: No. The Critical Peak Rate should not be adopted (A above), so no separate FAC line is needed; Staff's need to add design clarifications after its direct proposal shows the complexity of administering a critical peak charge to direct revenue to the FAC. (Lutz Surrebuttal at pp. 24–25; Lutz Rebuttal at pp. 64–66)

34. Storm Reserve

- A. Should a storm reserve be established in this case?

EMM POSITION: Yes. A storm reserve should be established for EMM, consistent with the reserves maintained for Evergy Kansas Central and Evergy Kansas Metro. Storm costs are a known cost whose timing and amount cannot be predicted, and a reserve avoids the cost and delay of an accounting authority order after each event. (Klote Direct at pp. 32–34; Klote Rebuttal at pp. 29–31)

- B. If approved, how much should be included in the cost of service?

EMM POSITION: The reserve should be funded at the annual storm reserve level in the Company's true-up, \$1,369,422, updated from \$1,092,086 in the direct filing, where the level was set at the three-year average of costs for individual storms exceeding \$250,000. (Klote Direct at p. 33; Klote Direct, Schedule RAK-4, p. 4, l. 79; Klote Surrebuttal/True-Up Direct, Schedule RAK-9, p. 4, l. 79)

35. Injuries and Damages

- A. Should an injuries and damages reserve be established in this case?

EMM POSITION: Yes. An injuries and damages reserve, funded through a consistent monthly expense, smooths the year-to-year volatility of claims cost and avoids setting rates on a single year's experience. (Klote Direct at p. 32) The reserve is not a tracker: it is credited with the annual accrual the Commission authorizes and charged with qualifying claim payments, it does not guarantee recovery of any deficiency, it operates symmetrically in low- and high-claim years, and the balance remains subject to review in the next rate case. (Klote Surrebuttal/True-Up Direct at pp. 13–15)

- B. If approved, how much should be included in the cost of service?

EMM POSITION: The reserve should be funded at the annual injuries and damages expense in the Company's true-up, which reflects a four-year average of claims paid

through the twelve months ended June 30, 2026, the averaging period Staff proposed, including corrections to 2024–2025 claims paid. (Klote Direct at p. 32; Klote Surrebuttal/True-Up Direct at p. 19)

36. Critical Infrastructure Protection and Cyber Security

- A. What level of critical infrastructure protection (“CIP”) and cyber security expense should be included in the revenue requirement?

EMM POSITION: The base level of CIP and cyber security O&M in the Company’s filing, \$4,492,878 on a total Evergy Metro basis, should be included, with the tracker addressed in B below. (Klote Direct at p. 36)

- B. Should EMM implement a tracker for CIP and cyber security costs?

EMM POSITION: Yes. CIP and cyber security costs are expected to increase substantially and are driven by threats that arise without warning. A tracker allows the Company to respond without waiting for a rate case and ensures customers pay only actual costs. The tracker also satisfies the criteria OPC’s witness proposes for tracker approval. (Klote Direct at pp. 34–36; Klote Rebuttal at pp. 32–33; C. King Rebuttal at p. 3, ll. 18–21; id. at p. 5, ll. 12–14) Evergy has received approval from Kansas regulators for a CIP/cyber security tracker, and a tracker for EMM would provide more consistent accounting across Evergy’s operating jurisdictions. (C. King Rebuttal at p. 7, ll. 5–9)

37. Revenue Sharing

- A. Should the Commission implement a mechanism to review or share earnings attributable to Schedule LLPS customers, and if so, how should it be designed?

EMM POSITION: The Company is not opposed to an earnings sharing mechanism as a regulatory tool; Evergy Kansas Central operates under one approved by the Kansas Corporation Commission. If the Commission adopts one in Missouri, it should evaluate the Company’s overall financial performance and overall cost of service, similar to the Kansas framework, rather than revenues from Schedule LLPS customers alone, because earned return depends on the combined effect of revenues, expenses, depreciation, taxes, financing, and investment. Dr. Berry’s proposal, with its 25-basis-point deadband and 75/25 split, and its reliance on the Ameren settlement should not be adopted. (Gunn Rebuttal at pp. 10–12) If the Commission adopts an earnings sharing mechanism, it should adopt the Company’s earnings review: an annual review, beginning with calendar year 2027, of EMM’s actual Missouri-jurisdictional earned return on equity against the return authorized in this case, based on the existing Surveillance Monitoring Report with only limited agreed adjustments and a defined schedule for Staff and OPC review; 50/50 sharing of earnings above the authorized return, with the customer share recorded as a regulatory liability; a secondary review under which sharing occurs only if actual Schedule LLPS base-rate revenues exceed those reflected in the revenue requirement, so that sharing responds to LLPS growth rather than weather or other company-wide factors; return of any portion attributable to PISA deferrals over twenty years; and termination when new rates from the next general rate case take effect. (Klote Surrebuttal/True-Up Direct at pp. 8–12;

Gunn Surrebuttal at pp. 2–7) Dr. Berry’s objection to the secondary review (Berry True-Up Rebuttal at pp. 6–7) should be rejected; without it, sharing would reach earnings unrelated to the LLPS growth that is the stated reason for a mechanism. (Klote Surrebuttal/True-Up Direct at p. 11)

38. Energy Burden Analysis

- A. Should the Commission order a 3rd party energy burden analysis for EMM that does not exceed \$150K in costs?

EMM POSITION: No. It is premature to order a third-party energy burden analysis while the Commission’s affordability working docket and workshop are examining affordability holistically, including rate design, bill assistance, arrearage management, and program coordination; EMM anticipates bringing forward enhanced low-income offerings informed by that process and the Commission’s report. (McDonald Rebuttal at p. 11; McDonald Surrebuttal at pp. 2–3)

39. Green Button Connect

- A. Should the Commission order EMM to implement Green Button Connect (“GBC”) in this rate case?

EMM POSITION: No. EMM already provides Green Button Download My Data to all customers, so customers can share their data in the Green Button standard format with any third party they choose. EMM’s 2024 evaluation of Green Button Connect My Data found the projected costs not justified by expected adoption, since only about 3% of unique Missouri residential customers have used the download capability, and the cost of serving a few customers would be borne by all. Staff also does not support adopting it at this time. (McDonald Rebuttal at pp. 2–7; McDonald Surrebuttal at p. 8)

- B. If the Commission orders EMM to implement GBC, should the Commission order the tariff proposed by Renew Missouri related to GBC?

EMM POSITION: No. Green Button Connect should not be ordered. If it is, the Commission should not prescribe its technical design, architecture, or implementation approach through a tariff; those decisions belong in the Company’s technology and operational management processes, subject to the Commission’s existing oversight. Staff agrees the proposed tariff is not appropriate at this time. (McDonald Rebuttal at p. 9; McDonald Surrebuttal at p. 8)

- C. If the Commission orders EMM to implement GBC, should the Commission adopt Renew Missouri’s revenue requirement recommendation?

EMM POSITION: No. Green Button Connect should not be ordered, so no revenue requirement for it should be added. The Company’s evaluation found the costs not justified by expected adoption and implementing it for only one jurisdiction would be more complex and more expensive. (McDonald Rebuttal at p. 6)

- D. If the Commission orders EMM to implement GBC, should Renew Missouri's recommended revenue requirement for studying a regional data hub be ordered by the Commission?

EMM POSITION: No. A regional data hub is not practical or cost-effective at this time: utilities in the region are at different stages of customer data access and use different technologies, vendors, and timelines, so a single platform would require extensive coordination on governance, cost allocation, cybersecurity, and privacy and could strand existing investment. In the Texas and New York examples Renew Missouri cites, third parties, not the utilities, sponsor and oversee the data hub. EMM's customers should not fund the study, and its cost should not be borne by the customers of a single Evergy affiliate. (McDonald Rebuttal at pp. 7–9)

40. Customer Battery Programs

- A. Should the Commission order the adoption of Renew Missouri's proposed battery programs?

EMM POSITION: No. Renew Missouri's three proposed pilots should not be ordered, and the Commission should not direct EMM to file a particular battery program or prescribe detailed design terms, as Staff alternatively proposes. EMM's Residential Battery Energy Storage pilot produced measurable peak reduction, and EMM is developing a scaled permanent battery program: it will use the pilot's final evaluation, evaluate scalable pathways beyond the pilot, solicit stakeholder feedback (including on the concepts Renew Missouri raises), and bring forward a program design through the appropriate regulatory process. Three stand-alone pilots would duplicate administration, split limited participation, and fix design choices before the supporting technical and cost-effectiveness work is complete. (Lutz Rebuttal at pp. 67–72; Lutz Surrebuttal at pp. 27–29)

41. Income-Eligible Solar Program

- A. Should the Commission order the adoption of Renew Missouri's proposed evaluation and expansion of the Income-Eligible solar program?

EMM POSITION: No. The Company should continue operating its existing Income-Eligible Solar Subscription Pilot under its approved terms and complete the evaluations already contemplated for it. (Lutz Surrebuttal at p. 27, ll. 12–13). The pilot is the appropriate vehicle for developing evidence on enrollment, participation, customer experience, bill impacts, administration, outreach, coordination with other assistance programs, and overall cost-effectiveness. (Lutz Surrebuttal at p. 27, ll. 1–3). A decision to modify the offering, expand it, or make it permanent should be informed by the pilot's actual results and lessons learned rather than predetermined in this case. (Lutz Surrebuttal at p. 27, ll. 3–5). Neither of the two conditions that would trigger the contemplated evaluation has occurred, because the Company has not requested expansion and the pilot has not operated for five years. (Lutz Surrebuttal at pp. 26–27). Customer adoption has also been weaker than expected, with participation steady through 2025 at a fraction of the solar

resource available to the program. (Lutz Surrebuttal at p. 26, ll. 3–5). Mr. Fracica himself identifies the importance and uncertain availability of federal, state, utility, and other funding mechanisms that could increase the economic benefit to income-eligible participants, and those funding options could be a critical driver of the next viable steps for this service. (Lutz Surrebuttal at p. 27, ll. 5–11).

42. MEEIA Margin Rates

A. What methodology should be used to calculate the net marginal rate for each rate class?

EMM POSITION: The net margin rates should be calculated using the method in Schedule GAJ-12, applied to the rates approved in this case. (Jaynes Direct at pp. 53–54; Jaynes Direct, Schedule GAJ-12)

WHEREFORE, the Company respectfully submits its Statement of Positions to the Commission.

Respectfully submitted,

/s/ Roger W. Steiner

Roger W. Steiner, MBN 39586
Cole Bailey, MBN 77268
Evergy, Inc.
1200 Main Street, 17th Floor
Kansas City, Missouri 64105
Phone: (816) 556-2314
roger.steiner@evergy.com
cole.bailey@evergy.com

Karl Zobrist, MBN 28325
Jacqueline M. Whipple, MBN 65270
Chandler Hiatt, MBN 75604
Michael Robinson, MBN 73482
Dentons US LLP
4520 Main Street, Suite 1100
Kansas City, Missouri 64111
Phone: (816) 460-2400
karl.zobrist@dentons.com
jacqueline.whipple@dentons.com
chandler.hiatt@dentons.com
michael.robinson@dentons.com

James M. Fischer, MBN 27543
Fischer & Dority, P.C.
2081 Honeysuckle Lane
Jefferson City, Missouri 65109
Phone: (573) 353-8647
jfisherpc@aol.com

Attorneys for Evergy Missouri Metro

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the above and foregoing document was served upon counsel for all parties on this 25th day of September 2026 by either e-mail or U.S. Mail, postage prepaid.

/s/ Roger W. Steiner

Roger W. Steiner