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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2026-0143

REBUTTAL TESTIMONY

OF

DARRIN R. IVES

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri

August 2026

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REBUTTAL TESTIMONY

OF

DARRIN R. IVES

Case No. ER-2026-0143

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Darrin R. Ives. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Evergy Metro, Inc. and serve as Senior Vice President – Regulatory and Government Affairs for Evergy Metro, Inc. d/b/a Evergy Missouri Metro ("Evergy Missouri Metro," "EMM," or the "Company"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("EMW"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("EKM"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a Evergy Kansas Central ("EKC"). These are the operating utilities of Evergy, Inc. ("Evergy").

Q: Are you the same Darrin R. Ives who previously filed direct testimony in this case?

A: Yes.

Q: Who are you testifying for?

A: I am testifying on behalf of Evergy Missouri Metro.

Q: What is the purpose of your testimony?

A: I respond to the direct testimony of Staff of the Commission ("Staff") and the Missouri Energy Consumer Group ("MECG") on six issues: (1) proposed changes to the fuel adjustment clause ("FAC") for large load customers; (2) Staff and the Office of the Public

Counsel ("OPC") additional recommended modifications to the Company's Large Load Power Service ("LLPS") Rate Plan and Schedule LLPS; (3) Staff's proposed removal of retired plant from rate base; (4) Staff's proposed allocation of Greenwood solar station costs to Evergy Missouri Metro; (5) the treatment of Nuclear Production Tax Credits ("Nuclear PTCs") and the related tracking mechanism; and (6) the useful life of the Wolf Creek Generating Station. My testimony addresses the regulatory and policy dimensions of these issues; the accounting, depreciation, and operational details are addressed by other Company witnesses throughout their rebuttal testimony.

Q. Please summarize the principal conclusions of your rebuttal testimony.

A: First, on the fuel adjustment clause for large load customers, the Company serves its customers through an integrated system participating in the Southwest Power Pool ("SPP") Integrated Marketplace, where generation is economically dispatched regionally to serve aggregated load and no cost is traceable to an individual customer. Adding to the complexity of the SPP Marketplace, issues of transmission congestion, transmission congestion rights, and ancillary products are all relevant when establishing a cost to serve. To attempt to apply the wholesale revenues and costs attributable to an individual customer is not feasible. Proposals to remove Schedule LLPS customers from the FAC or to establish a separate customer-specific fuel mechanism are unworkable, premature, and inconsistent with the LLPS package the Commission approved less than a year ago. The appropriate response is to modernize the FAC by eliminating the outdated 95%/5% sharing mechanism and reconciling all fuel costs and revenues within the FAC rider, so that customers see the actual price of energy.

Second, Staff and OPC recommend numerous other changes to the structure of the tariffs under the LLPS Rate Plan which were recently approved by the Commission in Case No. EO-2025-0154. As the Company has noted this case, it is a transitional case for implementation of the LLPS Rate Plan as the test year does not reflect an LLPS customer at this stage and only one LLPS customer is currently ramping load in EMM's service territory. Recommendations from Staff and OPC to modify the LLPS Rate Plan tariffs and restructure the Commission approved LLPS Rate Plan are at best premature and in many instances appear to relitigate positions that were denied by the Commission in No. EO-2025-0154.

Third, Staff recommends treating plant replacement activity as grounds for a rate base adjustment, without contending the replacement facilities were imprudent or are not serving customers. This is inconsistent with Plant In Service Accounting ("PISA")[1] which was enacted to encourage, and existing depreciation practice already addresses retirement experience without a separate rate base penalty.

Fourth, the Greenwood solar station serves only EMW customers, and allocating its costs to Evergy Missouri Metro departs from cost causation principles.

Fifth, the Company agrees customers should receive the benefits of Nuclear PTCs and supports a tracker to deliver those benefits. To date, no Nuclear PTCs have been monetized, and material uncertainty remains regarding both the calculation methodology and future values, so the tracker base should be set at zero.

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[1] See Mo. Rev. Stat. Section 393.1400. All statutory citations are to the Missouri Revised Statutes (2016), as amended.

Lastly, the Wolf Creek retirement date authorized by the plant's current NRC operating license, 2045, remains the most supportable life estimate for depreciation purposes today. Depreciation rates can be adjusted prospectively as the license renewal process advances, which preserves intergenerational equity between current and future customers rather than shifting costs based on an uncertain outcome.

II. FUEL ADJUSTMENT CLAUSE CHANGES RESULTING FROM SERVICE TO LARGE LOADS

Q: What do you address in this portion of your testimony?

A: Staff and OPC each propose to change how customers taking service under Schedule LLPS participate in the Company's fuel adjustment clause. I address the policy questions those proposals raise rather than their mechanics. My conclusion is that these parties have correctly observed that the arrival of large load has placed new pressure on the FAC, but that they have aimed their remedies at the wrong element — the customer class rather than the mechanism. Company witness Nunn responds to Staff's Options 1 and 2, the base factor, and Ms. Schaben's recommendations. Company witness Meitner addresses SPP market operations, load forecasting, and settlement. Company witness Gunn addresses the FAC and the sharing mechanism as matters of regulatory policy.

Q: Staff's Option 2 to remove large loads from the FAC and Ms. Schaben's recommendation both assume the Company can identify the fuel and purchased power costs associated with a single LLPS customer. Is that assumption sound?

A: I do not believe it is, and the reason is structural rather than administrative. The Company forecasts and settles load with SPP at the aggregated settlement location level, and SPP commits and dispatches generation resources regionally on economics. Witness Meitner describes that process, and his conclusion is that the impact of an individual customer on generation dispatch, market purchases and sales, and other SPP market activity cannot be isolated through a customer-specific calculation.

Q: Was this question examined in the Company's approval of new and modified LLPS tariffs in No. EO-2025-0154?

A: It was. The Commission observed that FAC cost separation could occur if LLPS customers were registered as a separate pricing node, but that SPP had voted down such a process.[2] The Commission then approved a structure that did not rely on customer-level separation.[3]

Q: Has anything changed since then that would support revisiting it?

A: If anything, developments have moved further from that option. As witnesses Gunn and Lutz discuss, SPP stakeholders rejected the proposal that included separate commercial pricing nodes, SPP's market design remains premised on aggregated utility load rather than customer-level registration, and recent FERC action on CHILLS points away from rather than toward nodal treatment of individual large loads. So the parties are asking the Commission to reopen a question it has already resolved, on a record that has developed against their position rather than in favor of it.

Q: If the underlying data is not customer-specific, what would Staff's Option 2 produce?

A: Staff's Option 2 would produce a cost allocation that would assign system-level SPP charges to LLPS customers based on their share of monthly Missouri jurisdictional kWh. Witness Meitner explains why that is not a valid measure of the costs associated with those customers — SPP settlement charges arise from the Company's integrated market

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[2] See Report & Order at 40, In re Evergy App. Regarding Large Load Tariffs, No. EO-2025-0154 (Nov. 13, 2025) ("Evergy Large Load Order").
[3] Id. at 41-42.

participation and do not move in proportion to any one customer's share of jurisdictional energy.

Q: Does Ms. Schaben's alternative address that concern?

A: I do not believe so. A separate FAC or customer-specific base factor is more granular, but granularity in the mechanism does not create it in the underlying data. It would still be built from system-wide production cost modeling and settlement information and then allocated down.

Q: Setting aside whether separation is achievable, how do these proposals relate to the LLPS cost recovery framework the Commission approved in No. EO-2025-0154?

A: The Commission approved an LLPS package, not just an LLPS rate.

Q: Please describe what that LLPS package included.

A: It assigns costs to LLPS customers through a combination of provisions working together: minimum bill and minimum demand requirements, a minimum service term, financial security, creation of a distinct customer class, and participation in the Company's riders, including the FAC. The Commission found that the agreement established reasonable protections and safeguards for existing customers and ensured that new large load customers would pay their share of system costs. That finding was made about the package as a whole.[4]

Q: What is the significance of the FAC having been part of it?

A: That FAC participation was not an omission to be corrected here. It was a component of how the Commission concluded LLPS customers would pay their share.

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[4] See Evergy Large Load Order at 46.

Q: Did that framework contemplate assigning net fuel costs to individual customers?

A: It did not. Costs were assigned through the general cost allocation and rate design framework applicable to the class.

Q: What is the significance of attempting to isolate net fuel costs for large customers in this proceeding?

A: The proposals here would change one element of a balanced package while leaving the other elements as approved. If the FAC element is re-examined, the re-examination should account for how it functions within the whole rather than testing it in isolation.

Q: Does that mean the Commission cannot revisit the question?

A: No. The Commission has broad authority to ensure just and reasonable rates and may consider these proposals. My observation is narrower and concerns how the question is framed.

Q: Does the timing of this case bear on that?

A: I believe it does. The Stipulation and Agreement contemplated that the Company would evaluate the costs and impacts of LLPS customers, and present a cost allocation and rate design proposal, in the first general rate case with a qualifying LLPS customer in the test year. This is not that case. The framework identified when this examination should occur, and we have not yet reached that point.

Q: Do you agree with the parties that circumstances have changed with the arrival of new large loads?

A: Yes. Large loads are arriving, they arrive in step changes rather than incrementally, and the amounts moving through the FAC are larger than when the original FAC framework was designed. While the large load tariff case resolved how costs are allocated to LLPS customers, what has not kept pace is the FAC itself. Staff and OPC have identified real pressure on the FAC and proposed to relieve it by removing a customer class. Instead, the mechanism itself is what needs attention.

Q: Is there a more appropriate approach to sending net energy cost price signals to large loads and other customers?

A: Yes. Rather than attempting to separate LLPS load from the FAC, the Commission should consider moving away from the base factor and true-up construct and toward an approach in which all eligible fuel and purchased power costs and revenues flow through the rider.

Q: Why does the current construct limit price signals?

A: Currently net energy costs are embedded in base rates through the base factor and only the variance from the base flows through the rider. What any customer sees is therefore not the price of energy. It is a residual, measured against an amount the customer cannot observe. Each rate case then resets the base factor, moving energy cost back into base rates and resetting the rider toward zero.

Q: How would placing all costs in the rider change that?

A: The rider would reflect the actual cost of energy. Customers, large load customers and all others, would see a price that tracks the market, rather than one inferred from a variance against an embedded assumption.

Q: Would this address a regulatory lag concern Staff has raised?

A: Yes. One concern is that when the base factor rests on forecast load and a step-change customer arrives between rate cases, the embedded assumption becomes stale, and the rider absorbs the difference. That is an outcome of the FAC mechanism reconciling against an embedded level. Including all costs in the rider allows for timely allocation of full net energy costs to all customers based on actual cost and load conditions.

Q: Does this recommendation conflict with the Company's support for Staff's Option 1?

A: No. I support Evergy witness Nunn's recommendation that LLPS customers remain in the FAC. However, my recommendation concerns the construct itself, not the treatment of LLPS customers within the construct that exists today. Witness Nunn is responding to testimony about the current construct, and within that construct, Option 1 is the appropriate outcome.

Q: Are there other elements of the FAC that have not kept pace with changed conditions?

A: Yes, and I would encourage the Commission to take one further step. If the FAC is to reflect current conditions, the 95/5% sharing mechanism warrants the same examination for the same reason.

Q: Why does the same reasoning apply?

A: Because the sharing mechanism was designed for conditions that no longer describe how the Company operates. Company witness Gunn explains that it was adopted as an efficiency incentive at a time when a vertically integrated utility served its own load with its own units, and that SPP's centrally dispatched market now substantially performs that function. The FAC construct and associated sharing mechanism were built for the same era, and both have been overtaken by the same large load developments.

Q: How does the arrival of large load relate to the FAC sharing mechanism?

A: Applied to variances driven by new large load rather than by procurement or dispatch decisions, the five percent FAC sharing functions less as an efficiency incentive than as a shareholder contribution toward the cost of serving new customers.

Q: How can concerns about changes between rate cases be appropriately addressed?

A: The Company recognizes that an earnings sharing mechanism is a regulatory tool the Commission may consider addressing uncertainty regarding earnings between rate cases, particularly during periods of significant customer growth. If the Commission elects to adopt such a mechanism, the Company believes it should be based on EMM's overall earnings and financial performance, rather than focusing on revenues from a particular customer class. Consistent with the approach used in Kansas, an earnings sharing mechanism should evaluate the Company's total revenues, expenses, capital investments, and other factors affecting earnings to provide a balanced and comprehensive assessment of whether actual earnings exceed the level contemplated in this proceeding.

Q: What should the Commission take from this section of your testimony?

A: Three things. First, the separation of LLPS from the FAC that Staff and OPC propose is not achievable in the market the Company operates in, and it was considered and set aside when the Commission approved the LLPS framework less than a year ago. Second, the LLPS framework assigned costs to new large loads as a package, and the FAC was part of it — changing that one element in a case with no LLPS customer in the test year would unsettle a balance the Commission struck, and it would do so before the operating experience the framework itself contemplated is available. Third, the concerns the parties raise about the FAC are better answered by modernizing the mechanism than by carving a class out of it. Specifically, I recommend that all eligible costs and revenues be placed into the FAC rider so that it reflects the full net cost of energy, and that those costs be reconciled in full rather than sharing outcomes the Company does not control.

III. SCHEDULE LLPS PROPOSALS

Q: Have parties made recommendations concerning Schedule LLPS or other topics related to large load?

A: Yes. Testimony from Staff and OPC explore and make recommended changes for large load related topics.

Q: Was there a Schedule LLPS customer in the test year of this case?

A: No. As detailed in the Company's direct testimony, this case did not have a large load customer in the test year, but a large load customer was billed under the Schedule LLPS minimum monthly bill provisions within the true-up period for the case. The Company took steps in its filing to recognize the known and measurable aspects of this customer and to honor the LLPS Rate Plan design approved by the Commission in November 2025 in No. EO-2025-0154.

Q: Since the LLPS Rate Plan was approved by the Commission approximately four months prior to the filing of this rate case, does it seem premature for parties to propose changes?

A: Yes. It is particularly frustrating that Staff and OPC, who were parties to the No. EO-2025-0154 case, are revisiting fundamental rate design issues already addressed by the Commission. Geoff Marke on behalf of OPC goes so far as to replicate major sections of his No. EO-2025-0154 testimony in his direct testimony in this proceeding.

Q: Are there other proposed changes that revisit recently approved topics?

A: Yes. There are a number of proposals and recommendations.

- Staff asserts the Interim Capacity provisions of the Schedule LLPS tariff are being ignored by the Company and failing to obtain customer-specific capacity contract and collect those costs directly from the specific large load customer.

- Staff proposes additional LLPS reporting requirements consistent with the Amended Non-Unanimous Global Stipulation and Agreement with Ameren approved by the Commission in Case No. ET-2025-0184 but denied similar reporting requirements sought by Staff in the Evergy EO-2025-0154 case.
- Staff proposes to "clarify" the Term of the Schedule LLPS tariff to include provisions for construction power.
- OPC revisits proposals made in Case No. EO-2025-0154 to require pre-construction reporting including, Power Usage Effectiveness ("PUE"), Water Usage Effectiveness ("WUE"), and Total Harmonic Distortion ("THD").
- OPC seeks to change the Applicability of the Schedule LLPS tariff, decreasing the threshold to 25 MW applicable to data centers.
- OPC seeks to expand the Schedule LLPS Term to 20 years.
- OPC seeks to change the Contract Capacity used for the monthly minimum bill to 90% with a 10% offset if a Schedule LLPS customer can demonstrate a significant financial contribution to the local service area.
- Unless noted otherwise, rebuttal testimony offered by Company witness Brad Lutz addresses each of these proposed changes and explains why each should be rejected, including those already litigated in the No. EO-2025-0154 case.

Q: Are there other proposed changes that are inappropriate for this case?

A: Yes. While not distinctly addressed in Case No. EO-2025-0154, parties seek to bring forward new tariff provisions and terms to address perceived issues with the LLPS Rate Plan.

- Staff proposes new tariff language to address potential issues of demand exceedance in light of the availability of non-firm service. Company witness Brad Lutz provides testimony explaining issues with this language.

Q: Should the Commission consider these proposals and recommendations?

A: The Commission is certainly within its authority to consider these proposals and recommendations under its broad authority to ensure just and reasonable rates for customers. I would suggest that many of the issues raised in this proceeding regarding the LLPS Rate Plan can be considered relitigation of issues advanced in the LLPS proceeding that were not adopted by the Commission at that time. As we have noted throughout this rate case, this is a transitional proceeding from an LLPS perspective as we do not have a representative test year for LLPS load. I believe at this early juncture it is premature for the Commission to consider the type of structural changes to the LLPS Rate Plan advanced by Staff and OPC. It is also notable that the proposals and recommendations advanced by Staff and OPC in this case are done without the input or involvement of any signatory parties to the Case No. EO-2025-0154 Stipulation and Agreement.

IV. RETIRED PLANT

Q: What Staff recommendation are you responding to in this section of your rebuttal testimony?

A: I am responding to Staff witness Matthew Young's recommendation to remove approximately $43.9 million of Missouri-jurisdictional plant from rate base based upon his conclusion that increased infrastructure investment following enactment of PISA which resulted in greater levels of early retirement activity among certain mass-property assets.

I do not address the technical shortcomings and oversimplification of Mr. Young's proposal in detail as a number of EMM witnesses will address those details. Instead, I address the broader regulatory and policy implications of Staff's recommendation and why adoption of that recommendation would be inconsistent with the objectives underlying Missouri's infrastructure investment policies.

Q: What was the purpose of Missouri's Plant In Service Accounting, or PISA, legislation?

A: At a high level, PISA was intended to reduce regulatory lag associated with infrastructure investment and to encourage electric utilities to make timely investments in modernizing, improving, and maintaining their systems. The legislation reflected a recognition that utilities should not be placed in a position where necessary infrastructure improvements are delayed because of the timing of rate case recovery. The objective was to support continued investment in reliability, resiliency, modernization, and replacement of aging infrastructure.

Q: Did the Legislature enact PISA to encourage utilities to defer replacement of aging assets?

A: No. The opposite is true. PISA reflected a policy determination that continued investment in utility infrastructure serves the public interest and that regulatory lag should not discourage prudent investment in the electric system.

Q: Does modernization of an electric system frequently involve retirement of existing facilities?

A: Yes. In many cases modernization cannot occur without replacement of existing assets. Utilities do not build entirely new systems on undeveloped rights-of-way. Rather, utilities typically modernize existing systems by replacing older infrastructure with newer infrastructure that provides improved reliability, resiliency, safety, operational flexibility, or other customer benefits. Consequently, replacement activity is not evidence that modernization has failed. It is often evidence that modernization is occurring.

Q: Is replacement before average accounting life necessarily evidence of imprudent behavior?

A: No. An average accounting life of assets is not an operating instruction. Utilities make replacement decisions based on operational considerations such as reliability performance, equipment condition, safety, capacity needs, resiliency requirements, technology changes, and customer needs. As Company witnesses Ryan Mulvany and Robert Hollinsworth explain, assets may be replaced before reaching average accounting life for many legitimate operational reasons. In fact, if you review the two witnesses' testimony you will see assets included in Staff witness Young's adjustment that were retired for specific operational reasons. Company witnesses, Spanos and Klote also discuss the realities of establishing an accounting service or depreciable life. They describe how, for example, an average depreciable life of 80 years necessarily indicates that there are a number of assets in that classification that retire before 80 years, for a myriad of reasons, and likewise a number of assets in that classification that necessarily retire after 80 years, thus establishing the "average" depreciable life. A retirement before the average depreciable life is expected for a subset of the class assets rather than an indicator of premature retirement as asserted by Mr. Young.

Q: What is the fundamental policy problem with Staff's proposal?

A: Staff's proposal creates conflicting regulatory signals. On one hand, Missouri policy encourages utilities to invest in modernization, reliability, resiliency, and replacement of aging infrastructure. On the other hand, witness Young would use the resulting replacement activity as the basis for a rate base adjustment. Those two concepts are difficult to reconcile.

Q: Why do you believe those concepts are in conflict?

A: Because replacement activity is often the expected and intended result of modernization programs. If a utility replaces aging poles, conductors, transformers, substation equipment, or other facilities as part of a modernization effort, some assets inevitably will retire before reaching their theoretical average accounting life (which may in fact be overstated based on past depreciation decisions). If those retirements later become the basis for a rate base penalty, utilities are effectively being told that they should modernize their systems but may be financially penalized if modernization results in replacement of existing infrastructure. That is a conflicting policy message.

Q: What effect could adoption of Mr. Young's recommendation have on future infrastructure planning?

A: It could discourage proactive asset management. Utilities routinely face decisions regarding whether assets should be replaced now or deferred until later. If retirement prior to average life becomes the basis for removing investment from rate base, utilities may face incentives to postpone replacement activity even when replacement would otherwise be prudent.

Q: Why would that be concerning?

A: Because waiting for assets to deteriorate further before replacement may not be the lowest-cost or lowest-risk outcome for customers. Proactive replacement often avoids increased maintenance costs, service interruptions, emergency repairs, operational inefficiencies, safety concerns, and reliability issues. A regulatory framework should encourage utilities to make prudent replacement decisions at the appropriate time, not encourage delays simply to avoid future accounting consequences.

Q: Does Mr. Young contend that the replacement facilities are not used and useful?

A: No. Mr. Young does not claim that the replacement facilities fail to provide service to customers, were imprudent, or unnecessary. Instead, his proposal is based upon the retirement characteristics of the assets that were replaced.

Q: Why is that distinction important?

A: Because the Commission is not being asked to deny recovery of investment based on a finding that the replacement facilities were unnecessary. Rather, the proposed adjustment would reduce recovery despite the fact that the investments were made, are in service, and provide benefits to customers. That is an important distinction from a regulatory policy perspective.

Q: How does the testimony of Witnesses Spanos and Klote affect your policy conclusions?

A: Their testimony demonstrates that established depreciation mechanisms already exist to evaluate and address retirement experience. Witness Spanos explains that retirement patterns, service lives, survivor characteristics, depreciation rates, and reserve relationships are all addressed through depreciation studies. Witness Klote explains that Staff's own depreciation witness applies those same principles and that witness Young's proposed rate base adjustment is inconsistent with that framework. Because accepted regulatory tools already exist to address retirement experience, there is no policy reason to create a separate rate base penalty tied to replacement activity.

Q: What should the Commission ultimately conclude regarding witness Young's recommendation?

A: The Commission should conclude after removing the errors embedded in the analysis that Staff's proposal is inconsistent with the policy objectives that support continued investment in Missouri's electric infrastructure. As demonstrated by witnesses Mulvany and Hollinsworth, a significant number of the investments at issue were driven by legitimate operational needs, including reliability, resiliency, asset condition, capacity requirements, aging infrastructure, and customer expectations. The key issue is whether the Commission should adopt a new regulatory policy that treats infrastructure replacement and modernization as the basis for a rate base penalty. In my opinion, doing so would discourage the very type of prudent infrastructure investment that Missouri policy has sought to encourage. For that reason, Staff's proposed rate base adjustment should be rejected.

V. GREENWOOD SOLAR

Q: What do you address in this section?

A: I address the Greenwood solar station, a facility EMW built at its own site, on its own system, to serve its own customers, and whether any portion of its costs should be borne by Evergy Missouri Metro's customers.

Q: What has Staff recommended regarding the Greenwood solar station?

A: Staff witness Matthew Young (Direct pp.4-6) recommends allocating the Greenwood solar station capital costs and all related expenses between EMW, EMM and EKM. Staff proposes to allocate costs between EMW and EMM based on the number of customers. Staff describes the basis of its proposal as satisfying conditions contained in the Commission's order granting the certificate for the solar station (EA-2015-0256).

Q: Do you agree with Staff's allocation proposal?

A: No. Staff's proposal clearly violates a fundamental ratemaking principle of cost causation. The Greenwood solar station provides power and other benefits exclusively to EMW's customers and does not benefit EMM. The solar plant is connected to a single circuit at the distribution level of EMW's electrical system and can only serve the load of customers on that circuit. Not a single electron produced by the Greenwood solar station will ever reach the EMM system. All energy produced by the system is for the benefit and use of EMW's customers.

In addition, the energy produced by the Greenwood station reduces EMW's load purchase requirement from the Southwest Power Pool ("SPP"). This reduces SPP load expense for the benefit of all EMW customers. As a result, the FAC charged or credited to EMW customers is lower because of the Greenwood solar station.

As a corporation with multiple operating utilities, many projects, both generation and distribution, are often done at one utility subsidiary and may result in benefits of an intangible nature to the other. One of the benefits identified during the acquisition of KCP&L Greater Missouri Operations (EMW's predecessor) by Great Plains Energy was the expertise that KCP&L Greater Missouri Operations had in maintenance of its natural gas plants. That expertise was shared with KCP&L (EMM's predecessor). Likewise, KCP&L had substantial expertise in maintenance of its coal fleet and that was then shared with KCP&L Greater Missouri Operations, without compensation through allocation of costs. KCP&L was one of the first utilities in the nation to implement an automated meter reading system many years ago. Both EMM and EMW implemented next generation automated metering. EMM began the implementation first and EMW received the benefit of EMM's expertise, without any transfer of costs to EMW for that knowledge.

The Greenwood solar project was constructed at a site, the Greenwood Energy Center, already owned by EMW and located within EMW's service territory. The 300-acre Greenwood site includes four combustion turbines that were constructed and in service prior to the construction of the solar facility. This site was selected for the solar project in part to minimize the cost of the solar installation based on the availability of land and existing electrical infrastructure. Furthermore, due to additional land availability at the site, it could allow for future expansion of solar as the company gains experience operating a solar facility and as the anticipated cost declines for the technology materialize.

As stated before, it is important to understand that the solar plant is connected to a single circuit at the distribution level of EMW's electrical system and serves the load of customers on that circuit. This energy reduces EMW's load purchase requirement from the SPP and reduces SPP load expense for the benefit of all EMW customers. As a result, the FAC charged or credited to EMW customers is lower because of the solar system.

Q: If the Commission requires EMW to transfer some dollar amount of the Greenwood solar station to EMM, how much might be appropriate and how could it be done?

A: First, I would reiterate that the Company is opposed to any allocation of the costs of the Greenwood Solar facility away from EMW to EMM. This is particularly true because the energy produced from the solar station goes 100% to the benefit of EMW customers. However, if the Commission requires some allocation of costs to EMM because this pilot project was built and operated to gain experience with a utility scale solar project, it is important to recognize that using a plant investment allocation which is typically used for these type of project costs is not practical. This is because of all the other impacts of the investment including specific tax benefits, Renewable Energy Credits, the energy from the facility, and operating costs which would remain with EMW, etc. If the Commission ordered the Company to make an allocation, my recommendation, similar to the Company's prior rate case, would be that it allocate no more than $100,000 to EMM in expenses to be reflected in future EMM's cost of service and subtract a like amount from EMW's cost of service. I would further recommend that the $100,000 be assigned to Missouri only, as this is more an issue with Missouri than it is with Kansas.

VI. <u>NUCLEAR PRODUCTION TAX CREDITS</u>

Q: What do you address in this section?

A: Nuclear PTCs are a potential source of significant benefits for customers, but their value has not yet been established. I address how those benefits should be reflected in rates while that uncertainty remains, and I respond to Staff witness Matthew Young's recommendations on that subject.

Q: Have you reviewed Staff witness Young's recommendations regarding Nuclear PTCs and the proposed IRA tracker?

A: Yes. I have reviewed Mr. Young's testimony concerning the inclusion of an ongoing amount of Nuclear PTC benefits in base rates, the amortization expense of Nuclear PTCs that were expected to be monetized by the true-up date, and the establishment of an IRA tracking mechanism.

Q: What is the Company's position in this rate filing about incorporating Nuclear PTCs into rates?

A: The Company's position is that there is currently no reliable basis on which to include an amount of Nuclear PTCs into rates other than zero at this time. While the Company originally proposed to include an amortization of Nuclear PTCs that were expected to be monetized by the true-up date, as Company Witness Hardesty's rebuttal testimony explains, no Nuclear PTCs were able to be monetized. While I agree with Staff it is appropriate to establish a tracking mechanism to ensure customers receive the benefits of the Nuclear PTCs, I disagree with Staff's recommendation to set a base amount for the tracker of $37 million. Instead the Company supports a tracker base amount of zero dollars which will be reflected in their true-up filing since no Nuclear PTCs were monetized at the true-up date and significant uncertainty remains as to whether credits will be able to be monetized.

Q: What ratemaking principles should guide the Commission's treatment of Nuclear PTC benefits in this proceeding?

A: Traditional ratemaking practice (as is applied in Missouri) seeks to establish rates using information that is known, measurable, and reasonably certain. When significant uncertainty exists regarding the amount that ultimately will be realized, regulators generally seek to minimize the risk that either customers or utilities will later be required to make large true-up adjustments. This supports the notion that setting rates based on realized outcomes rather than speculative forecasts supports rate stability, predictability, and fairness for all parties.

Q: Does the uncertainty surrounding Nuclear PTCs extend beyond the pending IRS guidance?

A: Yes. The uncertainty is two-fold. First, there is uncertainty regarding how the Nuclear PTC should be calculated. As discussed in Company witness Hardesty's direct testimony, the estimated annual value of the credit can vary dramatically depending on the methodology ultimately adopted. Under the Company's preferred interpretation utilizing SPP market pricing, the estimated annual Nuclear PTC benefit is approximately $60 million to $70 million on a 100% Metro basis, while an alternative interpretation based on customer revenues could result in little or no Nuclear PTC benefit being generated. Until this issue is definitively resolved, the range of potential outcomes remains substantial.

Second, even if the methodology issue is ultimately resolved in the Company's favor, uncertainty would still remain regarding the amount of Nuclear PTCs that may actually be generated in future years. Under the SPP market pricing approach, the value of the credit is dependent upon market prices, which can fluctuate significantly over time based on numerous factors outside the Company's control.

Q: Does Staff acknowledge uncertainty surrounding Nuclear PTCs?

A: Yes. Witness Young expressly acknowledges that final IRS guidance has not yet been issued regarding Nuclear PTC measurement, that previously claimed credits potentially could be revised, and that future monetization is uncertain. He also recommends a tracker specifically to address those uncertainties.

Q: Does the implementation of a tracker reduce the need to include aggressive projections in base rates?

A: Yes. In fact, the implementation of the tracker is one of the strongest reasons not to rely on aggressive forecasts. A tracker provides an established mechanism to return actual realized benefits to customers. Because the tracker can capture and flow through actual results in the Company's next rate case, there is less reason to expose customers or the Company to forecast risk by embedding highly uncertain estimates in base rates.

Q: Beyond rate volatility, are there other consequences if the Commission establishes Nuclear PTC credits in rates at a level higher than what is actually or expected to be realized?

A: Yes. Embedding an overstated Nuclear PTC credit in base rates directly reduces the revenue the Company is authorized to collect from customers. A Nuclear PTC credit is an offset to the Company's revenue requirement, so when the credit assumed in rates exceeds the credit actually generated, the Company recovers less cash than it requires to serve customers.

Q: Why is that cash shortfall a particular concern at this time?

A: The Company is in the midst of a substantial construction cycle driven by significant load growth. Meeting that growth requires substantial and sustained capital investment. When operating cash inflows are reduced by an overstated Nuclear PTC credit, the resulting shortfall does not eliminate the Company's underlying costs — it simply changes how those costs must be funded. Therefore, the Company would be required to rely more heavily on external financing to cover the gap, increasing the amount it must borrow at precisely the time its capital needs are high.

Q: What is the effect of that increased borrowing?

A: Increased borrowing increases the Company's financing costs. Additional debt carries additional interest expense, and a persistent drag on cash flow can also pressure the financial metrics that influence the terms on which the Company borrows. Those higher financing costs are ultimately recovered from customers in future rates. As a result, setting the Nuclear PTC too high does not actually save customers money; instead, it produces an offsetting, and entirely avoidable, increase in financing costs.

Q: Why should the Commission adopt the Company's proposed approach?

A: Simply put, there is currently no reliable basis for estimating the amount of Nuclear PTCs that may ultimately be monetized, and therefore no reasonable amount can be included in rates in this proceeding. Implementing a tracker with a base value of zero dollars allows customers to receive the actual value of Nuclear PTC benefits while avoiding unnecessary rate volatility associated with uncertain forecasts. Given the acknowledged, and material, uncertainty surrounding future Nuclear PTC values, this approach represents a reasonable balance between customer protection and accurate ratemaking. The Company's proposed approach also delivers customers the full value of the credit without creating an artificial cash shortfall that could increase borrowing costs during a critical construction period. Further, as explained by Company witness Hardesty, the proposed treatment is consistent with Commission’s treatment of Nuclear PTC benefits in Ameren Missouri’s rate case ER-2024-0319.

VII. WOLF CREEK GENERATING STATION USEFUL LIFE

Q: What do you address in this section?

A: I respond to MECG witness Brian Andrews' recommendation to change the assumed retirement date for Wolf Creek from 2045 to 2065.

Q: What is the basis for MECG's recommendation?

A: MECG points to Evergy's December 11, 2025, filing with the Nuclear Regulatory Commission ("NRC"), which was a notice of intent to pursue a Subsequent License Renewal Application.

Q: Has a Subsequent License Renewal Application been filed for Wolf Creek?

A: No.

Q: Has the NRC approved Wolf Creek's operation through 2065?

A: No, as noted, any such application has not even yet been filed.

Q: Does establishing a reasonable depreciation expense require certainty?

A: No. Depreciation necessarily relies upon estimates and judgment. However, estimates should be based upon information that is sufficiently known and reasonably supportable.

Q: Why does that matter here?

A: Wolf Creek currently possesses an NRC operating license through 2045. The Company has not yet filed a Subsequent License Renewal Application. Therefore, the currently authorized operating life remains the most objective and supportable life estimate available today.

Q: When does Evergy plan to file its Subsequent License Renewal Application?

A: The notice of intent indicated Evergy plans to file a Subsequent License Renewal Application in the first quarter of 2030.

Q: Does a notice of intent to pursue a license renewal guarantee Wolf Creek's license extension will be approved?

A: No.

Q: Can business and economic conditions change between now and the first quarter of 2030?

A: Absolutely. The notice of intent is a required filing step with the NRC in order for Evergy to make a future Subsequent License Renewal Application. However, many things could change between now and the first quarter of 2030 that could influence Evergy's and/or the NRC's decision. There is no need to speculate about those potential changes in business or economic conditions at this time, the NRC process is lengthy and Evergy is taking the appropriate steps at the moment to retain an open path to an extension of Wolf Creek's operating license with the NRC.

Q: Are long-term planning assumptions and depreciation lives necessarily the same thing?

A: No. Long-term planning analyses evaluate multiple potential futures and alternative scenarios. Depreciation studies require the Company to establish supportable estimates for regulatory accounting purposes based upon current facts and circumstances.

Q: Why is that distinction important here?

A: The Company may evaluate future operating scenarios beyond 2045 while still concluding that the currently authorized NRC operating license remains the most supportable life estimate for depreciation purposes today.

Q: When would it become reasonable to re-evaluate an extension to Wolf Creek's useful life?

A: The Company expects to reevaluate that issue as additional objective milestones are achieved. Examples include submission of a Subsequent License Renewal Application, completion of major stages of NRC review, significant investments supporting long-term operation, or other developments that materially increase certainty regarding operation beyond 2045.

Q: What customer risks arise from adopting MECG's recommendation prematurely?

A: MECG's recommendation lowers depreciation and decommissioning expense. While that may appear beneficial in the short term, it creates the risk that customers pay too little over the period leading up to retirement. If an extension ultimately does not occur or occurs later than anticipated, future customers could face substantially increased depreciation and decommissioning charges in later periods creating considerable concerns from a ratemaking perspective with intergenerational inequity.

Q: Does the opposite risk exist under the Company's proposal?

A: No comparable risk exists because the Company's proposal is based on the currently authorized NRC operating life and therefore reflects the best available estimate today. If future milestones support operation beyond 2045, the Commission can adjust depreciation rates prospectively. This approach is equitable because it avoids under-recovery of costs during the currently authorized operating life and preserves intergenerational equity between current and future customers. MECG's recommendation assumes a 20-year extension before the necessary regulatory approvals have been obtained and therefore risks shifting costs from current customers to future customers based on an uncertain outcome.

VIII. CONCLUSION

Q: What are your recommendations to the Commission?

A: I recommend that the Commission: (1) In regard to the FAC, first, the separation of LLPS from the FAC that Staff and OPC propose is not achievable in the market the Company operates in, and it was considered and set aside when the Commission approved the LLPS framework less than a year ago. Second, the LLPS framework assigned costs to new large loads as a package, and the FAC was part of it — changing that one element in a case with no LLPS customer in the test year would unsettle a balance the Commission struck, and it would do so before the operating experience the framework itself contemplated is available. Third, the concerns the parties raise about the FAC are better answered by modernizing the mechanism than by carving a class out of it; (2) reject Staff and OPC's premature or relitigated recommendations for other modifications to the Company's LLPS Rate Plan; (3) reject Staff's proposed rate base adjustment for retired plant; (4) reject Staff's proposed allocation of Greenwood solar station costs to EMM; (5) approve a Nuclear PTC tracker with a base amount of zero; and (6) retain the 2045 retirement date for Wolf Creek for depreciation purposes consistent with the current operating license.

Q: Does this conclude your testimony?

A: Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF DARRIN R. IVES

STATE OF MISSOURI)
) **ss**
COUNTY OF JACKSON)

Darrin R. Ives, being first duly sworn on his oath, states:

1. My name is Darrin R. Ives. I work in Kansas City, Missouri and I am employed by Evergy Metro, Inc. as Sr. Vice President – Regulatory and Government Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Evergy Missouri Metro consisting of forty-two (42) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Darrin R. Ives

Subscribed and sworn before me this 11th day of August 2026.

Notary Public

My commission expires: April 26, 2029

ANTHONY R WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2029
PLATTE COUNTY
COMMISSION #17279952