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Witness/Type of Exhibit: Schaben/Surrebuttal
Sponsoring Party: Public Counsel
Case No.: ER-2026-0143

SURREBUTTAL TESTIMONY

OF

ANGELA SCHABEN

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A
EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

*** ____________ ***
Denotes Highly Confidential Information that has been redacted.

** ____________ **
Denotes Confidential Information that has been redacted.

September 10, 2026

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EVERGY MISSOURI METRO, INC. D/B/A EVERGY MISSOURI METRO

CASE NO. ER-2026-0143

<u>INTRODUCTION</u>

Q. Please state your name, title, and business address.

A. Angela Schaben, Utility Regulatory Auditor, Office of the Public Counsel ("OPC" or "Public Counsel"), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Angela Schaben who filed rebuttal testimony for the OPC in this case?

A. Yes.

Q. What is the purpose of this testimony?

A. I am responding to the testimonies of Evergy Metro, Inc. ("Evergy Metro or "Company" or "EMM") and Staff witnesses on EMM's request to continue its Fuel Adjustment Clause ("FAC") with modifications, and its request for authority to have a CIP/Cyber Security tracker.

Q. Would you please summarize the FAC positions you are rebutting and your recommendations to the Commission in response to them?

A. Yes. EMM witness Linda Nunn testifies to EMM's position that the structure of EMM's FAC should not be changed in anticipation of the new hyperscale load being added to EMM's system. EMM witness Linda Nunn testifies to EMM's position that EMM's FAC should be modified to allow long-term capacity contracts and SPP administrative fees to flow through it. EMM witness Kevin Gunn testifies to EMM's position that its FAC should be modified so that there is no risk sharing mechanism in its FAC.

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I continue to recommend that if the Commission authorizes EMM to continue its FAC then the Commission should exclude LLPS customers from EMM's FAC to prevent new hyperscale load LLPS customers from being subsidized by EMM's other customers. Alternatively, I recommend LLPS customers be treated separately from other customer classes in EMM's FAC with a separate LLPS class base factor to prevent cross-subsidization as customers populate EMM's LLPS rate class add load to EMM's system. I also recommend that the Commission continue the current 95/5 sharing mechanism and adopt the additional EMM FAC reporting requirements that Staff sponsors. Further, I oppose EMM's proposal to modify its FAC to flow changes in its Regional Transmission Organization ("RTO") administrative fees through it.

Regarding continuing EMM's FAC, I question whether the Commission can authorize EMM to continue its FAC. EMM projects near-term post-rate case hyperscaler load revenues, natural gas prices have been very stable for several years, EMM manages its fuel and purchased power volatility through its hedging program, EMM has and is using PISA authority, and EMM is requesting CWIP for Mullin Creek #2. Given the foregoing EMM does not need a FAC "to provide [it] with a sufficient opportunity to earn a fair return on equity."[1] If the Commission does not authorize EMM to continue its FAC, modified or not, then all of the FAC issues become moot.

In response to EMM's request for Commission authority for it to use a CIP/Cyber Security tracker, I recommend that the Commission reject that request.

Q. Would you please summarize EMM's CIP/Cyber Security tracker position you are rebutting and your recommendation to the Commission in response to that position?

A. EMM is requesting a CIP/Cyber Security tracker for unpredictable cyber events that potentially may occur. My recommendation to the Commission is that EMM's request for authority to

[1] § 386.266.5(1), RSMo.

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use a CIP/Cyber Security tracker should be denied. EMM has shown no evidence of actual volatility in its cybersecurity spending nor does Evergy acknowledge serious cybersecurity events in recent years. Furthermore, Company witnesses have not identified unbudgetable or extraordinary costs that traditional ratemaking cannot accommodate. Evergy has not met its burden of proof that its cybersecurity costs are volatile, extraordinary, or unsuitable for treatment under traditional rate making and the tracker would improperly shift ordinary O&M risk to ratepayers.

FAC and LLPS Related

Q. Evergy witness Ms. Nunn suggests that under Staff's FAC Option 1, which includes all customers[2], the "FAC will perform as it is intended"[3]. Do you agree?

A. No. Ms. Nunn's claim assumes that the FAC will perform today precisely as it was intended when Section 386.266(1)[4], RSMo., became effective nearly twenty years ago on January 1, 2006[5]. At that time, neither the Commission nor the Legislature could have anticipated the existence of Large Load Power Service (LLPS) customers, or the magnitude, volatility, and operational characteristics associated with such large scale, rapidly ramping, market-dependent load.

The FAC statute and the Commission's original FAC rule were developed before the emergence of multi-hundred-megawatt hyperscale LLPS customers, before the Southwest Power Pool ("SPP") Integrated Marketplace began operation in 2014, and long before the current regional capacity constraints and resource adequacy requirements described by Evergy witnesses. In other words, the FAC statute and the Commission's original FAC rule were developed in a substantially different electric utility environment than the one that exists today.

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[2] Staff's FAC Option 1 encompasses all Evergy Metro customers, including data centers but utilizes a FAC base factor to include Customer A and Customer B based on various factors as specified by Sarah Lange.
[3] Rebuttal testimony of Linda Nunn, page 4.
[4] The language of Section 386.266(1) has remained largely unchanged since becoming effective.
[5] Lena FAC whitepaper; attached as Schedule ADS-S-1.

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To suggest that the FAC will "perform as intended" under Staff's Option 1 is therefore implausible, or at minimum speculative, because it makes presumptions based on circumstances that no longer exist.

Moreover, even Evergy acknowledges that LLPS load introduces new dynamics not present when the FAC was designed. As discussed further below, Evergy witness Gunn states within his testimony that the load associated with LLPS customers is "different in kind of impact to net fuel costs,[6]" confirming that today's operating context differs significantly from the conditions under which the FAC framework was originally established.

Q. Does Evergy witness Gunn further acknowledge that Schedule LLPS customers introduce circumstances that differ fundamentally from those present when the FAC was originally implemented?

A. Yes. In discussing the appropriateness of the existing FAC sharing mechanism, Mr. Gunn directly confirms this point when stating that "the load now arriving under Schedule LLPS is different in kind of impact to net fuel costs,"[7] in comparison to the period when the Commission first adopted the 95/5 percent sharing mechanism.

Mr. Gunn further explains that LLPS customers have unique energization timelines, uncertain ramp schedules, and associated interim capacity obligations driven by SPP reserve margin requirements[8]. These are characteristics that did not exist when Section 386.266 was enacted or when the Commission crafted its FAC rules. Mr. Gunn's acknowledgments underscore that the FAC is now being tasked to operate under conditions materially different from those originally contemplated, reinforcing that the FAC cannot simply be assumed to "perform as intended" under Staff's Option 1.

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[6] Kevin Gunn rebuttal page 16.
[7] Kevin Gunn rebuttal page 16.
[8] *Id.*

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Q. Why do LLPS customers raise cost allocation and risk allocation concerns within EMM's current FAC?

A. The operational characteristics of LLPS customers differ considerably from the traditional retail load the FAC was designed to reconcile. Since LLPS customers can significantly alter net fuel costs as their load develops, the FAC's reconciliation framework may shift significant risk to non-LLPS customers if LLPS load grows faster, slower, or in any way differently than forecasted[9]. In other words, the measures required to serve LLPS customers could contribute to fuel cost volatility, timing uncertainty, and capacity obligation risks that differ considerably from the load conditions under which the FAC was originally intended to operate. Without appropriate safeguards, non-LLPS customers may be exposed to cost shifts and increased risk that the FAC was not designed to absorb. Appropriate safeguards could include separate treatment, modified recovery rules, or a revised sharing mechanism.

Q. Is it accurate to surmise that these concerns arise from the sheer size of customer demand served under the LLPS tariff, in comparison to the size of the other classes?

A. I believe so. According to the record in this case, EMM is "currently working with large load customers with more than 1.5 gigawatts ("GW") of incremental demand that are interested in locating in its service territory."[10] This statement references demand not currently being served but will potentially be served in the future. In contrast, Evergy's Integrated Resource Plan documents show a near-term forecasted summer residential demand in the range of 0.815-0.818 GW between 2024-2026 and a long-term forecasted summer residential peak demand of approximately 0.833 GW with a modeled maximum of 0.914 GW[11]. Evergy's 2025 IRP annual update further states that residential customers account for approximately 45% of

[9] Lena Mantle Surrebuttal, File, No. EO-2025-0154; also included as Schedule ADS-S-2.
[10] Kevin Gunn Direct page 18.
[11] File No. EO-2024-0153, Evergy Missouri Metro Letter of Transmittal and Integrated Resource Plan, Appendix 3B_Evergy_Metro.pdf, page 2 of 21 and Appendix 3C_Evergy_Metro.pdf, page 2 of 9.

summer peak demand and 38% of winter peak demand across the EMM system[12]. In short, Evergy is working on serving the demand of large load customers that greatly exceed the forecasted residential customer demand in Evergy's 2024 and 2025 IRP filings. Furthermore, Evergy's 2026 annual IRP update forecasts an even lower residential load trajectory compared to the 2025 annual IRP update forecast.[13] Which indicates that hyperscale large load customers are driving the increased demand.

Q. How would this increase in large load demand impact EMM's FAC as it currently exists?

A. In order to serve such an increase in customer demand, Evergy would require interim capacity agreements. EMM is proposing to recover the interim capacity costs through its FAC, categorized as long-term capacity contractual agreements. Since EMM does not have its own excess capacity to serve LLPS customers and must enter into long term capacity agreements in order to serve increased demand, the revenues generated from excess fuel and purchased power to offset fuel and purchased power expenses in the FAC could be diminished and the cost of these interim capacity agreements would then be socialized across all classes within the FAC.

Q. What is your response to Ms. Nunn's testimony that the "Company has an obligation to maintain sufficient capacity to reliably serve all customers that rely on the Company for capacity service"[14]?

A. I am not disputing the fact that the Company has an obligation to maintain sufficient capacity. I disagree that the cost of long-term capacity contracts should be recovered through the FAC.

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[12] File No. EO-2025-0250, EMM 2025 IRP Annual Update, Appendix 8 Evergy 2023 DSM Market Potential Study.pdf, page 200 of 251.
[13] File No. EO-2026-0188, EMM 2026 IRP Annual Update, 2026 Metro Annual Update Public 5-7-2026.pdf, page 28 of 146.
[14] Rebuttal testimony Linda Nunn, page 23.

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The FAC is essentially a tracker, and trackers are not an appropriate tool to recover long term fixed contract costs or demand charges.

Q. Do you agree with Ms. Nunn's opinion that "including long-term capacity costs in the FAC better aligns cost recovery with the period of incurrence while preserving the Commission's existing review and prudence process"[15]?

A. No, I wholeheartedly disagree. The costs associated with long-term capacity contracts are demand charges to reserve capacity and are more like plant investment costs[16]. EMM's FAC was not designed as a pass-through for the recovery of plant investment type costs between rate cases. These types of known and measurable costs are already included in the revenue requirement. As stated by Staff witness Ms. Mastrogiannis, "the FAC is only designed to recover variable fuel and purchased power costs that are difficult to forecast between rate cases".[17]

Q. What is your response to Ms. Nunn's rebuttal testimony where she provides a generalized statement regarding other electric utilities that have the ability to recover purchased capacity costs through an adjustment mechanism through approval from their respective Commissions[18]?

A. Though Ms. Nunn provides examples of electric utilities that are allowed to recover purchased capacity costs through commission-approved capacity recovery mechanisms, she provides no context behind her examples. For instance, she provides no distinction between whether these commission-approved capacity recovery mechanisms distinguish between short-term capacity and long-term capacity. Furthermore, Ms. Nunn doesn't specify whether the rate adjustment mechanisms that allow for the recovery of capacity costs are stand alone, specifically for

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[15] Rebuttal testimony Linda Nunn, pages 23-24.
[16] File No. ER-2007-0004 *Report and Order*, pages 42-44.
[17] Rebuttal testimony Brooke Mastrogiannis, page 8.
[18] Rebuttal testimony Linda Nunn, page 24.

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capacity cost recovery, or if these mechanisms also allow the recovery of prudently incurred fuel and purchased power costs. Several of the states that Ms. Nunn mentions allow for capacity cost recovery through rate adjustment mechanisms specifically designed for capacity cost recovery, not through a FAC.[19]

Q. Is Ms. Nunn's apparent assumption that a separate rider would have to be created if long-term capacity costs continued to be excluded from the FAC accurate[20]?

A. No. Long-term capacity costs have historically been included in revenue requirement because they were known and measurable, not variable, and essentially demand charges synonymous with infrastructure investment. And, as Staff has noted within this case, if EMM finds it's not achieving its authorized Rate of Return, the Company has the option to file another rate case to increase its authorized revenue requirement.[21]

Q. Does Missouri currently authorize the ability to recover long term capacity costs through any specific tariff or rate adjustment mechanism?

A. Yes. EMM's LLPS tariff resulting from EO-2025-0154 includes an Interim Capacity provision. This provision allows EMM to enter into specific market contract agreements to

[19] The baseline position, codified in AES Indiana's Standard Contract Rider No. 6, is clear: capacity or demand charges are explicitly excluded from the FAC's calculation of estimated fuel expenses. The Purchased Capacity Cost Adjustment (PCCA) is used by Public Service Company of Colorado (PSCo) to recover purchased capacity payments made to power suppliers under specific power purchase agreements (PPAs) not included in base electric rates. The Capacity Cost Recovery Clause (CCRC), in Florida, is designed to permit full recovery of capacity costs and provide a return on certain assets. Like the PCCA, it balances short-term recovery methods with long-term financial commitments. These riders are separate from the FAC. Both the PCCA in Colorado and the CCRC in Florida are distinct, separate mechanisms from their respective Fuel Adjustment Clauses (FAC). Evidence strongly supports that capacity costs in both states are intended to be recovered through these specific capacity riders rather than through a FAC. Colorado's Electric Commodity Adjustment (ECA) is designed to recover prudently incurred electric fuel and purchased energy costs, while the PCCA is specifically dedicated to purchased capacity payments. Florida's Fuel Cost Recovery Clause (FCRC) recovers prudently incurred fuel and purchased power energy costs, while the CCRC recovers the capacity or demand component of purchased power agreements. The CCRC is separate from the FCRC across multiple Florida utilities, including FPL and Gulf Power.

[20] Rebuttal testimony Linda Nunn, page 24.

[21] Rebuttal testimony of Karen Lyons, page 11.

provide necessary capacity if a large load customer's demand cannot be met by existing system capabilities.[22]

Q. Based on the information provided in this case, do you agree that the long-term capacity contracts EMM seeks to recover through a FAC are related to LLPS customers?

A. Yes. Based on EMM's response to Staff DR 322.1 it appears that EMM seeks to recover ***______________________________ *** through the FAC. Ms. Mastrogiannis highlights a myriad of issues concerning this contractual agreement in her rebuttal testimony.

Q. Is there another Missouri investor-owned utility ("IOU") which recently filed a general rate case consistent with Staff's recommendation from its large load tariff case?

A. Yes. As discussed in the testimony of Ms. Mastrogiannis, Ameren Missouri recently filed a general rate case and proposed that capacity transactions related to LLPS customers should be excluded from the FAC in order to eliminate the double recovery of capacity costs.[25] Ameren recognizes, in its direct testimony, that the cost of interim capacity required for LLPS customers should be paid by the large load customer as a part of their electric service bill, instead of recovering these costs from all customer classes through its FAC. This is consistent with Staff's recommendation in ER-2026-0291. Ameren's acknowledgement, and attempts to follow Staff's recommendation, sends a clear signal that it's more conscious of the public perception that led to several Ratepayer Protection Pledges signed across the country.

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[22] Rebuttal testimony Brooke Mastrogiannis, page 3.
[23] ***______________________________***
[24] ***______________________________***
[25] Rebuttal testimony of Brook Mastrogiannis, page 5-6.

Q. What is your response to Ms. Nunn's disagreement with your position to either remove the LLPS customers from the FAC or establish an LLPS only FAC[26]?

A. Part of Ms. Nunn's argument for keeping LLPS customers in EMM's FAC is based on her assertion that the "Company's proposed LLPS tariffs are specifically designed to ensure LLPS customers pay their cost of service."[27] She goes on to say that several Company witnesses describe several different terms to which LLPS customers must adhere. My response to Ms. Nunn is that tariffs designed to achieve a specific outcome only work if the Company actually follows the tariff. In other words, if the Company does not enforce minimum contract terms, minimum billing provisions, or any of the several other tariff provisions that ensure the costs of serving LLPS customers are correctly allocated to LLPS customers, then even the most perfectly designed tariffs are not going to achieve their intended goal. Staff raises several examples in this case where Evergy does not adhere to the LLPS tariff, with the interim capacity issue serving as one.[28] Keeping the LLPS customers and LLPS interim capacity in EMM's FAC under Evergy's proposal, while also underbilling them for their true cost of service, would absolutely create a scenario where customers across all classes are subsidizing LLPS customers.

Q. What is your response to Ms. Nunn's claim that establishing "a separate FAC or customer-specific reconciliation mechanism for LLPS customers would add unnecessary administrative complexity without improving the operation of the FAC or better aligning cost recovery with the Company's actual cost incurrence"?

A. I disagree. A LLPS only FAC does not have to be overly burdensome and could be achieved through a LLPS only reconciliation administered within the current FAC process. Staff witness Ms. Sarah Lange calculated a LLPS only base factor of $0.030965 based on Staff's

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[26] Rebuttal testimony Linda Nunn, pages 25-27.
[27] Rebuttal testimony Linda Nunn, pages 26.
[28] Rebuttal testimony of Sarah L.K. Lange, pages 32-36.

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DA LMP for energy value and the corrected SPP transmission expense values.[29] Staff's LLPS only FAC base factor calculation appears reasonable.

Q. Do you support Staff's base factor recommendations?

A. Yes. I support Staff's proposed method for determining a base factor for Staff's Option 2, should the Commission order to remove LLPS customers from EMM's FAC, and I support Staff's LLPS only base factor of $0.030965. Furthermore, should the Commission decide to utilize Option 1, I support Staff's methodology for determining a base factor that insulates non-LLPS customers from adverse FAC impacts.[30]

Q. Why do you Support Staff's base factor recommendations?

A. Within her rebuttal testimony, Ms. Nunn suggests that production cost modeling which includes both Customer A and Customer B is a reasonable approach in developing a base factor.[31] It appears that EMM utilized this approach in developing a base factor of $0.01741, while Staff is proposing a true-up estimate base factor of $0.02172. As Ms. Mastrogiannis explains in her direct testimony, setting the correct base factor is "critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism."[32] Furthermore, setting a base factor too low causes subsidization between customer classes[33] and enables utility manipulation of rate design.[34] Staff is clear and forthcoming in its methodology for establishing the FAC Option 1 base factor. Staff also raises several points of concern questioning the accuracy of Evergy's LLPS customer billing practices, which lends concern to the production modelling inputs utilized to develop its base factor of $0.01741.

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[29] Rebuttal testimony of Sarah L.K. Lange, pages 27-28.
[30] In response to the Rebuttal testimony of Linda Nunn, pages 13-15.
[31] Rebuttal testimony of Linda Nunn, page 14.
[32] Direct testimony of Brooke Mastrogiannis, page 2.
[33] Surrebuttal Testimony of Lena Mantle in EO-2025-0154. Schedule ADS-S-2.
[34] Surrebuttal Testimony of Lena Mantle in ER-2024-0189. Schedule ADS-S-3.

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Q. What is your recommendation for LLPS customers and an EMM FAC?

A. I recommend the Commission continue with the precedent of not allowing the recovery of long-term capacity contracts through FACs. Long term capacity contracts are essentially demand charges that equate to infrastructure investment, and do not meet the criteria of variable fuel and purchased power costs. Furthermore, interim long term capacity required for LLPS customers should be allocated directly to LLPS customers, as directed in the LLPS tariff, as Ameren seeks to do based on Staff's recommendation. I also recommend the Commission order either to remove the LLPS class from EMM's FAC or establish a separate LLPS class base factor. I support Staff 's base factor calculations for both EMM's existing FAC and the LLPS only base factor. There are considerable questions in this case pertaining to whether Evergy is calculating LLPS bills correctly based on the approved tariff language. This also calls into question whether the data Evergy is utilizing for production modelling represents actuality and is producing a base factor that is too low.

A FAC is a Privilege, not an Entitlement

Q. What is your response to Mr. Gunn's recommendation that the Commission eliminate the FAC sharing mechanism based on his assertion that the 5 percent retention "becomes punitive" and is no longer an effective incentive in light of large load customers?

A. Mr. Gunn's characterization is inconsistent with the Commission's own precedent and the record developed in prior cases. As Ms. Mantle explained in her Surrebuttal Testimony in Evergy Missouri West's 2024 rate case (No. ER-2024-0189),[35] the 95/5 sharing mechanism has never operated as an effective incentive because Evergy retains virtually no meaningful share of fuel-cost variances. Under the existing mechanism, Evergy recovers approximately 98 percent of increased fuel and purchased power costs, even when those costs escalate significantly. Ms. Mantle demonstrated that this structure creates a persistent moral hazard,

[35] *Id.*

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where the Company bears almost none of the consequences of its procurement, resource-planning, and market-exposure decisions. By contrast, Mr. Gunn asserts the mechanism has suddenly become "punitive" due to LLPS load growth.[36] In reality, as Ms. Mantle showed, the incentive mechanism was already ineffective long before LLPS customers were contemplated. Eliminating the mechanism now would exacerbate longstanding concerns rather than resolve them.

Q. Do you agree with Mr. Gunn that variances in costs and revenues that flow through EMM's FAC are no longer within the Company's control because the SPP market dispatches resources centrally and LLPS customers create demand uncertainty[37] and justifies removing the sharing mechanism?

A. No. Mr. Gunn incorrectly associates the interim contract capacity requirements of LLPS customers with variable fuel costs. In actuality, demand charges associated with LLPS customer interim contract capacity requirements should be addressed under the large load tariff, not within a FAC tariff.

Q. Mr. Gunn also states that most states permit full pass-through of eligible fuel and purchased power costs, and that Missouri should adopt full reconciliation without sharing.[38] Would doing so be consistent with Missouri law?

A. In my opinion, "No." Missouri law expressly diverges from the majority approach Mr. Gunn describes. Section 386.266 of the Missouri Revised Statutes specifically authorizes **incentive mechanisms** designed to promote "efficient and cost-effective fuel and purchased-power procurement activities." As Ms. Mantle noted, Missouri adopted its FAC framework *later* than many states and did so with the Legislature's deliberate intent to incorporate incentives to manage procurement prudently. Mr. Gunn's recommendation ignores that statutory language

[36] Rebuttal testimony of Kevin Gunn, page 18.
[37] Rebuttal testimony of Kevin Gunn, page 16.
[38] Rebuttal testimony of Kevin Gunn, page 17.

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and would effectively remove the only incentive the Legislature provided. Full pass-through may exist elsewhere, but Missouri law expressly encourages incentives to mitigate customer risk, which is more than just cost recovery.

Q. Do you agree with Mr. Gunn that the policy purpose of the FAC is simply "to true-up actual energy costs against the level reflected in base rates,[39]" because fuel and purchased-power costs are volatile and beyond the utility's control, and § 386.266 allows recovery of those costs outside a general rate case?

A. No. Mr. Gunn's description does not reflect how the Commission has previously interpreted and applied § 386.266. The Commission's decision addressing the implementation of a fuel adjustment clause in its *Report and Order* in Case No. ER-2007-0002 makes clear that the policy purpose of a FAC is not simply to true-up volatile fuel costs. In Case No. ER-2007-0002, the Commission emphasized that volatility alone is not enough to justify a FAC. Instead, the Commission identified, and relied upon, another important factor:

> In an era where fuel costs are highly volatile, a fuel adjustment clause may be necessary if the Company is to earn its authorized rate of return.[40]

The Commission ultimately denied Ameren's FAC request because:

1. Ameren's fuel costs were rising but not volatile in the regulatory sense needed to justify a FAC.
2. Ameren retained a reasonable opportunity to earn its authorized return on equity without a FAC, due in part to offsetting profits from off-system sales.
3. Regulatory lag continued to provide proper incentives, and a FAC would impair those incentives by passing through fuel costs automatically.

[39] Rebuttal testimony of Kevin Gunn, page 14.
[40] File No. ER-2007-0002 *Report and Order*, page 19.

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The Commission denied Ameren's FAC request in ER-2007-0002 because it found that Ameren did have a reasonable opportunity to earn its authorized return without such a mechanism, since Ameren's fuel costs, while rising, were not volatile and that other revenue streams, specifically off-system sales margins, were sufficient to mitigate fuel-cost charges. This directly contradicts Mr. Gunn's claim that the FAC exists primarily to make fuel cost recovery independent of the timing of general rate cases. In Case No. ER-2007-0002, the Commission repeatedly warned that a FAC is a "powerful regulatory tool" and must be used "with careful consideration". As emphasized in several of the Case No. ER-2007-0002 Report and Order paragraphs provided below:

> While the new statute, Section 386.266, allows the Commission to approve a fuel adjustment clause, in effect, overturning a 1979 Missouri Supreme Court decision finding fuel adjustment clauses to be contrary to Missouri law, the statute does not require the Commission to approve a fuel adjustment clause. Instead, it specifically gives the Commission authority to reject a proposed fuel adjustment clause after giving an opportunity for a full hearing in a general rate case. The statute does not, however, provide specific guidance on when a fuel adjustment clause should be approved. A fuel adjustment clause is a powerful regulatory tool to be used with careful consideration. If a fuel adjustment clause is allowed in an inappropriate situation, the customers who pay for utility service can be forced to pay rates that are higher than they should be. In other circumstances, a fuel adjustment clause may be necessary to allow a utility an opportunity to earn a reasonable return on its investment.
>
> A fuel adjustment clause should be used cautiously because it runs contrary to some of the basic principles of traditional utility regulation. One such principle is the matching of expenses and revenues. Over time, certain expenses incurred by the utility may go up. For example, the wages the electric utility pays its linemen may increase, or a major industrial customer may close, causing a loss of income. At the same time, perhaps the utility saves money when the interest rate it must pay to borrow money goes down, or

it adds revenue by serving new customers. The increased costs or decreased income in one area may be balanced by decreased costs or increased revenue in another area.

In a traditional rate case, without a fuel adjustment clause, the Commission examines all the revenue and costs of the utility during a particular period known as a test year. The Commission then matches the revenue and costs, arriving at an amount the utility needs to recover from its ratepayers if it is to earn a reasonable return on its investment. If a fuel adjustment clause, or other tracking mechanism, is established, then the utility would be able to pass on increased costs in one area, in this case fuel and purchased power, without an examination of all the other areas in which its costs may have decreased or its revenues increased. As a result, ratepayers could be required to pay increased rates while the company enjoys increased profits.

Inclusion of a fuel adjustment clause also affects the operation of regulatory lag. Regulatory lag results because a rate case test year, at least in Missouri, is based on a historical test year, usually ending about the time the utility files for a rate increase. Since a rate case takes eleven months to complete, a utility will always be about eleven months behind. Of course, utilities do not particularly like regulatory lag when their costs are increasing, but regulatory lag can also favor the utility when their costs are decreasing. The good effect of regulatory lag is that it provides the utility with a strong incentive to maximize its income and minimize its costs. **If, however, a fuel adjustment clause is in place, the utility has less financial incentive to minimize its fuel costs because those costs will be automatically recovered from ratepayers.** (emphasis added) Efforts can be made to design a fuel adjustment clause in a manner that maintains some incentive; for example, the Missouri statute authorizing a fuel adjustment clause requires the utility to file a new rate case every four years and requires the Commission to review the prudence of the company's purchasing decisions every 18 months. But regulatory reviews are only a partial substitute for the direct incentives that can result from a utility's quest for profit. Based on the previous

> paragraphs, it might seem that a fuel adjustment clause should never be inflicted upon ratepayers. But there might be circumstances when the use of a fuel adjustment clause may be necessary to preserve the financial health of the utility, and no one, including ratepayers, benefits when a utility becomes financially unhealthy. In an era where fuel costs are highly volatile, a fuel adjustment clause may be necessary if the company is to earn its authorized rate of return. The problem then is how to determine when a fuel adjustment clause is necessary.[41]

Essentially, based on the language from both the Case No. ER-2007-0002 Report and Order and Section 386.266, a FAC is a privilege, not a right.

Q. How does the Commission's Case No. ER-2007-0002 decision clarify the actual policy purpose of a FAC?

A. The Commission implies that while a FAC allows more timely recovery of prudently incurred fuel costs, its true purpose is to ensure the utility can maintain financial health only when volatile fuel costs threaten a utility's ability to earn its authorized return. In other words, the FAC is not designed only to track volatility. It is designed to protect earnings adequacy when volatility prevents the utility from earning its authorized return.

Q. What relevance does the Commission's decision in Case No. ER-2007-0002 have to the circumstances presented in this case?

A. The circumstances in this case are directly comparable, and in certain respects more favorable, than those the Commission addressed in Case No. ER-2007-0002. In its order in that case, the Commission emphasized that rising but predictable fuel costs do not justify a FAC. The Commission stated that known increases are "the worst reason to implement a fuel adjustment clause" because such costs can be evaluated in a general rate case along with all other changing

[41] File No. ER-2007-0002 *Report and Order*, pages 17-19.

revenues and expenses. Additionally, the Commission concluded that Ameren had a reasonable opportunity to earn its authorized return based on off-system sales revenues that the Commission set at $230 million based on Staff's production cost model.[42] Those revenues were sufficient to maintain earnings without a FAC. The Commission concluded Ameren had a "reasonable opportunity to earn a fair return on equity without a fuel adjustment clause."

Q. Does EMM have similar opportunities to earn its authorized return without a FAC?

A. Yes. The record shows that Evergy has, or anticipates, substantial LLPS revenues that could serve the same mitigating function of off-system sales revenues provided in Case No. ER-2007-0002. EMM reduced its revenue requirement by approximately $25 million in its case, based on projected LLPS revenues expected during the true up period, and this amount is expected to increase to approximately $43 million. As in Case No. ER-2007-0002, these revenues directly increase earnings and offset cost variability. The LLPS revenues in this case are substantial, recurring, and governed by tariffed obligations, including minimum bills and long-term service commitments, making them at least as predictable as the off-system sales margins relied upon by the Commission in 2007. Furthermore, Evergy has the ability to utilize other mechanisms that reduce regulatory lag and further enhance its ability to earn its authorized rate of return, such as Plant In Service Accounting ("PISA"). Originally enacted in 2018, PISA allows utilities to defer 85% of depreciation and return on qualifying electric plant placed in service after August 28, 2018 into a regulatory asset rather than recovering it through immediate rate base inclusion,[43] meaning that EMM can still earn a return on plant placed in service between rate cases. In the current case, PISA deferrals amount to $183,471,055[44]. EMM requested a total annual revenue amount of $39.1 million related to PISA deferrals.[45]

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[42] File No. ER-2007-0002 *Report and Order*, page 33.
[43] Missouri Revisor of Statutes - Revised Statutes of Missouri, RSMo Section 393.1400
[44] Staff rebuttal Accounting Schedules.
[45] Direct testimony of Matthew Young, page 33.

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Furthermore, PISA has been characterized as "a mechanism that allows EMM to pass the financial impacts of what would otherwise be negative regulatory lag to its customers."[46]

Q. Is there evidence that EMM may exceed its authorized rate of return due to LLPS revenues?

A. Yes. Dr. Carolyn Berry testified that Evergy's projected LLPS revenues exceed the embedded cost of serving those customers and that, as LLPS customers energize and expand between rate cases, Evergy may earn above its authorized rate of return before those revenues are incorporated into base rates.[47] This concern is similar to the one identified by the Commission in Case No. ER-2007-0002, where the Commission cautioned that if profit levels are understated, companies may earn excess profits that are not credited to the ratepayers who made those profits possible. The distinction in this case is that EMM's LLPS revenues, which are already reflected in its proposed revenue requirement, appear likely to increase further, potentially causing earnings to rise above authorized levels without the need for a fuel adjustment clause to protect its earnings opportunity.

Q. Applying the Commission's standards from Case No. ER-2007-0002, would Evergy require a FAC to earn its authorized rate of return if LLPS customer revenue is as high as EMM anticipates?

A. No. Under the Commission's standards from Case No. ER-2007-0002, EMM would not require a FAC to earn its authorized rate of return when LLPS revenues and PISA deferrals are considered together. In Case No. ER-2007-0002, the Commission explained that a FAC may be necessary only when fuel-cost volatility is sufficiently severe that, without the mechanism, the utility may be unable to earn its authorized return. EMM utilizes a natural gas hedging program to mitigate fuel-cost volatility risk. PISA allows EMM to deter 85% of depreciation

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[46] Rebuttal testimony of Sarah Lange, page 13.
[47] Direct testimony of Dr. Berry, page 12.

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expense and return on eligible plant additions placed in service between rate cases, including carrying costs at the weighted average cost of capital. This statutory mechanism was specifically designed to reduce regulatory lag and ensure utilities can maintain their authorized returns even when substantial capital additions occur between rate cases. PISA, therefore, functions as a separate earnings-stabilizing mechanism independent of a FAC. When utilized together, the magnitude of LLPS revenues and the operation of PISA demonstrate that EMM possesses more than a reasonable opportunity to earn its authorized return without relying on a FAC. EMM would not require a FAC to earn its authorized rate of return under conditions where LLPS revenues and PISA deferrals are as abundant as anticipated.

Q. What do you recommend for an EMM FAC?

A. First, I recommend that the Commission conclude that EMM does not need a FAC "to provide [it] with a sufficient opportunity to earn a fair return on equity."[48] Second, if the Commission were to authorize EMM to continue its FAC, then I recommend:

1) LLPS customers be excluded from EMM's FAC to prevent new hyperscale load LLPS customers from being subsidized by EMM's other customers;

2) If LLPS are not excluded from EMM's FAC, then I recommend LLPS customers be treated separately from other customer classes in EMM's FAC with a separate LLPS class base factor to prevent cross-subsidization as customers populate EMM's LLPS rate class and add load to EMM's system;

3) The current 95/5 sharing mechanism continue;

4) The additional EMM FAC reporting requirements that Staff sponsors be imposed; and

5) Changes in EMM's RTO administrative fees not flow through EMM's FAC.

[48] § 386.266.5(1), RSMo.

<u>FAC Tariff and Administrative Charges</u>

Q. Summarily, what is Ms. Nunn's claim regarding Southwest Power Pool ("SPP") administrative fees?

A. Ms. Nunn indicates that SPP administration fees are charged by SPP on a per MWh basis and therefore should be recovered in EMM's FAC due to fluctuations based on customer usage.[49]

Q. Do you agree with Ms. Nunn?

A. No, for a variety of reasons. First of all, the Commission has previously found that SPP administrative fees are not directly linked to fuel and purchased power costs, recognizing the fact that "Schedule 1-A and 12 fees are variable, but not volatile in nature."[50] Furthermore, volatile costs are quite different than variable costs, and Ms. Nunn has not provided an analysis showing SPP administrative charges are volatile.

Q. What is Staff's position on flowing SPP administrative fees through EMM's FAC?

A. Staff Witness Stacy Henderson states that SPP purchased power administration costs "are not eligible expenses under the FAC under the Commission's historical guidance."[51]

[49] Rebuttal Testimony of Linda Nunn, page 5.
[50] File No. ER-2014-0370 *Report and Order*, page 36.
[51] Rebuttal Testimony of Stacy Henderson, page 2.

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Q. When Ms. Henderson refers to the Commission's consistent treatment of SPP administrative fees in past rate cases, to which historical guidance do you believe best explains this treatment?

A. The Commission's guidance in Case No. ER-2014-0370. The Commission specifically addressed KCPL's[52] request to include SPP administrative costs in its *Report and Order* in Case No. ER-2014-0370 where it made the following conclusion:

> KCPL has requested that SPP Schedule 1-A and 12 fees be included in its FAC. The Commission finds that these fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers. <u>These fees are neither fuel and purchased power expenses nor transportation expenses incurred to deliver fuel or purchased power. The Commission concludes that including such fees would be unlawful under Section 386.266.1, RSMo</u>, and, therefore, Schedule 1-A and fees should not be included in the FAC. These fees are appropriate for recovery in base rates. (Emphasis added)[53]

The Commission's conclusion was based on the following findings of fact:

- SPP Schedule 1-A fees are for SPP expenses associated with administering its Open Access Transmission Tariff. These expenses cover regional scheduling, planning, and market-monitoring services provided to facilitate the transportation of energy on the transmission system.
- SPP Schedule 12 fees are an assessment charged by FERC related to KCPL's membership in SPP.
- Schedule 1-A and 12 fees are administrative in nature and not directly linked to fuel and purchased power costs. These fees support the operation of SPP and are not needed for KCPL to buy and sell energy to meet the needs of its customers.
- RTO administrative fees, such as Schedule 1-A and 12 fees, are not included in the FACs of other regulated utilities in Missouri.

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[52] KCPL is the predecessor to Evergy Metro, Inc., an affiliate of Evergy Metro with the same parent company Evergy, Inc.
[53] Page 36.

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- Schedule 1-A and 12 fees are variable, but not volatile in nature. [54]

Q. What is your recommendation to the Commission regarding flowing RTO administrative fees through EMM's FAC?

A. I recommend that Regional Transmission Organization[55] ("RTO") administrative fees should be recovered in base rates, and not in any part through a FAC. Evergy Witness Nunn claims SPP administrative fees should be recovered in EMM's FAC due to the variable nature of these costs. While these costs may vary, they are not volatile. Furthermore, the Commission has found that RTO administrative fees are not purchased power or transportation expenses and should not be recovered through a FAC per Section 386.266.1, RSMo.

<u>CIP/CYBER SECURITY TRACKER</u>

Q. What is your response to EMM witness Klote's testimony, "Company should not be expected to budget for unpredictable, incremental costs that may not be reasonably predictable in a historical test year" [56]?

A. The cyber security space has been quickly evolving since at least 2012 when critical infrastructure threats increased 68% from the previous year.[57] Evergy, Inc. ("Evergy") has been complying with applicable North American Energy Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") Security Standards since around 2005. While NERC CIP Security Standards have been evolving since 2005 in response to a quickly evolving and dynamic cyber security space, Evergy's cyber security budget and its cyber security identified spending has remained relatively stable, mildly variable, not volatile. These known and

[54] *Id.*
[55] All Regional Transmission Organizations Evergy engages in business with, to include, but not limited to, both SPP and MISO.
[56] Rebuttal Testimony of Charles King, page 3.
[57] Schedule ADS-S-4.

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measurable expenditures show no volatility, even though the cyber security space continues to evolve, and are not expenditures based on "what ifs" and "maybes."

Q. What is your response to Mr. Klote's suggestion that federal reliability and cybersecurity requirements can result in "significant and unpredictable costs that are largely outside the Company's control"[58]?

A. In response to Staff Data Request 0272.1, the Company supplied a "non-exhaustive list of cyber security related activity in various stages of implementation at the Federal level that **may** drive requirements for Evergy. I will address several items on this list[59]:

1. Department of Defense (DOD) Cyber security Maturity Model Certification (CMMC) 2.0 is expected to be implemented Q1 2025. Evergy would have to implement cyber security measures to meet the NIST SP 800-171 (110 specific requirements) and potentially NIST SP 800-172 standards.

NIST SP 800-171 may include 110 specific requirements, in the areas of access control, audit and accountability, awareness and training, configuration management, incident response, etc. However, the list is made up of 31 basic security requirements with the remaining 79 requirements derived from the implementation of these 31 basic security requirements. Evergy has recently participated in the Cyber Security Capability Maturity Model (C2M2) Assessment and GridEx, receiving high ratings. As I stated in my direct testimony, Evergy's Cyber Security/IT Committee repeatedly reports that Evergy cyber security measures score higher than **______ ** with a score in the ** __ **. A cyber security score that high should be quite difficult to achieve if basic security requirements that did not already meet CIP requirements were not in place. Since Evergy is already achieving a cyber security score in

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58 Rebuttal Testimony of Ronald Klote, page 32-33.
59 Company's response to Staff Data Request 0272.1 in ER-2024-0189.

the ** ___ **, CMMC measures should already be achieved by Evergy's currently robust cyber security program.

2. Department of Energy/National Association of Regulatory Utility Commissioners (NARUC) Cyber security Baselines for Electric Distribution Systems and Distributed Energy Resources (DER) are expected to be completed by the end of 2024. This includes 32 cyber security controls[60] which are voluntary until state adoption which is unknown at this time.

The Cyber security Baselines for Electric Distribution Systems and DER consists of 32 cyber security controls. Without specifying which procedures or technologies to use, these baselines define cyber security controls that should be implemented. Examples of these controls include: asset inventory, organizational cyber security leadership, OT cyber security leadership, mitigating known vulnerabilities, etc. These are baselines.[61] Evergy has been subject to stringent NERC CIP Security Standards since at least 2005. NERC CIP Security Standards have been evolving since that time. There is a nuclear plant in its territory. Evergy's baseline cyber security controls should already be established if it's meeting rigorous CIP requirements and therefore should not be affected by the Cyber security Baselines for Electric Distribution Systems and DER requirements.

3. Cyber security and Infrastructure Security Agency (CISA) Cyber Incident Reporting for Critical Infrastructure (CIRCIA) Cyber security Reporting Rules - CISA must issue a final rule by October 4, 2026. This would require additional reporting capabilities for cyber incidents and ransomware payments.

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[60] https://www.naruc.org/core-sectors/critical-infrastructure-and-cyber security/cyber security-for-utility-regulators/cyber security-baselines/.
[61] The Oxford Languages definition of baseline: a minimum or starting point used for comparisons.

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Critical infrastructure organizations have called for clarity and voiced concerns over redundancy.[62] In comments to CISA regarding CIRCIA, The Edison Electric Institute ("EEI") stated that EEI members are already subject to extensive regulation relating to cyber security and incident reporting requirements through FERC/NERC and DOE:

> NERC's Reliability Standards and Critical Infrastructure Protection Reliability Standards (hereinafter Reliability Standards and CIP Reliability Standards, respectively) are promulgated by NERC; approved by FERC; and enforced by FERC, NERC, and NERC's Regional Entities. They apply to owners, operators, and users of the Bulk Electric System (BES).
>
> NERC's CIP Reliability Standards are designed to address physical and cyber security risks. CIP Reliability Standards "implement a defense-in-depth approach to protecting the security of the BES Cyber System at all impact levels." Moreover, "the CIP Reliability Standards are objective-based and allow entities to choose compliance approaches best tailored to their systems." CIP Reliability Standards allow EEI members the flexibility to tailor their risk management approaches. As FERC has recognized, this flexibility is important to accommodate the varying "needs and characteristics of responsible entities and the diversity of BES Cyber System environments, technologies, and risks."
>
> NERC cyber security standard CIP 008-6 stipulates the following requirements: (1) entities must implement one or more processes to identify and respond timely to security incidents; (2) the roles and responsibilities of the security incident response personnel must be clearly defined; (3) procedures for handling security incidents must be documented; (4) incident response plans must be tested once every months; (5) incident reports must be retained to optimize future responses; and (6) following the testing of an incident response event, a covered entity should document learnings, update its existing response plan, and disseminate findings to the security team. This Standard also requires applicable facility owners to provide an initial notification to the E-ISAC and CISA's National Cyber security and Communications Center within one hour after the determination of a Reportable Cyber Security Incident and by the end of the next calendar day after determining that a Cyber Security Incident was an attempt to compromise an applicable system.[63]

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[62] Schedule ADS-S-5.
[63] Docket CISA-2022-0010; COMMENTS OF THE EDISON ELECTRIC INSTITUTE ON THE DEPARTMENT OF HOMELAND SECURITY, CYBER SECURITY AND INFRASTRUCTURE SECURITY AGENCY'S,

In additional comments to CISA regarding CIRCIA, the Electric Power Supply Association ("EPSA") stated that EPSA members are currently required to report high and medium asset cyber incidents under rigorous NERC CIP standards and requested a line of communication between CISA and the entities to which EPSA members are already reporting information in order to streamline the reporting process.[64] The comments EEI and EPSA submitted to the CISA CIRCIA docket demonstrate that organizations such as Evergy are already subject to thorough cyber security regulations through FERC/NERC and DOE. Additionally, these comments show that utilities have advocates working to streamline regulation requirements between agencies in order to reduce redundancy and optimize existing processes.

Evergy also mentions various active NERC Projects in place that will update CIP standards. Several of the CIP standards engaged in the updating process have been in place over ten years. Evergy has been subject to various CIP standards since at least 2006. Since CIP requirements have been evolving since the early 2000s, the initial investment to launch CIP compliance programs has already been expended. Updating practices in response to changing regulations is a natural occurrence incurred through the course of regular business operations and should not necessitate extraordinary implementation costs. Additionally, Evergy has opportunities to identify efficiencies with each CIP standard update as inactive, outdated standards no longer require compliance.

Q. How do you respond to Mr. King's opinion that third-party risk also justifies a cybersecurity tracker[65]?

A. Third party risk is not a new phenomenon. Mr. King references the 2024 Crowdstrike outage in reference to third party dependency risk, even though the Crowdstrike outage was the result

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PROPOSED RULE REGARDING CYBER INCIDENT REPORTING FOR CRITICAL INFRASTRUCTURE; Schedule ADS-S-6.

[64] Docket CISA-2022-0010; COMMENTS OF THE ELECTRIC POWER SUPPLY ASSOCIATION; Schedule ADS-S-7.

[65] Rebuttal testimony of Charles King, page 5.

of a vendor software update issue, not a cyber event. Referencing true cyber events involving the breaching of third-party vendors would be more relevant here, such as the SolarWinds network attack around March 2020, or the Log4j vulnerability discovered around November 2021, or the MOVEit critical vulnerability discovered around May 2023. These are three major incidents, actual cybersecurity incidents, involving compromised third-party software that affected several major enterprises, and required remediation and patching. Yet, through these years Evergy's cybersecurity expenditures still remain flat. Attempting to predict these events a year in advance when devising a cybersecurity budget is infeasible. However, by following cybersecurity best practices, pursuing mitigation through contingency planning, cybersecurity insurance, and risk management strategies, within a reasonably set budget, an organization with a mature cybersecurity model could mitigate and remediate threats more effectively.

Q. What is your response to Mr. King's opinion that future business regulations "almost certain to occur" as a result of the CMMC program also justify a cybersecurity tracker[66]?

A. The only active CMMC requirement is Phase 1 Level 1/Level 2 self-assessment, which has been required since November 2025. These obligations are well-known, stable, follow existing NIST SP 800-171 Rev. 2 controls, and are already incorporated into Evergy's ongoing cybersecurity planning. CMMC Phase 2 was suspended on July 13, 2026. Phases 3 and 4 were also frozen until further notice. DoD launched a 60-day CMMC Reform Task Force to reevaluate the program. The federal agency announcing these changes stated this was a policy pause and not a regulatory enforcement action. No federal rulemaking currently requires utilities to adopt new compliance measures or incur new costs. Mr. King's assertion that imminent CMMC compliance creates unpredictable cost exposure is contrary to the federal government's current stance. Therefore, justifying a cybersecurity tracker based on future CMMC requirements is not logical since no effective dates or required compliance obligations

[66] Rebuttal testimony of Charles King, page 4.

beyond Phase 1 exist, and any future obligations remain subject to pending review and possible cancellation.[67]

Q. What is your response to Mr. King's opinion that potential threats from AI systems escaping containment justify a cybersecurity tracker[68]?

A. Again, Mr. King is looking at well publicized events, that did not directly apply to Evergy, in his attempts to justify a cybersecurity tracker. Mr. King's conclusion assumes a fallacy of composition, generalizing at least one event regarding alleged AI containment failure to imply that potentially all AI systems and all companies face similar risks. Mr. King's testimony does not provide specific examples, only generalizations. If Mr. King is referencing the well publicized Hugging Face[69] breach in his description of an AI model escaping containment, this event occurred due to specific circumstances in a particular test environment. His conclusion overlooks critical differences among AI systems and their environments, such as the variations in containment architecture and security controls, governance, and access restrictions. Individual test environment failures do not necessarily establish widespread systematic risk. Mr. King's reliance on generalized AI containment failures overly inflates the likelihood and scale of hypothetical AI threats by insinuating that isolated events justify broader assumptions regarding future targeting risks.

Q. Do you agree with Mr. King's opinion that "evolving requirements" and the "potential volatility in costs and their unknown and unpredictability" is why EMM is requesting a CIP/Cyber Security tracker[70]?

A. No. As I stated above Evergy's cyber security program complies with strict CIP standards and is already robust. Even if a regulation introducing new or updated cyber security requirements

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[67] https://www.war.gov/News/Releases/Release/Article/4542329/forging-the-arsenal-of-freedom-department-of-war-suspends-cmmc-phase-ii-require/.
[68] Rebuttal testimony of Charles King, page 4.
[69] Autonomous Sandbox Escape: OpenAI Models Breach Hugging Face – Lab Space.
[70] Rebuttal Testimony of Charles King, page 6.

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was passed, the Company would not have to implement new concepts from scratch. Cyber security is an evolutionary work in progress that builds upon previous iterations of standards. Furthermore, as demonstrated in the comments submitted to CISA regarding CIRCIA, utility advocates such as EEI were calling for streamlining regulations and communications across Federal agencies in order to combat existing redundancy. The fact that Mr. King refers to "potential volatility" and not actual volatility experienced by Evergy, along with actual EMM's historical cyber security related spending, indicates a tracker is unnecessary.

Q. What are your qualifications for testifying on cyber security?

A. I have participated in various cyber-related trainings, including CISA trainings. I am a member of the Information Systems Audit and Control Association ("ISACA") and I am familiar with the IT Audit framework based on the NIST Cyber security Framework 2.0. Additionally, I have reviewed study materials affiliated with CompTIA's Cyber security Analyst+ ("CySA+") certification.

Q. Do EMM's responses to data requests in this case support Mr. Klote's testimony that cybersecurity expenditures are "significant, they can vary materially from year to year as new threats and compliance requirements emerge, the Company has limited ability to control many of the external requirements driving those costs"[71]?

A. No. As I stated in direct testimony, EMM provided cybersecurity actual expenditures between 2021 through 2025 that are fairly consistent, with little fluctuation. New threats have been emerging regularly for years now, and Evergy's cybersecurity-related spending remains stable, which is not surprising given its robust security environment.

[71] Rebuttal Testimony of Ronald Klote, page 33.

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Q. What is Staff's position regarding EMM's request for authority to have a CIP/Cyber Security tracker?

A. Staff also found EMM's CIP and cyber security costs consistent each year, and Staff does not recommend that the Commission authorize EMM to employ a CIP/Cyber Security tracker.[72]

Q. What do you recommend in response to EMM's request for Commission authorization to use a CIP/Cyber Security tracker?

A. A CIP/Cyber Security tracker is unnecessary as Evergy's CIP and cyber security costs are neither volatile nor extraordinary. Even though cyber security standards have been evolving for over a decade Evergy's CIP and cyber security costs are flat, with little fluctuation. Even if current standards are updated or new standards are proposed at the federal level, the industry has active advocates working to maximize communications between agencies and to minimize redundancy.

Q. Does this conclude your testimony?

A. Yes.

[72] Rebuttal Testimony of Karen Lyons, page 11.

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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 ANGELA SCHABEN

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Angela Schaben, of lawful age and being first duly sworn, deposes and states:

1. My name is Angela Schaben. I am a Senior Utility Regulatory Auditor for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Angela Schaben
Senior Utility Regulatory Auditor

Subscribed and sworn to me this 9th day of September 2026.

TIFFANY HILDEBRAND
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES AUGUST 8, 2027
COLE COUNTY
COMMISSION #15637121

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2027.