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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EO-2025-0154

SURREBUTTAL TESTIMONY

OF

STEVEN M. WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
September, 2025

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STEVEN WILLS

FILE NO. EO-2025-0154

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven M. Wills. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. Are you the same Steven M. Wills that submitted rebuttal testimony in this case?

A. Yes, I am.

Q. To what testimony or issues are you responding?

A. I am responding to Staff's rebuttal report generally. I will explain why the recommendations contained in Staff's report with respect to the tariff and other regulatory frameworks that Staff contends should govern Evergy's[1] large load service must be rejected in their entirety. Staff's approach is extreme in many ways and does not reflect reasonable commercial terms for large load service, nor sound regulatory policy. I will address several specific concerns that I have with Staff's recommendations to illustrate why. However, I will not address each and every detail of Staff's proposal. My silence on a particular element of Staff's recommendations should not be construed as an endorsement of that particular element. Rather, I am simply seeking to provide the Commission with enough

[1] References to "Evergy" are to Evergy Missouri Metro (or "EMM") and Evergy Missouri West (or "EMW"), collectively.

evidence and examples of the deeply flawed nature of Staff's entire approach to large load service to support the outright rejection of the Staff's position.

II. OVERVIEW OBSERVATIONS OF WHY STAFF'S PROPOSAL IS DEEPLY FLAWED AND WHOLLY UNREASONABLE

Q. You indicate that Staff's recommendations are deeply flawed. Before getting into the details, would you please provide some context for that opinion?

A. Yes, and this context is also discussed in the Surrebuttal Testimony of Ameren Missouri witnesses Rob Dixon and Ajay Arora and in Mr. Arora's Rebuttal Testimony. The large load issue in this case should first and foremost be viewed as the historic opportunity that it is to attract massive investment to the state and avoid losing those investment opportunities and the benefits they will bring to other states with whom Missouri is competing. The large load issue, of course, must also be viewed in the context of the requirements of Senate Bill 4[2] ("SB 4"), which requires that the Commission conclude that there is reasonable assurance that large load customer rates will reflect their representative share of costs and will not result in unjust or unreasonable costs arising from their service being imposed on existing customers. It is critical, therefore, to be cognizant of the commercial terms reflected in any large load tariff proposal, and how those terms:

1) are reasonably in line with, so as to be competitive with, terms being established in the industry across various jurisdictions with whom Missouri is competing,

2) meet the needs and preferences of potential customers where those can reasonably be accommodated, and

3) provide reasonable assurance that large load service under those terms will not result in unjust or unreasonable impacts on existing customers.

[2] Section 393.130.7, RSMo.

In my opinion, Staff's proposal in this case reflects absolutely no consideration whatsoever of items 1 and 2 above and advances a perspective on item 3 that is so extreme as to fully undermine any efforts to establish the type of reasonable commercial terms that will create a competitive and attractive landscape for economic development in Missouri. To summarize the significant issues that I will walk through later in testimony, Staff's proposal suffers from the following fatal flaws:

- The rate structure is extremely complex for little, if any, benefit, which will reduce the transparency of the rate structure to prospective customers;
- Staff adds administrative burdens of separately registering large loads in energy markets to chase an unnecessary level of precision in tracking of very minor categories of cost;
- Staff's rate calculations are not reflective of Evergy's cost of service for a number of reasons, including:
  - The Generation Demand Charge is overstated due to the inappropriate omission of Accumulated Deferred Income Taxes and capacity sale revenues;
  - The energy charge is set to a market-based benchmark – not to the costs that will be included in Evergy's actual revenue requirement – and therefore overstates energy-related costs; and
  - The "Stable Fixed Revenue Contribution" and "Variable Fixed Revenue Contribution" charges are completely arbitrary and are also overstated due to Staff's gross up for non-existent "phantom" income taxes.

- Staff's method for triggering exit fees is wholly unreasonable and unfair to prospective customers;
- Staff's regulatory lag proposals are contrary to good regulatory policy and skew outcomes to be biased against the utility's financial interest;
- Staff's regulatory lag proposals are so mechanically flawed that they severely double-count the potential favorable regulatory lag a utility could temporarily benefit from and turn them into significant detriments; and
- The totality of Staff's rate proposal and accompanying regulatory treatment is unjust and unreasonable and will not result in a competitive environment whereby Missouri will obtain the benefit from large load customer investment in the state.

Q. What makes you say that Staff does not take into account the first item you listed above, the need to establish competitive terms with those being established elsewhere in the industry across various jurisdictions?

A. Simply put, I've never seen anything quite like the rate structure that Staff has constructed. It is certainly far afield of the large load rate structures in the industry with which I am familiar. The complexity of Staff's structure appears to be intended, at least in part, to chase an impossible standard that seeks to impose almost "to the penny" accounting of various sources of uncertainty with respect to costs of serving large loads, with very little, if any, practical benefit from that incredibly fine slicing and dicing of costs. The rate itself is also based on an incoherent mixing and matching of ratemaking principles that results in a rate level that is unjustified by basic cost of service principles. Beyond that, Staff creates extremely onerous terms of service that make little sense and create unreasonably burdensome conditions for prospective customers. Many of these terms are also inconsistent with what I have typically seen in other industry frameworks for large load service. What emerges is a rate structure and regulatory framework that, if adopted, I expect would create an environment where new prospective large load customers would tend to dismiss Missouri as a potential home for their investments and pursue opportunities to locate in jurisdictions with reasonable electric service terms. Messrs. Arora and Dixon also discuss this in their Surrebuttal Testimony.

Q. And why do you contend that Staff is not taking into account the second item you listed above, the need to meet the needs and preferences of prospective customers where reasonably possible?

A. My contention is grounded in the non-competitive nature of the Staff's rate and onerous service terms, which I just discussed in response to the previous question. I have little doubt that, with prospective large load customers and industry organizations intervened in this docket, they will directly express their concerns about Staff's proposal. I expect those comments will reflect an extremely negative reaction to Staff's recommendations. I say this based on the fact that my colleagues and I have spent considerable time interacting with potential customers and learning what is important to them in choosing a jurisdiction in which they will seek to establish service and make considerable investments in the local economy. Based on those interactions with several different prospective customers, the key aspects that such customers are seeking, above and beyond the basic availability of power, is a good utility partner that will work with them to establish transparent and fair pricing and contract terms. Beyond that, many of them are also actively seeking utilities that can help them achieve clean or carbon free energy goals. In my experience, large load customers generally express a willingness, indeed a preference, to pay their fair share (which the statute expresses as paying a representative share). But in doing so, they also do not want (nor should they be expected) to pay *more* than their fair share. Staff's rate, as I will discuss in more detail, is neither transparent nor a reasonable representation of large load customers' fair (or representative) share. And on its face, it clearly wasn't the product of any meaningful interaction with or effort to understand the needs of prospective large load customers.

Instead Staff, who is neither a utility nor clothed with the right or responsibility to manage a utility or to serve utility customers, appears to have ignored Evergy's large load customer rate plan, which the testimony in this case shows was informed by the considerations I highlighted above, and chose to invent out of whole cloth an entirely new rate proposal. Staff's invention bears no relationship to the utility proposal in this case and, to my knowledge, has no other analog in the industry. That Staff apparently wants to be in the driver seat with respect to establishing every detail of the rates, terms, and conditions that utilities will offer to large load customers tells you everything you need to know about the likelihood of attracting large load investment under Staff's paradigm. Indeed, no utility can be the good partner prospective large load customers are looking for – and thus actually attract them to the state – if an unworkable rate structure is imposed upon the utility, especially when the imposed rate structure is completely uninformed by the needs of the prospective customers to which it would apply.

Q. Please address Staff's proposal in the context of the third item you list above, that is, the standard reflected in SB 4?

A. In my Rebuttal Testimony in this case, as well as in my Direct Testimony in Ameren Missouri's large load case (File No. ET-2025-0184), I shared perspectives on the standard reflected in SB 4 that requires tariff frameworks under which the Commission must establish a rate for large load customers that reasonably ensures that the rates they will pay will reflect a representative share of costs and not cause unjust or unreasonable costs to be borne by existing customers. Ideally, demonstrating this would take the form of a robust risk analysis, like that conducted by Ameren Missouri in its case, that compares expected incremental costs of serving these customers to the incremental revenues derived from the provision of that service. I also explained in my Rebuttal Testimony in this case why I believe Evergy's slightly different form of analysis also provided sufficient evidence that the SB 4 standard would be met. Staff, in stark contrast, fails to articulate any means by which the SB 4 standard can be measured, but rather just jumps in to building a rate by throwing together a hodge podge of methods and rationales on each different rate element that it wishes to propose. The result is not an analysis that really demonstrates *anything* with respect to the prospective impact of large load service on other customers. There is simply no evidence provided to support the conclusion that Staff's rate does or does not comport with SB 4's requirements. That said, the decisions that Staff makes appear to overwhelmingly skew Staff's rate to a level that is *higher* than traditional cost-based ratemaking approaches would justify and suggest a Staff approach to interpretation of the standard in SB 4 that is consistent with the extreme risk aversion Staff witness Jim Busch articulated in his rebuttal testimony[3] – i.e., Staff's rate, whether deliberately or not, tips the balance significantly away from any concern for the competitiveness of the rate offering in terms of its ability to attract customers and the economic development benefits that they can bring.

Q. Before turning to those other sections of testimony, do you have any other issues to respond to as a part of your overview review of Staff's and the Office of the Public Counsel's ("OPC") rebuttal testimony?

A. Yes. Both Staff[4] and OPC[5] voice significant concerns with what they characterize as "stranded costs" associated with the provision of large load service. Those concerns lead Staff and OPC to a variety of recommendations with respect to the terms and conditions, and presumably even the development of the rate structure and other regulatory considerations that Staff proposes. Staff and OPC's references to stranded costs are really misnomers in this situation. The term stranded cost generally refers to costs of resources or infrastructure that are or become no longer useful in providing service prior to the end of their useful life, when there is still unrecovered investment on the utility's books. Generation that is *accelerated* to serve large load customers is not possible to be stranded. This is the case because, as the term "accelerated" implies, the generation that is being built to serve large loads is generation that would be needed a few years later anyway, to replace retiring generation and/or meet other load growth. Power plants that utilities construct, even if primarily driven by load growth from large load customers, will be needed to

[3] See James Busch Rebuttal Testimony at p. 5, ll. 15-17, which includes the following Question and Answer:
"Q. But are not the economic advantages of locating large data centers in Missouri worth the risk?
A. Not in my opinion."
[4] James Busch Rebuttal Testimony, p. 5, ll. 1-14.
[5] Geoff Marke Rebuttal Testimony, p. 17 l. 25 through p. 18 l. 3.

provide service to the whole system for the foreseeable future, and can meet retail customer needs and/or create revenues in wholesale power markets by serving the market at large. That said, I certainly appreciate that providing service to large load customers is likely to cause those significant investments in accelerated generation resources sooner than they otherwise would. And absent large loads to contribute revenues toward the revenue requirement of the acceleration of those resources, the potential exists for existing customers to bear additional costs on a net present value basis. To that end, Staff and OPC's concerns reflect a legitimate perspective – one that I believe was shared by the legislature in passing the provisions of SB 4 that require utilities to create large load tariffs. But that's exactly the point of Evergy's and Ameren Missouri's respective filings in the large load tariff cases pending in front of the Commission. Both utilities have developed robust frameworks that reflect a requirement that prospective large load customers bring a long-term financial commitment along with their request for service and that therefore reasonably ensure that those customers pay their representative share of costs. And both utilities have performed different, but adequate, analyses to illustrate how their proposed frameworks do address the issue that underlies the large load provisions of SB 4 as well as Staff and OPC's concerns. Neither Staff nor OPC conducts its own analysis of the likelihood or magnitude of potential "stranded costs" in this case.

Q. Staff witness Jim Busch also articulates a concern[6] that utilities have an incentive to "overstate" their infrastructure needs in order to benefit shareholders financially, which could influence utilities' approaches to developing infrastructure to support large load service. What is your response?

[6] James Busch Rebuttal Testimony, p. 6, l. 21 through p. 7, l. 5.

A. I cannot speak for Evergy on this point, although I would be surprised if they viewed the issue differently. But as far as Ameren Missouri is concerned, first, let me say unequivocally that we understand that our business interests – the interests of our shareholders – are inextricably intertwined with our customers' interests. While this reality is true for most or all businesses, it is uniquely true for a regulated utility that has a franchise to be the sole provider of service within its territory. Ameren Missouri, as a provider of critical infrastructure, is a part of the fabric of the communities we serve, and we take seriously our obligation to pursue the types of investments that are in the mutual interest of all stakeholders – customers, communities, and shareholders – to ensure the type of infrastructure exists that is needed for our region to thrive, rather than intentionally overbuilding, resulting in unneeded infrastructure as Staff insinuates. Ameren Missouri stands behind its historical track record of making good investment choices that have resulted in a high standard of service at reasonable rates.

Staff acts as though the incentive it identifies associated with the framework of the existing regulatory model for utilities to invest in their systems is an inherently bad thing. But to the extent this incentive is at work, it has been present in the regulated utility model for over a century and has resulted in the transformation of our society through the development of now critical infrastructure that has become the backbone of the lifestyles and economies of our communities. If there was no incentive to invest in the system, we would not have the system we have. Said simply, utilities *should* have an incentive to invest in useful infrastructure for the benefit of their customers.

Q. But do you agree that the Commission does have an important role in balancing the interests of shareholders – i.e., balancing the incentive to invest in useful infrastructure – with the interests of customers, in order to ensure that these infrastructure solutions are cost effective and promote the public interest?

A. Absolutely. The Commission's oversight allows it to balance those interests, as it will do with its continued oversight of the tariffs that govern large load service and the Certificate of Convenience and Necessity applications by which it will decide whether to authorize the accelerated generation needed to serve large load customers. To be clear, nothing about Evergy's proposal in this case, nor Ameren Missouri's in its case, limits the Commission's future authority to continue to evaluate large load service including large load customer rates in the context of SB 4's requirements and its basic mandate to protect the public interest and ensure just and reasonable rates.

Q. Staff witness Luebbert suggests[7] that large load service is contradictory to Evergy's past efforts to promote demand side management and energy efficiency under the Missouri Energy Efficiency Investment Act? Do these things represent a contradiction?

A. Not at all. In fact, they are perfectly complementary when one steps back and considers sound energy policy holistically. Staff's implicit suggestion that energy efficiency - making cost effective investments to provide the same level of end use service with less electricity and requiring less new resource additions than would otherwise be required - conflicts with trying to grow the economy and enable the benefits of new investment is completely nonsensical and just plain wrong. The existence of growth in

[7] Staff Rebuttal Report, p. 8, ll. 5-11.

useful applications of electricity does not reduce or eliminate the merits of using that electricity efficiently or avoiding more new resources than would *otherwise* be required. Energy efficiency and demand response programming can make room for new load to be brought onto the system without requiring even more new capacity than would otherwise have been required had we not bothered to utilize energy efficiency programs in the first place. If existing loads were higher because energy efficiency had been foregone, even more new generation would be needed today to serve the demand of large load and existing customers.

III. STAFF'S RATE DESIGN IS OVERLY COMPLEX FOR LITTLE, IF ANY, BENEFIT

Q. What concerns do you have with the complexity of Staff's large load rate design proposal?

A. As I suggested in my introductory comments, Staff's rate structure is unnecessarily and *extremely* complex. Staff's rate design workpaper includes, and testimony describes, rate values or placeholders for up to *twenty-seven unique rate elements* that would apply to large load customer bills, including at least *eight brand new discrete charges* above and beyond what other industrial customers' rates reflect, with opaque, obscure, and confusing charge names such as "variable fixed revenue contribution." To my knowledge "variable fixed revenue" is a term of Staff's invention that is not used anywhere in the industry, and which is perplexingly convoluted (i.e., is it variable or is it fixed – those are inherently contradictory). What is a prospective customer supposed to make of this charge?

The base energy charge itself is subdivided into 12 unique seasonal and time of use ("TOU") rate values. Yet even Staff itself says that the TOU rates are not intended to drive these customers' behavior.[8] I agree, which begs the question: what benefit could there be of adding so many – 12 additional discrete energy rates?

All of the complexity reflected in Staff's rate structure – the 12 additional discrete energy rates I just mentioned and the existence of a total of 27 different charge types - does little, if anything, to provide benefits to anyone. But it does dramatically reduce the transparency and understandability of the rate offering for prospective customers that are very likely to desire detailed information about the trends, trajectories, and potential risks of each of these very specific costs that will be on each and every one of their bills. Staff notes that large load customers are among the most sophisticated of energy consumers, and therefore should be able to understand and contend with the complexity of the rate.[9] While I agree, in general, with the notion that most large load customers are sophisticated energy consumers, in my opinion the complexity of the rate would be a red flag for them related to the lack of transparency of energy pricing and the potential for uncertain and unpredictable outcomes.

Q. Is the complexity of Staff's rate proposal consistent with other large load rates you have seen in the industry across jurisdictions?

A. No, it is an obvious outlier. I have reviewed information from large load cases of several utilities. Rate proposals for Evergy, Ameren Missouri, AEP Ohio, Dominion Virginia, Consumers Energy (Michigan), Kentucky Power, Santee Cooper, and Arizona Public Service all rely on the same rate elements for large load base rate charges as their existing industrial rates.[10] A couple of utilities, including Indiana & Michigan

[8] Staff Rebuttal Report, p. 49, ll. 22-23.
[9] Staff Rebuttal Report, p. 39, ll. 14-15.
[10] Some of these utilities may introduce a new rider, such as Evergy's Rider SSR in this case, but the base rate charges are the same as existing large load service.

Power and Florida Power & Light supplement their existing rate framework with a small number of additional charges for large load customers. One utility, Wisconsin Electric Power, has a more complex large load rate offering but it is predicated on market-based pricing and it still has substantially fewer charges than Staff's rate proposal. Staff's rate design is completely out of step with the industry and that will impact Missouri's competitiveness for the investment of large load customers.

Q. Are there other elements of Staff's rate proposal that introduce unnecessary complexity?

A. Yes. Staff is focused on the idea of requiring large load customers to be served under dedicated commercial pricing nodes ("CP Nodes") that would be separately registered with the utility's regional transmission organization ("RTO"), in Evergy's case, the Southwest Power Pool ("SPP"). This is an example of Staff adding tremendous administrative complexity in what appears to be a pursuit of "to the penny" accounting of the impacts of large loads on existing customers. Let's be clear about the standard articulated by SB 4, which requires *reasonable* assurance that no "unjust or unreasonable" costs be reflected in other customer classes' rates as a result of large load service. That standard, however, does nothing to remotely require "to the penny" tracking of every potential source of cost impacts associated with large load service. The statutory requirement is to "reasonably ensure" a rate that reflects "the customers' representative share of the costs incurred to serve." I am not an attorney, but "reasonably ensur[ing]" that the rate reflects a "representative" share certainly means there is not a requirement to be exact or "to the penny." Furthermore, the existence of the qualifiers "unjust or unreasonable" also in that same sentence in SB 4 necessarily means that there could exist a level of costs (or benefits) that are reflected in other customer classes' rates that would not reach the threshold of being considered unjust and unreasonable. Those words would not be there if there was to be a complete ringfencing of every possible cost down to the penny. It is absolutely the case that utility ratemaking is not a perfect science and that the Commission establishes just and reasonable rates for various classes of service all of the time using various estimates, allocations, and averages that are imperfect, but reasonable. The important thing in establishing the justness and reasonableness is to think critically about factors that can and do have a material impact on rates and use the best information available to ensure that those factors are considered and addressed reasonably in the ratemaking process, including via the Commission's ongoing authority to ensure all rates are just and reasonable as we move through time.

Q. Are RTO level forecasting and energy market imbalance costs likely to be a major determining factor as to whether existing customer rates are unjustly or unreasonably impacted by large load service?

A. No. In the context of potentially billions of dollars of investment in generation that may be accelerated to enable large load service, energy market imbalance (or load forecast deviation) costs – which are costs Staff targets by advocating for a separate CP Node for every large load customer -- are very small and should not even be on the Commission's radar as a place to spend significant effort in this proceeding. While I cannot speak specifically to Evergy's cost levels, I can say that my experience at Ameren Missouri suggests that energy market imbalance costs are, relatively speaking, a very small component of the utility's overall revenue requirement. They are not remotely comparable to the costs associated with the scale of investments in new generation that will be accelerated in order to provide large load service. But even if the absolute level of imbalance costs were significant in this context, one would have to have an expectation that the level of imbalance costs attributable to large load customers would be materially and systematically different from the costs associated with all other customers for there to be any potential impact that would even begin to be worth tracking.

Q. Do you have such an expectation (i.e., that imbalance costs will be materially and systematically different for large load customers than for all other customers)?

A. No.

Q. What experience do you base that opinion on?

A. In my first role at Ameren over several years, I had the responsibility for developing the forecasting system that Ameren uses for RTO load forecasting and operating and supervising that system to conduct day-ahead forecasts that were submitted to MISO. I "lived" day-ahead load forecasting inside and out during that time, while developing an understanding of different load types, and the impact on RTO settlement statements of forecast variances (imbalances).

Q. Are large loads likely to have a systematically different average level of imbalance cost (load forecast deviation) than the rest of the system load?

A. While it can depend on the individual load, my overall expectation is that they will not – and that many may drive *down* the average cost of forecast variances for the system as a whole. Particularly the type of high load factor loads that I think are most prevalent among the largest category of customers I see currently seeking large load service: data centers. Such customers will almost certainly design their facilities and systems to achieve high utilization of their equipment, resulting in very high load factors. High load factor customer loads are generally much more predictable and result in relatively lower forecast variance than the system as a whole.

Q. Do you have any experience forecasting high load factor loads?

A. Yes. I developed forecasts for the Noranda aluminum smelter in my forecasting experience, which was an approximately 500 MW, 95% load factor customer. While this occurred the better part of two decades ago and I do not have load forecast statistics at my fingertips today, I can say with a high degree of certainty that inclusion of that load into the same CP Node as the rest of Ameren Missouri's system load *reduced* the average forecast variance and created *benefits* for all customers in the form of lower average forecast deviation costs. In fact, for RTO settlement charges like MISO's revenue sufficiency guarantee charge that are billed based on the total forecast error irrespective of the direction of that error (i.e., the charge is the same whether the load forecast was too high or too low), it is a mathematical certainty that the overall cost for all customers (including the large load customer) will be lowest when aggregating all loads into a single CP Node. In this regard, Staff's call for separate CP Nodes will necessarily *increase* the cost for the entire body of retail customers to the extent that there are similar charges in SPP that are a function of overall forecast deviation irrespective of the direction of that deviation.

Q. Staff mentions certain conditions or circumstances that they allege may cause large load customers to have higher levels of forecast deviation than the rest of the customer base, including the potential for unpredictable loads like arc furnaces and potential weather sensitivity of cooling loads at data centers. Are these circumstances justification for separate CP Nodes for all large load customers?

A. No. I have personal experience forecasting the load on a day ahead basis for an arc furnace. This is one time in this case that I can say Staff is not wrong, at least in terms of its characterization of the challenge associated with forecasting a load of that type. Arc furnace loads are nearly impossible to forecast on a day ahead basis with a high degree of accuracy. That said, I do not believe that the outside possibility that an arc furnace or similar load could seek service in a utility's service territory should be the over-riding consideration for the entire tariff framework that will serve all large loads, which will initially likely be dominated by data centers, with perhaps some other advanced manufacturers in play as well. It makes no sense to subject all large loads to onerous and complex CP Node requirements out of fear that one difficult to forecast customer will show up. If that occurs, the utility and the Commission have the ability to deal with that circumstance at that time.

As far as weather sensitivity of potential data center loads, that should not be cause for any increase in forecast deviation relative to the highly weather sensitive system load that utilities already forecast every day. Forecasting models are very sophisticated in their treatment of weather sensitivity, and given a good weather forecast, we can be extremely accurate in our forecasts of weather sensitive loads. And a bad weather forecast will negatively impact the forecast of the overall system load every bit as much, or more, than the forecast of a data center. Meaning that the forecast for a data center should not be systematically prone to greater levels of deviation than the rest of the retail customer base. I would simply say that there is absolutely nothing in my quite extensive day ahead load forecasting experience that gives me any reason to believe that energy market imbalance (or load forecast deviation) costs of large load customers should be a noticeable source of cost for anyone. Staff's attempt to impose "to the penny" tracking of this cost is simply yet another administrative burden without any meaningful benefit.

IV. THE COST BASIS OF STAFF'S RATE IS INTERNALLY INCONSISTENT AT BEST, AND TOTALLY LACKING AT WORST, RESULTING IN AN UNREASONABLE RATE FOR LARGE LOAD SERVICE

Q. Setting aside the complexity of the structure of the rates, do you have concerns with how Staff calculated the level of the charges that it proposes to subject large load customers to?

A. Absolutely, in fact, I would use the phrase significant concerns. In several respects Staff's rates lack a proper relationship, and for some charges *any* relationship, to the costs that are or will be reflected in Evergy operating companies' revenue requirements. Staff's rates simply cannot be said to reflect Evergy's cost of serving large load customers. It is foundational to utility ratemaking that rates be set in a manner that is intended to allow the utility a reasonable opportunity to recover its prudently incurred costs and earn a reasonable return on the investments it has made to serve customers. That principle manifests itself in rate cases as the determination of the utility's annual revenue requirement - the amount of money that rates should be designed to produce in order to provide the utility with that opportunity - based on a thorough review of that utility's costs. Fairness to customers also dictates that just and reasonable rates should not be knowingly and deliberately set obviously higher than the utility's cost to provide them service, at least without some policy justification (e.g., incentives, sharing of savings, etc.), so as to create a significant likelihood of the utility earning revenues that exceed its revenue requirement. Staff's rate proposal fails to achieve these basic principles.

Q. What about the way Staff creates its rate results in this failure?

A. Staff takes a different approach to establishing each type of charge, with little to no consideration of how those charges work together to recover the costs that make up the revenue requirement. And while Staff may argue that they are not making large load rates on an embedded cost basis, but are rather trying to capture some incremental cost of serving large loads instead, the assessment of costs still needs to reasonably reflect the actual costs that are and will be in Evergy's revenue requirement, and certainly should not recover the same costs multiple times across multiple different charge types, or reflect costs that do not exist. If Staff employed its large load methodology to develop rates for all of Evergy's retail service classifications, it is a virtual certainty that the sum total of the annual revenues from those charges would be higher, perhaps significantly so, than Evergy's cost-based revenue requirement. The piecemeal approach Staff has taken to selecting one basis for this charge over here, and a different basis for that charge over there is inconsistent, at best, and is entirely lacking in cost basis at worst. I will illustrate this by walking through some of the most obvious examples of the inaccurate and inconsistent ratemaking reflected in Staff's approach, starting with Staff's proposed Generation Demand Charge.

Q. How does Staff set the level of its proposed Generation Demand Charge?

A. Staff considers several methods, but ultimately bases its recommended rate on a method it describes as "[t]he cost of owning and operating the actual generation fleets of each utility, excluding the cost of fuel-related operating expenses, divided by the capacity requirements of existing ratepayers."[11] In essence, Staff attempts to calculate an annual revenue requirement for what most Class Cost of Service studies would call the Production Demand-related costs – i.e., the fixed (or as Staff would call them, "stable") costs of owning and operating Evergy's generation fleet. These costs generally include the depreciation and return on investment in those plants and the operations and maintenance expenses associated with running the plants,[12] other than the cost of fuel consumed by them. Staff then divides that total revenue requirement by Evergy's retail customer demand to create a demand charge to cover this category of costs.

On its face, this would seemingly be a reasonable method for determining this particular charge. However, it isn't reasonable because there are at least two significant flaws in the calculation. First, in Staff's determination of the rate base of the production function (i.e., Evergy's investment in production facilities and related inventories), Staff fails to include a rate base offset for Accumulated Deferred Income Taxes ("ADIT").[13] ADIT exists and provides a real benefit to customers by displacing the need for some

[11] Staff Rebuttal Report, p. 45, ll. 11-13.
[12] Ameren Missouri considers some non-fuel O&M expenses to be energy-related in its CCOS, but for simplification of this discussion I am not differentiating those from the majority of costs reflected in Staff's generation demand charge which the Company considers to be Production Demand-related costs.
[13] This is not the first occasion where Staff witness Sarah Lange has failed to account for ADIT in the analysis she has conducted for utility cases – see the Surrebuttal Testimony of Mitch Lansford in File No. EA-2023-0286, which is attached to my testimony as Schedule SMW-S1 for more details of other similar circumstances.

amount of utility capital and the cost that goes with it, and Missouri ratemaking reflects this benefit in utility revenue requirements and resulting lower rates paid by customers. Consideration of ADIT would certainly be a necessary element for determining "the cost of owning and operating the generation fleet." This omission overstates the rate base and thereby overstates the eventual rate that Staff calculates. Staff makes no mention of ADIT in its discussion of calculating this charge but this is a glaring omission that almost certainly significantly overstates this component of the rate. To illustrate the impact of this flaw for EMM only,[14] EMM's ADIT balance is around $800 million, based on Staff's workpapers. For sake of discussion, assume half of that is related to the underlying plant contemplated in this charge, ADIT would reduce Staff's charge by approximately 10% or around $6 million.[15] Not having the underlying allocation of EMM's ADIT balance, the actual number may be more or less, but the failure to consider ADIT, a basic and essential regulatory accounting component to determine cost of service, necessarily undercuts the reliability of Staff's proposed charge.

Staff does, however, mention a deliberate choice that it made to also exclude capacity revenues associated with the sale of excess generation capacity from Evergy's fleets as an offset to the revenue requirement. Staff claims that this is appropriate treatment of capacity revenues, saying, "Since the net effect of adding significant load is increasing the net expense or reducing the net revenue, it is not reasonable to allocate the revenue to

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[14] The same omission of ADIT occurs in Staff's workpapers for EMW.

[15] I calculated these estimates using Ms. Lange's workpaper titled "Confidential Misc workpaper 1" by adding a value of 1 to cell E511 on the tab "EMM RR", which causes her formula in cell E6 to add Deferred income taxes from row 511 into the net rate base. I also divided the ADIT in cell K511 in half to create the illustrative effect of the assumption that half of the ADIT related to production rate base, and also made that value negative so that adding it into the net rate base would represent a rate base offset rather than an addition. The result of these modifications is a demand charge of $14.11 instead of $15.61 as Ms. Lange originally calculated.

the customer causing the revenue reduction."[16] This logic is faulty. If it is true that there is excess capacity to sell today that produces the revenue that Staff is excluding from its calculation of its Generation Demand Charge, that means that there is more capacity than is needed to serve the current load (i.e., capacity that was sold wholesale to other load serving entities). However, Staff, in developing its rate, divides the cost of this capacity (more than needed to serve the retail load) by only using the current level of Evergy's retail load as the denominator of the rate calculation. This means there is a clear mismatch between the costs included in the numerator, which implicitly (due to the existence of capacity sale revenues) can support a higher level of load than the current Evergy retail load, and the denominator of the rate that *only* includes the current retail load. This is not a reasonable basis for establishing a retail charge. The numerator and denominator of the rate must be internally consistent. Staff could have, but didn't, do one of two things to remedy this inconsistency: 1) it could include the capacity revenues (that it chose to exclude) as an offset to the revenue requirement to reflect the revenue generating capability of the excess capacity (where in the future that revenue could come from either the market as capacity sales or from new customers such as large load customers that would make efficient use of the existing excess capacity), or 2) it could impute additional load into the denominator to represent the amount of large load (or other) customer load that could be served by the existing generation fleet. Either of these solutions would reduce Staff's Generation Demand Charge by making the rate calculation internally consistent.

Table 1 below illustrates this effect with a hypothetical, but plausible example. Assume a utility had 2,000 MW of generating capacity with a revenue requirement of $100

[16] Staff Rebuttal Report, p. 45 l. 25 – p. 46 l. 2.

million, but only 1,800 MW of load – i.e., they had 200 MW of "excess" capacity length.[17] Assume they sold that length in a given year for $4 million (a little over $50 per MW-day), resulting in a net revenue requirement for this production capacity of $96 million. Staff would calculate the rate as shown in line 6, which divides the gross revenue requirement in line 3 by the mismatching load in line 2 that is 200 MW lower than the amount of capacity available. However, in reality at that given time, the capacity sales revenues are real – meaning the appropriate rate should be as shown in line 7, which divides the full net revenue requirement in line 5 by the total customer load in line 2, which is how a rate would be set today in order to allow the utility an opportunity to recover its revenue requirement from its existing retail load. Now imagine in the future that 200 MW of new load (let's call it a single large load customer of 200 MW) initiates service. Consistent with Staff's theory, it *could* be appropriate to exclude the capacity sales when setting a rate for this future state. However, that is true *if and only if*, in that future state, the total gross revenue requirement is divided by the new level of retail load that will exist in that future state – i.e., 2,000 MW inclusive of the new 200 MW large load customer. This approach, which imputes the load that is expected in the future state, but excludes the capacity sales revenue (as it must, since the capacity will be used to serve the new 200 MW customer), represents a rate that would recover the utility's actual revenue requirement from its then current retail customer base. That rate is shown in line 8. Note that in both line 7 and 8 – i.e., the two methods that do not include mismatching numerators and denominators – the rate is *lower* than in line 6 which includes Staff's mismatch.

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[17] To simplify the example, I am ignoring losses and reserves in my hypothetical. However, the effect is the same when including those elements, there just would need to be more complexity shown that is unnecessary for the illustrative effect here.

Table 1 – Illustration of Staff's Mismatching Rate Calculation Methodology and the Two Possible Solutions to Fixing It

Line	Description	Amount
1	Total Capacity (kW)	2,000,000
2	Total Load (kW)	1,800,000
3	Gross Revenue Requirement Associated with Generation Capacity (Excluding Capacity Sales Revenue)	$100,000,000
4	Capacity Sales Revenues	$4,000,000
5	Net Revenue Requirement (Including Capacity Sales Revenues)	$96,000,000
6	Per kW Rate Using Staff's Method (Line 3 divided by Line 2 divided by 12 months)	**$4.63**
7	Per kW Rate Recognizing Capacity Sales Revenue, which represents revenue generating capability of excess capacity (line 5 divided by line 2 divided by 12 months)	**$4.44**
8	Per kW Rate Based on Exclusion of Capacity Sales Revenue but Imputing Retail Load that Can and Will Contribute to Covering Revenue Requirement in the Future (Line 3 divided by Line 1 divided by 12)	**$4.17**

Both of these issues – the omission of ADIT and the deliberate exclusion of capacity revenues – are just two examples of how Staff's proposal is outside of normal ratemaking, leading to the result of Staff's rate being too high to accurately reflect Evergy's production demand-related unit costs of serving large load customers. The result: large load customers would unfairly overpay.

Q. How does Staff calculate its proposed energy charge rates?

A. Staff uses a simple multi-year average of the locational marginal price ("LMP") at Evergy's SPP load CP Node as its energy charge. In doing so, Staff has used a *wholesale* market price as the basis for a *retail* service charge that, if properly determined, should reflect Evergy's actual energy-related costs of providing *retail* service – i.e., the costs that are or will be actually reflected in Evergy's revenue requirement.

Q. Does the wholesale market price represent the variable costs of providing energy to retail customers within Evergy's revenue requirement?

A. No, as discussed further below.

Q. Does Staff think they do?

A. Not according to the Staff's auditing function. When the Staff's auditing function employees build a revenue requirement in a Missouri electric utility's rate case, there is not a line item in Staff's revenue requirement model that reflects the utility's retail load times the LMP as a representation of the utility's variable energy-related costs. If Staff was right in this case – that the wholesale market price represents the variable cost of providing energy to retail customers – such a line item would necessarily have to be included in the revenue requirement**,** which would possibly support using the LMP itself as a basis for retail charges designed to produce revenues to cover that revenue requirement.

Q. Is there anything in Staff's revenue requirement model in a rate review that does represent the utility's embedded variable energy-related production costs within that revenue requirement?

A. Yes. Staff and electric utilities in Missouri calculate, directly from their revenue requirements, Net Base Energy Costs to use as the baseline for their Fuel Adjustment Clause ("FAC") tariffs. This calculation is a representation of the utility's actual variable production costs including fuel and purchased power net of off-system sales, which is also stated as a rate in the FAC tariff called the Base Factor. EMM's Base Factor of 1.8 cents per kilowatt-hour is lower than Staff's LMP-based energy charge of 2.7 cents per kilowatt hour for the same utility,[18] in a manner that is internally consistent with the revenue requirement used to establish base rates for the utility.

Q. It sounds like Staff's energy charge in this case is too high. Why does use of the LMP to develop Staff's energy charge create this result?

A. The only reasonable conclusion is that setting a discrete charge to cover Evergy's variable energy-related costs using the LMP will over-recover the energy-related production costs included in Evergy's revenue requirement. Staff witness Lange has misinterpreted the "buy all, sell all" nature of wholesale energy markets in her development of this charge, just as she did in her Class Cost of Service work in Ameren Missouri's most recent electric rate review.[19] While the mechanics of wholesale market design in SPP and MISO do result in the utility selling all generation into the market and buying all energy from the market that is needed to serve load, this necessarily results in *equal and offsetting transactions*[20] that FERC *requires* utilities to net for purposes of financial reporting. That netting has also been recognized explicitly by this Commission in its discussion of "true purchased power" in File No. ER-2014-0258 that established the treatment of transmission

[18] Rates as reported in Staff Rebuttal Report, p. 64, l. 14 for the average LMP-based energy rate and p. 65, l. 6 for the Base Factor.
[19] File No. ER-2024-0319. See the Surrebuttal Testimony of Ameren Missouri witnesses Nicholas Phillips and myself, excerpts of which are attached to this testimony as Schedule SMW-S2.
[20] While the LMP for the sale and purchase of energy are unlikely to be identical, the energy component of the LMP for both transactions is identical and therefore offsetting. Differences in LMP arise from the inclusion of the cost of transmission congestion and losses in the same transaction.

expenses within Missouri electric utilities' FACs.[21] And FERC's netting requirement (and this Commission's recognition of it in the FAC context) exists for good reason – the utility still plans and operates its generation on an integrated basis for the primary purpose of serving its own load, while protecting its customers from the very exposure to wholesale power prices that Staff's rate is based upon.

There is simply no expense on a utility's income statement associated with the purchase of power for load from the market unless the utility did not have sufficient generation of its own to cover its load, and it was therefore truly buying energy from the market at large instead of self-supplying it. That this expense does not exist on the utility's income statement is appropriate and is also illustrative of the reason it also does not exist in a utility's ratemaking retail revenue requirement. *Setting a charge at this level is not reflective of the utility's cost of providing service, period.*

Q. Does utilization of this charge in a retail rate systematically bias the rate to either over- or under-recover the revenue requirement?

A. Yes, in practice it would tend to systematically overrecover the revenue requirement. That is because the LMP itself provides almost all generators with sufficient revenue to contribute toward the recovery of that generator's fixed costs.

[21] To the extent that the Commission deviates from the FERC netting approach for purposes of ratemaking for Missouri electric utilities, as Staff has now suggested on multiple occasions, it would also be entirely appropriate and consistent with that decision to include 100% of transmission expense within the FACs of those utilities since any such deviation would necessarily mean that there is no such thing as "true purchased power".

Q. Aren't those the same fixed costs that are already being covered by Staff's Generation Demand Charge?

A. Yes, the very same. Recall that in SPP and MISO wholesale energy markets, the energy component of the LMP is equal to the offer price, typically based on the variable production cost of the *most expensive* unit operating in the market at a given point in time. That means that for *every other unit*[22] – those that are not the marginal, price-setting unit – the energy component of the LMP is *higher* than the variable cost of producing energy. When utilities in Missouri generate energy above and beyond their load requirements, these excess off-system sales produce margins (revenues in excess of the variable cost of generation) that reduce the revenue requirement for the benefit of all customers. That the LMP is sufficient to make *any* contribution to the fixed cost of a generator, and that Staff is using the LMP to set a retail energy rate when they already designed another rate to recover *all* of the fixed costs of generation,[23] necessarily means that Staff's rate *double counts* some amount of generation costs – i.e., it charges more than the cost of service, and by implication would result in a utility systematically recovering more than its revenue requirement associated with the provision of service to a customer. The result: once again, large load customers would unfairly overpay.

Q. Next, please discuss Staff's proposed "Stable Fixed Revenue Contribution Charge" and "Variable Fixed Revenue Contribution Charge."

A. I think it's a fair question which of Staff's proposed charges within its large load rate structure is the most removed from having a legitimate basis in cost of service

[22] Some exceptions exist when a higher cost unit is brought on for reliability purposes, but market designs also generally provide "make whole payments" that cover those higher costs to the generator, ensuring that they at least fully recover their variable costs of generation, like the marginal unit in the market does.
[23] And then some, due to the flaws in the generation charge development that I discussed previously.

analysis, but at the end of the day it is these charges that truly take the "overcharge large load customers" cake. Staff simply takes all of the other charges it has concocted and grosses them up by 24.77%.

Q. What is Staff's stated rationale for these gross up charges?

A. Staff suggests that these charges will contribute to Evergy's "day-to-day costs of doing business, such as computer systems, computer software, office buildings, office furniture, management employees, investor relations costs and expenses, other overheads, and the revenue requirement associated with policy-driven activities, such as solar rebates, electric vehicle charging stations, and supports for low-income rate payers."[24] I'll refer to this categorization as Administrative and General ("A&G") expenses, as that is the cost of service categorization into which many of these costs tend to fall. And Staff set the level of the charge based on a goal of achieving a gross up of 20% of the revenue from the rest of the charges, which Staff says is "essentially the floor for economic development discount recipients established by Section 393.1640 RSMo."[25] To be clear, this means that these day to day costs for which Staff is designing the charge to cover are not based on an assessment of those day to day A&G costs *at all*, but rather on a percentage of all of the utility's *other* costs, with that percentage coming from the economic development law Staff referenced.

Q. Is Section 393.1640 RSMo (the economic development law) an appropriate basis for establishing a cost-based rate for large load customers?

A. No. That section of the law exists to determine when and to what degree new and expanding customers can and should, for policy reasons in support of economic

[24] Staff Rebuttal Report, p. 57, ll. 24-28.
[25] Staff Rebuttal Report, p. 58, ll. 4-5.

development, be allowed to receive *discounted* rates from the level that the Commission has otherwise determined to be the just and reasonable cost-based rates for their class. Said another way, this section of law is all about developing a rate (or discount applied to a rate) that *intentionally deviates* from cost-based rates – again, for policy reasons. It has nothing whatsoever to do with how to *establish* a *cost-based* rate. The fact that the legislature saw fit to give certain customers discounted rates so long as they made a certain contribution to fixed cost recovery in no way means or even suggests that that level of contribution is reflective of the utility's A&G, or any other costs, of serving large load customers. Essentially, Staff's use of this percentage to create a rate applied to large load customer bills is nothing short of the establishment of an arbitrary charge that Staff seems to hope is at least loosely reflective of some costs of providing utility service.

Q. Is using an arbitrary adder, even if that adder is based on a number that appears in Missouri law associated with an unrelated topic (i.e., the conditions under which economic development discounts *from* cost-based tariffed rates may be offered), a reasonable basis for establishing the cost basis for a large load retail rate?

A. No, I can't even imagine why Staff would think it is.

Q. Do you have any other criticisms of the "Stable and Fixed Variable Revenue Contribution Charges"?

A. Yes. Above and beyond the arbitrary nature of the 20% statutory contribution that Staff points to as the basis of the charge, Staff then goes on to further gross up its gross-up rate by another amount, purportedly to cover income tax impacts of the charge.

Q. Should revenues that cover expenses in the revenue requirement be grossed-up for taxes as part of the ratemaking process?

A. No. When rates are designed to produce revenues that match, so as to create a one-for-one offset to, an expense (of course here, Staff's revenues only do that in the loosest of senses, but I think it is still a fair characterization of Staff's intent), there is *no resulting income tax impact*.

Q. Why?

A. When a utility receives rate revenues to cover a utility expense, it receives the revenue to cover an expense in exactly the same amount (e.g., if the expense to be covered is $100, the utility receives $100 in revenue). The net of the two is zero income. On what are taxes paid? Income, but since there is no income there is no income tax expense. The effect of Staff's gross-up of their gross-up factor for income taxes is just to pad Staff's rate for "phantom" tax expenses that do not exist in the context of the rate Staff is designing.[26] The result: a third time when large load customers would unfairly overpay.

Q. You indicate that each of these methodological flaws all are biased such that Staff's rate would overcharge large load customers. How does that square with Staff's analysis comparing the average per kilowatt-hour cost for large load customers under its tariff versus Evergy's proposed tariff?

A. For Evergy Metro, the average realized cost per kilowatt-hour Staff calculates associated its own rate proposal is significantly – approximately 14% - higher

[26] Again, I would encourage a review of the Surrebuttal Testimony of Mitch Lansford in File No. EA-2023-0286, which, again, I have attached to this testimony as Schedule SMW-S1, for another example of Staff witness Sarah Lange introducing "phantom" income taxes that do not exist in reality into a revenue requirement calculation as a part of her analysis. This is similar to her omission of ADIT I discussed earlier, which also occurred in her analyses in each of these cases. I have personal knowledge of the "threshold analysis" errors as documented in Mr. Lansford's testimony and schedules thereto in that case.

than the average cost based on Evergy's rate proposal[27] reinforcing the notion that Staff's rate is biased high. This comparison *includes* Evergy's proposed Rider SSR charge. Because Evergy's Rider SSR factors in forward-looking costs of accelerated generation, and given that Staff does not use any forecasts of future generation costs, one would expect Staff's rate to result in lower average per kilowatt-hour costs than Evergy's rate. However, the opposite is obviously true. Staff's rate for Evergy Metro is markedly higher than Evergy's rate, and higher than Evergy's cost of service would support.

For Evergy West, Staff's rate appears to produce an average per kilowatt-hour cost that is roughly comparable to Evergy's rate, inclusive of Rider SSR[28]. Again, my expectation would be for Staff's rate, which does not forecast future generation costs and therefore is exclusively based on historical cost analysis to result in a lower per kilowatt-hour cost. It doesn't, due primarily to the methodological concerns I have identified above. It is noteworthy that Staff's rate for Evergy West has a Generation Demand Charge that is less than a third of the comparable charge for Evergy Metro. While I am not an expert on Evergy's cost structure, it appears to me that a relatively low production rate base at Evergy West is partially muting some of the factors that would drive Staff's average cost even higher (i.e., when Staff's Stable and Variable Fixed Revenue Contribution charges are a calculated as a function of the costs reflected in the other rate elements, and the production rate base is relatively low, the A&G costs are not overstated as severely as they are at Evergy Metro). As Evergy West adds new generation into its production rate base, Staff's

[27] Based on the revised workpaper provided by Staff titled "Confidential Misc workpaper 1 Rebuttal workpaper – reviewing for DR responses", which was provided by the Staff after Staff recognized that it had made an error in the original workpaper. See Staff Response to Data Center Coalition Data Request No. 231, attached as Schedule SMW-S3.
[28] Based on the same revised workpaper.

methodology will quickly push the effect of its rate to be substantially higher than Evergy's rate (even inclusive of Rider SSR), mirroring the effect at Evergy Metro. As Staff itself recognizes, Evergy West will be adding substantial generation to its production rate base, including new combined cycle natural gas generation and additional renewable generation, recently approved by the Commission in File Numbers EA-2024-0292 and EA-2025-0075 (referenced in Staff's Report at page 12, ll. 1-2). The combined cycle generation alone will cause Evergy West to incur capital costs estimated to be nearly $1.6 billion (and this does not count additional generation additions for the solar generation the Commission recently approved).

Q. Please summarize your perspective on the cost basis of Staff's proposed large load rate.

A. It is internally inconsistent at best and totally lacking at worst. To be clear, as I stated at the outset of my testimony, I am not even delving into *every* problem with Staff's proposal. I have only commented on *some of the most egregious* problems with it. That said, the fact that Staff's Generation Demand Charge is systematically biased high by not reflecting ADIT or capacity revenues, that Staff's energy charge is systematically biased high by reflecting wholesale market prices that contribute to the same fixed costs (i.e., that double counts costs) as the Generation Demand Charge, and that the Stable and Variable Fixed Revenue Contribution charges are arbitrary, with no relationship to Evergy's actual costs, and then further biased high by grossing them up for phantom income taxes, suggests that Staff's rate is wholly unreasonable. If all of Evergy's retail rates were made this way, it would be in a position where it was likely to over-recover its Commission-determined revenue requirement and customers subject to the rate would simply pay too much. Large load customers would also pay too much here, meaning Staff's rate would obviously decrease the competitiveness and attractiveness of Missouri as a home for the investments in economic development that such customers can create.

V. THE NON-RATE TERMS OF SERVICE IN STAFF'S PROPOSAL ARE POORLY DESIGNATED

Q. Why are the non-rate terms of service in a large load proposal important?

A. Contract term length requirements, minimum bills, termination provisions, and credit and collateral requirements are critical to creating the revenue assurance needed to make the large investments that utilities may need to make in order to provide large load service without unjustly or unreasonably impacting existing customers. Such terms and conditions should be commercially reasonable in a manner that balances the need to provide reasonable revenue assurance with the need to avoid becoming unnecessarily onerous or inflexible for prospective customers. Such onerous terms will discourage the types of large load investments that can provide significant economic development benefits in the state.

Q. What terms in Staff's proposal do you find to be particularly onerous for customers in a manner that creates little additional revenue certainty to prevent unjust or unreasonable costs from impacting existing customers?

A. In the interest of brevity, I will just highlight the most extreme problem with Staff's proposal. That relates to the conditions that could trigger the payment of exit, or contract termination, fees for a large load customer. Staff's proposal includes an automatic trigger of exit fees any time a large load customer's demand falls below 50% of their contract demand for three consecutive months.[29] This is truly remarkable!

Q. How so?

A. Exit fees exist to ensure a long-term revenue stream is available to provide a fair contribution to the costs of long-lived assets. Because of the size of prospective customers and the size of the investments being accelerated to serve them, the potential exists for exit fees to be very substantial sums of money, even for entities the size of hyperscale data center customers. It is easily imaginable that under Evergy's or Ameren Missouri's proposed paradigms for exit fees to approach or exceed a *billion* dollars. That Staff would propose to trigger mandatory payment of such fees due to a three-month reduction in usage is preposterous. A three-month reduction in usage is *not* a clear indication of a permanent termination of service. Presumably such a customer would continue to exist on the system and provide retail revenues going forward. Yet, they would be required to pay the very substantial exit fees immediately despite the customer's likely intent to continue operations in the service territory. This simply makes no sense whatsoever.

Q. Is there an alternative to triggering exit fees to deal with temporary reductions in usage?

A. Of course, the solution reflected in Evergy's proposal in this case (as well as Ameren Missouri's in its large load case): minimum billing demands. If customer usage drops, large load customers would still provide a minimum revenue contribution under

[29] The period of time during which the customer can be below 50% of the contract demand can be extended based on notification from the customer if they know of an outage or other temporary condition resulting in load reduction.

Evergy's proposal due to the requirement that the minimum demand charge be at least 80% of the customer's contract demand. Staff appears to include no minimum demand billing requirement but fills the gap by taking the extreme measure of triggering massive exit payments based on what may simply be temporary usage declines. There has to be, and is, a better way. Staff's proposal clearly demonstrates a lack of thoughtfulness with respect to balancing large load customer interests with the interest of creating reasonable revenue assurance.

VI. STAFF'S REGULATORY LAG PROPOSALS ARE INAPPROPRIATE

Q. Please describe Staff's recommendation related to the accounting treatment for LLPS customer revenues?

A. Staff is recommending that, "until a rate case recognizing the customer at the full level of projected demand, the difference between the revenue for each charge considered for that customer in the last general rate case, and the current level of revenue for that charge will be recorded to a regulatory liability account"[30] for future refund to customers.[31] Essentially, Staff is proposing a new *one-way* tracker[32] to track any increases in LLPS customer revenues that occur between rate cases so that such amounts can be refunded to customers in a future rate case.

[30] File No. EO-2025-0154, Staff Recommendation, Appendix 2, Schedule 1.
[31] This treatment would be applicable to revenue from all charges except the Customer Charge, Facilities Charge, Demand Deviation Charge, Imbalance Charge, Capacity Shortfall Rate, the Capacity Cost Sufficiency Rider, and the RES Compliance Charge.
[32] The term "tracker" refers to a rate mechanism under which the amount of a particular cost of service or revenue item actually incurred by a utility is "tracked" and compared to the amount of that item currently included in the utility's rate levels. Any over-recovery or under-recovery of the item in rates compared to the actual revenues or expenditures of the utility is then booked to a regulatory asset or regulatory liability account, and would be eligible to be included in the revenue requirement used to set the utility's rates in its next general rate proceeding through an amortization. In the case of Staff's proposed one-way tracker, only over-recoveries would be tracked in the form of a regulatory liability.

Q. What is Staff's rationale for its proposal to track increases in LLPS customer revenues that occur between rate cases when increases in all other base rate revenues are not similarly tracked?

A. Staff states that it believes the positive regulatory lag[33] that will occur between any increase in LLPS customer revenue, and when that revenue is recognized in a rate case is somehow different than what it calls "ordinary" positive lag associated with customer growth. Staff's concerns are focused on the scale of the LLPS customer revenues and a *claimed* lack of offsetting revenue requirement increases.

Q. Please provide some overview about the role of regulatory lag in the ratemaking process in an historical test year jurisdiction like Missouri.

A. Ratemaking in Missouri is based on a review of the utility's cost of providing service over a historical period as compared to its revenues over the same period, subject to certain normalizations, annualizations and other regulatory adjustments. The use of a historical test year results in regulatory lag – i.e., inflation, new investment placed into service, and other variations in costs mean that the utility's rates frequently do not fully cover its current period costs when rates take effect. Put another way, while the historical test year-based revenue requirement is intended to be a proxy for what the actual revenue requirement will be once rates are set, it often is insufficient by a significant amount.

Q. Can regulatory lag result in a utility's rates being higher than its current period costs?

[33] Staff defines "positive regulatory lag" as regulatory lag that is beneficial to the utility, such as an increase in revenues or a decrease in the cost of service, and "negative regulatory lag" as regulatory lag that is detrimental to the utility, such as a decrease in revenues or an increase in the cost of service.

A. It's certainly possible, but it is also certainly far from the norm. We are in an industry (perhaps like most other businesses) with inclining costs over time. That is particularly true today where utilities are in an investment cycle to replace aging infrastructure and retiring generation facilities. Certain categories of cost may decline. Revenues may increase through load growth, which also has the effect of creating lag that offsets inclining costs and could theoretically result in a utility's revenue exceeding its revenue requirement. However, it is typically the case that regulatory lag negatively impacts Missouri utilities' ability to earn the rate of return authorized by the Commission due to the prevalence of increasing cost categories.

Q. What is the rationale for perpetuating a system that includes such an impediment to utilities earning the rate of return that the Commission authorizes as reasonable?

A. Regulatory lag tends to provide an incentive for cost control and efficient management of the business. The fact that increases in costs inherently diminish the utility's earnings until a subsequent rate case many months or years later gives utilities incentive to hold the line on costs to protect its earnings as best they can. While this incentive feature is real and important, it also can create challenges for utilities to make the investments needed in modern infrastructure while maintaining adequate financial results to attract the capital needed to invest in that infrastructure. In order to create an environment where utilities can attract that capital, a constructive regulatory framework that relies on regulatory lag should be as balanced as possible, meaning that a utility should not be expected to absorb earnings declines from *unfavorable* (negative) regulatory lag but, in the event that it does experience potential earnings enhancement from *favorable* (positive) lag, be expected to forego the benefit. Also, the availability of regulatory tools, such as Plant in Service Accounting ("PISA") that exists in Missouri law, is critical to ensuring the financial integrity of utilities through periods of substantial investment. Regulatory lag should not be so extreme as to prevent utilities from investing in their systems while still maintaining their financial integrity. That is why policy may have to change and adapt over time based on the facts and circumstances that exist for utilities.

Q. Would adoption of Staff's one-way tracker in this case represent a significant policy shift in the treatment of regulatory lag, and if so do the facts and circumstances warrant such a shift?

A. Yes, adoption of Staff's proposal would represent a significant policy shift and no, such a shift is not warranted. Even with the availability of PISA, Missouri electric utilities are still disproportionately experiencing unfavorable regulatory lag. As I just mentioned, a balanced policy would not expose utilities to such unfavorable lag for sustained periods of time only to take away all of the benefits of favorable regulatory lag when there are opportunities for utilities to offset some of the financial losses it has incurred due to the systematic earnings erosion that arises from the typical form of inclining cost regulatory lag.

Q. Has Staff previously testified that opportunities for positive regulatory lag are a critical ingredient in cost of service rate regulation?

A. Yes. The following testimony on regulatory lag was provided by Staff witness Keith Majors in File No. ER-2024-0319:

> **Q. What is regulatory lag?**
>
> A. Regulatory lag refers to the time between when a utility experiences a change in expense or revenue levels and when

> that change is recognized in rates that the Commission allows a utility to charge its customers. Regulatory lag can either increase or decrease a utility's actual earnings performance compared to its authorized rate of return in between rate cases. It can be beneficial to customers, as well as to utilities. When a utility's costs increase or its revenues decreases over a period of time, regulatory lag will tend to reduce the utility's profits, adverse to the utility, unless other circumstances either completely offset or mitigate the expense increases or revenue declines. When expenses are decreasing or revenues are increasing, regulatory lag will reward the utility with increased profits during the interval before the rates are changed by the Commission to address the decreased costs or increased revenues, which is a benefit to the utility. Regulatory lag provides the utility with either a penalty or a reward under traditional cost of service ratemaking where all costs are considered. This inherent penalty or reward system incentivizes a regulated utility to produce lower costs levels in between rate cases and to maximize efficiency.[34]

Another example from File No. ER-2024-0189, also from Staff witness Majors:

> Utility managers working with regulatory lag, much like managers of competitive businesses working with fixed prices of goods and services, seek to find ways to operate the business more efficiently to counteract expense or rate base increases or potential revenue decreases during the period of time of when prices are fixed, or regulatory lag. Conversely, utilities benefit from regulatory lag when expenses or rate base decrease or when revenues increase while rates remain unchanged. This is exactly why regulatory lag is a critical ingredient in cost of service rate regulation.[35]

Staff's prior testimony leaves no room for ambiguity—regulatory lag is meant to be a two-way street. As noted by Mr. Majors above, regulatory lag "can be beneficial to customers, as well as to utilities." However, Staff's proposal in this case upends the "inherent penalty or reward system" referenced by Mr. Majors as a critical ingredient in

[34] File No. ER-2024-0319, Keith Majors Rebuttal Testimony, p. 3 ll. 16 through p. 4 ll. 7.
[35] File No. ER-2024-0189, Keith Majors Rebuttal Testimony, p. 52 ll. 4-10.

cost of service rate regulation by removing any potential "rewards" available to the utility from growing revenues by attracting LLPS customers to its service territory.

Q. Have other parties to this case similarly acknowledged that opportunities for positive regulatory lag are a critical ingredient in cost of service rate regulation?

A. Yes. For example, OPC provided the following commentary on regulatory lag in File No. EW-2016-0313:

> Regulatory lag is not, in and of itself, inherently bad for the utility. The Commission recognizes that there are shared benefits, as well as risks, that run to both shareholders and ratepayers. Regulatory lag can serve to make the utility more efficient and more prudent, as well as provide the utility with retained benefits from synergies. Regulatory lag is a phenomenon which naturally occurs in ratemaking because the regulatory ratemaking process lags behind the actual costs and revenues incurred by the utility. See James C. Bonbright et al., “Principles of Public Utility Rates”, 96 (2nd ed. 1988). When a utility is under-recovering revenues, regulatory lag can be seen as deleterious to the utility. Noranda Alum., Inc., et al., v. Union Elec. Co. d/b/a Ameren Mo., 2014 Mo. P.S.C. Lexis 882, *29-30 (2014). When a utility is over-recovering revenues, regulatory lag can be seen as deleterious to the customer. Id. Traditional regulatory ratemaking is predicated on the idea that over a sufficient period of time the benefits and detriments of regulatory lag balance for both the utility and the consumer; sometimes a utility will over-recover, sometimes it will under-recover. See Alfred E. Kahn, The “Economics of Regulation: Principles and Institutions”, 48 (1989). In effect, regulatory lag creates the “quasi-competitive environment” that mimics how competitive firms operate and ensures that natural monopolies are not abusing their power. (Footnotes omitted.)[36]

As noted above by OPC, "traditional regulatory ratemaking is predicated on the idea that over a sufficient period of time the benefits and detriments of regulatory lag

[36] File No. EW-2016-0313, Initial Comments of the Office of the Public Counsel, p. 4 - 5.

balance for both the utility and the consumer; sometimes a utility will over-recover, sometimes it will under-recover." If Staff's intent is to eliminate any possibility for the utility to benefit from favorable regulatory lag, then ratemaking becomes one sided, and the benefits and detriments of regulatory lag will no longer balance.

Q. Please summarize your overall opinion respecting what the Commission should do with Staff's proposed one-way tracker.

A. It should reject it. Staff's recommendation to track any increases in LLPS customer revenues that occur between rate cases is entirely inconsistent with the ratemaking treatment of similar increases in other customer revenues associated with customer growth and replaces the "inherent penalty or reward system" referenced by Mr. Majors as a critical ingredient in cost of service rate regulation with an asymmetrical penalty system that removes the incentive for a utility to grow its revenues, thereby benefiting all customers by spreading the utility's fixed costs across higher delivery volumes and supporting economic development in the state of Missouri.

Q. As noted above, Staff suggested that the scale of potential LLPS revenues are a justification for differentiating the treatment of favorable regulatory lag associated with those revenues from "ordinary" regulatory lag. How do you respond?

A. The potential scale of the LLPS customer revenues alone does not constitute a valid basis for completely upending the inherent penalty or reward system that underlies traditional cost of service ratemaking. Staff's attempts to quantify the scale of potential favorable regulatory lag available to Evergy lack critical context regarding the unfavorable regulatory lag Missouri electric utilities are already exposed to.

Q. In developing their recommendation, did Staff provide any testimony or analysis on how the potential positive regulatory lag related to LLPS customer revenues compares to Evergy's historical and future uncovered costs resulting from negative regulatory lag?

A. No. Staff's recommendation is based on a completely one-sided analysis that fails to acknowledge regulatory lag cuts both ways. In making its decision on Staff's proposed one-way LLPS revenue tracker, the Commission should also consider the historical and likely future inability of the historic test year-based ratemaking paradigm to cover Missouri utilities' costs due to unfavorable regulatory lag and ensure that the benefits and detriments of regulatory lag reflect a reasonable balance for both the utility and the consumer.

Q. What are the primary sources of uncovered costs due to unfavorable regulatory lag?

A. While I cannot speak for Evergy, I would expect that Evergy and Ameren Missouri largely face similar sources of unfavorable regulatory lag in between rate cases. Some of the larger sources of unfavorable regulatory lag faced by utilities in Missouri are the 15% of depreciation expense and return on qualifying electric plant that is unable to be deferred to the PISA[37] regulatory asset,[38] increasing transmission costs due to the ongoing substantial expansion of the transmission network, and general inflationary pressures.

[37] PISA permits deferred recovery of 85% of the depreciation expense and return on rate base for certain property, plant, and equipment placed in service and not included in base rates.
[38] Per § 393.1400.2(1).

Q. Are you able to quantify these historical uncovered costs?

A. Not for Evergy. However, I can for Ameren Missouri. Over the last five years our earned return on equity[39] has consistently been below the 9.53 percent return on equity most recently authorized by the Commission in File No. ER-2014-0258. During that period, Ameren Missouri's average earned return on equity was just **_____** percent, or **___** basis points below the return on equity most recently authorized by the Commission. This represents an average of over **___** million per year in costs the revenue requirement used to set rates did not cover.[40]

Q. Does Ameren Missouri expect that it will continue to experience significant uncovered costs due to negative regulatory lag?

A. Yes, unless the primary sources of negative regulatory lag referenced above are addressed either by the Commission or through new legislation, we expect that future uncovered costs will continue to exceed **_________** per year, consistent with our recent historical experience, and will likely grow over time due to increasing levels of infrastructure investment.

Q. Please provide an example to illustrate the significant level of uncovered costs associated with a large capital investment despite PISA helping to offset a portion of the regulatory lag.

A. Below is an example of the regulatory lag faced by Ameren Missouri on a hypothetical $2 billion capital investment in a 1,600-MW simple-cycle natural gas energy

[39] Per Ameren Missouri's required quarterly surveillance reporting per 20 CSR 4240-20.090(6).
[40] Uncovered costs are calculated as the difference between Ameren Missouri's actual electric operating income per our quarterly surveillance reporting required by and submitted each quarter per the Commission's rules, and our rate base multiplied by the 9.53 percent return on equity most recently authorized by the Commission in File No. ER-2014-0258.

center with an estimated 45-year useful life.[41] Using the weighted average cost of capital ordered by the Commission for purposes of calculating PISA deferrals in Ameren Missouri's most recent rate review,[42] I have calculated the level of uncovered costs due to the 15% of the return and depreciation on the capital investment not included in the PISA regulatory asset. Assuming the project is placed in service shortly before the true-up date in a rate case and the investment is subject to only 5 months of lag until the new rates incorporating the investment become effective,[43] Ameren Missouri will still experience $11 million in unfavorable regulatory lag, and that is on just that one investment with optimal timing of its in-service date. If Ameren Missouri is unable to perfectly time a rate case in order to align the true-up date with the project's in-service date, the uncovered costs will increase rapidly as shown in Table 2 below.

Table 2 – Regulatory Lag on Generation Investment with Different Rate Case Timing

Project In-Service Date	Months of Lag	Uncovered Costs
At true-up date	5 months	$11 million
6 months prior to true-up date	11 months	$25 million
12 months prior to true-up date	17 months	$39 million

The above example does not account for additional unfavorable lag arising from the 15% of investment to which PISA does not apply, including the balance of the $16.2 billion, five-year plan Ameren Missouri submitted to the Commission as required by the

[41] Ameren Missouri plans to add 1,600 MWs of natural gas-fired simple-cycle generation by 2030, which includes the 800-MW Castle Bluff Natural Gas Project and the 800-MW Big Hollow Natural Gas Project.
[42] File No. ER-2024-0319.
[43] For example, in Ameren Missouri's most recent electric rate case (File No. ER-2024-0319), an investment placed in service prior to the December 31, 2024 true-up date would have experienced approximately 5 months of regulatory lag before new rates became effective in June 2025.

PISA statute in February of this year, which includes continued investments to replace aging transmission and distribution infrastructure and otherwise to enhance grid reliability and resiliency. That plan incorporates hundreds of different projects, all with different in-service dates. Therefore, it would be impossible to time each project perfectly with the true-up date in a rate review. Using the above illustrative example, one can extrapolate this outcome across a cumulative investment of over eight times this size over the next five years under that plan to see that Ameren Missouri will continue to experience significant uncovered costs in relation to its capital investments. I expect that Evergy faces similar pressures from regulatory lag.

Q Are there any other omissions from Staff's analysis that paint an overly rosy picture of the positive regulatory lag Evergy may stand to benefit from?

A. Yes. Staff's attempt to quantify $177 million of positive regulatory lag related to a hypothetical 384 MW LLPS customer is drastically overstated due to Staff's erroneous assumption that 26%[44] of total LLPS customer revenues over the entire term of their 15-year Electric Service Agreement ("ESA") would be received during an assumed initial four-year period that would occur prior to any LLPS customer revenues being reflected in a rate case.[45] This example is flawed and extremely biased to the high side for numerous reasons. First, in reality, I would expect that Evergy's LLPS customers would be expected to gradually ramp up to their full demand over a number of years. I know that is true of Ameren Missouri's large load customer expectations and based on my interactions with large load customers it is my understanding that it is generally true for customers of

[44] Calculated by Staff as an assumed four-year period prior to the LLPS customer revenues being reflected in a rate case divided by the full fifteen-year term.
[45] Staff Rebuttal Report, p. 73, ll. 22-24.

this type nationwide. Appropriately factoring in a realistic ramp up period would substantially reduce the proportion of LLPS customer revenues expected to be received in the first four years of its ESA. Next, it seems *highly* implausible to me that, given the generation investments I understand Evergy to be making, that it would not have any rate cases until the end of that four-year period, even considering any benefit of regulatory lag associated with the large load revenues. But if Evergy did manage to have no rate increases for that four-year period because of the favorable regulatory lag, it seems like that alone would be a pretty huge affordability win for everyone. However, the additional rate cases that I'm sure would happen would necessarily result in such revenues being reflected in rates far sooner than the end of the first four years of such large load service. Additionally, in those intervening rate cases during which the large load customer was ramping up, invariably the large load customer revenues would be considered for annualization and normalization based on the facts and circumstances that are known and measurable as of the true-up date of a general rate case. Such regulatory adjustments would further reduce the positive regulatory lag Evergy would experience during the ramp up of large load customer usage to full load relative to Staff's overly simplistic reliance on annual revenues and a four-year period without rate cases in its analysis.

Q. Staff also differentiated LLPS lag from what it characterizes as "ordinary" positive lag associated with customer growth by suggesting that LLPS revenue will not have offsetting revenue requirement increases. Do you agree with Staff's assertion that positive regulatory lag is only acceptable when offset by corresponding increases to the revenue requirement?

A. Absolutely not. Staff's assertion that favorable regulatory lag from attracting new sources of revenue is only acceptable when offset by corresponding unfavorable regulatory lag is paradoxical. This is the same as arguing that favorable regulatory lag should not exist at all and directly contradicts Staff's prior testimony that "Regulatory lag can either increase or decrease a utility's actual earnings performance compared to its authorized rate of return in between rate cases. It can be beneficial to customers, as well as to utilities."[46]

Q. Is Staff's claim that there will be no offsetting revenue requirement increases even accurate?

A. No. The acceleration of generation investments will create larger amounts of unfavorable regulatory lag than utilities would otherwise experience. There are also other categories of costs that are likely to increase with large load service. For example, at least for Ameren Missouri (Evergy may have similar dynamics in SPP), MISO load-based transmission charges, which are for the most part not included in the FAC or any other tracking mechanism or rider, will increase along with the increase in load. Under Staff's proposal, the utility would be forced to absorb these cost increases while the revenues that could cover them would be deferred in Staff's one-way tracker for future return to customers. This is patently unfair.[47]

[46] File No. ER-2024-0319, Keith Majors Rebuttal Testimony, p. 3 ll. 19 – 21.
[47] It is made even more unfair by Staff's consistent and aggressive opposition to utility proposals to establish a *two-way* transmission cost tracker due to the ongoing significant negative regulatory lag electric utilities in Missouri face from rising transmission costs, negative regulatory lag that is expected to continue. See File Nos. ER-2010-0356, ER-2012-0174, ER-2014-0130, ER-2021-0312.

Q. What other concerns do you have with respect to Staff's proposals related to regulatory lag?

A. Staff's proposals are not only inappropriate from a policy perspective, but they are severely flawed in terms of the mechanics of the proposals. I want to be unequivocal about the fact that my recommendation is to reject Staff's one-way tracker outright for policy reasons. However, I would be remiss if I did not include in the record evidence of the mechanical flaws that exist in Staff's proposals.

Q. What is the first flaw?

A. Staff proposes to defer substantially all new large load revenue increases in between rate cases.[48] However, through the standard operation of Missouri FACs, a not-insignificant portion of these revenues will *already flow back to customers*. That is because the Missouri electric utility FACs are based on a comparison of the net energy costs experienced by the utility to the net energy costs that are already reflected in the revenue requirement used to set base rights, i.e., the net base energy costs. When base rate revenues increase subsequent to a rate case, as they would with the ramp up of a large load customer, the revenue contribution of that customer offsets increases in net energy costs that would otherwise flow through the FAC. In effect, this mechanism returns to customers the benefit of that portion of the large load revenues that are already built into base rates to cover net energy costs. This is illustrated in Evergy Metro's FAC tariff in the following formula for the calculation of the Fuel and Purchased Power Adjustment ("FPA"):

[48] Staff does identify a few rate elements whose revenues would not be included in the tracker, but the overwhelming majority, over 97% based the detail of charges on the "Rate Elements" tab of the workpaper of Sarah Lange titled "Confidential Misc workpaper 1", of new large load retail revenues would be subject to this deferral.

> FPA = 95% * ((ANEC – B) * J) + T + I + P, where B is equal to the utility's total load times the Base Factor of approximately 1.8 cents per kilowatt hour – i.e., the amount of retail revenue per kilowatt hour that is already built into base rates to cover net energy costs.

The fact that B is subtracted from Evergy's ANEC (Actual Net Energy Costs) illustrates that the increase in revenue is offsetting costs that would otherwise be borne by all customers. Therefore, tracking the entire revenue increase from large load customers between rate cases would double-count a substantial portion of new large load revenues and pass them back to all customers twice. Such an outcome is absolutely inappropriate, unjust, and unreasonable.

Q. Are there other problems with Staff's regulatory lag proposals?

A. Oh yes, indeed. The next problem is even far more egregious than the one I just described. Staff's double counting reaches incredible proportions through their proposal to adopt an "N-Factor"-like mechanism within Evergy's FAC tariff. To understand why requires knowing some context about what the "N-Factor" was. The "N-Factor" was a mechanism employed in Ameren Missouri's FAC tariff when it provided service to an aluminum smelter (Noranda) that was at a similar scale to the large load customers that are the subject of this case. The N-Factor was a mechanism to mitigate impacts of regulatory lag when significant load reductions occurred for what was then by far the largest load in the state of Missouri. The operation of the N-Factor recognized that, if Noranda's load decreased, then Ameren Missouri's retail revenues also decreased materially. At the same time Ameren Missouri's net energy cost decreased (because we either had more generation available to sell off-system as a result the reduced retail load obligation, or we had to purchase less energy from the market to serve that retail load obligation, with either of these possibilities reducing net energy costs). Essentially, prior to the institution of the N-Factor, the reduction in retail revenue was retained by Ameren Missouri as a negative impact of regulatory lag, but the reduction in net energy cost arising from the same source was passed through the FAC to the benefit of other customers. The N-Factor "carved out" the reduction in net energy costs from the FAC and allowed Ameren Missouri to retain the benefit of the lower net energy costs in order to offset and partially mitigate its lower retail revenues. The solution was in effect two-way: Ameren Missouri had to absorb the revenue reduction but also got the retain the benefit of the corresponding expense reduction.

Q. So how is Staff's proposed adoption of an N-Factor-like mechanism double counting?

A. Because Staff has *already* proposed to capture the regulatory lag associated with revenues from large load service in its proposed one-way tracking mechanism so that the utility would not benefit from it, yet Staff also recommends adoption of an N-Factor-like mechanism that would shift the *increase* in net energy costs (the flip side of the decrease in net energy costs experienced when large load such as that associated with the aluminum smelter declined) out of the FAC where it would otherwise be passed on to all customers back to the utility. So, the Staff proposes to both shift the positive regulatory lag that the utility would experience to the benefit *of customers* through the one-way tracker, and shift the negative regulatory lag associated with the change in net energy costs to the detriment of *the Company*. The net effect is to "double dip" and move from a condition of net favorable regulatory lag for the utility to a position of net negative regulatory lag for the utility. It's certainly possible that Staff did not even recognize the existence of the double counting in its proposal due to its extreme complexity, but whether the effect is deliberate or not, it makes no sense whatsoever and is patently unfair, unjust, and unreasonable. And this reality is clearly evident in the text of Staff's rebuttal report, where Staff witness Sarah Lange states:

> Depending on the actual size of the LLPS customer and the wholesale cost of energy in the future, EMM and EMW will recover substantial portions of the LLPS customer's cost of energy through the FAC, and fully recover that cost of energy through LLPS rates.[49]

It should be obvious that EMM and EMW will not "fully recover the cost of energy through LLPS rates," as Staff claims, if all of the revenue generated by those rates is tracked and returned to customers via Staff's one-way tracker. Staff simply cannot have it both ways and ask to track the revenues to return to customers and also shift the increase in net energy costs to the utility.

Q. Can you please provide an example that would illustrate the totality of the effects from Staff's regulatory lag proposals, and why they are unjust and unreasonable?

A. Yes. See table 3 below.[50] While the table reflects an illustration, it is based on realistic assumptions. Assume that, subsequent to the conclusion of a rate case, a utility gains a large load customer that uses about a million Megawatt-hours ("MWh") per year. Assume further that the retail tariff that this customer takes service under has an effective all-in rate of approximately $60/MWh and that the utility in question has an FAC Base Factor of $15/MWh and that the average market price of energy for the time period of the new service provided to the customer is approximately $30/MWh. Based on those

[49] Staff Rebuttal Report, p. 65, ll. 10-12.
[50] Note that for simplicity, I have not tried to capture the effects of the 95/5% sharing mechanism on the FAC, which would slightly alter these amounts. But the simplified example is still quite illustrative of the order of magnitude of these effects.

assumptions, when the customer begins taking service, the utility will, all else equal, experience favorable regulatory lag – see line 3 in Table 3 below. The new revenues of $60 million per year are offset for the portion of those revenues that effectively is returned to customers through the standard operation of the FAC – i.e., the new load volume times the Base Factor (see the tariff formula description earlier in this section of my testimony). The FAC offset in this example if $15 million (1 million MWh times the base factor of $15/MWh). And the net favorable regulatory lag to the utility is $45 million ($60 million of incremental retail revenue less the $15 million that effectively is returned to customers through the standard operation of the FAC as a result of the base rate contributing to the recovery of net base energy costs) – see lines 6 and 7 in Table 3 below. While, as I have stated repeatedly, I do not think it is good policy to "recapture" this regulatory lag for customers in a system that inherently produces mostly unfavorable lag for utilities, Staff's goal is presumably to do exactly that and recapture this amount. However, under Staff's approach in this case – its use of a one-way tracker – it would recapture the full $60 million of new revenue. This alone reverses the regulatory lag into a negative position of $15 million for the utility due to the fact that Staff failed to recognize the revenues that are already effectively retuned to customers through the standard operation of the FAC. But under Staff's approach in this case, the negative outcome for the utility gets even worse than the $15 million the utility already lost. This is because, despite the fact that Staff has already reversed the regulatory lag from favorable to unfavorable for the utility, it goes on to take another step (the N-Factor like approach Staff takes) to carve out the increase in net energy costs experienced by the utility from serving the new large load (i.e., the $30 million in market energy costs less the $15 million in contribution toward those that comes through the customer's base rate revenues as reflected in the base factor) and force the utility to absorb that cost increase of $15 million. The totality of these Staff proposals is to turn $45 million of favorable regulatory lag into $30 million of unfavorable regulatory lag. Again, such a result would be unjust and unreasonable.

Table 3 – Totality of Effect of Staff's Regulatory Lag Proposals

Line	Description	Amount	Calculation
1	New Large Load Usage Subsequent to a Rate Case (MWh)	1,000,000	
2	Average Large Load Retail Rate ($/MWh)	$60	
3	New Large Load Retail Revenue Subsequent to a Rate Case	$60,000,000	Line 1 x Line 2
4	FAC Base Factor ($/MWh)	$15	
5	Market Price of Energy ($/MWh)	$30	
6	Large Load Revenues Implicitly Returned to All Customers through Standard Operation of FAC	$15,000,000	Line 1 x Line 4
7	Regulatory Lag Experienced by Utility Prior to Staff's Proposals	**$45,000,000**	Line 3 - Line 6
8	One-way Tracker Impact of Deferring All Revenue for Return to Other Customers	-60,000,000	Opposite of Line 3
9	"N-Factor" Impact (Carves Out the increase in Net Energy Costs Based on the Difference Between the Market Price of Energy and the Base Factor to All Customers for Each MWh Served)	15,000,000	(Line 5 - Line 4) x Line 1
10	Regulatory Lag Experienced by Utility After Staff's Proposals	**-30,000,000**	Line 7 + Line 8 - Line 9

VII. OTHER ISSUES

Q. Are there any other topics you would like to address from the Staff Recommendation in this case?

A. Yes. While again I am not attempting to provide a point-by-point rebuttal of each aspect of the Staff Recommendation that I disagree with, I do want to address one additional topic. Staff's recommended early termination provisions include the following:

> *F. The remaining termination charge revenue shall be recorded as a regulatory liability and treated as an offset to production ratebase in perpetuity, without amortization;*[51]

Staff's proposal to treat a regulatory liability as a perpetual rate base offset is completely at odds with relevant and basic accounting rules. Such a proposal runs contrary to over 100 years of regulatory precedent[52] and is incompatible with the fundamental ratemaking principle of intergenerational equity that has historically been considered by the Commission in setting just and reasonable rates. The ratemaking principles behind promoting intergenerational equity dictate that the customers who could see their rates increase due to the early termination of a Service Agreement by an LLPS customer should receive any benefits that accrete to customers from the termination charge revenues, rather than transferring that benefit to completely unaffected customers decades or even centuries into the future.[53] The Commission (and indeed Staff historically) has recognized the importance of seeking to maintain intergenerational equity.[54]

Staff's proposal is also inconsistent with the requirements of the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USofA").[55] By

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[51] File No. EO-2025-0154, Staff Recommendation, page 68 ll. 9.

[52] Union Electric Company was incorporated in Missouri in 1922 and, over the past 103 years, has never been ordered by the Commission to treat a regulatory liability as an offset to rate base in perpetuity as is being requested by Staff in this case. I am also unaware of any other instances of the Commission ordering a Missouri utility to treat a regulatory liability as a perpetual rate base offset.

[53] While I am only addressing the most egregious example of how the Staff Recommendation diminishes, rather than promotes, intergenerational equity, the Staff Recommendation includes various other amortization proposals that are similarly ill-conceived and completely unsupported. For example, the Staff Recommendation proposes the creation of multiple new regulatory liabilities that it requests be treated as an offset to production ratebase with a 50-year amortization. However, Staff provides absolutely no rationale as to why it believes a 50-year amortization would be appropriate for the balances in question.

[54] See, e.g., *Re: Missouri Public Service*, Report and Order, File No. ER-97-394 (Mar. 18, 1998) ("The principle of intergenerational equity states that the costs of providing the service should be borne by the generation of ratepayers that caused the costs to be incurred, not by an earlier or later generation. * * * It would be ill-advised to adopt the tax life approach because it does not reflect the item's useful life and violates the concept of intergenerational equity.").

[55] 20 CSR 4240-20.030 requires every electrical corporation subject to the Commission's jurisdiction to keep all accounts in conformity with the FERC USofA.

definition, a regulatory liability is an amount that is probable of being refunded to customers due to the rate actions of a regulator.[56] Given that Staff is proposing that such amounts *never* be returned to customers, Staff is proposing that Evergy be ordered to record a regulatory liability for an item that would not even meet the definition of a regulatory liability.

In short, Staff's proposal is inconsistent with fundamental ratemaking principles, over 100 years of regulatory precedent in Missouri, and accounting requirements and provides yet another example of why Staff's unjust and unreasonable recommendations in this case should be entirely discarded by the Commission.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

[56] The definition of a "regulatory liability" is established by 18 C.F.R., Part 101, USofA, Definitions, 31. Regulatory Assets and Liabilities.

Exhibit No.:	
Issue(s):	Project modeling
Witness:	Mitchell Lansford
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	EA-2023-0286
Date Testimony Prepared:	December 15, 2023

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EA-2023-0286

SURREBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
December, 2023

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SURREBUTTAL TESTIMONY

OF

MITCHELL LANSFORD

FILE NO. EA-2023-0286

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Mitchell Lansford. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom are you employed and what is your position?

A. I am employed by Ameren Services Company as Director of Financial Reporting and Regulatory Accounting. Ameren Services Company provides various support services to Ameren Missouri and its affiliates, including finance, treasury, environmental, health and safety, accounting, and legal.

Q. Please describe your educational background and employment experience.

A. I received Bachelor of Science and master's degree in accountancy from the University of Missouri at Columbia in 2008. I am a licensed Certified Public Accountant in the State of Missouri and a member of the American Institute of Certified Public Accountants. From 2008 to 2017, I worked for PricewaterhouseCoopers LLP, most recently as a Senior Manager in its assurance practice. In that capacity, I provided auditing and accounting services to clients, primarily in the utility industry. From 2017 to 2019, I worked for Ameren Services Company as the Manager of Accounting Research, Policy, and Internal Controls. My primary duties and responsibilities included accounting analysis for non-standard transactions, overseeing the implementation of new accounting guidance, implementation of new accounting policies, and assessments of the internal control environment. From 2019 to October 2023, I worked for Ameren Missouri in multiple regulatory accounting roles, including as Director of Regulatory Accounting effective in April 2020. In November 2023, I became the Director of Financial Reporting and Regulatory Accounting.

Q. What are your responsibilities in your current position?

A. In my current position, my primary duties and responsibilities include preparation of the revenue requirement for Ameren Missouri rate filings, preparing written testimony for rate, regulatory, and audit proceedings, and testifying before the Missouri Public Service Commission. As of November 2023, my responsibilities were expanded to include oversight of financial reporting for Ameren Corporation and its subsidiaries.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will identify, explain, and demonstrate that Staff's "threshold analysis," which is tied into Staff's theory that if the projects at issue in this docket don't pay for themselves they should not be approved (Company witness Steve Wills addresses the flaws in that theory in his surrebuttal testimony), contains serious flaws that render its modeled results completely inaccurate, irrespective of whether this threshold analysis has any relevance in this case in the first place. Specifically, the workpapers of

Staff witness Sarah Lange, whose testimony sponsors and reports on the results of Staff's threshold analysis, demonstrate that the analysis contains at least three (and likely more) significant and fundamental flaws:

> 1. The threshold analysis fails to reflect the reduction in rate base that occurs via accumulated depreciation and the effect of that reduction in reducing the deferred return component of Plant In-Service Accounting ("PISA") (over the life of the project), and thus overstates the cost to customers of PISA, which artificially inflates Staff's claimed cost of the projects to customers;
>
> 2. The threshold analysis fails to reflect one of the most fundamental requirements of estimating the cost of projects to customers, that is, reducing rate base by Accumulated Deferred Income Taxes ("ADIT") produced by the projects, which in turn lowers the cost of the projects to customers – a mistake that overstates that cost to customers across the four projects by approximately $251 million; and
>
> 3. The threshold analysis overstates income tax costs arising from the projects because Staff's modeling reduces energy and capacity sales revenues the projects are estimated to produce by "phantom" income taxes that will not exist because energy and capacity revenues do not increase the Company's net income and generate no income taxes. Instead, they are passed back to customers as a reduction to rates – this mistake overstates the combined cost of the projects by approximately $768 million.

The latter two mistakes, which are easily quantified, total approximately $1 billion and if one were to use Staff's threshold analysis after correcting those mistakes, Staff's analysis gives exactly the opposite conclusion to that conclusion drawn by Staff, that is, instead of the projects adding to customer revenue requirements they in fact would lower customer revenue requirements under Staff's assumptions.

Q. Are you sponsoring any schedules?

A. Yes, I am sponsoring Schedules ML-S1 through ML-S8.

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

A. The schedules represent the following:

- Schedule ML-S1 - Staff Witness Sarah Lange's workpaper underlying her threshold analysis included in rebuttal testimony in this case.
- Schedule ML-S2 - Staff workpaper (EMS run[1]) reflecting its revenue requirement recommendation at true-up from File No. ER-2022-0337. File No. ER-2022-00337 was the Company's most recent rate case.
- Schedule ML-S3 - Staff Witness Sarah Lange's workpaper underlying her threshold analysis included in rebuttal testimony in this case (the same as Schedule ML-S1), with two corrections made by the Company for errors I will discuss later in my testimony.
- Schedule ML-S4 - Staff workpaper (EMS run) reflecting its revenue requirement recommendation at true-up from File No. ER-2022-0337 (the same as ML-S2), with one edit to off-system sales revenue made by the Company for illustrative purposes that I will discuss later in my testimony.
- Schedule ML-S5 – The Company's project model workpaper supporting the results included in the direct testimony of Company witness Matt Michels for the Bowling Green project, assuming election of the Investment Tax Credit ("ITC").

[1] Staff's EMS run establishes Staff's recommended revenue requirement in rate cases.

- Schedule ML-S6 – The Company's project model workpaper supporting the results included in the direct testimony of Company witness Matt Michels for the Cass County project, assuming election of the ITC.
- Schedule ML-S7 – The Company's project model workpaper supporting the results included in the direct testimony of Company witness Matt Michels for the Vandalia project, assuming election of the ITC.
- Schedule ML-S8 – The Company's project model workpaper supporting the results included in the direct testimony of Company witness Matt Michels for the Split Rail project, assuming election of the ITC.

Q. What is the source of Schedules ML-S1 and ML-S2?

A. The file that comprises Ms. Lange's threshold analysis (Schedule ML-S1) was downloaded directly from EFIS using the link provided by Staff Department Diana Vaught on October 13, 2023. The file that comprises Schedule ML-S2 was received via email from Staff member Karen Lyons on March 16, 2023. The files that comprise those schedules have not been modified or altered in any way and all data and formulas contained in them remain exactly as we received them from Staff.

III. STAFF'S ATTEMPT AT ECONOMIC MODELING CONTAINS SIGNIFICANT ERRORS

Q. After criticizing the Company's economic modeling, Staff witness Lange presents modeling which she has performed, which she calls Staff's "threshold analysis," to support Staff's assessment of the Solar Projects.[2] What observations do you have related to Staff's "threshold analysis"?

A. Company witness Steve Wills' surrebuttal testimony addresses why Staff's threshold analysis modeling is irrelevant, that is, he discusses why it is predicated on a faulty premise that the market revenues created by the Solar Projects must pay for the entire cost of the resource, and why acceptance of such a premise would reflect poor regulatory policy. Putting aside those points, however, it is critical for the Commission to understand the *foundational errors* that Staff has made in its threshold analysis modeling, which irrespective of the appropriateness of Staff's premise (or inappropriateness), render the results produced by Staff's modeling *wildly inaccurate*. In fact, I will demonstrate that when these errors are corrected, Staff's conclusions about the proposed Solar Projects reverse and even if a "threshold analysis" of some kind were appropriate, with those corrections Staff's modeling supports continued evaluation of the Solar Projects, rather than rejection of any of them.

Q. Please elaborate on the errors in Staff's threshold analysis modeling related to PISA.

A. Staff's threshold analysis models are poorly executed and contain multiple mechanical flaws associated with PISA that significantly overstate the overall cost to

[2] Cass County, Split Rail, Bowling Green, and Vandalia.

customers of the projects. The first sign that Staff's modeling of PISA is inaccurate and is readily observable in Ms. Lange's workpaper, when examining the details of the first assumed rate case after a project is placed in service. To illustrate this, see Figure 1 below, which is a screenshot of Ms. Lange's threshold analysis workpaper (Schedule ML-S1) related to Staff's modeling of the Cass County project. The figure demonstrates the recognition of approximately $7.2 million in depreciation expense (column “2024”)[3] as a part of the PISA regulatory asset – and yet, in the very next column (2025) there is zero accumulated depreciation reflected in the net plant calculation and thus Staff has failed to reduce the rate base to recognize the effect of the depreciation that occurred in 2024.[4] This is an obvious error because for every dollar of depreciation expense incurred, accumulated depreciation must increase[5] (which reduces rate base dollar for dollar), yet Staff's modeling completely overlooked this fundamental reality. If there truly had been approximately $7.2 million of depreciation expense already accumulated for PISA purposes in 2024, that depreciation expense must cause the line labeled "Net Plant" to have a lower value than the line labeled "Original Depreciable Plant" in the next period. **

[6]

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[3] The recognition of $7.2 million of depreciation expense in 2024 in it of itself is illogical given the project is expected to be placed in-service on December 31, 2024. Staff’s calculation of this amount approximates a full year of depreciation when the project will only be in service for one day of that year.
[4] The workpaper uses the term "reserve" which is synonymous with "accumulated depreciation."
[5] That is to say without violating the requirements of the Federal Energy Regulatory Commission’s Uniform System of Accounts with which, under the Commission's rules, the Company must comply.
[6] $301,989,833 Non-Land Capital Costs per Schedule ML-S1, tab Cass Illinois, cell H86 divided by 30 years per cell K86 equals $10,066,328, which is 100% of depreciation expense recorded in a year for this project.

** The result is Staff's modeling reflects greater rate base levels and therefore greater costs to customers each year throughout the 30-year life of the project. This same error has been repeated for each of the other projects in this case as well.

Figure 1 – Staff's Flawed Modeling of PISA **

**

Additionally, in her scenarios described as 1-year and 4-year rate case frequencies, Staff has entirely ignored the effects of PISA that occur *after* the first assumed rate case post-the in-service date of the project (2025). The deferred return component of PISA requires that changes in accumulated depreciation (less retirements) and accumulated deferred income taxes be tracked between all cases. What this means is that, while customer base rates do not go down between rate cases to reflect the lower return (resulting from incremental accumulated depreciation over time) the Company would get if base rates were reset continuously, under the PISA mechanism we are required to track and defer this decrease in return which is then credited to customers in the next rate case. Ms. Lange captures the regulatory lag in her rate case scenarios that causes *increased* costs to customers (deferring 85% of the depreciation and return on new qualifying plant placed in service that occurs before a project is included in base rates) but fails to capture the *benefit* of PISA that customers experience as accumulated depreciation accrues throughout the rest of the life of the project.

Q. Have you identified any other errors in Staff's threshold analysis modeling unrelated to its handling of PISA?

A. Yes. Quite frankly, there are numerous other errors in Staff's threshold analysis modeling and Ms. Lange's underlying workpapers that I have identified, and I suspect there are probably more that I have yet to identify as of this date. In my attempt to decipher Staff's modeling it became clear that there were significant errors in addition to the errors in the modeling of PISA I just described, including related to ADIT and the calculation of income taxes, which I will address below.

Q. What error have you identified related to Staff's threshold analysis modeling of ADIT?

A. Staff's modeling completely ignores the customer benefits that result from ADIT – this significant source of reduction to rate base and therefore to the revenue requirement is literally absent from the calculations in Ms. Lange's workpapers. How or why this benefit is absent I cannot say, but I am sure Staff as a whole understands how ADIT impacts the revenue requirement and understands the fact that it reduces the revenue requirement to the benefit of customers, as evidenced by Staff's own treatment of ADIT in the ratemaking process on numerous occasions.

In fact, during the Company's recent electric rate review (File No. ER-2022-0337), Staff witness and accountant Matthew Young testified,

> The net balance in the deferred tax reserve represents a source of cost-free funds to Ameren Missouri. Therefore, Ameren Missouri's rate base is reduced by the ADIT balance to avoid customers paying a return on investments that are ratepayer funded.[7]

In File No. WO-2018-0373, Staff witness and accountant Lisa Ferguson similarly testified,

> The net credit balance in the deferred tax reserve represents a source of cost-free funds; therefore, rate base is reduced by the deferred tax reserve balance to avoid having customer pay a return on funds that are provided cost-free to the company.[8]

And aside from the Staff personnel responsible for developing revenue requirements own words, it is my own understanding, from working with Staff auditors for many years, that they clearly understand how ADIT should not be ignored, as Ms. Lange did here, and that if it is ignored when determining the revenue requirement generally or of a project specifically, the result will artificially overstate the revenue requirement and ultimately the costs to be paid by customers through rates.

Ms. Lange herself, at least in the Company's last rate review, appeared to understand this as well yet she failed to apply that understanding in Staff's modeling in this case. That she apparently understood it in the prior rate review is shown by Ms. Lange's workpapers from the Company's recent rate review, as seen in Figure 2 below, which

[7] File No. ER-2022-0337, Matthew Young Direct Testimony p. 22, ll. 19-21.
[8] File No. WO-2018-0373, Lisa Ferguson Direct Testimony p. 4, ll. 3-6.

reflect that ADIT (i.e., "deferred taxes") is a reduction to a utility's rate base – and a substantial one at that – *nearly $3 billion* in her workpaper from that rate review.[9]

Figure 2 – Screenshot of Sarah Lange Workpaper from ER-2022-0337

Showing ADIT as a Rate Base Offset[10]

2								
3			Plant In Service	$ 21,382,784,095				
4				$ -				
5			Less Accumulated Depreciation Res	$ 8,683,990,601				
6				$ -				
7			Net Plant In Service	$ 12,698,793,494				
8				$ -				
9			ADD TO NET PLANT IN SERVICE	$ -				
10	Add	.	Payroll and Withholdings - from CW(	$ 23,199,311				
11	Add	.	Other Employee Benefits - from CWC	$ 2,464,342				
12	Add	.	Pensions and OPEBs - from CWC	$ (2,865,603)				
13	Add	.	Fuel - Nuclear - from CWC	$ 3,660,104	1			
14	Add	.	Fuel - Coal - from CWC	$ 25,590,714	1			
15	Add	.	Fuel - Gas - from CWC	$ (246,060)	1			
16	Add	.	Fuel - Oil - from CWC	$ 242,355	1			
17	Add	.	Purchased Power - from CWC	$ 4,136,089			1	
18	Add	.	Incentive Compensation - from CWC	$ (15,585,255)				

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9 Ms. Lange's workpaper referred to ADIT as "deferred taxes." I would also note that Ms. Lange has testified for Staff in many Missouri utility rate reviews where she often cites the National Association of Regulatory Utility Commission ("NARUC") Manual as support for her positions and underlying workpapers on Class Cost of Service. The NARUC Manual also reflects ADIT as a reduction to a utility's rate base. See Figure 3.

10 This workpaper was provided by Staff assistant Diana Vaught via an email containing a link to EFIS received by the Company on March 17, 2023. The workpaper is titled "4 functionalized CCoS updates" and the relevant tab is titled "Other Rate Base."

Subtract	.	Pension Tracker Liability ER-2019-0335	$	27,321,432
Subtract	.	Pension Tracker ER-2021-0240	$	(9,801,675)
Subtract	.	Pension Tracker Liability-Current Pension	$	11,547,466
Subtract	.	OPEB Tracker ER-2012-0166	$	(63,940)
Subtract	.	OPEB Tracker Liability ER-2014-0258	$	205,483
Subtract	.	OPEB Tracker Liability ER-2016-0179	$	47,346
Subtract	.	OPEB Tracker Liability ER-2019-0335	$	4,897,773
Subtract	.	OPEB Tracker Liability ER-2021-0240	$	436,332
Subtract	.	OPEB Tracker Liability-Current OPEB	$	4,559,466
Subtract	.	Deferred Taxes	$	2,961,689,001
		TOTAL SUBTRACT FROM NET PLANT	$	3,052,204,868
			$	-
		TOTAL RATE BASE	$	10,459,995,033

Figure 3 – Screenshot of NARUC Cost Allocation Manual Defining ADIT as Offset to Ratebase

This subsection discusses the elements that are generally included in rate base, where rate base is based on net original investment costs. The development of such rate base is as follows:

<u>RATE BASE</u>

Original Cost of Electric Plant in Service
Less: Accumulated depreciation reserves
: Accumulated provision for deferred income taxes (Accounts 281 283)
: Operating reserves
Plus: Electric plant held for future use
: Construction work in progress (if allowed)
: Working capital
: Accumulated provision for deferred income taxes (Account 190)
Equals: Rate Base

Despite this fundamental ratemaking principle, which when properly accounted for lowers the modeled revenue requirement associated with the projects, Ms. Lange's modeling and underlying workpapers in *this case* do not include rate base reductions for ADIT. This means that Staff's threshold analysis modeling failed to calculate and include the third largest (in terms of absolute value and as reflected in figure 2 above) component of the Company's existing rate base.

Q. Will the Solar Projects create deferred taxes that ultimately will generate customer benefits resulting from ADIT, reducing rate base in future rate proceedings?

A. Yes. The Solar Projects are eligible for accelerated depreciation, which will result in customer benefits early in the life of the Solar Projects that will manifest as an ADIT reduction to rate base.

Q. What are the rate base components for the Projects in Staff's threshold analysis?

A. The entirety of the components of rate base reflected in Staff's modeling include items that are labelled in Ms. Lange's workpapers as Net Plant, Land, PISA tranche 1 RB, PISA tranche 2 RB, and PISA tranche 3 RB. Notably absent is anything related to deferred taxes or ADIT. Below is a screenshot of the workpaper containing Ms. Lange's calculation of rate base for her modeling of the Cass County Solar Project's revenue requirement. This can also be found in the tab labeled "Cass Illinois," rows 99 through 114 in Schedule ML-S1. This error of excluding ADIT as an offset to rate base occurred for all years and is repeated in Schedule MJL-S1 for all of the Solar Projects proposed in this case.

Figure 4 – Screenshot of Sarah Lange Workpaper Calculating Rate Base for Cass County Solar Project without Consideration of ADIT (Schedule ML-S1) **

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Q. Did the Company's modeling reflect the appropriate treatment for ADIT?

A. Yes, ADIT was quantified and appropriately included as an offset to rate base in the Company's modeling of each of the projects. The ADIT balances by year are displayed in the tabs labeled "Financial Statements," row 122 in Schedules ML-S5 through ML-S8.In determining the Company's return on rate base and specifically the equity component of return on rate base (labeled "incremental equity" on the Financial Statements tab, row 107 of those same schedules) for the Solar Projects, the Company's modeling appropriately reflects a reduction to rate base for the ADIT balance before multiplying by the equity component of the Company's WACC.

Q. **What impact would the inclusion of ADIT as an offset to rate base in Staff's model have on Staff's modeled costs of the Solar Projects?**

A. I varied Schedule ML-S1 to include ADIT as an offset to rate base and attached the result as Schedule ML-S3. The Vandalia, Bowling Green, Split Rail, and Cass Illinois tabs of Schedule ML-S3 now include ADIT balances as an offset to rate base in inserted rows 101 and 251 (Staff's modeling of rate cases every one and four years, respectively).[11] The reflected ADIT balances are those calculated by the Company in Schedules ML-S5 through ML-S8 and the amounts are negative in order to result in a rate base reduction without modification of any of Staff's formulas. The result is a reduction of $251 million in the combined costs to customers resulting from the projects found on row 31 of the summary tab in Schedule ML-S3 (as compared to Staff's original workpaper that ignores ADIT, Schedule ML-S1).

Q. So far you have identified Ms. Lange's failure to model PISA correctly, and her failure to offset rate base for ADIT. You mentioned a third significant modeling error. Is that third error related to Staff's threshold analysis modeling of income tax costs?

A. Yes. For two of the projects, Cass County and Split Rail, the modeling more than double counts income tax costs, which radically misstates Staff's comparison of the costs and revenues of these projects.[12]

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[11] Column D of rows 101 and 251 must contain "RB" in order for Staff's existing formulas to identify these rows as a component of rate base.

[12] This mistake was not made for the Bowling Green and Vandalia Projects, presumably since those projects do not generate off-system sales revenues but instead offset the Company's load.

Q. Please explain the mistake that was made regarding income tax expense.

A. Staff's modeled revenue requirement for each project reflects income tax costs relating to the Company's expected earned return on equity – this is the customary treatment of income tax expense in a model of a project's revenue requirement - as shown in the screenshot from Ms. Lange's threshold analysis workpaper (Figure 5) below for Cass County.

Figure 5 – Screenshot of Sarah Lange Workpaper Incorporating Income Tax Expense in Cass County Project Revenue Requirement (Schedule ML-S1)

**

**

However, Ms. Lange doesn't stop there with respect to attributing income tax costs to the Cass County and Split Rail projects. Instead, Ms. Lange also *reduces all energy and capacity revenues* (i.e., off-system sales) from the Cass County and Split Rail projects by the same income tax factor noted in figure 5 above (tick-mark A). See the Value tab of Staff's threshold analysis workpaper (Schedule ML-S1), where Staff has reduced all energy and capacity revenues from the project as if income taxes were separately owed on those revenues for the lifetime of the projects.[13] However, off-system sales revenues *do not produce income tax expense*. To the contrary, the off-system sales revenues generated by these projects (and all other Company-owned generation facilities) are passed back directly to customers on a dollar-for-dollar basis,[14] by means of base rates each time base rates are reset and via the Company's Fuel Adjustment Clause mechanism between rate cases. The pass-through of these off-system sales revenues reduce customer rates rather than adding to the Company's net income, yet Ms. Lange has increased the net revenue requirement impact of the Cass County and Split Rail Projects by adding income tax costs that the projects do not produce.

Q. How impactful is this mistake?

A. It has caused Ms. Lange to understate revenues associated with the Cass County and Split Rail projects (and therefore overstate net costs to customers of the projects) by approximately ***$679*** million for "phantom" taxes that will not be generated, owed, or reflected in customer rates. In the tab labeled "Value" in Ms. Lange's workpaper, Schedule ML-S1, this total is the result of adding up the values in rows 69,70,72, and 73 (titled "Tax Gross-up for Energy Sales" and "Tax Gross-Up for Capacity Sales"). These rows of phantom taxes on off-system sales underlie Staff's revenue modeling for the Cass County and Split Rail projects, and therefore reduce Staff's quantification of revenues associated with those projects. Deleting the values in these rows increases revenues for the Split Rail and Cass County projects found in row 33 of the Summary tab in Ms. Lange's

[13] Specifically rows 2 and 3 are Staff's summations of 'value' by year for the Cass County and Split Rail Projects. The Formulas contained in these rows reflect the summation of several other rows but notably includes reductions for income taxes calculated in rows 69, 70, 72, and 73.
[14] The only exception of the dollar for dollar pass through of off-system energy and capacity sales revenue is associated with the 95%/5% FAC sharing mechanism, which only applies to variations from base amounts established in rate cases in between rate cases.

workpapers, Schedule ML-S1. Schedule ML-S3 reflects the correction of this error as I have just described.

Q. You say this is an obvious flaw. Is there any evidence you can provide that Staff understands the mechanics of off-system sales in a revenue requirement, which should have caused it to identify this tax treatment as an error?

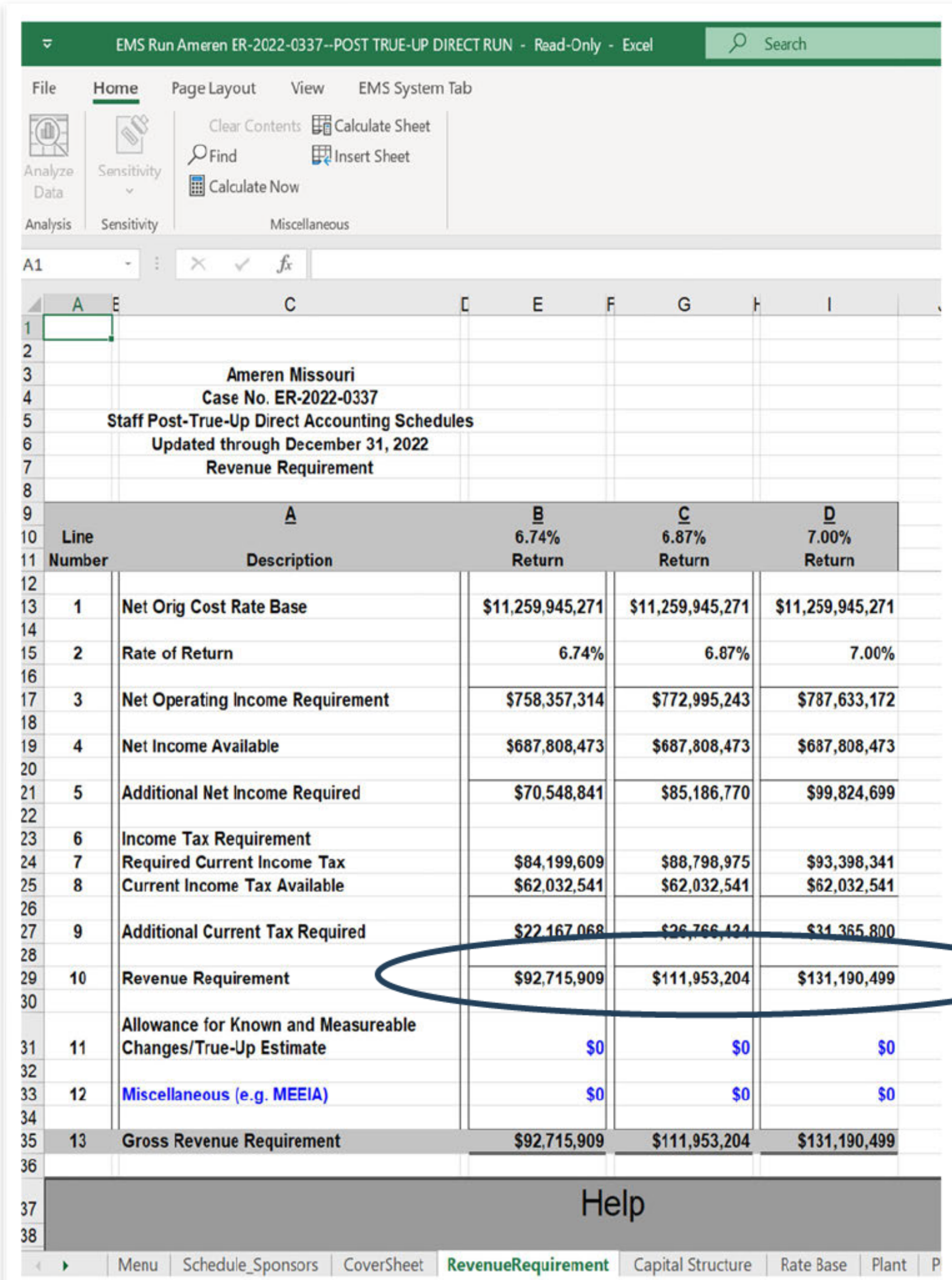
A. Yes. Again, it should go without saying that Staff knows how to model a revenue requirement. In this case, the existence of the Solar Projects, and therefore their inclusion in rate base, result in earnings for the Company. Those earnings will result in income tax expense for the Company, which is properly reflected in Staff's threshold analysis through the income tax calculation reflected in Figure 4 above. This is analogous to the income tax calculation in a rate review that is based on the application of a combined federal/state income tax rate to the equity return on rate base.[15] Revenues, like off-system sales, that are provided back to customers do not increase the Company's taxable income and do not result in tax expense; this is obvious since the Company does not keep those revenues – customers receive them instead. As a result, a dollar of off-system sales revenues is a one-for-one tradeoff in the calculation of a retail revenue requirement. An incremental dollar of *off-system sales revenue* will always result in a dollar less of *retail revenue requirement*, and a dollar less in off-system sales revenue will always result in a dollar more of retail revenue requirement. In no revenue requirement calculation scenario do the incremental off-system sales dollars result in incremental net income that generates a new income tax liability. Instead, those incremental off-system sales revenues simply offset the need for retail revenues.

[15] Generally, all revenues other than those relating to the Company's return on equity have a corresponding cost such that the Company's taxable income (revenues minus expenses) is equal to its return on equity.

Q. Is there a way to demonstrate that this is true?

A. Yes, Staff's own workpapers from the Company's last rate case (File No. ER-2022-0337) demonstrate that incremental off-system sales revenues do not increase income tax expense reflected in a revenue requirement used to set rates. Figures 6 and 7 below are screenshots of Staff's workpapers from that case, exactly as Staff produced them. I have attached Staff's original workpaper as Schedule ML-S2. Figure 6 shows the total revenue increase of $111,953,204 (at the midpoint of Staff's recommended rate of return) determined by Staff in Schedule ML-S2. Figure 7 (from the same schedule) shows $223,763,608 as the total dollars of off-system sales (labelled "Sales for Resale Energy") that Staff determined were appropriate to reflect in that model, and which therefore offset required retail revenues.

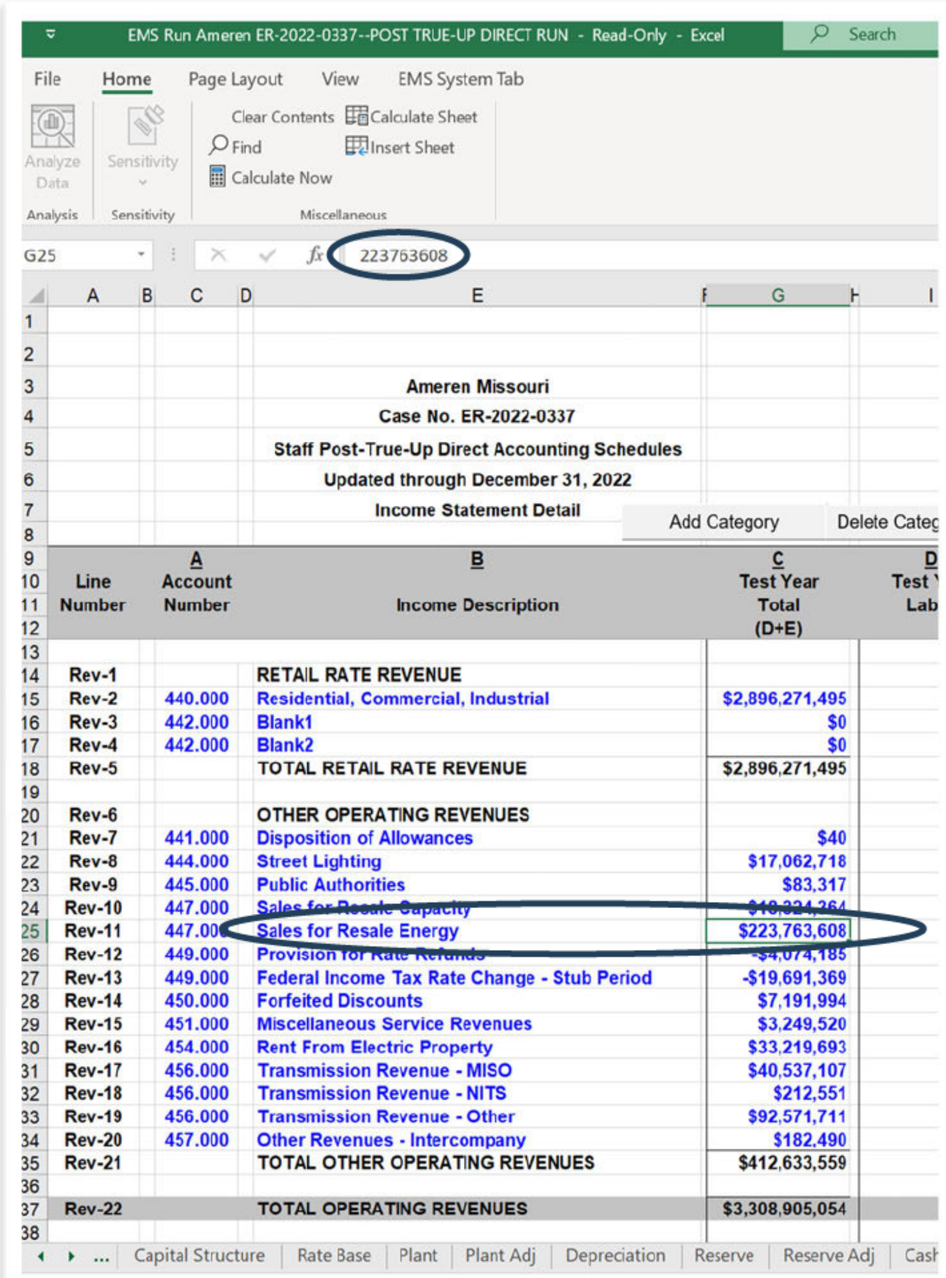
Figure 6 – Staff's Recommended Revenue Increase in its True-Up EMS Run from File No. ER-2022-0337 (Schedule ML-S2)



Ameren Missouri
Case No. ER-2022-0337
Staff Post-True-Up Direct Accounting Schedules
Updated through December 31, 2022
Revenue Requirement

Line Number	A Description	B 6.74% Return	C 6.87% Return	D 7.00% Return
1	Net Orig Cost Rate Base	$11,259,945,271	$11,259,945,271	$11,259,945,271
2	Rate of Return	6.74%	6.87%	7.00%
3	Net Operating Income Requirement	$758,357,314	$772,995,243	$787,633,172
4	Net Income Available	$687,808,473	$687,808,473	$687,808,473
5	Additional Net Income Required	$70,548,841	$85,186,770	$99,824,699
6	Income Tax Requirement			
7	Required Current Income Tax	$84,199,609	$88,798,975	$93,398,341
8	Current Income Tax Available	$62,032,541	$62,032,541	$62,032,541
9	Additional Current Tax Required	$22,167,068	$26,766,434	$31,365,800
10	Revenue Requirement	$92,715,909	$111,953,204	$131,190,499
11	Allowance for Known and Measureable Changes/True-Up Estimate	$0	$0	$0
12	Miscellaneous (e.g. MEEIA)	$0	$0	$0
13	Gross Revenue Requirement	$92,715,909	$111,953,204	$131,190,499

1 **Figure 7 – Off-System Sales Revenue Input in Staff's True-Up EMS Run**
2 **from File No. ER-2022-0337 (Schedule ML-S2)**



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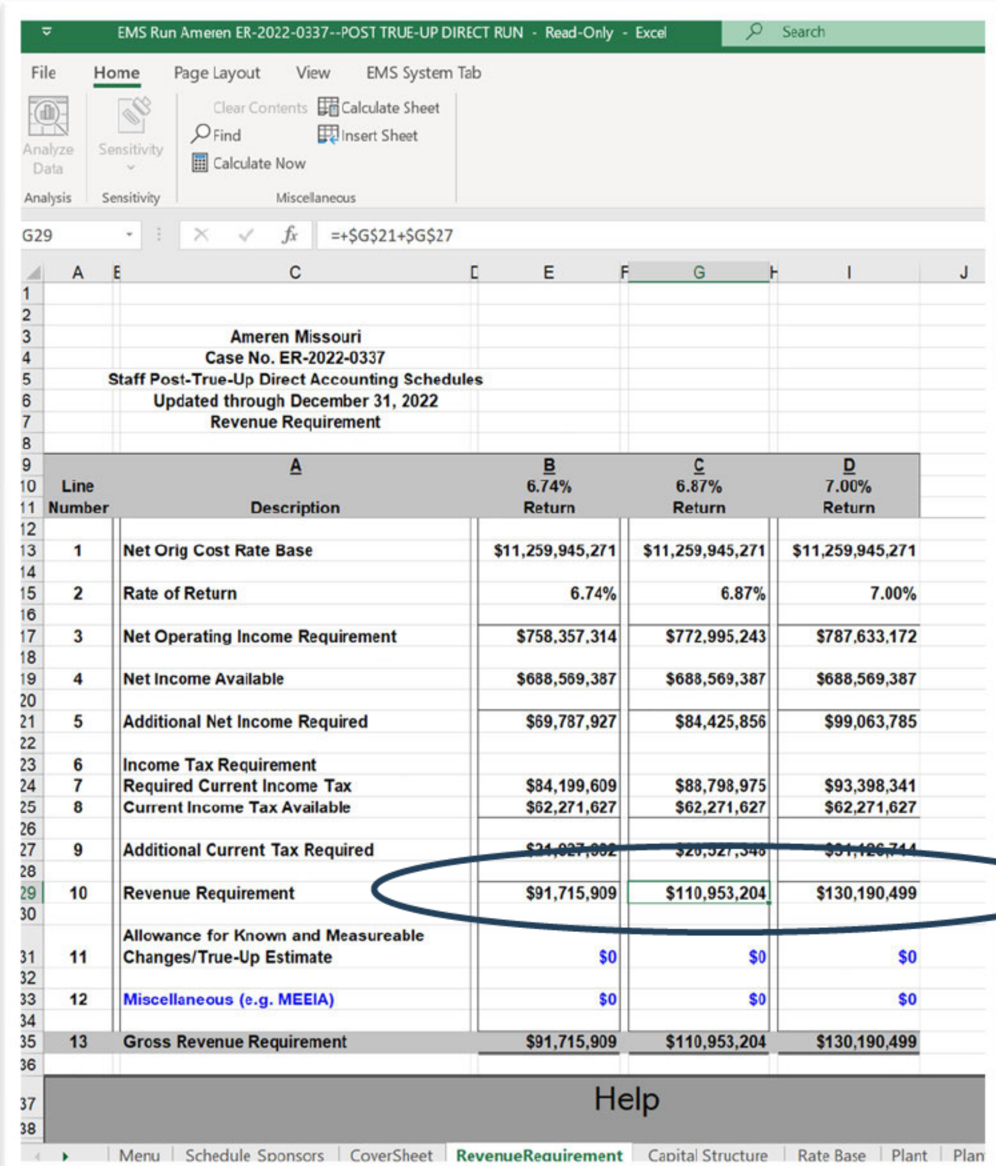
Line Number	A Account Number	B Income Description	C Test Year Total (D+E)
Rev-1		RETAIL RATE REVENUE	
Rev-2	440.000	Residential, Commercial, Industrial	$2,896,271,495
Rev-3	442.000	Blank1	$0
Rev-4	442.000	Blank2	$0
Rev-5		TOTAL RETAIL RATE REVENUE	$2,896,271,495
Rev-6		OTHER OPERATING REVENUES	
Rev-7	441.000	Disposition of Allowances	$40
Rev-8	444.000	Street Lighting	$17,062,718
Rev-9	445.000	Public Authorities	$83,317
Rev-10	447.000	Sales for Resale Capacity	$10,324,264
Rev-11	447.000	Sales for Resale Energy	$223,763,608
Rev-12	449.000	Provision for Rate Refunds	-$4,074,185
Rev-13	449.000	Federal Income Tax Rate Change - Stub Period	-$19,691,369
Rev-14	450.000	Forfeited Discounts	$7,191,994
Rev-15	451.000	Miscellaneous Service Revenues	$3,249,520
Rev-16	454.000	Rent From Electric Property	$33,219,693
Rev-17	456.000	Transmission Revenue - MISO	$40,537,107
Rev-18	456.000	Transmission Revenue - NITS	$212,551
Rev-19	456.000	Transmission Revenue - Other	$92,571,711
Rev-20	457.000	Other Revenues - Intercompany	$182,490
Rev-21		TOTAL OTHER OPERATING REVENUES	$412,633,559
Rev-22		TOTAL OPERATING REVENUES	$3,308,905,054

3 To confirm that indeed every incremental dollar of off-system sales revenue (e.g.,
4 incremental revenues from the projects at issue in this case) will reduce the retail revenue
5 requirement, I varied the Sales for Resale Energy (off-system sales revenue) in Staff's

workpaper by adding one million dollars to cell G25 of the "IncomeStatementDetail" tab (reflected in Schedule ML-S4) - while changing nothing else at all within the file - and recorded the impact on the revenue requirement increase that would occur based on the existing formulas and logic that Staff has programmed into its EMS model. Figure 8 below is a screenshot of the result of varying the value in that one cell by one million dollars and shows that doing so produces a retail revenue requirement increase of $110,953,204 (at the midpoint of Staff's recommended rate of return) – precisely $1 million less than the original revenue requirement increase reflected in Figure 5 above, based on the addition of precisely $1 million of off-system sales revenue. Shown in Figure 9 below where I replaced $223,763,608 with an off-system sales revenue value of $224,763,608. Taken together, Figures 8 and 9 show that using Staff's own revenue requirement model, the $1 million of incremental off-system sales revenue perfectly offsets the retail revenue requirement, but the income tax expense reflected in the revenue requirement does not change because the off-system sales have no impact on income tax expense. But as earlier discussed, Ms. Lange's workpaper, attached as Schedule ML1-Staff's threshold analysis, in fact did reduce the off-system sales revenues by taxes that will never be generated, which incorrectly understates the revenues and overstates the cost of the projects. The Company's own modeling in this case and prior rate cases produce the same result if varied in the same way.

Figure 8 - Revenue Increase in Staff's True-Up EMS Run from File No. ER-2022-0337 After Addition of $1 Million of Incremental Off-System Sales Revenue (Schedule ML-S4)



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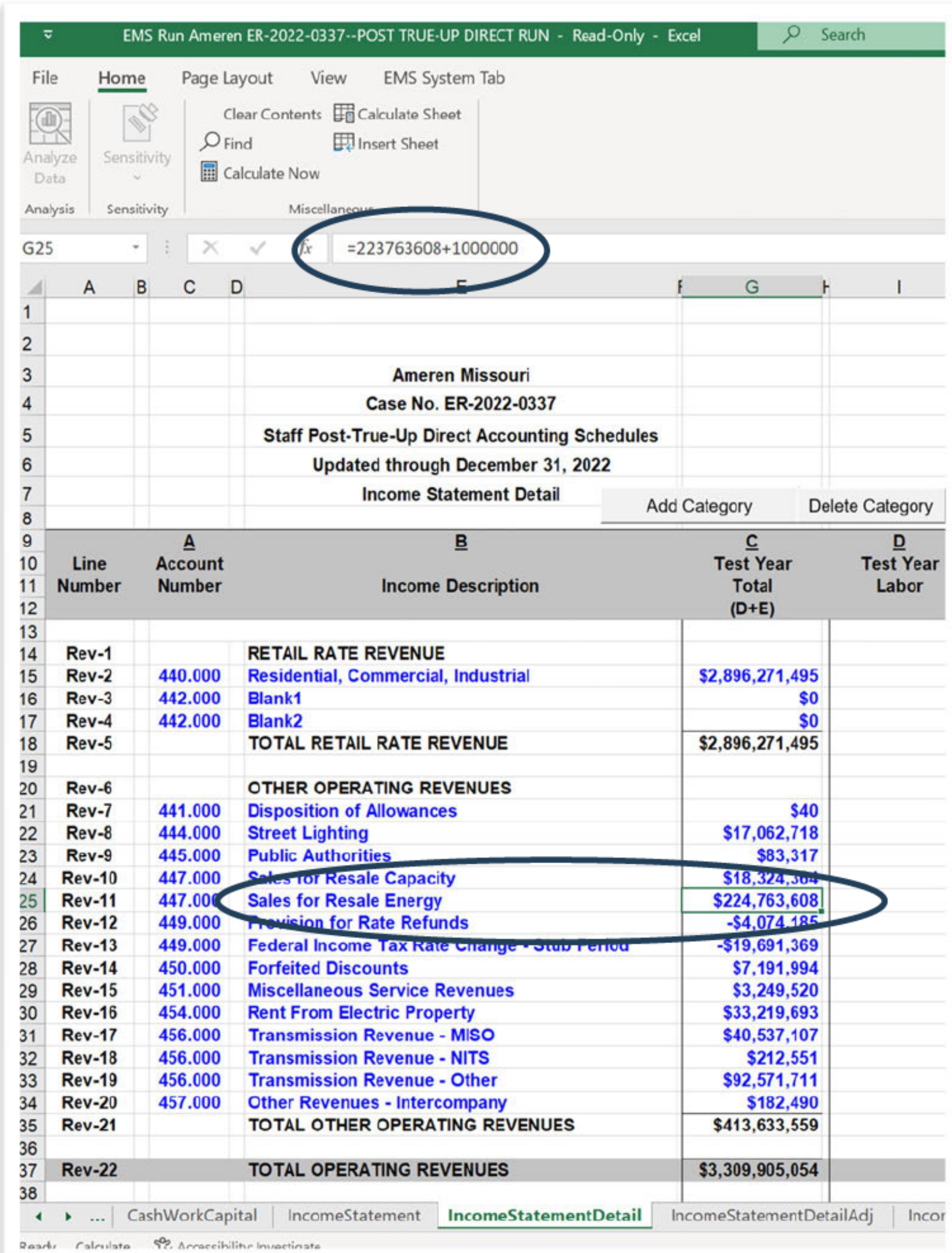
3	Net Operating Income Requirement	$758,357,314	$772,995,243	$787,633,172
4	Net Income Available	$688,569,387	$688,569,387	$688,569,387
5	Additional Net Income Required	$69,787,927	$84,425,856	$99,063,785
6	Income Tax Requirement			
7	Required Current Income Tax	$84,199,609	$88,798,975	$93,398,341
8	Current Income Tax Available	$62,271,627	$62,271,627	$62,271,627
9	Additional Current Tax Required	[illegible]	[illegible]	[illegible]
10	Revenue Requirement	$91,715,909	$110,953,204	$130,190,499
11	Allowance for Known and Measureable Changes/True-Up Estimate	$0	$0	$0
12	Miscellaneous (e.g. MEEIA)	$0	$0	$0
13	Gross Revenue Requirement	$91,715,909	$110,953,204	$130,190,499

Figure 9 – Addition of $1 Million of Off-System Sales Revenue to Staff's True-Up EMS Model from File No. ER-2022-0337 (Schedule ML-S4)



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Rev-14	450.000	Forfeited Discounts	$7,191,994	
Rev-15	451.000	Miscellaneous Service Revenues	$3,249,520	
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Rev-17	456.000	Transmission Revenue - MISO	$40,537,107	
Rev-18	456.000	Transmission Revenue - NITS	$212,551	
Rev-19	456.000	Transmission Revenue - Other	$92,571,711	
Rev-20	457.000	Other Revenues - Intercompany	$182,490	
Rev-21		TOTAL OTHER OPERATING REVENUES	$413,633,559	
Rev-22		TOTAL OPERATING REVENUES	$3,309,905,054	

While adding the $1 million of incremental off-system sales in Staff's File No. ER-2022-0337 workpaper is a simple exercise, *that's exactly the point*. What happens to a revenue requirement when incremental off-system sales revenues are realized by a utility is not difficult to figure out: retail revenue requirements change on precisely a dollar-for-dollar basis with those off-system sales revenues. The bottom line is that it is completely inexplicable why Staff would invent an unnecessary and inappropriate tax "gross up" calculation in its "threshold analysis" in this case, which "burdens" the projects in this case with $679 million of non-existent income taxes given that doing so is completely at odds with Staff's own understanding of revenue requirements based on irrefutable evidence from its own EMS model. Clearly, Staff's threshold analysis should be completely ignored given a mistake of this magnitude -- in addition to the other mistakes I discussed earlier.

Q. What is the combined impact of the errors in Staff's threshold analysis and Ms. Lange's testimony related to ADIT and income tax expense?

A. Correcting these two errors would in fact be sufficient to completely reverse the conclusions one could reasonably draw from Staff's threshold analysis evaluated under the assumption that the Company will employ ITCs (as we currently expect to do). These two serious modeling mistakes alone (failing to account for the ADIT reduction to rate base and drastically overstating income tax expense) cause Staff's total net revenue requirement (costs less revenues generated by the projects) estimates in its threshold analysis for the projects to be too high by more than $929 million across the four projects ($251 million for failing to offset rate base for ADIT and $679 million for the erroneous application of income taxes to all Split Rail and Cass County project revenues). I have reproduced below as Figure 10 the table from page 58 of Ms. Lange's rebuttal testimony, illustrating that *all four* Solar Projects would have benefits exceeding costs in the ITC scenarios under Ms. Lange's modeling framework when her own modeling is corrected for just these significant and obvious errors. I have also attached Schedule ML-S4 where I corrected Staff's modeling for these two errors.

Figure 10 – ADIT and Income Tax Corrected Result of Staff's "Threshold Analysis" Demonstrating that *Revenues Exceed Costs for All Four Solar Projects* **

**

Q. Please walk the Commission through how Figure 10 shows this?

A. The value of 1.00 on the x-axis means the market-based revenues for the project equals its costs, so any bar reaching a height at or below 1.00 is either cost neutral or will lower revenue requirements. If the ITC is used, every single project would be expected to lower revenue requirements using Ms. Lange's own modeling, that is, once the ADIT and income tax mistakes are corrected. If the PTC were used (which we do not currently expect), there would be some cost associated with two of the projects while two of them would be expected to lower costs for customers.

Q. Please summarize the conclusions from your testimony.

A. No reliance can or should reasonably be placed on Staff's modeling (its "threshold analysis") in this case. Ms. Lange's modeling that produces the results of this threshold analysis unreasonably inflates the costs of the Solar Projects through erroneous and incomplete modeling of PISA, unreasonably inflates the costs of the Solar Projects by $251 million by ignoring the customary treatment of ADIT as an offset to rate base, and incorrectly understates energy and capacity revenues from the projects by reducing those revenues by $679 million for income taxes that do not exist. As I stated earlier, I believe there are additional errors in Staff's modeling that I have not yet identified, but the magnitude of the errors I have identified make Staff's modeling so flawed that it simply cannot be relied upon.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for a Certificate of Convenience and Necessity for Solar Facilities	)))	EA-2023-0286

AFFIDAVIT OF MITCHELL LANSFORD

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Mitchell Lansford being first duly sworn on his oath, states:

My name is Mitchell Lansford, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

*/s/ Mitchell Lansford*______________
Mitchell Lansford

Sworn to me this 14th day of December, 2023.

Exhibit No.:	
Issue(s):	Class Cost of Service
Witness:	Nicholas L. Phillips
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	February 14, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

SURREBUTTAL TESTIMONY

OF

NICHOLAS L. PHILLIPS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
February 2025

related costs given clean energy legislation passed in the state.[12] While a consensus was not reached among all parties, DEC, the North Carolina Staff, and the Industrial Group reached a settlement that was approved by the North Carolina Commission to move from a 1CP allocator to the A&E allocator precisely because it captures both demand and energy characteristics and many of the fixed cost investments in the system are expected to be related to renewable generation due to the clean energy legislation.[13]

Q. What do you recommend for the allocation of the recent renewable resource acquisitions made by Ameren Missouri on behalf of its customers?

A. I reinforce the recommendation included in my Rebuttal Testimony, namely that the Commission reject Staff's proposal and instead approve Ameren Missouri's proposal for classification and allocation of production plant.

III. RESPONSE TO STAFF POSITION TO INCLUDE WHOLESALE ELECTRIC ENERGY PRICES WITHIN THE DEVELOPMENT OF THE CLASS COST OF SERVICE STUDY

Q. Please discuss Staff's position regarding Wholesale Energy Expenses and Revenues.

A. Similar to Staff's Direct Testimony on the subject, the discussion in its Rebuttal Testimony fails to tell the entire story of how the Staff is using wholesale electric energy prices within its class cost of service study, nor do Staff testimony or workpapers provide sufficient detail regarding the distinction between classifying and allocating costs. Despite this deficiency, the Staff asserts that the Commission has not considered complexities created by Ameren Missouri's (now 20 years of) participation in the MISO

[12] Docket Nos. E-7, Sub 1214 and E-2, Sub 1219.
[13] Docket Nos. E-7, Sub 1276 and E-2 Sub 1300.

energy markets.[14] Staff continues by faulting Ameren Missouri and other parties for failing to consider wholesale energy prices in allocating the cost to serve load and instead relying upon net wholesale costs.[15] Staff concludes that relying upon a study to allocate costs to customers that fails to acknowledge the gross costs and revenues of Ameren Missouri's participation in the MISO market is unreasonable.[16]

Q. Has the Commission previously considered the issue raised by Staff?

A. Yes. In its Final Report and Order in ER-2014-0258 (Schedule NLP-SR2) the Commission found that:

> Furthermore, under FERC Order 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) sale for resale (i.e. off-system sale under account 447 when the utility's cleared generation exceeds the cleared load, or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. That order states "Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load." That means that for accounting purposes, Ameren Missouri is required to recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power.[17]

The Commission further clarified that:

> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.[18]

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[14] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange, p. 17.
[15] Id.
[16] Id.
[17] Schedule NLP-SR2, File No. ER-2014-0258, *Final Report and Order*, p. 113, issued April 29, 2015.
[18] Id at 115.

Q. What was expressed by the FERC in Order 668?

A. The FERC, in Order 668 (Schedule NLP-SR3) stated:

> ***Recording RTO energy market transactions on a net basis is appropriate as purchase and sale transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined. Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load. Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential.*** The Commission will, therefore, adopt the proposed accounting for RTO energy market transactions with certain modifications and clarifications as discussed below. The Commission does expect public utilities, however, to maintain detailed records for auditing purposes of the gross sale and purchase transactions that support the net energy market amounts recorded on their books.
>
> Additionally, we clarify that transactions are to be netted based on the RTO market reporting period in which the transaction takes place. For example, if the RTO market in which the transaction takes place uses an hourly period for determining energy market charges and credits, then non-RTO public utilities purchasing and selling energy in the market must net transactions on an hourly basis. Requiring participants to net transactions over the RTO market's reporting period leads to consistent and comparable energy market information for decision making purposes by the Commission and others.
>
> Further, we clarify that the netting of purchases and sales in an RTO energy market is appropriate not only for transactions where participants are required to bid their generation into the market and buy generation from the market to supply their native load, but also in cases where an RTO offers an energy market in which participants may choose to offer all generation to and buy all power from the energy market.
>
> We also clarify that if a participant is a net seller, rather than a net buyer, during a given market reporting period it must credit such net sales to Account 447, Sales for Resale, instead of Account 555, Purchased Power.
>
> Finally, one purpose of this rule is to establish uniform accounting requirements for the purchase and sale of energy in RTO markets. The purpose of reporting of gross information in EQRs, in contrast, is to provide the Commission and the public

> with a more complete picture of wholesale market activities which affect jurisdictional services and rates, thereby helping to monitor for any market power and to ensure that customers are protected from improper conduct. These are not necessarily the same criteria and principles that should be used in establishing uniform accounting requirements. In any event, the reporting of wholesale market activity in EQRs falls outside the scope of this rule.[19] ***(emphasis added)***

Q. Please discuss the except from FERC Order 668 you emphasized above.

A. It is critical to understand that the "buy all, sell all" aspect of the energy markets does not in and of itself cause changes in *how* the utilities serve native load, nor does it cause new costs or revenues to be incurred. As discussed by the FERC, purchase and sales transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined.

Q. What is meant by "done in contemplation of each other?"

A. For a load serving entity that also owns or contracts for generation resources, if only those owned and contracted resources were used to serve native load (no market purchases or sales) the net wholesale cost will be close to zero. This is because, when the energy market clears, it clears at a single marginal energy cost. The difference between each Locational Marginal Price ("LMP") in a given operating interval is related to the costs for congestion and losses.[20] As a consequence, if the accepted generation volumes in a given hour equal the load purchase volumes for the same hour, the revenues paid to the generators will almost entirely offset the cost of the load purchases.[21] The load

[19] Schedule NLP-SR3, FERC Order No. 668, Paragraphs 80-84 (Pages 39-40).
[20] Locational Marginal Price (LMP) = Marginal Energy Cost (MEC) + Marginal Loss Cost (MLC) + Marginal Congestion Cost (MCC)
[21] The market has additional mechanisms (Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), etc.) vertically integrated utilities such as Ameren can use to further limit exposure to congestion costs and further tightening the difference between generation revenue and load purchases for service of native load. Though it is worth noting that congestion and losses are not new costs, these have

serving entity then would be incurring the cost of fuel, variable O&M, etc. (including losses and congestion) just as it would have absent the presence of the market. The market does enable a more efficient mechanism to economically dispatch the system when it may be more advantageous for a given participant to back down generation and buy energy from the market or generate additional energy to create off-system sales. These would show up as a difference in net wholesale cost for the given interval and would also coincide with an increase or decrease in fuel expense just as it would have, absent the market.

Q. Would it be reasonable to include gross wholesale costs in the allocation of costs as recommended by the Staff?

A. No. In addition to the discussion in my Rebuttal Testimony demonstrating why the approach leads to illogical results when incorporated into the cost study, the MPSC and the FERC have both already weighed in on why it is appropriate for utilities to net these costs, as done by Ameren Missouri in its cost study. Additionally, as I discussed at the opening of this testimony, there is no clear connection between the NARUC Manual and Staff's proposal as it relates to the use of wholesale energy prices within allocation of costs to customers. Given the law requiring the use of allocation methods aligned with the NARUC Manual, the Commission should consider as a threshold question whether the CCOSS put forth by Staff meets the statutory requirements in Missouri before weighing arguments on the (un)reasonableness of the approach. As I discussed earlier, I do not believe that Staff has met the statutory requirement.

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always existed prior to the market and have been included in rates as part of Ameren's cost of service. The MISO market has made these cost components more transparent.

Q. Does the participation in the MISO energy market actually cause new multi-billion-dollar costs and revenues as Staff claims?[22]

A. No. In the last sentence emphasized in FERC Order 668 above, it states that, "Recording these transactions on a gross basis, in contrast, would give an *inaccurate picture of a participant's size and revenue producing potential*." The plain reading of this contradicts Staff's position, i.e. the buy-all, sell-all wholesale energy market transactions, if recorded on a gross basis would actually cause an inflated view of actual costs and revenues rather than, as Staff asserts, be a more accurate reflection wholesale energy transactions. Incorporating this into the CCOSS would thereby distort rather than improve the results.

Q. What do you recommend regarding the use of wholesale energy prices in cost allocation as proposed by Staff?

A. I recommend the Commission reject Staff's proposal and rely on the CCOSS put forth by the Company.

IV. RESPONSE TO STAFF POSITION REGARDING THE SELECTION OF HOURS FOR USE IN THE DEVELOPMENT OF A PRODUCTION DEMAND ALLOCATION METHOD

Q. Staff raises concerns regarding the selection of peak hours for use in a production demand allocator. Please summarize Staff's concerns.

A. At the most basic level, Staff believes that due to Ameren Missouri's participation in the MISO market and its requirement to demonstrate compliance with the MISO's seasonal resource adequacy construct, that the hours used by the MISO in the seasonal resource adequacy construct should be the same hours used to allocate production

[22] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange p. 17, l. 9 to p. 18, l. 8.

Exhibit No.:	
Issue(s):	Policy
Witness:	Steven Wills
Type of Exhibit:	Surrebuttal Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	February 14, 2025

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

SURREBUTTAL TESTIMONY

OF

STEVEN WILLS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
February, 2025

V. CLASS COST OF SERVICE PRODUCTION COST ALLOCATIONS

Q. Staff witness Sarah Lange, on the topic of production cost allocations contained in the Company's Class Cost of Service Study ("CCOSS"), states that "Ameren Missouri sells all of its generated energy…into the integrated energy markets, and Ameren Missouri purchases all of the load requirements of its customers…from the integrated energy markets. It is not reasonable to rely on any study that fails to acknowledge the cost and revenue causation of these market activities".[9] What is your response?

A. Company witness Nick Phillips responds in more depth to this topic, but I also feel compelled to weigh in on this extreme and inappropriate take on the proper allocation of production costs. I can't think of any way to characterize Staff's preferred production allocation method (which it criticizes the Company for not using for its CCOSS) other than as an attempt to break the vertically integrated utility – a utility that plans, owns, and operates its own generation fleet for the very purpose of serving its load and therefore insulates its customers from undo market reliance and price exposure – apart into an apparent merchant generation function and a load serving entity function that relies exclusively on the market, and allocate the impacts of those two functions distinctly, resulting in massive shifts of fixed costs between classes based on nothing but market prices.

Mr. Phillips discussed this in his rebuttal testimony and expounds on the topic further in his surrebuttal testimony. One of the observations he raises in his surrebuttal relates to the concept of netting market purchases and sales for accounting purposes for

[9] File No. ER-2024-0319 Sarah L.K. Lange Rebuttal Testimony, p. 18, ll. 3-8.

vertically integrated utilities that is dictated by FERC rule, and a related Commission ruling in the Company's 2014 electric rate case (File No. ER-2014-0258) related to "true purchased power" and how that concept relates to recovery of transmission expenses in the Fuel Adjustment Clause ("FAC").

If Staff's perspective that wholesale market transactions that otherwise are netted for accounting purposes and FAC inclusion should be discretely treated as *new sources of cost and revenue causation* were adopted by the Commission, it would directly undermine the whole concept of "true purchased power" that underlies the Commission's historical treatment of transmission expense in Missouri FAC's. To the extent that occurred, the Company would and certainly should propose full inclusion of all transmission expenses in its FAC in a future rate review – and the Commission should agree.

VI. MISCELLANEOUS ISSUES

Q. What issue does Staff witness Eubanks take with the recommendation proposed in the direct testimony of CCM witness Hutchinson related to reimbursement of food spoilage and other related expenses associated with power outages exceeding 48 hours?

A. Witness Eubanks raises the concern that such a policy would potentially raise costs for all customers.

Q. Do you agree with her concern?

A. Yes. Longer duration outages such as those that would be the subject of CCM's proposal are overwhelmingly the result of severe storms that cause damage to the system. Such events are beyond the control of the Company, and therefore it would be unreasonable for the Company to have to provide financial insurance to customers

Data Response Display - EO-2025-0154 - 0231.0

Request Summary

Submission No.
EO-2025-0154

Request No.
0231.0

Requested Date
8/19/2025

Due Date
8/29/2025

Issue
Tariff Issue

Other

Requested From
MO PSC Staff (Other)
Lexi Klaus (lexi.klaus@psc.mo.gov)

Requested By
Data Center Coalition (Other) (Industry or Business Association)
Alissa Greenwald (agreenwald@keyesfox.com)

Brief Description
Section III – Staff Recommended LLPS Tariff Rates (Generation & Transmission Demand Charges)

Description
In her “Confidential Misc workpaper 1” workpaper, does Staff Witness Sarah L.K. Lange admit that she has a formulaic error in the derivation of the Generation and Transmission Demand Charges in the “EMW RR” worksheet? If not admitted, please explain the exclusion of any A&G expenses, depreciation/amortization expenses, or other expenses from the derivation of these charges for the EMW utility.

Request Security
Confidential (DR)

Response Date
8/28/2025

Response
Staff appreciates DCC for bringing this error to its attention. Yes, the cells summing revenue requirement components erroneously reflected a range that did not capture the full rows of the spreadsheet. This results in changes to several rates for EMW. A corrected workpaper will be distributed shortly. Staff did intend to include depreciation expense, the Iatan amortization expense, property taxes, pension expenses, and property insurance as those components relate to generation and transmission assets, respectively. However, the exclusion of the majority of A&G expenses from the revenue requirement calculation was intentional, as discussed in the section of the Report “Charges for Contributions to Fixed Cost Recovery.” A revised workpaper will be provided.

Objections

Response Security
Public (DR)

Rationale

Attachments

Name	Size	Security
Confidential Misc workpaper 1 Rebuttal workpaper - reviewing for DR responses.xlsx	241.36 KB	Confidential (DR)

Total: 1 file(s), 241.36 KB

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Evergy Metro Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of New and Modified Tariffs for Service to Large Load Customers.	))))	File No. EO-2025-0154

AFFIDAVIT OF STEVEN M. WILLS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

Steven M. Wills, being first duly sworn states:

My name is Steven M. Wills and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Steven M. Wills
Steven M. Wills

Sworn to me this 12th day of September, 2025.