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# MISSOURI PUBLIC SERVICE COMMISSION

## FILE NO. EA-2025-0238

## SURREBUTTAL TESTIMONY

## OF

## STEVEN M. WILLS

## ON

## BEHALF OF

## UNION ELECTRIC COMPANY

## D/B/A AMEREN MISSOURI

**St. Louis, Missouri**
**January, 2026**

## TABLE OF CONTENTS

**SURREBUTTAL TESTIMONY**

**OF**

**STEVEN M. WILLS**

**FILE NO. EA-2025-0238**

## 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. By whom and in what capacity are you employed?**

A. I am employed by Union Electric Company, d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), as the Senior Director of Regulatory Affairs.

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

A. Yes, I am.

## II. PURPOSE OF TESTIMONY

**Q. To what testimony or issues are you responding?**

A. I will primarily respond to the testimony of Office of Public Counsel ("OPC") witness Dr. Geoff Marke. Dr. Marke provides conditional support for the issuance of a Certificate of Convenience and Necessity ("CCN") for the Big Hollow gas turbine generator ("CTG") and Battery Energy Storage System ("BESS") projects ("Projects" or "Big Hollow"). However, the framing of his proposed conditions on the CCN reflect an over-simplification of complex issues, and run counter to both the letter and spirit of the

Commission's order in the Company's large load tariff case (File No. ET-2025-0184, "Large Load Tariff Case") as well as the large load tariff provisions of Senate Bill 4 ("SB 4"). I will discuss why the conditions Dr. Marke proposes are inappropriate for a CCN case and why Dr. Marke's call for cost allocation determinations and solutions are neither practical nor appropriate from a policy perspective. I appreciate Dr. Marke's concern for affordability of electric service in the future. However, that concern cannot be resolved by either denying the Company the ability to construct capacity resources that are needed to ensure reliability for all customers and support economic development in the state, nor by blindly foisting all costs of accelerated generation on large load customers.

I will also reply to certain items included in the rebuttal report of the Staff of the Missouri Public Service Commission ("Staff Report" and "Staff," respectively), particularly with respect to the Tartan Factor of economic feasibility and the related economic conditions Staff proposes as a part of the approval of this CCN.

## III. THE OPC'S PROPOSED CONDITIONS ON THE BIG HOLLOW CCN MUST BE REJECTED

**Q. Let's start with where you left off in your introductory discussion of OPC's concerns raised in this case – affordability. Is affordability a legitimate concern related to utility service?**

A. Of course. Affordability is central to the conversation around utility service and promoting affordability (i.e., just and reasonable rates) is a foundational goal of this Commission. This dynamic is especially true today, when utilities nationwide are facing increasing investment needs to replace aging infrastructure and bolster reliability, and utility rates in general have very recently risen faster than the rate of general inflation, which itself is already pressuring consumers. It is natural and appropriate for parties to utility cases and the Commission to focus on the issue of affordability. That said, the overarching affordability question related to the totality of utility investment being undertaken is well beyond the scope of this docket. Further, the solution to addressing affordability simply cannot be to fail to make investments that are critical to ensuring reliability for all customers, as well as to capturing economic development opportunities, which both this Commission in the Company's and Evergy's large load tariff cases just ruled were critically important to the state. That viewpoint is shared by the legislature and the state's executive branch, who have both also articulated quite clearly that capturing those opportunities is a key priority for Missouri.

**Q. Dr. Marke recommended that the Company provide in surrebuttal testimony, or alternatively that the Commission order the Company to provide prior to issuance of a CCN in this case, an analysis of the expected bill impacts of the planned investment reflected in the Company's full 5-year forward-looking capital expenditure ("CapEx") plan. Is this an appropriate condition for approval of a CCN for the Projects?**

A. No. The 5-year CapEx plan is made up of a variety of investments, from replacing aging substations, to hardening and automating distribution circuits, to new or upgraded transmission facilities to move power from generation to load centers, and investment in new and existing generating plants to reliably produce the energy needed by our customers when they need it. Each investment in that portfolio is evaluated on a standalone basis by the Company and later is subject to review in a general rate proceeding where parties have the opportunity to assess the prudency of those investments. The CCN process is appropriately focused on the need for specific projects – in this case, the Big

Hollow Projects – and can only be evaluated based on the need for those specific projects and whether they are in the public interest. The rate impact of the Company's, for example, distribution investments in modernizing substations is, while important in its own right, not a proper issue in this case. There is simply no reason to condition the approval of a CCN on a rate analysis related to the impact of investments that are not at issue in this case.

That said, the Company recognizes that this is an important topic and OPC's calls for transparency about what is known regarding future rates, generally, are well taken. While the many sources of significant uncertainty about future costs, revenues, tax policy, and other relevant drivers of changes in rate levels make any attempt to provide a specific forward-looking forecast of retail rates almost certain to be inaccurate, it is reasonable to look at information related to future scenarios and industry trends to inform generalized expectations. To that end, I will point out various places where the Company has provided information with which to develop expectations for future rate trajectories, so that, as Dr. Marke said, "no one can be accused of being "caught off guard" by future rate requests."

I will start with the Company's recently concluded Large Load Tariff Case. In that case, I performed a risk analysis that included scenarios that assumed, based on recent history informed by awareness of future investment plans, long term growth in retail rate levels from 3 to 5 percent annually. I also indicated that the higher end of that range – specifically growth at or above 4% per year -- was a likely outcome going forward. Note that rate increases are "lumpy" in that base rates are generally flat for periods of time and then "catch up" to the annualized trend levels that I just discussed in a single rate case that reflects more than a single year's increase in the cost of serving customers, so individual rate filings are likely to include higher levels of proposed revenue increases than the annualized average rate increase trends that I discussed.

Another relevant data point about future rate increases comes from the Company's Integrated Resource Plan ("IRP"). The Company analyzes the 20-year net present value of revenue requirement ("NPVRR") of its plan to serve customers going forward. Additionally, another metric used to evaluate candidate plans, as a part of the planning objective associated with customer satisfaction, is a measure of future rate increases. In the Company's 2023 IRP, which included generation investment levels similar to what is included in the Company's current CapEx plans, [1] the calculations of future rates related to this metric showed future rate increases across the 20-year planning horizon averaging 4.6% on a Probability Weighted Average basis, with higher increases (of up to 12% in the highest year) in certain individual years, due to the lumpiness of the significant generation investments in the plan[2]. This analysis did not include either the acceleration of generation to serve higher load requirements with new large loads on the system (e.g., Big Hollow), nor the impact of revenues from large load customers which we expect to contribute to the Company's fixed costs in a manner that will be beneficial to all customers, even after accounting for such investments. These 2023 IRP views represent a baseline expectation of rate growth that is totally divorced from any influence arising from large load issues and expectations. This is an important point to remember. Future rate increases were and are expected *irrespective of large loads joining the system*, so the existence of a future rate

[1] IRP analysis also includes estimates of the investments the Company will make in other functions of its operations including transmission and distribution.
[2] Rate increase values from Ameren Missouri 2023 IRP (File No. EO-2024-0020) workpaper titled, "PVRR 08-21-23_Confidential", rates tab, plan 4 (RAP – Renewable Expansion plan).

increase most certainly cannot be blindly ascribed to the impact of large load customers and any investments that may be accelerated in order to enable their service.

**Q. Has Dr. Marke of OPC acknowledged this dynamic previously?**

A. Yes. In his rebuttal testimony in the Large Load Tariff Case, Dr. Marke stated:

> It is highly probable that Missouri will soon face much higher electricity costs, reduced reliability, and increased negative externalities in its electric utility services. The promise of hyperscale customers partaking in more fixed cost recovery is an attractive solution…[3]

While Dr. Marke went on immediately following this preamble to caution about the potential for unintended consequences, this initial framing of the whole Large Load Tariff Case acknowledged that both (1) significantly higher utility costs should be expected *irrespective* of large load customer additions, and (2) we cannot assume that the impact of large load customers is higher rates, but rather that large load customers can spread fixed costs over more usage thereby offering at least some potential mitigation of higher rates. By virtue of its decision in the Large Load Tariff Case, the Commission has provided its assessment that the large load tariff framework in that case, along with its ongoing authority to adjust cost allocations and rate levels going forward, is in fact an appropriate solution to meeting the requirements of SB 4 and ensuring that large load customers pay rates that reflect their representative share of the costs of providing their service.

**Q. Is the first condition to the CCN proposed by Dr. Marke – that the Company acknowledge that the full cost of Big Hollow is fully attributable to the expected large loads and should be recovered from that class in future rate cases – reasonable and consistent with the outcome of the Large Load Tariff Case?**

[3] File No. ET-2025-0184, Dr. Geoff Marke Rebuttal Testimony, p. 2, ll. 5-7.

A. No. Dr. Marke, by virtue of recommending that the costs of a specific generation facility be fully allocated to, and therefore presumably borne by, future data center customers, attempts to relitigate the Large Load Tariff Case by turning the paradigm that the Commission has approved for large load service – as well as the overarching premise of regulated service by a vertically integrated utility - on its head. Dr. Marke provides several quotes made by Commissioners in the context of its vote approving the Large Load Tariff Case and goes on to infer that "everyone appears to agree that existing ratepayers should be held harmless from costs incurred by Ameren Missouri to serve this unique subset of data center customers."[4]

However, none of those quotes, nor the Commission's Large Load Tariff Case order, directly or implicitly signal a "hold harmless" provision. Moreover, imposition of a hold harmless provision is *directly contrary* to the standard in SB 4, and it is *inconsistent* with what the Commission approved in the Large Load Tariff Case. The SB 4 standard requires *reasonable* assurance that Large Load Customers will pay a representative share and, as the Commission recognized, the Company has an obligation to serve these customers and the Commission has ongoing regulatory and ratemaking authority – including in how it allocates costs over time – to ensure that the standard is met.

**Q. How do you know that the Commission did not approve a "hold harmless" provision?**

A. First of all, while I am not a lawyer, I can't imagine that such a provision is allowed in a regulatory and ratemaking construct where utilities have an obligation to serve and to do so safely and adequately and thus have an obligation to build and maintain utility

[4] File No. EA-2025-0238, Dr. Geoff Marke Rebuttal Testimony, p. 7, ll. 14-16.

systems that allow them to do so. In turn, so long as they prudently build and maintain those systems, they are entitled to charge rates that reflect the cost of those systems and provide a reasonable opportunity to earn a fair return.[5] But a "hold harmless" provision turns this regulatory construct on its head by ignoring whether the utility needed to build its system to meet its obligation, and whether it did so prudently, by making the utility a guarantor of outcomes that will play out over decades. There is no indication in the Commission's order approving the Stipulation and Agreement that resolved the Large Load Tariff Case, or within that Stipulation and Agreement itself, that suggests the Commission on the one hand recognized the Company had an obligation to serve large loads and wanted the Company to attract them, but at the same time expected the Company to guarantee how those economic development opportunities would play out over the coming decades. Further, the discussion in the context of the case, as well as context in Evergy's similar case (File No. EO-2025-0154) that ran in parallel with the Large Load Tariff Case, suggests no such provision was needed or appropriate. Indeed, in approving the Company's large load tariff, the Commission specifically found that doing so would result in just and reasonable rates based on a record that was fully transparent respecting the prospects for adding multiple gigawatts of new load from large load customers and that as a result the Company had adopted an updated Preferred Resource Plan that called for the acceleration of significant new natural gas simple cycle CTGs and BESS – the very assets at issue in this case – as discussed in Company witness Matt Michels' direct testimony.

[5] Indeed this is the regulatory compact between the Commission and its regulated utilities, as Dr. Marke himself has recognized. Surrebuttal Testimony of Geoff Marke, File No. ER-2021-0240, p. 12, ll. 14 – 18 ("Q. What is the regulatory compact? A. Often argued in regulatory settings, the regulatory compact constitutes an agreement between the utility and the government. The utility accepts an obligation to serve in return for the government's promise to set rates that will compensate it for the prudently incurred costs it incurs to meet that obligation.").

**Q. Is there further elaboration on why a hold harmless provision would be poor policy and inappropriate that you would like to provide?**

A. Yes. First, it is entirely impractical to try to identify and "ringfence" all of the costs the Company will have with large loads on its system as opposed to not having those loads on its system. Even Staff witness Sarah Lange, who in my experience across many rate cases has shown the strongest preference of any cost of service analyst I know to directly assign specific costs to specific customers, said so in the Large Load Tariff Case:

> Because a customer of the size that is subject to the LLCS tariff could necessitate the addition of an entire new power plant, or a significant portion of a new large power plant, it could be reasonable to allocate the cost of that plant (net of the revenues produced by that plant) to the LLCS customers. However, as plants are built and retired over time, and as other customer classes grow and contract over time, it would be difficult-to-impossible to track where revenue responsibility for a given plant should appropriately lie. Further, at this time, generally, a simple cycle natural gas combustion turbine would be the least costly means of meeting additional capacity requirements caused by an LLCS customer; however, overall system needs should dictate the appropriate type of plant addition which may be a combined cycle or other more expensive capacity.[6]

While I disagree with Ms. Lange's initial comment about it being reasonable to allocate the cost of a new power plant solely to large load customers, she goes on to recognize the practical reality that such an allocation becomes unwieldy to the point of being unworkable over time.

But the reason that this recommendation reflects poor policy goes beyond the practicality of its execution. Ms. Lange touched on the even more foundational reason that such an approach is unreasonable when she says "…overall system needs should dictate the type of plant addition…" This gets to the heart of the issue. Generation is neither

[6] File No. ET-2025-0184, *Staff Recommendation Rebuttal Report*, p. 51 l. 25 through p. 51. l. 9, filed September 5, 2025.

planned nor built on a customer (nor customer class) specific basis, irrespective of the size of that customer or class. Generation is a shared resource by all customers on the system. The nature of serving a diversified load (customers and classes that each place different levels of demand on the system at different times) with a diversified pool of shared resources with different operating characteristics and strengths, is far more efficient than it could ever be to build generating resources specific to individual customers.

The Commission even alluded to this effect, at least an analogous effect that exists with respect to short term planning and forecasting of generation and load, in the Findings of Fact in its order in Evergy's large load tariff case (File No. EO-2025-0154) on the issue of whether large load customers should be segregated into their own Commercial Pricing nodes for settlement in wholesale power markets, saying:

> 97. There are a multitude of issues with the disaggregation of commercial pricing nodes. The settlement process would forego the single, unified energy charge and would require separate accounting for fuel procurement expense, uplift charges, and congestion-management costs.
>
> 98. Disaggregation magnifies forecasting errors. Under an aggregated model, any over or under-estimation at a specific node is statistically decreased by the diversity of the broader portfolio.
>
> 99. Once the portfolio is separated into discrete, high-volume nodes, that diversity benefit of an aggregated model is lessened, and forecasting inaccuracies accumulate, thereby increasing volatility in settlement results.[7]

The same effects of load diversity that led the Commission to reject *separate CP nodes* for large load customers also strongly supports the notion that *separate generation facilities* dedicated to certain customers or classes is an inappropriate way to plan or build a system, and therefore similarly an inappropriate basis for the allocation of the costs of that system. And I think it is pretty facially evident when you talk about billions of dollars

[7] File No. EO-2025-0154, Report and Order, p. 41-42, filed November 13, 2025

of planned investment in generating plant that the increase in cost that would arise from planning the construction or acquisition of the generation that makes up the system on a disaggregated customer-by-customer basis is even orders of magnitude greater than the increase in cost that the Commission did appropriately recognize would exist with respect to disaggregating loads for purposes of short term forecasting and market operations.

**Q. Dr. Marke asked that the Company acknowledge that the resources being constructed are not merely being accelerated but are being built because of large load customers. How do you respond?**

A. Again, system generation is planned to meet the totality of the retail load of the utility, considering retirements of existing generation and all sources of future demand. No system generation is built specifically for any individual or small group of customers. I think some of Dr. Marke's argument comes down to semantics here really. When the Company says it is accelerating generation resources to meet large load demand, the Company has already acknowledged that the *timing* of the construction of resources is heavily influenced by the fact that its retail load is significantly higher due to new large load customer demand. And the Company did indeed appropriately analyze its generation plan through that lens in the large load tariff case. I conducted a risk analysis that was presented in my direct testimony in that case that looked at the impact on existing customers rates of the timing differences in generation build relative to a plan with no large load customers. This analysis appropriately looked at rate impacts over a long time horizon and across a number of scenarios with different values for key variables that will influence those rate impacts. This type of long-term analysis is the appropriate way to assess the cost responsibility of large load customers under the requirements of SB 4 to ensure that existing customers' rates are not being unjustly or unreasonably impacted by large load service. And apparently the Commission did not disagree, as it approved the Company's plan as modified by the negotiated Stipulation and Agreement in that case, even articulating that it provided adequate protection for existing customers in the very quotes of Commissioners Dr. Marke included in his rebuttal testimony.

**Q. What other complications would arise from adoption of Dr. Marke's recommendation that the cost of Big Hollow be fully attributed to large load customers?**

A. Rate case cost allocation models are very complex. If one were to fully allocate the cost of Big Hollow to a single customer or customer class, one would also have to figure out what to do with cost allocations of the remainder of the generation fleet. If the large load customer or class was included in the Class Cost of Service Study ("CCOSS") in a traditional manner, it would end up double-paying for capacity because it would be fully paying for the Big Hollow capacity via the direct assignment to it but still receiving cost allocation of the remaining generation fleet as well. However, it's not as simple as just removing the large load customers from the CCOSS model allocations of generation then. If that were done, large load customers would pay nothing toward the *higher* capital cost plant that they will also benefit from, such as large energy producing plants like the Callaway nuclear energy center. There is almost no reasonable way I can think of to directly attribute the entirety of the cost of one system resource to one customer or class, and still reasonably allocate the totality of generation investment to all customers including that customer or class, when we know that all system resources have attributes (i.e., resources that primarily provide capacity to support the system in peak times, baseload energy resources, flexible resources that load follow and respond to changing conditions) that work together to provide service to all customers. The wholistic approach to allocation of generation in the CCOSS already contemplates the investment in the generation fleet as a whole and uses allocation factors picked to best represent the manner in which each customer or class in the study utilizes and benefits from that generation fleet.

Another complication is that, if one were to allocate the costs of the Big Hollow project to a specific customer or class, it is logical then that that customer or class's rates would need to, at least for that portion of the rate that is covering the cost of that plant, track the revenue requirement of the plant over time. This means that the rate for recovery of generation costs from the customer or class in question would start high when the full investment in plant goes into rate base and decline over time as the plant depreciates. It is antithetical to almost all forms of ratemaking with which I am familiar to take this approach where a customer or class's rates start high due to the relatively higher cost of new infrastructure as compared to more depreciated plant and then decline as the customer or class "pays down" that asset over time. The much more appropriate paradigm for ensuring that the large customers' impact on the timing of investment in new assets is recognized in rates is, once again, the long-term perspective included in the risk analysis the Company presented in the Large Load Tariff Case.

**Q. Dr. Marke suggests an alternative path where the question of how cost of investment in Big Hollow should be allocated essentially be decided in a future rate case, with his testimony in this case serving as notice of OPC's intended position in that future rate case. How do you respond?**

A. A future rate case is the appropriate venue to decide on cost allocation issues, so this alternative is entirely reasonable. OPC is welcome to take whatever position it likes related to allocation of the investment in Big Hollow in a rate case, once the plant is in service. I would certainly anticipate the Company's position in that future case to also be consistent with what I am saying in this docket. So, I guess we all have a nice preview of a future debate that the Commission will have the opportunity to weigh-in on when the time comes. However, it fails to serve the public interest to delay the approval of needed generation while a cost allocation debate that is appropriately held in a rate case plays out here. The Commission should reject the conditions proposed by OPC, approve the Big Hollow CCN, and fully consider every party's position about cost allocation when the appropriate time arises.

**Q. Dr. Marke goes on to cite three different news articles related to the Company's future large load service to amplify his concerns. Please briefly address the articles and Dr. Marke's commentary on them.**

A. The first article cited by Dr. Marke is from the *Montgomery Standard*, a local newspaper in Montgomery County, Missouri. Dr. Marke highlights quotes from Ameren Missouri Senior Director of Business and Economic Development Rob Dixon.[8] Dr. Marke posits two primary takeaways from these quotes. First, that the Company "lacks agency" regarding large load impacts on customer rates and has instead conceded responsibility for protecting consumers to the Commission.

Let me say unequivocally that the Company absolutely recognizes its role in ensuring compliance with SB 4, i.e., in reasonably ensuring that unjust and unreasonable

[8] Mr. Dixon is now the Vice President of Regulatory and Legislative Affairs

costs do not impact existing customers – and the Commission specifically found that the Company indeed did so with its Large Load Rate Plan. And the Company intends to base its future rate recommendations consistent with those requirements. Mr. Dixon was also correct that, regardless of what the Company or any other party proposes in a future rate case, actual cost allocation decisions are ultimately made *by this Commission* and not unilaterally by the Company. I am confident that Mr. Dixon pointed this out to give the communities assurance that there are checks and balances that exist with the backstop of the legal authority vested in the Commission to ensure that the public will ultimately be treated fairly with respect to its rates for electric service. There is absolutely nothing wrong with Mr. Dixon making that statement.

The second point related to this article made by Dr. Marke pertains to Mr. Dixon's statement that all direct costs of interconnection will be fully borne by the large load customer. Dr. Marke uses the example of the Rootbeer substation project to raise the specter of costs that are not directly associated with interconnection, but which may be driven by large load customers and which may then be reflected in the rates of all customers. However, the example of the Rootbeer substation is both misleading and misplaced. The facts are – and Dr. Marke provides no information that in any way contradicts this – that the Rootbeer substation was planned and being constructed prior to any large load service plans in order to interconnect the Company's planned Split Rail solar energy center (approved by the Commission in 2023) to the network transmission system. I have attached Appendix A from the Split Rail Generator Interconnection Agreement to my testimony as Schedule SMW-S1. That agreement, executed in November 2023, well before the prospects for significant new large load customers was even on our radar, clearly and repeatedly references the new Rootbeer substation as the interconnection point for the Split Rail facility. Clearly the investment in this substation is not caused by large load customers. But irrespective of that point, large load customers *will* be paying retail rates that reflect the costs of network transmission infrastructure, including this substation. I conducted analysis for my surrebuttal testimony in the Large Load Tariff Case that demonstrated the high likelihood that bundled rates paid by large load customers will include enough revenues designed to cover hundreds of millions of dollars in shared network transmission upgrades, should those arise and at least partially be driven by the addition of large load customer load. Despite the fact that the example of the Rootbeer substation is inapplicable, as that investment is being undertaken irrespective of large load customer demand, any transmission upgrades that are at least partially a function of large load customer demand are very likely to be covered by revenues from the retail rates applied to their service (and the Commission can further adjust those rates in the future should evidence demonstrate that those revenues haven't covered any properly attributable network transmission system upgrade costs).

**Q. Please address the second article cited by Dr. Marke.**

A. The second article Dr. Marke discusses, also from the *Montgomery Standard*, featured a quote he highlighted where Amazon stated that the facility that it had under consideration in the area could be accommodated by the "existing grid planning process" and would not require additional generation. Dr. Marke takes exception with that characterization, saying that this CCN represents the additional generation. While the entity being quoted in this particular instance is not the Company and therefore does not necessarily reflect the Company's view, it seems pretty clear what point Amazon was making. The "existing grid planning process" is the Company's IRP process. And long before this article was published, on February 28, 2025, the Company changed its Preferred Resource Plan ("PRP"), and that new plan – the *existing* plan at the time the article was published – included capacity sufficient to integrate at least 1.5 Gigawatts of new large load demand and in fact called out the CTG facility at issue in this case (800 MW of new simple cycle generation at the former Rush Island site) and called out substantial BESS additions. That capability of the Company's PRP and the generation included within it (without necessitating any additional generation) was and is enough to serve the load under discussion in the article, and that appears to be what Amazon was communicating in that quote.

**Q. And the third article?**

A. The third article, this one from KRCG TV, is similar to the second, in that Dr. Marke now cites Mr. Dixon's claim that we have the power to serve the proposed new load – similar to his citation of Amazon in the prior article indicating that no new generation was needed for the potential Montgomery County facility. Clearly, Mr. Dixon *was* referring to the PRP, which includes sufficient generation to accommodate the load in question.

Dr. Marke goes on to challenge Mr. Dixon to put "in writing" Mr. Dixon's subsequent commitment that the Company can provide that power in a way that ensures that large loads pay their fair share. Ignoring for the moment Dr. Marke's not so subtle insinuation that Mr. Dixon was not telling the truth, it is already in writing, inasmuch as the Commission has approved the Company's Large Load Tariff Case with a finding that the resulting rates will be just and reasonable. There is simply nothing in any of these articles or quotes by Company personnel or others that is at all inconsistent with the

Company's public plans and with the Commission-approved framework for large load service. And frankly, OPC feeding into the anxiety of the public about the impact of data centers with speculative and inaccurate claims (e.g., Rootbeer mischaracterization) does a disservice to the process we are engaged in here at the Commission to ensure that the requirements of SB 4 and the public interest are fulfilled.

**Q. Are there any other conditions proposed by Dr. Marke that you wish to address?**

A. Yes. Dr. Marke also recommends that the CCN be conditioned on the Company agreeing to meet with Staff and OPC within ninety days of the operation of law date in this case to discuss plans for fire suppression and emergency response associated with the proposed BESS facility at Big Hollow. With the clarification that the Company is unaware of this case having an "operation of law date" and so would suggest that that phrase be changed to refer to the effective date of an order approving a CCN, the Company is agreeable to having such a dialogue with Staff and OPC. It is certainly in all parties' interest to build confidence in the plans we have for safely deploying a new (at least new to the Company at this scale) technology on the Company's system.

**Q. Dr. Marke also articulates that the Company's response to a Data Request indicating that it did not plan to utilize Construction Work in Progress ("CWIP") ratemaking treatment for the Big Hollow investment alleviated some other concerns that OPC might otherwise have in this case. Is it correct that the Company does not intend to utilize CWIP for this facility?**

A. Yes.

## IV. RESPONSE TO STAFF'S POSITION REGARDING ECONOMIC FEASIBILITY

**Q. What position does Staff take with respect to the economic feasibility of the Big Hollow Projects?**

A. Ultimately, Staff finds that the Projects are economically feasible.[9] But in its discussion leading to that conclusion, Staff makes several statements about the Company's approach to describing economic feasibility that I would like to address, and Staff also recommends certain "economic conditions" be imposed on the CCN that would establish future requirements for additional CCN cases.

**Q. What does Staff say about the Company's perspective on economic feasibility?**

A. With respect to Ameren Missouri's description of the economic feasibility of the Projects, Staff states:

> Several of their points rely on the total Net Present Value of Revenue Requirement ("NPVRR") of alternative resource plans in the Ameren Missouri analysis as the fundamental basis for justification of this project. However, the IRP and NPVRR analysis should not be conflated as a review of the economic feasibility of individual generating assets.
>
> None of those discussions demonstrate quantitatively that the benefits of the project outweigh the costs or more reasonably address the identified need than other viable alternatives.[10]

**Q. How do you respond?**

A. It is noteworthy that Staff points to "several" of the Company's points regarding economic feasibility relating to the IRP, rather than "all" of them. In fact, the Company has never relied on the IRP and the lowest NPVRR as a *sole* determinant of

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[9] File No. EA-2025-0238, *Staff Rebuttal Report*, p. 2, ll. 8-9,filed December 12, 2025.
[10] File No. EA-2025-0238 *Staff Rebuttal Report*, p. 36, ll. 13-19,filed December 12, 2025.

economic feasibility in a CCN case. We have consistently recognized that (1) the Commission has historically taken a broad view of the benefits of a project in order to determine whether it is an improvement justifying its costs, and (2) the IRP is only the first step in selecting individual resources and a careful evaluation of options related to the specific resources that will be selected to implement the PRP is necessary.

That said, the backbone of resource selection *must* be the IRP. And it would make no sense whatsoever to not lean heavily on the process that the Commission rules require a utility to undertake as the foundation of its plan for serving customers – a process that is extremely robust and heavily vetted in Commission proceedings. In fact, for this reason, state law has been modified so that, going forward beginning in a couple of years, resource selection will be even more integrated into the IRP process. Plain and simple, it is entirely appropriate for "several" of the points the Company makes about the economics of a resource to relate to the IRP.

I do agree with Staff that it is also appropriate to examine additional factors specific to the resource in question in the final selection of specific projects, which the Company routinely does by engaging in thorough site selection efforts considering numerous factors including interconnection costs, using competitive bidding to acquire parts and services, or in some cases entire projects, evaluating available tax credits, and potentially other factors depending on the project. Staff on the other hand has, for several CCN cases in front of the Commission, continually evolved its position on economic feasibility. In fairly recent cases, Staff argued essentially that the IRP was merely a "modeling exercise"[11] that, in effect, should be discarded entirely and replaced with a full new analysis that would amount

[11] For one example of this, see the Rebuttal Testimony of J Luebbert from File. No. EA-2022-0245, p. 7, ll. 19-20.

to a "re-do" of the entire resource planning exercise. I appreciate that Staff has moved off of that stance, but I am still puzzled why Staff would question the use of the IRP to make "several" (but not all) points about economic feasibility of the Projects.

**Q. Staff proposes certain "economic conditions" be adopted with the approval of this CCN which would be required as part of the analysis to support future CCN cases. Are those conditions necessary and appropriate?**

A. No. First of all, the question in this case is whether this project is in the public interest. And Staff agrees that it is, with its own finding of economic feasibility. There is simply no reason to encumber the approval of a needed project with a lengthy debate on how *future* CCNs should be supported. The Commission has successfully processed a lot of CCN applications in the last few years without dictating complex requirements into the process that go beyond what is required by relevant law or rules.

Further, to the extent Staff's economic conditions are appropriate, they are largely consistent with what the Company already does for CCN cases and therefore do not need to be imposed as additional conditions on the approval of this CCN. Company witness Matt Michels provides additional perspective on the specific economic conditions proposed by Staff. I will just supplement witness Michels' review of the conditions with comment on one of the conditions Staff proposed that I find to be particularly problematic.

**Q. What condition is that?**

A. Condition 7, which would require:

> Ameren Missouri shall file sensitivity analyses in the future IRP cases that model the impact on customer rates under various scenarios, including the non-materialization of large load customers and the persistence of high battery costs.[12]

[12] File No. EA-2025-0238, Staff Rebuttal Report, p. 92, ll. 20-22.

Staff seems to be suggesting that the analysis supporting a CCN case be expanded to include class level rate analysis, and in fact Staff conducted a form of such an analysis itself for this case.[13] Further, Staff also seems to be suggesting significant scenario analysis around large load risk, despite the fact that the Commission has approved a large load tariff framework with significant protections to ensure an adequate long-term financial commitment of large load customers before they initiate service on the system. Finally, they suggest an analysis of "persistence of high battery costs," which is really a technology selection issue appropriately undertaken in the IRP. None of these analyses are informative as to whether the specific resource in question is in the public interest or economically feasible.

**Q. Please elaborate on why that class allocations and rate calculations in the context of a CCN are not a reasonable condition.**

A. From a policy perspective, I can't understand what use arises from a class level rate analysis of the Big Hollow Projects. In fact, as I mentioned, Staff conducted an analysis of that nature in this case, saying that "the Commission should be aware of the rate impacts to be expected in future cases under the class cost of service allocation approach taken by Ameren Missouri in its most recent rate case, and Ameren Missouri's allocator calculations,"[14] but then went on to provide no recommendations or even perspective on how to consider the results of the analysis to inform a decision about whether the project is in the public interest. This further makes me question Staff's intent of including rate class level analysis in a CCN.

[13] As discussed below, what Staff is recommending for the Company would be far more problematic and complex, and although Staff conducted some kind of analysis, it made no use of it.
[14] File No. EA-2025-0238, Staff Rebuttal Report, p. 83, ll. 8-10.

Of course, general awareness of future rate impacts is good information for the Commission to have. And in response to Dr. Marke's call for a rate analysis, I provided some perspective on that earlier in this testimony. However, detailed class allocations are not useful in this process. What would be done with class level outcomes? If a resource is the lowest cost option (as established through a combination of the minimization of NPVRR in the IRP and the site-specific factors studied including competitive bidding for projects or project inputs), under what *class-specific* outcomes should the Commission order the Company to pursue a *higher* cost option? Said another way, it makes absolutely no sense to reject the lowest cost resource option, and then necessarily pick something with a higher overall cost, because of the way the costs of the lower cost resource would get allocated to the classes. If that allocation becomes a concern due to a disproportionate impact on some class (which I find to be an unlikely outcome to begin with), then that allocation should be adjusted in a future rate review, which the Commission always has the authority to do. What we shouldn't do is discard the best resource to cost-effectively meet the need and pick something that is a more costly or otherwise less optimal solution in order to avoid a simple allocation issue.

In fact, as I noted previously, when Staff conducted this analysis itself in this case, it appears to draw no conclusions. Staff generates many numbers and charts yet puts forth no summary or recommendation whatsoever of how to draw any meaningful conclusions about whether that supports or undercuts a finding that the Big Hollow projects are in the public interest or economically feasible. And in fact, Staff finds that the projects should be approved.

What the proposal does do is add tremendous complexity to the analysis needed to conduct a case. While Staff was able to perform an analysis in this case and I really do not know how much time and effort it took them, that time and effort resulted in no recommendation to the Commission. But further, for the Company to be subject to this condition, it would have to integrate this allocation framework into its economic modeling – i.e., the modeling it conducts for IRPs – which is several orders of magnitude more complex than Staff's analysis to begin with. Adding class allocations and rate calculations into the Company's IRP model would be a monumental task that would require substantial resources, time, and cost, for very little (if any) practical benefit. Just because a study *can* be done does not mean that it *should* be done. I strongly recommend that the Commission reject this seventh economic condition proposed by Staff.

**Q. You noted previously that the Staff draws no conclusions from its analysis. But given that Staff presented it for the Commission's consideration in this case, do you have any concerns with the analysis?**

A. Yes. Because Staff's analysis does not result in any recommendations that impact the outcome of the CCN, the review I have undertaken of their analysis is limited. But even with that limited nature of my review, I have concerns that there are significant errors in the calculations underlying the rate analysis presented by Staff that would make it unreliable in the event that some party or the Commission did try to draw a conclusion from it. Specifically, in the calculation of energy revenues sponsored by Staff witness Sarah Lange, a formula error in the determination of the normal market price to apply to the energy sales from the CTG caused that price to be significantly understated, which in turn understates the energy market revenues significantly (and, in turn, suggests higher rates than the analysis should). In Staff's workpaper titled "Highly Confidential Revenue Requirement", on the tab "Market Energy Input", the formula in cell X3 is the source of the value of $59.57 that Staff reported using for the energy revenue modeling on page 82 of its Rebuttal Report, which it described as representing "the historic average market price that would be applicable to the top 7% highest-priced hours of the year, regardless of when those hours fell."[15] That formula does not in fact do what Staff intended.[16] Rather than calculating the market prices applicable to the top 7% highest-priced hours, it calculates the price for only those hours *in* the 7th percentile (thereby excluding all of the top 6% highest-priced hours and focusing only those within a single percent range). Correcting that error would increase the market price of $59.57 reported on page 82 and subsequently used in Staff's analysis to $88.92. Using this price would reduce the revenue requirements (because those revenue requirements would be offset by higher market energy revenues) reported in Table 4 on page 85 of Staff's Report significantly. Table 1 below shows the total revenue requirements, first as calculated by Staff, and then as corrected for this error. While I'm not sure this is the only error due to the limitations of my review, this alone demonstrates that Staff's analysis is erroneous and therefore unreliable.

**Table 1 – Staff Revenue Requirements – Original and Corrected**

| Net Revenue Requirement | | | |
|---|---|---|---|
| | Sum | NPV @ 2% | NPV @ Ameren WACC |
| Original | $3,579,849,438 | $2,609,787,056 | $1,254,997,399 |
| Corrected | $3,049,539,599 | $2,254,591,319 | $1,114,667,877 |
| Magnitude of Error | $530,309,839 | $355,195,736 | $140,329,521 |

15 File No. EA-2025-0238, Staff Rebuttal Report, p. 81, ll., 16-17.
16 The error Staff made is in its use of an "averageif" formula in a cell, which averages all of the values in one cell range where the corresponding value in another cell range is equal to some specified condition. The condition Staff included to determine the values to average was that the value in the range of cells that contained the percentile ranking of each hour was *equal to* 7, rather than using a condition of *less than or equal* to 7.

**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 Permission and Approval and Certificate of Public Convenience and Necessity Authorizing it to Construct a New Generation Facility and Battery Energy Storage System | ) ) ) ) ) | File No.: EA-2025-0238 |

**AFFIDAVIT OF STEVEN M. WILLS**

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

Steven M. Wills being first duly sworn on his oath, states:

My name is Steven M. Wills, 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/* Steven M. Wills
Steven M. Wills

Sworn to me this 16th day of January 2026.

**Appendix A To GIA**

**Interconnection Facilities, System Protection Facilities, Distribution Upgrades, Generator Upgrades and Network Upgrades**

**1. Description of Generating Facility**

Interconnection Customer shall install a 327.6 MVA facility, rated at 305.4 MW gross and 300 MW net, with all studies performed at or below these outputs. The Generating Facility is composed of seventy-eight (78) SMA MVPS 4200-S2-US Inverters in a solar farm rated at 4.2 MVA each. Interconnection Service provided under this agreement is 300 MW of conditional ERIS that will become 300 MW of ERIS and/or NRIS upon completion of Network Upgrades, Common Use Upgrades, Affected System Upgrades under this GIA and transmission assumptions listed in Table A10-1 of Exhibit A10.

Interconnection Customer shall install a collector substation with the appropriate protection equipment coordinated per Appendix C to this GIA. The Interconnection Customer's collector substation shall contain two (2) generator step-up transformers 34.5/345 kV, 126/168/210MVA, two (2) 345 kV 2000A circuit breakers connected in parallel fashion and transmission line/bus protection as described in Exhibit A1.

The collector substation shall also include capacitor banks at 34.5 kV buses as required to meet FERC Order 827.

**2. Interconnection Facilities**

**(a) Point of Interconnection, Point of Change of Ownership, and Metering Point**

i. The Point of Interconnection (POI) will be at the point where the Transmission Owner Interconnection Facilities connect to the 345 kV bus at the new J976 Interconnection switching station (a.k.a. Rootbeer).

ii. The Point of Change of Ownership between the Interconnection Customer and Transmission Owner occurs at the arbor connection for hardware and shield wire, the terminal pads for conductor, and the splice point at the base of the arbor for OPGW. Transmission Owner will provide hardware to secure OPGW to the arbor leg and splicing of fiber optic cables inside the Transmission Owner's new Rootbeer switching station.

iii. The metering point will be at the 345 kV leadline terminal in the new Rootbeer switching station.

**(b) Interconnection Facilities (including metering equipment) to be constructed by Interconnection Customer.** Interconnection Customer shall construct Interconnection Customer Interconnection Facilities. These facilities shall include:

- A short 345 kV generator leadline from the Generating Facility collector substation to the adjacent Rootbeer Switching Station.

- Interconnection Customer shall provide all connection hardware up to the arbor in the Rootbeer Switching Station, OPGW, shield wire, and conductor, including downward pointing NEMA four-hole terminal pads, finished on both sides, for Transmission Owner connections at the Point of Change of Ownership.
- The Interconnection Customer's OPGW shall comply with the Transmission Owner's requirements during the design phase of the work.
- The Interconnection Customer shall install, own, and maintain its conductor, hardware, shield wire, and OPGW with prearranged escorted station access provided by the Transmission Owner.
- Interconnection Customer has the right, in accordance with Section 5.2 of the GIA, to install the Interconnection Customer Interconnection Facilities required under the GIA on Transmission Owner's station property. However, all Interconnection Customer transmission structures must be at least 75 feet from the station fence.
- Interconnection Customer shall coordinate with Transmission Owner on final physical connection logistics following GIA execution.

**(c) Transmission Owner Interconnection Facilities (including metering equipment) to be constructed by Transmission Owner and funded by Interconnection Customer**

The Transmission Owner Interconnection Facilities will consist of one 345 kV terminal in the Rootbeer Switching Station. The terminal will consist of all necessary terminal equipment to connect the Generating Facility leadline to the Rootbeer Switching Station bus. See Exhibit A2.

**Major Items:**

- One (1) 345 kV steel dead-end arbor structure
- One (1) 345 kV motor-operated disconnect switch, 3000A rated
- Three (3) 345 kV surge arresters
- Three (3) 345 kV potential/voltage transformers
- Three (3) 345 kV free-standing current transformers
- Revenue Metering
- One (1) line relay panel (SEL-411L and SEL-311C)
- One (1) fiber patch panel housing, fiber splice box, and fiber termination in the control house
- Bus and Fittings: five (5) inch aluminum tube and portions of 2500AAC (2) wire conductor with bolted aluminum bus connectors, fittings, and terminals
- Insulators: high-strength porcelain station post insulators
- Foundations: designed per Transmission Owner standard design criteria
- Structures: steel tapered tube style

**Total Estimated Cost:** **See Exhibit A5 ***

* Estimated costs are in 2025 dollars, do not include escalation or gross-up for income taxes, and are accurate to ±20% for the assumed location of the Rootbeer

Switching Station. Project J976 may be required to document that it satisfies the 'safe harbor' requirements under IRS Notice 2016-36.

**3. Network Upgrades**

As provided under Article 11.3 of the GIA, Transmission Owner has elected to fund the capital for the Network Upgrades to be constructed under the GIA. Pursuant to the Tariff, Interconnection Customer remains ultimately responsible for the actual costs of Network Upgrades, and pursuant to Article 11.6 of the GIA Interconnection Customer remains responsible for providing security to Transmission Owner for the estimated costs of the Network Upgrades.

Transmission Owner and Interconnection Customer will establish a service agreement between the Transmission Owner and the Interconnection Customer pursuant to which the Interconnection Customer will pay the Transmission Owner's revenue requirement associated with the Network Upgrades identified in Exhibit A9 to the GIA (the "Revenue Requirement"). The service agreement shall be filed with FERC, either on an executed or unexecuted basis, if required.

**(a) Stand-Alone Network Upgrades to be constructed and funded by Transmission Owner**

The new Rootbeer Switching Station will be located in Warren County, Missouri. The site will be on the north side of the Belleau Montgomery/Warrenton Montgomery double-circuit transmission lines ~0.3 miles east of Highway A. The approximate GPS coordinates are 38°54'19.4" North, 91°12'25.3" West.

The switching station will be a ring bus arrangement with three line terminal positions and provisions for one additional future terminal position. The future terminal position is not included in the scope of work or cost given in the GIA, it will be funded by whatever entity drives the need for the future installation. The existing Belleau-Montgomery 345 kV transmission line will be cut and the new ends terminated at two terminal positions in the switching station. The Generating Facility will interconnect at the third terminal position. See Exhibit A2.

The Rootbeer Switching Station will be constructed adjacent to the Belleau-Montgomery/Warrenton-Montgomery double-circuit transmission lines. The property for the site will be purchased by the Interconnection Customer and quit claimed to the Transmission Owner. The site dimensions must be a minimum of 600 feet by 800 feet as shown in Exhibit A3. The Interconnection Customer will bear the full cost and responsibility for property acquisition, site grading to Transmission Owner specifications, constructing and furnishing an access road, permitting, right of way acquisition, and all other costs associated with acquiring the necessary real estate for the station.
The Interconnection Customer is to provide detailed topographical and boundary

surveys of the site. Transmission Owner will obtain the soil borings required for the design of the switching station foundation. The Interconnection Customer shall provide the Transmission Owner and its contractors early access rights and an access route to the site for the purpose of site inspections and soil borings.

Site work such as the clearing, compacting, and grading of the site to finished subgrade elevations and grades shall be completed to Transmission Owner specifications by the Interconnection Customer before start of construction by the Transmission Owner. Transmission Owner shall review Interconnection Customer's final grading and site design for approval, in general accordance with the Transmission Owner's design review/deliverable schedule, prior to construction. The pavement surface for the switching station will be constructed by the Transmission Owner.

All permit, flood plain, storm water, environmental, jurisdictional, and regulatory issues with the site must be resolved by the Interconnection Customer before start of construction by the Transmission Owner.

The Interconnection Customer shall provide an access road to Rootbeer Switching Station site prior to the start of construction activities by the Transmission Owner. The access road shall be constructed according to Transmission Owner specifications, complete with the required pavement surface.

The Interconnection Customer shall be responsible for storm water run-off requirements. This includes meeting all storm water management plans and regulatory requirements listed by the local governing agencies. If no plans or requirements exist, it shall be assumed that the peak outflow rate be limited to that which existed from the same watershed before development for a specific range of flood frequencies. See Exhibit A15 for additional information.

The Interconnection Customer shall bear responsibility for all road damages caused by construction activities.

**Major Items:**

- Three (3) 345 kV gas circuit breakers, 3000A, 40kA interrupting capability
- Nine (9) 345 kV motor-operated disconnect switches, 3000A rated
- Two (2) 345 kV steel dead-end arbor structures
- Six (6) 345 kV coupling-capacitor voltage transformers
- Eleven (11) 345 kV surge arresters
- Bus and Fittings: five (5) inch and/or six (6) inch aluminum tube with portions of 2500 AAC (2) wire conductor with bolted aluminum bus connectors, fittings, and terminals
- Insulators: high-strength porcelain station post insulators
- Ground Grid: designed per Transmission Owner standards utilizing buried copper wire and exothermic welds
- Fence: standard chain link fencing with seven foot fabric, three strands of

barbed wire, and reinforcement cables

- Prefabricated Steel Control Enclosure containing:
  - Relaying and Control: two (2) line protection relay panels, three (3) breaker control panels, one (1) RTU panel, one (1) communications panel, one (1) fiber panel, and one (1) network panel
- DC Station Service Equipment: two (2) 125 volt battery, two (2) battery chargers, and two (2) DC distribution panels
- AC Station Service Equipment: two (2) 345 kV station service voltage transformers, one (1) automatic AC transfer switch, and three (3) AC distribution panels

**Total Estimated Cost:** **See Exhibit A5***

* Estimated costs are in 2025 dollars, do not include escalation or gross-up for income taxes, and are accurate to ±20% for the assumed location of the Rootbeer Switching Station.

**(b) Network Upgrades to be installed by Transmission Owner.**

**i. Cut and Terminate the Belleau-Montgomery 345 kV Transmission Line at the Rootbeer Switching Station**

Split the existing Belleau-Montgomery 345 kV transmission line between Montgomery and Enon (AECI) substations and terminate the ends at the new Rootbeer Switching Station.

Transmission Owner will install two double circuit steel monopole dead end transmission structures on drilled pier foundations in-line with the existing line, and remove an existing double circuit steel lattice tower. The existing conductor will be dead-ended on these deadend- structures and new tapping conductor will be run from these dead-end structures to arbor structures in the Rootbeer Switching Station. Jumpers will be installed at the dead-end structures to connect the existing line conductor to the new tapping conductor.

**Major Items:**

- Two (2) 345 kV double-circuit steel monopole dead-end structures on drilled pier foundations
- Conductor, shield wire, and OPGW
- Typical 345 kV insulators
- Compression type connectors

**Total Estimated Cost:** **See Exhibit A5***

* Estimated costs are in 2020 dollars, do not include escalation or gross-up for income taxes, and are accurate to ±20% for the assumed location of the Rootbeer Switching Station.

**ii. Upgrade Relaying at Belleau Substation**

Replace the existing relays at the Beleau terminal for the line from Montgomery to match the SEL-411L and a SEL-311C relays that will be installed at the Rootbeer Switching Station.

**Major Items:**
- One (1) relay and control panel

**Total Estimated Cost:** **See Exhibit A5***
* Estimated costs are in 2025 dollars, do not include escalation or gross-up for income taxes, and are accurate to ±20% for the assumed location of the Rootbeer Switching Station.

**iii. Upgrade Relaying at Montgomery Substation**

Replace the existing relays at the Montgomery terminal for the line from Belleau to match the SEL-411L and a SEL-311C relays that will be installed at the Rootbeer Switching Station.

**Major Items:**
- One (1) relay and control panel

**Total Estimated Cost:** **See Exhibit A5***
* Estimated costs are in 2025 dollars, do not include escalation or gross-up for income taxes, and are accurate to ±20% for the assumed location of the Rootbeer Switching Station.

**(c) Shared Network Upgrade(s) to be funded by Interconnection Customer.** None.

**4. System Protection Facilities**

**(a) System Protection Facilities not listed in Section 2 or 3 to be constructed by Interconnection Customer.** None.

**(b) System Protection Facilities not listed in 2 or 3 to be constructed by Transmission Owner.** None.

**5. Distribution Upgrades**

**(a) Distribution Upgrades to be constructed by Transmission Owner.** None.

**6. Contingency List.** See Exhibit A10.

**7. Affected System Upgrades List**

Interconnection Customer is responsible to enter into necessary agreements with Affected System Owner for Interconnection Customer's share of following upgrades:

- AECI
  - Relay upgrades at Enon Substation
  - Add an additional 345/161 kV 500 MVA transformer at Palmyra
  - Add fiber between the AECI Enon Substation and Ameren structure 176

**8. Common Use Upgrades List.** None.

**9. Exhibits – The following exhibits are included:**

A1. Interconnection Customer One-Line and Site Map
  A1-1: Interconnection Customer One-Line Diagram
  A1-2: Interconnection Customer Project Site Map
A2. Transmission Owner Substation One-Line Diagram
A3. Transmission Owner Substation General Arrangement Drawing
A4. {RESERVED}
A5. Cost of Facilities to be Constructed by Transmission Owner
A6. Detailed Cost of Facilities to be Constructed by Transmission Owner
A7. Facilities to be Constructed by Interconnection Customer
A8. Detailed Cost of Facilities to be Constructed by Interconnection Customer
A9. Estimated Cost of Network Upgrades to be Funded by Transmission Owner
A10. Contingent Facilities
A11. {RESERVED}
A12. {RESERVED}
A13. Permits, Licenses, Regulatory Approvals, and Authorization
A14. Interconnection and Operating Guidelines