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STATE OF MISSOURI

MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of New Modified Tariffs for Service to Large Load Customers	))))	Docket No. ET-2025-0184

Rebuttal Testimony of Caroline Palmer

On Behalf of
Sierra Club

September 5, 2025

Table of Contents

List of Exhibits

I. INTRODUCTION AND QUALIFICATIONS

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

A My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics, Inc.

A Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Please summarize your work experience and educational background.

A At Synapse, I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue allocation, advanced rate design, low-income rate design, load management, decoupling, distributed energy resource ("DER") interconnection and compensation, electric vehicle ("EV") infrastructure investments, and pilot frameworks. Prior to joining Synapse, I worked at Strategen Consulting for five years performing similar work. I have submitted expert testimony in nineteen dockets across ten jurisdictions.

I was awarded a Fulbright Research Fellowship to Greece in 2019 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science from Georgetown University. I have 10 years of professional experience. My resume is attached as Exhibit CP-1.

Q Have you previously testified before the Missouri Public Service Commission?

A Yes, I testified in Docket Nos. ER-2024-0319, WR-2024-0320, and ER-2024-0261.

I have also sponsored testimony before a number of other commissions, including the Michigan Public Service Commission, New Hampshire Public Utilities Commission, New York Public Service Commission, the Massachusetts Department of Public Utilities, Maine Public Utilities Commission, the Oklahoma Corporation Commission, the North Carolina Utilities Commission, and the Nova Scotia Utility and Review Board. I have also assisted with testimonies and regulatory analyses in numerous other jurisdictions.

II. Summary of Conclusions and Recommendations

Q Please summarize your conclusions.

A My conclusions are as follows:

1. The riskiness and magnitude of infrastructure investment associated with potential new large load customers taking service in Ameren's territory necessitates robust

safeguards to ensure that the new customers, rather than existing ratepayers, bear the risk of stranded investments should the new customer have lower usage than anticipated or leave the Company's service territory. It also necessitates re-evaluating the traditional ways that Ameren would track and allocate the costs of its investments for data centers.

2. Ameren's risk analysis, intended to demonstrate that its proposals for large load rate treatment adequately protect other customers from the risk of cost shifting, is rooted in numerous unreasonable assumptions and thus cannot be relied upon to conclude that the Company's proposals satisfy SB 4.
3. Ameren's optional clean energy program tariffs should better facilitate customer-driven decarbonization efforts with select modifications.

Q Please summarize your recommendations.

A I recommend that the Commission direct Ameren to:

1. Lower the eligibility threshold for the large load Large Primary Service subclass to 40 megawatts ("MW") (at single site or aggregated meters).
2. Create a separate large load customer rate class as soon as possible, including filing a Cost of Service Study ("COSS") with a separate large load class in its next rate case.
3. Extend the minimum service term to 20 years (up to a 5-year ramp plus 15-year full load).
4. Increase the minimum billing demand requirement to 90% of contracted capacity.
5. Adjust COSS allocators to reflect minimum billing demand.

6. Expand the termination fee to include at least the infrastructure portion of the customer charge.
7. Extend termination fees through the end of the contract term.
8. Require 42 months' advance notice for contract termination or end-of-term changes and apply penalties for failing to provide advance notice.
9. Extend capacity reduction termination fees through the end of the contract term.
10. Do not approve Ameren's proposals unless the risk of cost shifting is eliminated.
11. Instead of allocating the incremental costs of large load customers as system-wide costs through traditional cost of service methods, require Ameren to directly identify and assign incremental generation and transmission costs to large load customers.
12. Explore alternative cost allocation methodologies for fairly allocating embedded power system costs in light of significant, high-load-factor growth on the Company's power system.
13. Modify the Clean Energy Choice Rider to allow a customer to request replacing existing or planned high-emission resources with clean energy; narrow the definition of "clean energy" to renewable, demand management, and storage; and provide credits when customer-funded resources benefit other customers.
14. Modify the Clean Capacity Advancement Program and Renewable Solutions Program – Large Load Customers to ensure that resources supported are incremental.

III. AMEREN'S APPLICATION AND LARGE LOAD CUSTOMER EXPECTATIONS

Q Please summarize Ameren's application.

A In anticipation of new, large-scale, energy-intensive customers taking service, Ameren proposes changes to its Service Classification 11M – Large Primary Service ("LPS") rate, designed to attract large load customers in a manner that fairly protects non-large load customers from undue risk.[1] Ameren anticipates unique risks associated with serving large load customers and introduces a set of provisions meant to ensure an adequate long-term revenue stream from large load customers.[2] The provisions include a minimum term of service, minimum level of demand charges, financial security provisions, and exit fee requirements. Ameren also conducts a "risk analysis" to support its determination that existing customers are sufficiently protected from bearing unjust or unreasonable costs as a result of the service to large load customers.[3]

Q Describe Ameren's expectations for new data center load.

A Ameren states that it has over 30 gigawatts ("GW") of prospective new large load customers in its development pipeline.[4] The Company has already executed construction agreements for transmission-level infrastructure necessary to serve approximately 2.3 GW of new large customer load within its service territory starting as early as 2026, and several of those customers have also requested that Ameren study an additional 1.7 GW

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[1] Application and Request for Variance, p. 4.

[2] Direct Testimony of Steven M. Wills, p. 11 [hereinafter "Wills Direct Testimony"].

[3] *Id.* at p. 25.

[4] Direct Testimony of Ajay K. Arora, p.7 [hereinafter "Arora Direct Testimony"].

of load.[5] Customers representing a further 11 GW of potential new load have requested transmission studies, and Ameren states that "there is a significant pipeline of additional Large Load Customer additions" beyond the 15 GW in the transmission study process.[6]

Q How does prospective data center load compare with Ameren's current system?

A Ameren's peak demand in 2024 was 7.2 GW.[7] An additional 15 GW of new large load customers could triple the Company's peak demand. Even the initial 2.3 GW of load that have executed transmission agreements would represent a 31% increase in Ameren's peak demand.

In terms of energy consumption, the expected large load customer additions would have an outsized impact on Ameren's energy generation, given that they are expected to have high load factors in the 85-90% range.[8] A conservative estimate of an additional 2.3 GW of load operating at 85% load factor would consume 17,125,800 MWh[9] in a year, which would require a 52% increase in Ameren's 2024 energy generation of 32,987,148 MWh.[10]

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[5] *Id.* at p. 6.

[6] *Id.* at p. 6-7.

[7] Ameren Response to Sierra Club Data Request SC 1-3, Attachment "SIERRA 1-SC 001.3 Attachment.xlsx."

[8] Wills Direct Testimony, p. 14-15.

[9] 2,300 MW * 8,760 hours * 0.85 load factor.

[10] Ameren Response to Sierra Club Data Request SC 1-3, Attachment "SIERRA 1-SC 001.3 Attachment.xlsx."

Q Why is this load growth different than the growth experienced in the past?

A These considerable new demand and energy requirements would occur over an extraordinarily short period of time and at an extraordinary pace relative to historical load growth.[11] The unprecedented nature of this load growth also brings with it substantial risks due to unique uncertainty around potential reduction or elimination of data center load leading to stranded assets. The riskiness and magnitude of potential infrastructure investment associated with large load growth necessitates careful consideration of safeguards to ensure that the new large load customers bear that risk, rather than existing ratepayers. It also necessitates re-evaluating the traditional ways of tracking and allocating the costs of related new investments, since these investments are largely driven by a few customers, rather than by diffuse growth across the broader customer base.

IV. AMEREN SHOULD STRENGTHEN ITS PROPOSED PROTECTIONS

Q Describe the applicability of Ameren's Rate LPS large load customer provisions.

A The LPS subclass will apply to customers with loads of 100 MW or more, to be served at a transmission voltage of at least 115 kilovolts. The application does not specify a threshold for aggregating more than one site in the Company's service territory. The Company justifies the 100 MW threshold as "sufficiently different from all existing customers on the system that it creates a clear separation from existing LPS customers."[12] Ameren also notes that SB 4 establishes "a legal requirement for separation of large load customers" above 100 MW, specifically that such customers' rates will reflect the costs

[11] *Id.*

[12] Wills Direct Testimony, p.10.

incurred to serve them and prevent unjust or unreasonable costs to other customer classes.[13]

Q Do you recommend a lower eligibility threshold for Ameren's large load LPS subclass?

A Yes. I recommend that Ameren lower the eligibility threshold to 40 MW at a single site or for aggregated meters. A lower threshold would capture a broader range of potential large load customers, limiting more of the risk associated with accelerating generation investment to serve large load customers.

Ameren's justifications for a 100 MW threshold reasonably apply to these thresholds as well. First, Ameren states that the largest individual customer on the Company's system in 2024 had a peak demand of approximately 32 MW.[14] Customers on Ameren's LLC Rate Plan needn't have three times the peak demand of the current largest customer to be "clearly separated" from existing LPS customers. Indeed, any size above 32 MW would be differentiated from most existing LPS customers, who tend to be far smaller than 32 MW.[15] Second, although SB 4 may establish criteria at 100 MW, the Company should still prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to large load customers at a lower – and still unprecedented – level of demand.

[13] *Id.*

[14] *Id.* at p. 4.

[15] Wills Workpaper, "LPS_yearlyLoadFactorWorkbook.xls."

Ameren's proposed 100 MW threshold is also high compared to other jurisdictions. For example, the Public Utilities Commission of Ohio recently approved a settlement agreement setting a 25 MW threshold for new load or expansion of an existing load under AEP's data center tariff.[16] In its recent rate case, Dominion Energy Virginia ("Dominion") proposed to create a new high load rate class including all existing and new customers with demand above 25 MW on contiguous sites and measured or expected load factor of at least 75%.[17] The Commission-approved settlement agreement in Indiana Michigan Power Company's ("I&M") Industrial Power tariff set a threshold of 70 MW at an individual site or 150 MW on an aggregated basis.[18] Finally, a recent unanimous settlement regarding Evergy Kansas' large load tariff proposes a 75 MW threshold.[19]

Q Why is it important to aggregate meters for eligibility under the LLC Rate Plan?

A A data center complex might have multiple buildings that are individually metered and smaller than 100 MW each - or 40 MW, per my recommendation - but together aggregated to over 100 MW. In other circumstances, one could envision a parent

[16] Opinion and Order, Case No. 24-508-EL-ATA, *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers,* (July 9, 2025). Available at: https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G09B43531I00509.

[17] Direct Testimony of Stan Blackwell, Filed on Behalf of Dominion Energy Virginia, Case No. PUR-2025-00058, at p. 11. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/84sc01!.PDF.

[18] Order of the Commission, Cause No. 46097, *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P.,* at p. 31. Available at: https://www.in.gov/iurc/files/ord_46097_021925.pdf.

[19] Joint Motion for Approval of Unanimous Settlement Agreement of the Procedural Schedule, Docket No. 25-EKME-315-TAR, *In the Matter of the Application of Evergy … for Approval of Large Load Power Service Rate Plan and Associated Tariffs,* at p. 3, (Aug. 18, 2025). Available at: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20250818120216891 5.pdf?Id=9e907841-85a6-49d2-8321-59acf777cfd6

corporation that creates multiple subsidiaries to own smaller data centers that are within Ameren's service territory. In both cases, the utility would still incur substantial combined infrastructure costs to serve those cohorts of data centers, and would still be exposed to the same risk that Ameren is trying to avoid at sites with a single meter - i.e. the risk that the customer (or parent company) could either fail to transpire or could become insolvent during the contract period. Ameren should ensure that these facilities are subject to the same consumer protection provisions, and should be aggregated under Ameren's large load tariff.

Q Why does Ameren propose to serve large load customers on Rate LPS rather than on a separate rate?

A Ameren argues that the LPS rate is appropriate for service to large load customers because of the customers' load factors and the voltage at which the customer or customer class is served.[20]

Q Does the Company plan to study the cost to serve new large load customers in future rate cases to determine whether they should be served on a separate tariff?

A No. The Company states that it does not "expect to study large load customers as a separate customer class from the Large Power Service class in future rate cases."[21]

[20] Wills Direct Testimony, p. 14-15.

[21] Ameren's Response to Commission Staff Data Request MPSC 0008.

Q Is it reasonable to serve large load customers on Rate LPS rather than a separate rate?

A No. Using Rate LPS rather than a separate rate could result in future rate increases for other customers. As I discuss below, there is a significant potential for cost shifting between classes if Ameren does not revisit cost of service allocation methods. Having these very large load customers served through a different rate class allows the Company and Commission to assess the impact of different allocation mechanisms.

Q What do you recommend regarding the creation of a new data center rate class?

A I recommend that Ameren create the new rate class as soon as possible – based on terms no less stringent than approved for the Rate LPS data center provision – and require all existing large load customers to take service on that rate. Doing so will better reflect cost causation associated with large load customers under current cost of service methodologies and facilitate direct assignment of large load customer-specific costs as I discuss in Section VI. To facilitate creation of a new rate class, I recommend that the Commission require Ameren, in its next rate case, to file a cost of service study that includes a new large load rate class and to address in testimony whether existing allocation methods appropriately prevent cost shifting between rate classes since this class may impose additional costs on the system given its requirements for round-the-clock generation resources. I discuss high-level concerns with current cost allocation methods in Section VI.

Q What minimum contract term does Ameren propose?

A Ameren proposes to require large load LPS subclass customers to commit to a term of service of at least 15 years. The 15 years would include a ramp-up period of up to five years, with a "full load period" commencing upon conclusion of the ramp period that extends for at least an additional 12 years (for a total of 15 years). Ameren justifies the length of its proposed service term using its risk analysis,[22] which does not adequately demonstrate that the combined large load terms would sufficiently avoid cost shifting to other customer classes, as I discuss in Section V of my testimony.

Q Do you support Ameren's 15-year contract term?

A No. The cap of fifteen years, or twelve years after a ramp period, is insufficient from a consumer protection standpoint. I recommend that Ameren extend the large load customer term of service to 20 years, or 15 years plus up to a 5-year ramp period.

Q Have other jurisdictions adopted a 20-year contract term?

A Yes. The Kentucky Public Service Commission ("PSC") recently approved a 20-year minimum contract term for Kentucky Power's large load tariff.[23] Consumers Energy in Michigan recently proposed a 15-year term commencing after a five-year ramp period.[24]

Q Describe Ameren's minimum billing demand requirement.

A Ameren proposes requiring new large load customers to pay a monthly minimum level of demand charges for the term of their Electric Service Agreement ("ESA"), equal to 70% of the contracted capacity. This minimum billing demand would apply to the ramp

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[22] Wills Direct Testimony, Section V.

[23] Order, Case No. 2024-00305, *In the Matter of: Electronic Tariff Filing of Kentucky Power Company to Revise its Industrial General Service Tariff,* at 3, 5, (Mar. 18, 2025). Available at: https://psc.ky.gov/pscscf/2024%20Cases/2024-00305/20250318_PSC_ORDER.pdf.

[24] Direct Testimony of Laura M. Connolly, Filed on Behalf of Consumer Energy Company, Case No. U-21859, *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD*, at p. 5 (Feb. 7, 2025). Available at: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000ZUNZTAA5.

period[25] and full load term. Ameren also proposes to continue applying the minimum demand after the contract term ends.

Q How did Ameren develop its minimum billing demand requirement of 70% of contracted capacity?

A Ameren does not justify the proposed minimum billing demand level beyond its risk analysis, which as I discuss in Section V of my testimony, does not show the combined large load terms to sufficiently avoid cost shifting to other customer classes.

Q Is Ameren's 70% minimum billing demand requirement adequate to protect other customers?

A No. Ameren fails to demonstrate that a 70% minimum billing demand would ensure that large load customers utilize and pay for the system investments they require. Further, 70% is low relative to other jurisdictions' minimum billing demand requirements. The Kentucky PSC approved a 90% minimum monthly billing demand for Kentucky Power's large load tariff. [26] AEP Ohio's recently-approved settlement sets an 85% minimum billing demand for loads above 116 MW.[27] The recent unanimous settlement regarding Evergy Kansas' large load tariff proposes an 80% minimum billing demand.

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[25] The customer will be required to provide a ramp demand by quarter over the ramp period, to which the minimum demand charges will apply over the ramp period. *See* Ameren's Response to Sierra Club Data Request SC 1-9.

[26] Order, Case No. 2024-00305, *In the Matter of: Electronic Tariff Filing of Kentucky Power Company to Revise its Industrial General Service Tariff,* at 3, 5. Available at: https://psc.ky.gov/pscscf/2024%20Cases/2024-00305/20250318_PSC_ORDER.pdf.

[27] The minimum billing demand decreases incrementally below 116 MW. The Public Utilities Commission of Ohio has not yet ruled on the case. Joint Stipulation and Recommendation, Exhibit B, Case No. 24-508-EL-ATA, *In the Matter of the Application of Ohio Power Company*

Q Do you recommend a higher minimum billing demand requirement?

A Yes. I recommend raising Ameren's minimum billing demand requirement to 90% to ensure that Ameren collects payment from large load customers for a greater portion of the investments made for them. This is particularly critical given the magnitude of the load in the pipeline. If Ameren makes investments to accommodate 15 GW of new load, but billed demand is only equal to 70% of that (10.5 GW), costs associated with the remaining 4.5 GW would shift to Ameren's existing customers. Given that Ameren's existing peak demand is only 7.2 GW, the ramifications of this cost shift for existing customers' bills would be severe.

Q Does the minimum billing demand requirement impact cost allocation?

A Yes. It is important that Ameren update its COSS to reflect the minimum billing demand requirement. Traditionally, demand allocators are based on actual load data so costs would be allocated to classes based on actual demand rather than minimum billing demand. For example, a large load customer with 100 MW of contract capacity but a peak demand of 60 MW would be treated as 60 MW for allocating demand costs. However, the revenues from that customer would reflect 70 MW of demand due to the proposed 70% minimum billing demand requirement. This discrepancy would underrepresent the cost to serve the customer class, causing it to appear to have higher revenues than costs, or a very high rate of return. It would also exaggerate the cost to serve other customer classes, appearing as though they are responsible for a higher proportion of system costs, when those costs are actually attributable to investments

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for New Tariffs Related to Data Centers and Mobile Data Centers, (Oct. 23, 2024). Available at: https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A24J23B55758I01206.

made for large loads. Other customer classes would therefore appear to have a lower rate of return, artificially justifying higher rate increases for those customers. By imposing a minimum billing demand requirement on large load customers, the Company is acknowledging that it incurred at least that portion of demand costs for those customers; the costs should therefore be allocated accordingly in the COSS.

Q How do you recommend accounting for the minimum billing demand in the COSS?

A To reflect the minimum billing demand in its COSS allocators, Ameren should adjust the allocator data to include any additional demand that would have been billed to the class under the minimum demand requirement. I recommend that Ameren incorporate this methodology into its next rate case COSS filing regardless of whether data center load has begun taking service to begin the process of finalizing the methodology and to inform any data collection that the Company may need to put in place once large load does materialize. To implement these representative allocators through this adjustment without potentially unfairly burdening existing LPS customers, large load customers would need to take service on a separate rate than the current LPS class.

Ideally, this recommendation will not be necessary if the Commission approves my recommendations in Section VI to initiate a more robust method of direct cost assignment to data centers, but incorporating the minimum billing demand in Ameren's COSS is necessary until that time.

Q Have other jurisdictions incorporated a minimum billing demand in the COSS?

A Yes. Dominion proposed such an adjustment in its recent rate case. Dominion noted that the adjustment better matches the costs incurred to meet the expected requirements of these large customers with the customers causing those costs to be incurred. "In addition, the adjustment ensures that the revenues associated with these minimum charges do not artificially inflate the class rate of return while the associated costs are allocated to other classes, making their rates of return appear to be lower."[28]

Q Describe Ameren's termination fee requirement.

A Ameren proposes that large load customers be allowed to terminate their ESA upon 24 months written notice to the Company subject to a termination fee, which comprises demand charges at the 70% minimum for (i) the ramp period plus (ii) five years after the termination date or the remaining term, whichever is less, as well as termination fees related to participation in any optional clean energy programs. Termination fees are subject to mitigation if the Company is able to find a replacement customer to take on the capacity or alternatively sells the capacity for which the customer has paid through its termination fee into the capacity market.[29]

Q Do you have concerns with the Company's proposed termination fee provision?

A Yes, I have several concerns:

- I am concerned that the termination fee does not cover the full extent of the costs incurred to serve large load customers, potentially resulting in cost shifting to other customers should the large load customer depart. Specifically, the termination fee does not include costs that are recovered through the customer charge.
- The termination fee is based on too few years of charges.

[28] Direct Testimony of Robert E. Miller, Filed on Behalf of Dominion Energy Virginia, Case No. PUR-2025-00058, at pp. 30-32. Available at: https://www.scc.virginia.gov/docketsearch/DOCS/84sl01!.PDF.

[29] Wills Direct Testimony, p. 13.

- If Ameren secures capacity-market revenues, those should be allocated among the customer classes consistent with the Company's established revenue allocation practices, not preferentially allocated to data center customers.
- Ameren's termination fee does not require large load customers to provide sufficient advance notice of termination, which is inconsistent with best practice.
- The timing requirement for customer termination is inconsistent with the Company's capacity reduction timing requirement.

Q What other costs should be included in the termination fee?

A The exit fee should not be limited to the minimum billing demand; it should also include Rate LPS' customer charge, which is designed to collect depreciation, rate of return, and operations and maintenance ("O&M") associated with meters and small amounts of other distribution capital, as well as customer account expenses and customer services and sales expenses.[30] If a large load departs Ameren's territory, the costs associated with the large load customer's meter would be recovered from other customers unless another customer takes service at the same premise. Therefore, the departing large load should continue to pay its customer-related costs to avoid saddling other customers with these costs. Specifically, I recommend that Ameren's termination fee include at least the infrastructure portion of Rate LPS's customer charge (e.g., the cost associated with the meter), if Ameren can demonstrate that it would not continue to incur any of the account maintenance components once the customer departs.

[30] Ameren Response to Sierra Club Data Request SC 1-4.

Additionally, if at the time of termination, the terminating customer has not yet paid in full for facilities which are dedicated to serving their load, I recommend that the termination fee include such costs.

Q Do any other jurisdictions include customer costs in the termination fee?

A Yes. For example, the I&M settlement agreement includes the monthly customer charge in a monthly minimum charge, which customers must pay as their exit fee.[31] Likewise, the unanimous settlement to Evergy Kansas' large load tariff proposes to include the monthly customer charge in its exit fee.[32]

Q Why do you say that the termination fee is based on too few years of charges?

A As demonstrated in the Company's risk analysis and discussed in Section V below, the proposed termination payments are based on too few years to cover the costs of accelerated generation investments attributable to large load customers, unless the Company assumes that it will be able to stop that generation investment upon a customer's termination. Until the Company demonstrates otherwise, I recommend requiring the termination fee through the end of the contract term. Several jurisdictions require exit fee payments for the full remaining service term in large load tariffs, such as

[31] Order of the Commission, Cause No. 46097, *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to Its Industrial Power Tariff – Tariff I.P.,* at pp. 33-34. Available at: https://www.in.gov/iurc/files/ord_46097_021925.pdf.

[32] Joint Motion for Approval of Unanimous Settlement Agreement of the Procedural Schedule, Docket No. 25-EKME-315-TAR, *In the Matter of the Application of Evergy … for Approval of Large Load Power Service Rate Plan and Associated Tariffs,* at p. 6, 10, (Aug. 18,2025). Available at: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20250818120216891 5.pdf?Id=9e907841-85a6-49d2-8321-59acf777cfd6.

in the unanimous settlement proposed for Evergy Kansas, Consumers Michigan's proposal, and a proposed tariff at Kentucky Utilities / Louisville Gas and Electric.[33]

Q Explain your concern regarding Ameren refunding a customer's termination fee.

A It is reasonable to refund a customer if Ameren subsequently reassigns the capacity to a replacement customer. However, the Company has not clarified how it will isolate the capacity for which the customer has paid through its termination fee and refund only those capacity costs to the departed customer. Given that the Company proposes to treat its entire power system as a shared capacity resource, with all customers contributing to the additional capacity costs driven by large load customers, Ameren cannot reasonably use a specific amount of market revenues to offset a particular portion of large load customer costs. Thus, because the terminating LPS subclass customer would have paid into the shared system costs (via their termination fee), it would be reasonable to make them eligible for Rate LPS' standard allocation of the system benefits.[34] Different

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[33] Direct Testimony of Michael Hornung, Kentucky Public Service Commission Docket 2025-00113 & -00114, at p. 6:9-12 ("In addition, Rate EHLF includes provisions that ensure customers taking service under the rate schedule pay all minimum demand charges and basic service charges for the full 15-year initial term; there are no exceptions for capacity reduction or early termination requests."). Available at https://psc.ky.gov/pscecf/2025-00114/rick.lovekamp%40lge-ku.com/05302025095212/36-Hornung_Direct_Testimony.pdf; *See also* Attachment, Filing Requirement Tab 4 - 807 KAR 5:001 Section 16(1)(b)(3), at p. 34 of 204 ("TERMINATION OF CONTRACT: If Customer provides the required 60 months advance notice of termination prior to expiration of the Initial Contract term, Customer will be subject to payment of an Exit Fee. The Exit Fee shall be due and payable to the Company upon the effective date of the contract termination. The Exit Fee shall be calculated as the nominal value of the remaining minimum non-fuel revenue over the remaining term." Available at: https://psc.ky.gov/pscecf/2025-00114/rick.lovekamp%40lge-ku.com/05302025095212/08-LGE_Filing_Requirements_-_1_of_11_%28Tabs_1-5%29.pdf

[34] Ameren currently includes a base amount of net wholesale capacity sales in the revenue requirement used to set base rates, which it allocates using an energy allocator. *See* Ameren's Response to Sierra Club Data Request SC 1-11(c).

accounting might be possible if Ameren attributed and directly assigned specific costs to the LPS subclass.

Q Please describe best practices regarding requirements that large load customers provide advance notice prior to substantial capacity reductions or departure.

A Utilities rely on accurate forecasts of future load to make system capacity investments and avoid over-investing in capacity. Jurisdictions across the country have begun to recognize that it is critical to require large load customers to provide adequate advance notice of load reductions or departure to protect remaining customers. As the Virginia Joint Legislative Audit and Review Commission stated, "[r]equiring advance notice of at least several years is important so that utilities can appropriately plan for system needs, secure needed capacity, and protect other customers from rate fluctuations."[35] The aforementioned I&M settlement requires large load customers to give 42 months' written notice prior to terminating a contract. The recently proposed unanimous Evergy Kansas settlement requires large load customers to provide written notice 36 months prior to the requested date of termination. For increased confidence in Ameren's ability to mitigate incremental generation costs upon a customers' termination, it should require a longer notice period before termination.

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[35] Joint Legislative Audit and Review Commission. Data Centers in Virginia: Report to the Governor and the General Assembly of Virginia. JLARC Report 598, at pp. 54-55, (Dec. 9, 2024). Available at: https://jlarc.virginia.gov/pdfs/reports/Rpt598-2.pdf.

Q Do you also recommend requiring advance notice before the end of the contract term?

A Yes. As the end of the 15-year term approaches, Ameren must be able to plan around the large load customer's future load. The departure of the customer, even after 15 years, will have a significant impact on the Company's planning, such as whether it needs to procure extra resources for other new load or not. I therefore recommend that Ameren require large load customers to provide 42 months' advance notice before the end of the 15-year contract term of their intention to maintain, reduce, or terminate their contract capacity at the end of the term, and implement penalties equal to the minimum billing demand and customer charge for each month less than the 42-month required notice.

Q Does Ameren propose restrictions on when a customer can terminate its service?

A No. Although Ameren only allows customers to reduce their maximum contract capacity after the first five years of their ESA, a customer may terminate its service at any time during the term of that ESA.[36] If the Commission chooses not to accept my recommendation that the termination fee extend for the entire length of the remaining contract, I recommend that Ameren only allow termination after the first five years of their ESA.

[36] Wills Direct Testimony, p. 13.

Q Does Ameren propose that customers be allowed a one-time capacity reduction?

A Yes. Customers may reduce their maximum contract capacity by up to 10 percent after the first five years of their ESA, subject to a prorated, five-year termination fee applied to the amount of capacity being reduced.[37]

Q Do you recommend a longer capacity reduction termination fee?

A Yes. As with the termination fee beyond 10 percent capacity reduction, I recommendation that the capacity reduction termination fee extend for the entire length of the remaining contract.

V. <u>AMEREN'S RISK ANALYSIS IS INSUFFICIENT FOR CONCLUDING THAT OTHER CLASSES WILL NOT PAY UNJUST OR UNREASONABLE COSTS PER SB 4.</u>

Q Does Ameren's proposal adequately address potential sources of cost-shifting?

A No. Ameren recognizes that under SB 4 it must protect existing customers from the risk of cost shifting due to the extra cost of serving large load customers, regardless of whether the large load customers terminate their contracts early or whether they remain on the Company's system. Ameren conducts a risk analysis based on which it asserts that the Commission can determine if there is "expected to be any unjust or unreasonable impacts on other customers."[38] As a result of the analysis, Ameren claims that its proposed "combination of contract term, minimum demands, and termination fees…provide a reasonable level of revenue assurance to justify the investment acceleration needed to bring approximately 2 gigawatts of load onto the system over the

[37] *Id.* at p. 13.

[38] *Id.* at p. 27.

next several years."[39] Ameren considers impacts on other customers to be just and reasonable under scenarios when no large load customers terminate their load and under possible termination of some or all load. Below, I describe my concerns with Ameren's risk analysis and conclusions.

Q How did Ameren conduct a risk analysis?

A Ameren uses an incremental cost assessment from its recent Integrated Resource Planning ("IRP") Process update to isolate the expected generation revenue requirement impact of large load customers. Specifically, Ameren identifies the accelerated generation resources that are required to enable reliable service on the Company's system with the addition of the large loads.[40] Then, Ameren compares those incremental generation costs to the incremental revenues that new large load customers will contribute by paying embedded-cost retail rates to determine whether the revenues from these new large load customers would offset the incremental costs associated with accommodating the new load. Ameren posits that if the system costs (i.e., the revenue requirement) increase by an amount less than or equal to the new revenue, existing customers will either benefit from or be neutral to the Company providing service to large load customers.[41]

Q What is the incremental generation cost associated with the large load customers?

A Given Ameren's signed construction agreements for 2.3 GW of load, the Company uses its 2 GW IRP modeling results and finds that 2 GW of accelerated large load produces an

[39] *Id.* at p. 14.

[40] *Id.* at p. 28-29.

[41] *Id.* at p. 30.

estimated increase of $8.8 billion in the 20-year net present value revenue requirement ("NPVRR") compared to the "no large load" scenario.[42]

Q Does Ameren find that embedded LPS revenues offset the incremental large load generation costs when there are no large load terminations?

A It depends on the scenario. Under certain assumptions, Ameren finds that the new large load revenue would offset the incremental costs associated with the additional load, while under other assumptions, the opposite would occur. Table 1 below shows the results of Ameren's analysis under different assumptions regarding retail rate growth. Ameren calculates the NPVRR as the incremental generation costs minus incremental embedded revenues. Under scenarios in which LPS retail rates grow at 3 or 4 percent annually throughout the large load customers' contract term, Ameren finds that the costs outweigh the benefits (i.e., the NPVRR remains positive, resulting in a cost shift to other customers. Only under the highest annual rate increase (5 percent) would revenues fully offset costs (shown as a negative NPVRR).

[42] *Id.* at p. 29.

Table 1: Revenue requirement impact on non-large load customers

	Future Retail Rate Growth		
	3%	4%	5%
NPVRR ($Millions)	$762	$144	($537)

Q What does Ameren conclude from its risk analysis?

A Ameren concludes that the impact of "adding large load customers…is largely a 'wash,'" because its analysis shows that there is almost as much of a chance that other customer rates go down by adding large loads as the chance that they go up.[43]

Q Does Ameren assert that clean energy revenues from large load customers will improve the outcomes in Table 1?

A Yes. Because large load customers may contribute incremental revenues through their participation in some or all of Ameren's optional clean energy programs, Ameren argues that such revenues would provide insurance against any scenario where there might otherwise be a gap between the incremental large load costs and revenues.[44] Ameren states that "this juxtaposition…should contribute to the Commission's analysis of whether approval of the Company's proposal in this case (as required by SB 4) would result in just and reasonable rates for other customers."[45] Using prices from prior phases of an existing clean energy program, Ameren estimates that the NPV of clean energy program revenues could range from $296 to $1,110 million,[46] potentially offsetting some or all of the detrimental NPVRR scenarios that Ameren forecasted.

[43] *Id.* at p. 35.

[44] *Id.* at p. 36.

[45] *Id.* at p. 38.

[46] *Id.* at p. 37, and Table 4.

Q What is your impression of Ameren's risk analysis methodology?

A I appreciate Ameren's effort to isolate some of the system costs of new large load customers and ensure that those customers will pay those costs. However, I have several concerns about the sufficiency of the analysis for concluding that other customers will not be harmed by new large load, including concerns about the ability of these customers to contribute to the embedded and ongoing costs of maintaining the existing system, as well as concerns regarding the assumptions and methodology Ameren used in its analysis.

Q Please explain your concerns regarding contribution to the cost of the existing system.

A Ameren assumes that revenues based on embedded costs can be fully used to offset incremental costs. This assumption does not hold the new large load customers responsible for any embedded system costs. While, on paper, the majority of those customers' generation needs might be met with the modeled incremental generation, the Company will continue to invest in and maintain other parts of the generation infrastructure to support those customers, such as black start capability. It is not reasonable to assess only whether these customers will pay their incremental costs without considering their contribution to applicable embedded costs.

Q Please explain your concerns regarding the assumptions and methodological choices in Ameren's risk analysis.

A Ameren makes several unreasonable assumptions and methodological choices that impact its incremental revenue projections, such as 1) expectations of future LPS retail rates, 2) the choice of LPS retail rate components that may offset incremental generation costs, and 3) expectations of potential clean energy revenues. I discuss each issue below.

Q What are your concerns with Ameren's expectation of future LPS retail rate growth?

A As Table 1 demonstrates, different assumptions about the annual retail rate increase (compound annual growth rate, or "CAGR") cause the expected impact on non-large load customers to vary dramatically. Ameren Witness Wills states that "in [his] opinion the odds of the 5% annual growth rate are higher"[47] – which is the only annual rate increase Ameren tested that leaves other customers better off. However, the odds of a 5% annual growth rate seem lower than Ameren implies.

For example, the Company evaluates recent trends in Ameren, Midwest, and national rate increases. For the latter two, the comparison uses data that appear to represent total retail class increases (including residential, commercial, and industrial), rather than industrial-specific rate increases.[48] Table 2 shows that isolating the industrial rates yields a much lower CAGR for both the Midwest and nationally compared to the total retail rate CAGR that Ameren presented as indicative of large customer rate trends. In fact, using industrial-specific rate increases results in CAGRs that are at least a full percentage point lower than total retail rate CAGRs for the most recent period (2019-2024).

[47] *Id.* at p. 35.

[48] Wills Workpaper, "Rate Change History Calculator," tab "EEI Data."

Table 2: Rate increases (CAGR) for total retail class vs industrial-specific

		Total Retail Rate CAGR		Industrial Rate CAGR	
Start of Period (12 months ending)	End of Period (12 months ending)	Midwest Avg	National Avg	Midwest Avg	National Avg
Jun 2018	Jun 2023	2.9%	4.6%	2.9%	4.0%
Dec 2018	Dec 2023	2.9%	4.4%	2.6%	3.0%
Jun 2019	Jun 2024	3.9%	4.3%	2.9%	3.1%

Further, when the Company evaluates trends in Ameren-specific rates, it should focus on LPS trends, not system-wide trends. Ameren argues that a statutory provision (which is now gone) capped LPS rates in the 2022 rate case, causing the LPS rate increase to be lower than it otherwise would have been and making the system-side rates "much more representative."[49] The Company could have but does not provide the counter-factual LPS CAGR based on the alternative 2022 LPS rate increase without the cap. Ameren does not justify why system-wide rates are a superior point of comparison to counter-factual LPS rates, but this methodological choice once again focuses on a higher CAGR, as shown in Table 3, which misleadingly supports the Company's conclusion that a higher CAGR is a reasonable assumption.

Table 3: Rate increase (CAGR) in Ameren Missouri Retail Rates

		Base Rate CAGR	
Start of Period	End of Period	LPS	System wide
April 1, 2019	April 1, 2024	2.0%	2.8%
April 1, 2020	April 1, 2025	2.3%	2.9%
June 1, 2020	June 1, 2025	3.9%	5.0%

When considering Midwest, national, and Company rate trends for industrial customers, a 5.0% annual rate increase does not appear to be as likely as Ameren claims.

[49] Wills Direct Testimony, p. 32, n.14.

Q What are your concerns with the LPS retail rate components that Ameren calculates will offset incremental generation costs?

A I am concerned that Ameren accounts for more revenues from LPS customers than can reasonably be considered to offset incremental generation costs. Ameren appropriately removes transmission revenues from its retail revenue calculation because the "transmission-related portion of the retail revenues should be available to cover transmission-related costs and not assumed as an offset to the generation-related incremental retail revenue requirement."[50]

However, Ameren includes expected revenues from the LPS customer charge,[51] which, as described above, is designed to collect costs of meters and other customer-related expenses that have nothing to do with generation. Although the Company states that large load customers should not be allocated any distribution costs, since they are to be served at transmission voltages, the Company will continue to incur the cost of meters and customer service on behalf of large load customers regardless of their voltage. Ameren should not consider the LPS customer charge a part of the incremental revenues that can offset incremental generation costs. Removing these revenues from Ameren's calculation should cause large load customers to offset less of the incremental generation cost, therefore raising the net NPVRR in all scenarios that Ameren considered and increasing the likelihood of a cost shift to other customers.

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[50] *Id.* at p. 34.

[51] Wills Workpaper, "PVRR - risk analysis," tab "Calculations," cell B5.

Q Describe your concerns with Ameren's assumption of potential clean energy revenues.

A Ameren estimates the NPV of a range of potential clean energy revenues based on possible renewable energy credit ("REC") prices.[52] Ameren provides a huge range of possible additional revenue for a single clean energy program, without demonstrating whether prior REC prices for that program reasonably represent future REC prices under large load purchasing, nor whether participation in the two other clean energy programs would likely generate comparable revenue. Ameren also has not demonstrated that it is reasonable to assume that large load customers will subscribe to clean energy programs at the capacity levels calculated in its clean energy revenues estimate. While the supplemental revenues from optional clean energy programs are valuable, they cannot reliably support a conclusion that there will be no shift of large load customer costs to other customers.

Q Do you agree with Ameren's conclusion that the impact of adding large load customers who do not terminate their contracts is "largely a 'wash'"?

A No. As I've explained, retail rates will not likely offset the incremental large load generation costs the way that Ameren claims – both because Ameren has included more retail rate components than appropriate and because the only scenario in which Ameren's analysis leaves other customers better off assumes an oversized and unlikely rate of LPS retail rate growth over the service term. It is also not reasonable to assume that revenues from participation in voluntary clean energy programs will be substantial and consistent,

[52] Wills Direct Testimony, p. 37.

or that they will produce credit sales at a value sufficient to offset costs. Further, even if retail rates *would* offset incremental generation costs, embedded retail rates must also collect the embedded cost responsibilities of large load customers, not only collect incremental revenues. For all of these reasons, Ameren's claims that "risk is symmetrical"[53] and that new large load customers "will be neutral to beneficial for existing customers"[54] are unsubstantiated.

Q Do you recommend that the Commission approve ESAs under the circumstances of Ameren's risk analysis?

A No. If there is a reasonable possibility of negative impact on other customers, the Commission should conclude that other customer rates may reflect unjust or unreasonable costs arising from service to large load customers, which contradicts SB 4. When considering Ameren's flawed assumptions, the Company's analysis shows a *likelihood* of negative impact on other customers from generation costs alone – let alone transmission costs or other power system impacts. The Commission should conclude that Ameren's proposed rate treatment does not satisfy SB 4. In Section VI, I discuss other cost allocation and rate treatment to mitigate these concerns.

[53] *Id.* at p. 45.

[54] *Id.*

Q If new large load customers cause costs for other customers, how will that impact the residential class?

A Ameren allocates the residential customer class 51% of production costs and 43% of fuel costs, meaning that based on current allocators,[55] residential customers will disproportionately and unjustly pay for the cost of serving large load customers.

Q Does Ameren find that embedded LPS revenues offset the incremental large load generation costs when there are large load terminations?

A Generally not. The Company calculates that there will be a detrimental impact on other customers in 11 out of 12 scenarios it tested in which large load customers terminate 100% of their load at various points in their contract term and pay the contractual termination fee.[56] The one scenario without a detrimental impact assumes the most aggressive retail rate growth (5%) – an unrealistic assumption that I addressed earlier – and the latest termination year tested.

However, Ameren argues that it can mitigate these detrimental revenue requirement impacts after a customer termination by adjusting its generation investment plan to defer some of the previously accelerated generation.[57] When the Company calculates the same termination scenarios with the assumption that it can avoid the capital investment associated with the now-deferred generation, nine out of the 12 scenarios tested show a net benefit to non-large load customers. Ameren asserts that the mitigated set of scenarios

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[55] Per the filed Company COSS from Docket No. ER-2024-0319. *See* Ameren's Response to Sierra Club Data Request SC 1-17, Attachment "SIERRA_1-SC_001_17-Att-MO ECCOS_2024 Final.xlsx," tab "AF Sum Sht."

[56] Wills Direct Testimony, p. 40 and Table 6.

[57] *Id.* at p. 39.

– in which other customers benefit – represent “how things would be likely to play out in reality.”[58]

Q Do you agree with Ameren’s conclusion that mitigation is likely to “address all of the residual risk (after termination payments) created by the prospect of early termination”?[59]

A No. Ameren claims that the “termination fee structure, combined with the likelihood of actionable mitigation strategies, thoroughly address any incremental risk.”[60] However, Ameren’s approach still has a glaring risk – the risk of the Company being able to mitigate generation investments – that Ameren has placed on other ratepayers. It is unreasonable to burden non-large load customers with that risk, when the Company incurs the generation costs on behalf of large load customers. Large load customers must bear the risk of whether or not the Company can mitigate incremental generation investments.

Q How do you recommend that large load customers bear the risk of whether or not the Company can mitigate incremental generation investments?

A I recommend that the ESA require large load customers to pay the termination fee for as long as needed to cover the incremental cost if Ameren can't mitigate those costs. Under Ameren’s current rate-setting approach, this likely means through the end of the contract

[58] *Id.* at p. 41.

[59] *Id.* at p. 43.

[60] *Id.*

term. If Ameren successfully mitigates the incremental generation investments, it can credit the mitigated costs back to the terminated customer.

VI. <u>AMEREN MUST MAKE GREATER EFFORT TO MITIGATE COST-SHIFTING FROM LARGE LOAD CUSTOMERS</u>

Q Does Ameren's proposal adequately address potential sources of cost-shifting?

A No. As discussed above, Ameren must make significant investments to serve large load customers. Not only will Ameren's embedded costs not likely cover the incremental generation costs to serve those customers, but if Ameren tracks and allocates costs among its customer classes using traditional methodologies and processes, other customers will likely end up paying for substantial portions of that investment.

Q How does Ameren plan to track and allocate the cost of investments required to serve large load customers?

A Ameren does not plan to separately track or allocate costs associated with large load customers. Instead, the Company states that large load customers should "just be subject to normal embedded cost of service ratemaking;" in other words, "LPS rates should simply be set at levels that cover the embedded cost of service."[61] Embedded cost of service ratemaking means pooling the costs of providing service as a shared system cost and then allocating to each customer class using its COSS.

Despite holding large load customers responsible for incremental generation costs in its risk analysis, Ameren does not propose to directly assign those costs to large load customers, stating that "[g]eneration resources are not planned, developed, or constructed

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[61] *Id.* at pp. 27-28.

on a customer-specific basis, and their allocation or assignment on that basis would unfairly deprive large load customers of retail service on equivalent terms as other retail customers."[62]

Q Do you agree with Ameren's reasoning for not separately tracking or allocating costs associated with serving large load customers?

A No. While it is true that generation resources traditionally served too diverse a set of loads to be directly assigned, Ameren itself has demonstrated that large load customers alter this paradigm so substantially that the Company is able to isolate incremental generation costs, justifying alternative cost treatment. While some degree of cost socialization is inherent in utility cost allocation, the scale of the anticipated investment described in Section III calls for reevaluating the treatment for customers that, as a class, drive a fundamentally different set of utility investments.

Ameren also claims that it would be inappropriate to try to isolate the costs of serving large load customers because they, "like all customers, have a right to seek service."[63] However, the right to seek service doesn't remove the obligation to pay their system costs and isolating such costs does not contradict the right to receive service. In fact, it ensures alignment with James Bonbright's widely-recognized cost causation principle.[64]

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[62] *Id.* at p. 16.

[63] *Id.* at p. 26.

[64] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press (1961), p. 291.

Q Do you agree that Ameren's COSS will fairly allocate large load customer costs?

A No. The Company's decision to maintain embedded cost of service methods is premised on the assumption that system costs are generally shared by or attributable to a mix of customer classes, and that the COSS properly allocates those costs to the customers who cause them. In other words, the incremental costs of serving large loads should be treated as shared among all customers because the costs will flow to the appropriate classes through the traditional allocation methods.

However, a cost of service study is an inherently imprecise tool in which cost analysts make numerous subjective determinations that may dramatically impact the study results. Ameren's allocation methodologies do not adequately reflect the costs incurred to meet the operating characteristics of new large loads. Allocating these investments via the cost of service study would exacerbate the COSS's existing imprecisions to an unjust and unreasonable level.

Q How would Ameren's COSS allocate generation investments made for large loads?

A Ameren allocates production costs based on class load factors determined using four non-coincident peaks through an Average and Excess ("A&E") allocation methodology.[65] This approach combines the Company's various demand resources into one cost pool and assigns it to customers based on a measure of their demand, rather than based on the specific resources required by their demand. Because baseload plants tend to have higher capital costs than peaking plants, customers that use a higher share of the baseload

[65] *I.e.*, based on the customer class's maximum load at any time of the study period regardless of the time of occurrence or magnitude of the Company's system peak. *See* Direct Testimony of Thomas Hickman, Filed on Behalf of Ameren Missouri, Docket No. ER-2024-0319, at p.16 (June 28, 2024). Available at: https://efis.psc.mo.gov/Document/Display/788993.

resource should be held responsible for a higher share of the utility's costliest resources. Data center and other high load factor customers are expected to use continuous power, which would likely translate to a higher proportion of baseload, while other customers use power at different rates across the day and year. Therefore, large load customers would be allocated a relatively lower proportion of generation costs than those incurred to serve them.

Q How could Ameren improve its COSS' generation allocation methodologies?

A Ideally, Ameren would use a production allocation methodology that examines how each customer class utilizes each generation resource, such as the probability of dispatch method. However, as I explained above, it may not be reasonable to allocate incremental large load costs using the cost of service study, given the unprecedented magnitude of those costs, because of the way the COSS would allocate costs to all customer classes.

Q Has Ameren addressed potential cost shifting due to transmission system costs?

A Only at a very high level. Ameren's risk analysis "is predicated on the assumption that the transmission revenues will be fair and adequate to cover transmission-related costs that may arise from service to large load customers."[66] Ameren deems that a reasonable assumption because the customers' construction agreements will require payment for any customer specific transmission upfront, leaving no "incremental transmission costs of serving these customers other than their share of any future system-wide upgrades as well as MISO allocated transmission costs."[67]

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[66] Wills Direct Testimony p.34.

[67] *Id.* at p. 34.

Q Has Ameren sufficiently accounted for potential cost shifting due to transmission system costs?

A No. First, the Company may inappropriately treat large load-triggered transmission upgrades as system-wide, network (i.e. socialized) upgrades. For example, the Company considers the cost of necessary upgrades to its existing facilities to be network upgrades even though "Ameren Missouri will be making [the upgrades] because of the [economic development] project."[68] If the Company makes the upgrades *because of* large load customers, it is not reasonable to treat such upgrades – the costs of which could be substantial – as shared network upgrades. Ameren should publicly identify the costs of such upgrades and allocate them to the large load customers rather than to its entire customer base.

Second, transmission cost allocation otherwise concentrates recovery of capacity costs into the highest peak hours, which may enable some large users to avoid consumption during key hours and escape paying for – despite using at all other hours – the transmission capacity paid for by others.

Q Do you recommend that Ameren explore separately identifying and directly allocating large load customer costs?

A Yes. First, the ability to isolate costs of this magnitude calls into question the necessity and reasonableness of treating them as shared costs and using a COSS to allocate them at all. Second, the imprecision of current COSS methodologies makes it very likely that non-large load customers will bear a disproportionate of the costs to serve the new load.

[68] Ameren's Response to Commission Staff Data Request MPSC 0005(h).

Ameren has astutely observed that there is currently "no practical or reasonable way to ringfence the costs of serving one set of retail customers…such that any other retail customers' rates are entirely isolated from impacts;" however, there is also currently no one set of retail customer load of the magnitude that Ameren forecasts. I recommend that the Commission order Ameren to explore cost allocation methodologies that would enable separately identifying and directly allocating large load customer costs.

VII. Ameren Should Modify its Optional Program Tariffs to Facilitate Customer-Driven Decarbonization Efforts

Q Describe Ameren's proposed new program tariffs.

A Ameren proposes new programs that enable large load customers to subscribe to "premium services that help meet the[ir] clean energy goals."[69] For example, under the Clean Capacity Advancement Program ("Rider CCAP"), large load customers would pay dedicated charges to support Company-owned energy storage systems ("ESS"), while Renewable Solutions Program – Large Load Customers ("Rider RSP LLC") enables the same for Company-owned wind and solar. The Clean Energy Choice Rider ("Rider CEC") offers an option to influence the Company's IRP Process by requesting and paying for clean energy resources in place of or in addition to resources selected in the Company's preferred resource portfolio.

Q Do you support Rider CEC?

A Yes, this rider offers an important opportunity for large load customers to introduce clean energy resources onto Ameren's system that the Company would not otherwise have

[69] Wills Direct Testimony, p. 3.

procured. It gives new customers a meaningful opportunity to advance decarbonization in Missouri, which, as the Company has explained, is an important factor in some of these customers' siting and operational decisions. With a few modifications, Rider CEC could be even more impactful.

Q How do you recommend modifying Rider CEC?

A Ameren's large load customers will likely have rigorous corporate decarbonization and clean energy goals that can be facilitated by Ameren to the benefit of all customers. Ameren's Rider CEC offers an opportunity for customers to request to add specific portfolios of additional clean energy to the Company's resource plan, but Rider CEC could be significantly more attractive with provisions that allow customers to help make Ameren's system more efficient and directly reduce emissions.

First, I recommend that the rider allow customers to request that clean energy resources be evaluated in addition to or in lieu of planned new, or existing, resources. This would enable the Company to examine, at the customer's behest and through the Company's IRP, portfolios in which existing high emissions resources are replaced by low emissions resources. Ameren has already proposed that large load customers could examine alternative resource plans in its IRP, asset replacement decisions are already part of the IRP evaluation process, and a customer's decarbonization outcomes might be met at a relatively low incremental cost with a replacement portfolio.[70]

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[70] To implement this change, Ameren should modify the "Purpose/Availability" section of Rider CEC to read that "…Customer may request one or more Clean Energy Resources be deployed in place of or in addition to one or more **proposed or existing** resources selected in the Company's Preferred Resource Portfolio" and modify the definition of Clean Energy Preferred Resource

Second, Ameren should narrow its definition of Clean Energy Resource under the tariff, which currently reads: "A resource that does not contribute any net carbon emissions to the atmosphere." This definition is overly broad in terms of what generation resources constitute "clean energy"; at the same time, it is unclear if it also includes non-generating resources. The tariff should instead specify Clean Energy Resources as: renewable energy, demand management, and/or storage.

Finally, a customer covering the costs associated with the Clean Energy Preferred Resource Plan may be contributing value to other customers that is not accounted for in the tariff. To the extent that the requesting customer brings a resource that replaces something that would have been paid for through other customer rates, it may be valid for the Rider CEC agreement to include a credit for the energy and capacity that the large load customer paid for.

The recent unanimous settlement regarding Evergy Kansas' large load tariff proposes a very similar rider with many of the elements I've described, such as allowing for asset retirement, demand-side management, energy efficiency, and battery storage, and including "any appropriate credit" as part of "cost recovery from the customer for the selected resources."[71]

Plan to read "the addition **and/or retirement** of one or more generation resources." (modification **emphasized**).

[71] Joint Motion for Approval of Unanimous Settlement Agreement of the Procedural Schedule, Docket No. 25-EKME-315-TAR, *In the Matter of the Application of Evergy … for Approval of Large Load Power Service Rate Plan and Associated Tariffs,* at p.18, (Aug. 18,2025). Available at: https://estar.kcc.ks.gov/estar/ViewFile.aspx/S20250818120216891 5.pdf?Id=9e907841-85a6-49d2-8321-59acf777cfd6.

Q What are your concerns with Riders CCAP and RSP LLC?

A While Riders CCAP and RSP LLC may offer clean energy benefits on paper that large load customers seek, they do not appear to enable new clean resources for customers who opt into the program. Rather, they likely reshuffle clean resources that the Company would or otherwise already plans to build and allocate to existing customers. For example, the energy storage capacity that the large load customer would support under Rider CCAP would have already been procured by the Company regardless of the customer's payments.[72] I recommend that Ameren modify Riders CCAP and RSP LLC such that they specify any new capacity or renewable resources under the Riders are incremental to Ameren's system - i.e. they must be for resources that would not otherwise be selected or built by the utility.

VIII. CONCLUSION

Q What do you recommend to the Commission?

A Please see a summary of my recommendations in Section II of this testimony.

Q Does this conclude your testimony?

A Yes.

[72] Ameren's Response to Sierra Club Data Request SC 1-13(a).

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 Approval of New Modified Tariffs for Service to Large Load Customers	))))	Case No. ET-2025-0184

AFFIDAVIT

Pursuant to Missouri Public Service Commission requirements, I, Caroline Palmer, hereby state:

1. My name is Caroline Palmer, and I am a Principal Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

2. Attached hereto and made part hereof for all purposes is my Rebuttal Testimony on behalf of Sierra Club, including exhibits, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that based upon my personal knowledge, the facts stated in the rebuttal testimony are true. In addition, my judgment is based upon my professional experience, and the opinions and conclusions stated in the testimony are true, valid, and accurate.

Under penalty of perjury, I declare that the foregoing is true and correct to the best of my knowledge and belief.

Date: September 5, 2025

Caroline Palmer

Caroline Palmer