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Testimony of Sarah L.K. Lange
Surrebuttal
Case No. ET-2025-0184

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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ET-2025-0184

Jefferson City, Missouri
November 2025

****** Denotes Confidential Information ******

TABLE OF CONTENTS OF

SURREBUTTAL TESTIMONY OF

SARAH L.K. LANGE

CASE NO. ET-2025-0184

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Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, Missouri Public Service Commission, 200 Madison St., Jefferson City, Missouri, 65101.

Q. Are you the same Sarah L.K. Lange who contributed to Staff's Rebuttal Report filed on September 5, 2025?

A. Yes.

SUMMARY

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to the testimonies of,

1. Mr. Ryan Hledik on behalf of Evergy, largely addressing the differences among rate structure and related issues,
2. Ms. Caroline Palmer on behalf of Sierra Club, largely addressing the reasonableness of Mr. Steven M. Wills's "risk analysis," the usefulness of embedded class cost of service studies for large loads, and the components and scale of Ameren Missouri's cost of service.
3. To provide greater context around my responses to Mr. Hledik and Ms. Palmer, and also to address a correction noted below, I will explain significant events related to Ameren Missouri's historic large load customer, the Noranda aluminum smelting facility, that was located at Marston, Missouri, near New Madrid.

CLARIFICATIONS AND CORRECTIONS

Q. Did areas you addressed in the Staff Rebuttal Report include inadvertent errors or incomplete information?

A. Yes, at this time, Staff is aware of the following:

1. Staff's recommended tariff sheet included a typographical error using "kWh" in place of "MWh," in the "Applicability" section.[1]

2. Staff's recommended tariff sheet failed to include language discussed in the body of the Report related to a +/- 5% tolerance in application of the Demand Deviation charge.[2]

3. Staff's references to the historic load of Noranda reflected an error. The sentences on lines 16 – 19 of page 2 of the Report should state, "The 100 MW threshold proposed by Ameren Missouri for LLCS service, is a higher demand than all but one investor owned utility customer Staff is aware of in State history. The Noranda aluminum smelter previously served by Ameren Missouri at a maximum capacity of approximately ** [redacted] ** MW at its highest operation." The figure provided at line 20 should be modified to the following, confidential, figure:

**

[redacted]

**

[1] Corrected in Schedule SLKL-s1, attached.

[2] Corrected in Schedule SLKL-s1, attached.

RATE STRUCTURE AND BARRIERS TO ENTRY

Q. On page 5 of his rebuttal testimony, Mr. Hledik provides Figure 1, which is his summary of "Large Load Tariff," regulatory activities. The table includes summaries of several items he identifies as related to "data centers," and other specific end uses. What end uses are specified under Missouri's SB4?

A. No end uses are identified under SB4. SB4 sets out a statutory requirement for Commission-promulgated tariffs to govern service applicable to customers who are reasonably projected to have above an annual peak demand of one hundred megawatts or more (including smaller customers if the Commission determines it appropriate).[3]

Q. Are all large load customers likely to be data centers?

A. I don't know, but it is reasonable to assume that with a flat energy charge and a contract demand requirement without seasonal variation,[4] the rate structure is designed with the interests of data centers in mind. And it is designed in a way that would discourage data center demand practices such as precooling and thermal energy storage.

Q. Would a biofuel refinery that may have seasonal load such as grain drying, or that can curtail during peak summer months or peak winter months, be attracted to Ameren Missouri's requested rate structure?

A. While it would depend on whether other utilities offer more lucrative rate structures for more flexible loads, in general, probably not. If a rate structure effectively penalizes load flexibility, then loads which are either naturally or easily flexible would not seek out that structure.

[3] Section 393.130.7, RSMo.

[4] The Ameren Missouri LLCS tariff does include some provisions for time-based demand variation. However, it is unclear how this tariff feature is intended to interact with contract demand specifications and minimum demand requirements.

Q. Mr. Hledik states that a common feature in these tariff proposals includes objectives to "attract new large customers to the service territory," "mitigate the risk of stranded assets if the large customer does not materialize as expected," and "protect customers from a potential cost shift resulting from the addition of the large load customers to the system."[5] Is it reasonable to expect that features that accomplish these goals in one jurisdiction would accomplish the same goals in another jurisdiction?

A. No. The easiest example of this is the tension between attracting new customers and protecting customers from a cost shift, particularly with regard to the cost of energy to serve new load. Many jurisdictions, such as Kansas, do not include fuel or net energy market expense in base rates - those net expenses are billed entirely through the fuel adjustment clause or equivalent rider. In Kansas, when a new customer load is added, the utility will not retain the revenue in each kWh that is associated with the Fuel Adjustment Clause (FAC) base amount, which is responsible for the double-recovery that I noted in the Staff Rebuttal Report at pages 4-5.

There are two ways to look at this disparity between Missouri and other jurisdictions such as Kansas – one is to say that the new customer should pay the full revenue and full bill set out in Ameren Missouri's application, and that the value of the double-recovery should be deferred and used to offset risk for other ratepayers and the increasing revenue requirement of Ameren Missouri that will be caused by adding new large customers. The other is to say that the new customers should not pay the portion of the full bill set out in Ameren Missouri's application in the interest of attracting new customers. A reasonable outcome is not to set up

[5] Hledik Rebuttal, page 5, lines 3-9.

Ameren Missouri to double-recover the value of the energy charge that is backed by the FAC for its own benefit, as Ameren Missouri's current proposal seemingly does in this case.

Staff's recommendation to defer Large Load Customer Electric Service ("LLCS") customer revenues between rate cases to the extent that those revenues exceed those used to set rates for LLCS customers in the last rate case has the benefit of funding regulatory liability accounts that can be offset against the capital costs of new power plants necessitated by large load customers, which would be a tool to "mitigate the risk of stranded assets if the large customers does not materialize as expected," which was the remaining feature noted by Mr. Hledik.[6]

Q. At page 10, Mr. Hledik sets out a bullet point list summarizing the elements of the rate structures proposed by Ameren Missouri in this case, and by EMM and EMW in EO-2025-0154. At pages 20 – 21, Mr. Hledik includes the following exchanges:

> Q. Are there outliers that you have seen in your review of large load tariffs?
>
> A. Yes. While many of the large customer tariffs I have reviewed aim to balance the three objectives described in my Rebuttal Testimony, the Missouri PSC Staff's proposal in Evergy's LLPS proceeding represents a departure from these emerging rate design practices. The table in Schedule RH-2 documents the key differences.
>
> Q. In what ways is Staff's proposal an outlier?
>
> A. At a conceptual level, there are two important ways in which Staff's proposal differs from proposals I have reviewed in other jurisdictions. First, Staff's proposal does not provide flexibility to attract new large load customers to Missouri. Specifically, Staff has recommended rejecting all of Evergy's proposed options designed to enable new customers to choose clean energy resources or provide capacity through local generation or demand response.
>
> Second, Staff's proposal is more complex than proposals I have reviewed in other jurisdictions and includes elements that I have not

[6] Hledik Rebuttal, page 5, lines 6-7.

> observed elsewhere. For example, Staff's proposal includes a four-season time-of-use energy charge with three pricing periods, several fixed cost adjustments, and two separate fees for variance between forecasted and actual demand that would require the customer and utility to update financial estimates on a monthly basis. I would expect this complexity, combined with a lack of flexibility, to make Staff's proposal unattractive to large load customers relative to competing proposals in other jurisdictions.

What is Staff's response?

A. It is helpful to think of the massive terms that Ameren Missouri has requested be authorized in this provision as related – but separate – elements.

First, the literal rates to be charged to LLCS customers. Secondly, the interaction of those rates with the existing regulatory framework. Third, the riders and other changes requested to the existing regulatory framework. Finally, the risks created by the previous factors, and risk mitigation or risk sharing mechanisms to address them.

Q. Are the literal rates to be charged to LLCS customers under Staff's recommendation outliers, as represented by Mr. Hledik?

A. No. As an initial point, Staff concedes that its recommendation to price out demand deviations as a risk mitigation mechanism may make its recommendations appear more complex or unusual compared to the utility proposal; however, this approach actually provides flexibility to LLCS customers and can be less costly to LLCS customers than the static demand requirements and minimum demand construct that Mr. Hledik advocates. The actual rate components that Staff recommends are:

1. A customer charge for the revenue requirement of billing LLCS customers, and for the salaries of the regulatory team associated with acquiring and serving LLCS customers.[7]

[7] It would take more than 20 LLCS customers each paying Ameren Missouri's requested $412.66/month customer charge to cover each $100,000 in salary related to LLCS customers each year.

2. A facilities charge to recover the changes in expenses such as property taxes, insurance, and vegetation management associated with the new transmission infrastructure.

3. Energy charges that, preferably, recover exactly the wholesale energy expense for serving that customer, enabling the customer to save money if desired, and protecting other customers during events such as polar vortexes or extreme summer heat. In the alternative, energy charges that allow LLCS customers to beneficially load shift, which are revenue neutral to a flat energy charge for customers with a 100% load factor.[8]

4. A generation demand charge that recognizes that Ameren Missouri does not have the capacity to serve LLCS customers with its existing generation resources. This rate is calculated by dividing the current generation plant balances (minus depreciation reserve) by the number of MW of current peak load for each utility. To that value are added the costs of maintaining generation (such as property taxes), but not the cost of fuel for those plants nor the cost of the labor associated with actual operation and generation of those plants.[9]
   a. The depreciation expense, capital costs, and fixed operating and maintenance expense of Ameren Missouri's current power plants is $16.60 per kW. That amount does not include any recovery for executive salaries, office buildings, PISA, regulatory expenses, expenses allocated from Ameren to Ameren Missouri, or special programs like low income programs, or electric vehicle programs.
   b. The demand charge is billed based on on-peak demand, similar to the Ameren Missouri proposal.

5. A transmission demand charge is a clean reflection of the cost of service calculation for the transmission function. It does not include an estimate of new transmission expense which will be caused by the operation, taxes, and insurance associated with yet-to-be-built transmission facilities which will be prepaid by LLCS customers, which will be recovered through the Facilities Charge. This charge is not designed to include any recovery for

[8] This charge is not designed to include any recovery for executive salaries, office buildings, PISA, regulatory expenses, expenses allocated from Ameren to Ameren Missouri, or special programs like low income programs, or electric vehicle programs.

[9] Staff's recommended rates neither buffer this calculated rate for the cost of service of the new power plants which will need to be built to serve LLCS customers, nor artificially reduce the cost of service of existing generation with an offset allocation of the Accumulated Deferred Income Tax balance (ADIT). ADIT is a rate base offset that results from tax timing differences under which legacy ratepayers have effectively prepaid the taxes for utility assets relative to the utility's actual payment of taxes on those assets. Missouri law requires that the LLCS tariffs to be developed in this case "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers." It would be inconsistent with that law, general rate making policy, and patently unfair to offset the rates of large incremental customers causing incremental plant investment with the prepayment of income tax by legacy ratepayers. Further, Missouri law requires that the tariffs under development in this case "prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers." Allocating away a substantial portion of the prepaid tax burden of legacy customers to discrete new customers would be inconsistent with this legislation, inconsistent with general rate making policy, and would be patently unfair.

executive salaries, office buildings, PISA, regulatory expenses, expenses allocated from Ameren to Ameren Missouri, or special programs like low income programs, or electric vehicle programs.

6. Line items to exactly recover the cost of service of Renewable Energy Standard (RES) compliance and the statutory requirements associated with Ameren Missouri's recovery of the revenue not received from customers receiving economic development discounts.

7. Fixed Revenue Contribution charges to recognize that none of the previously listed charges would result in an LLCS customer contributing towards recovery of the revenue requirement of things like executive salaries, office buildings, PISA, regulatory expenses, expenses allocated from Ameren to Ameren Missouri, or special programs like low income programs, or electric vehicle programs.

With one exception, these charges are not outliers and are not particularly creative. Staff concedes that it is not common for a rate structure to give the authorizing Commission the ability to set the level of recovery that customers will contribute towards items like executive salaries, office buildings, PISA, regulatory expenses, expenses allocated from Ameren to Ameren Missouri, or special programs like low income programs and electric vehicle programs. Typically, allocation of the revenue requirement associated with these items is buried in the internal allocators of a class cost of service study. Staff prefers this approach as it provides transparency into not only the level of contribution LLCS customers will make towards those overhead costs, but it also allows transparency into items like the cost of generation capacity on a $/kW basis, and the wholesale energy expense for serving loads.

Q. Could the Commission order that the Fixed Revenue Contribution charges be incorporated into the rate elements like the generation demand charge and the energy charges?

A. Absolutely. The Commission could determine that 10%, or 25%, or 30%are appropriate contributions towards the overheads discussed above. Multiplying the other rate elements to incorporate those costs of service into those charges is a simple calculation.

Personally, as someone who has developed and reviewed tariffs and rates for over a decade, I prefer separate charges to facilitate review of those charges in future rate cases, but it is a simple matter to add the recovery of "fixed" cost of service to the charges for recovery of owning power plants and selling energy.

Q. What is important about the interaction of LLCS rates with the existing regulatory framework?

A. There are likely to be additional items that become identifiable over time, but at the outset, the interactions of LLCS customer growth with the Ameren Missouri Renewable Energy Standard Rate Adjustment Mechanism (RESRAM), FAC, resource planning, and regional transmission planning must be considered.

Q. Using the RESRAM as an example, what interactions are concerning with regard to the factors identified by Mr. Hledik?

A. Under current tariffs, 15% of the capital cost of qualifying resources and 100% of the expense will be flowed through the RESRAM and paid by all customers. Consider if Ameren Missouri builds a solar power plant or a wind farm either because it chose that resource to serve new capacity requirements or because an LLCS customer requested that resource. When the LLCS customer begins taking service, the LLCS customer will also pay into the RESRAM, but it will not pay the full RESRAM recovery of that resource that would not exist except either indirectly or directly because of that new LLCS customer. Other customers will pay for that new resource through the RESRAM.

Q. What is important about riders and other changes requested to the existing regulatory framework?

A. The concerns fall into a few categories:

Certain riders may be generally reasonable with appropriate tariff revisions, but the intent can already be effectuated with out a rider;

Certain riders may be generally reasonable with appropriate tariff revisions, but the intent cannot be effectuated currently due to factors outside of the utility's control;

Certain riders would provide an avenue for deviations from prudent resource planning, which is implicitly concerning; and

Certain riders would effectively modify the bills for LLCS customers from those anticipated in designing the rates for LLCS customers.

It is important for the Commission to recognize that mechanisms such as those proposed by Ameren Missouri are incredibly complex and will have consequences that last for decades. Many of the goals of the riders are related to giving LLCS customers the ability to claim clean energy powers the LLCS facility. The proposed riders are not the only avenues towards achievement of those goals, and those goals are facially at odds with concerns Staff hears raised by members of the general assembly with assurance of what they characterize as reliable baseload power.[10]

Q. Mr. Hledik expresses concern that Staff would propose to reject all proposed riders.[11] Is this accurate?

A. It is accurate that Staff did not recommend that any of the Evergy-proposed riders be promulgated at this time in the Evergy case, and that Staff did not recommend promulgation at this time of the Ameren Missouri-proposed riders in this case. However, as

[10] Staff is not opposed to development of mechanisms for customers to support or contribute towards the development of generation, but such mechanisms require dedicated and unified effort to develop. This case is not a reasonable framework for such work. Further, while such work could be established as a priority outside of this case, development of a mechanism to facilitate customer support of, for example, a nuclear power plant, need not be concluded within the procedural schedule of this case.
[11] Hledik Rebuttal page 21, lines 6-9.

discussed in the respective Rebuttal Reports, Staff noted that each utility currently has the ability to enter capacity and/or energy purchase agreements with effectively any counterparty – including LLCS customers. Staff also noted that there is no current registry of nuclear energy credits which is anticipated to be necessary to support other proposed riders. Staff is generally opposed to the concept of allowing any customer to make changes to prudent resources planning decisions which are the responsibility of the utility, or to allowing a utility to delegate its responsibility for prudent resource planning to a customer.

Q. Staff raised a concern in its Rebuttal Report that the Ameren-proposed riders would be used to change the demand or energy determinants an LLCS customer is billed. Has that concern been resolved?

A. No. Staff followed up informally with Ameren Missouri after Ameren Missouri issued a data request to Staff on the subject. I emailed Mr. Wills, asking "Could you confirm that the proposed tariffs for these riders would not be using the Agreements referenced in the tariff to modify metered energy or demand charges for purposes of billing LLCS customers?" Mr. Wills responded, "I can confirm it for sure for CCAP. Since CEC doesn't have any pre-established pricing framework, but would be based on customized agreements (subject to Commission approval), I can't say definitively for CEC, although I have no current expectation that we would price it in such a way as to modify an existing energy or demand charge."[12]

Q. The final item you describe above in your response to Mr. Hledik are the risks created by the previous factors, and risk mitigation or risk sharing mechanisms to address them.

[12] The Clean Energy Choice Program, or "CEC," is a proposal to deploy clean energy technologies above and beyond the amounts of those resource types reflected in the Company's Preferred Resource Plan. The "Clean Capacity Advancement Program", or "CCAP," is a proposed program that will allow large load customers to enable clean energy storage systems.

How is Staff's recommended demand charge arrangement more advantageous to many potential LLCS customers than that proposed by Ameren Missouri?[13]

A. First, for a customer who accurately predicts their future demand requirements and that customer has the same demand in each month and each year, there is no difference in the impacts of Staff's or Ameren Missouri's proposal. However, for customers who anticipate future changes in their demand requirements or who may have different demands at different times of the year, Staff's recommendation provides lower bill impacts in many scenarios.

A minimum demand charge looks at what a customer didn't use, and bills the customer at the full demand charge for that amount. Staff's approach looks at what a customer didn't use, and bills the customer at a lower amount.

In place of a set minimum demand level to be billed at the tariff demand rate, Staff has recommended a more customer-friendly approach which better aligns revenue recovery with cost causation, encourages accurate demand forecasts to facilitate system planning, and is not punitive.

Staff recommends that at the outset of service of an LLCS customer, the customer provide its projection of the monthly demands for each month of its term of service. Each year, the customer is to update these projections, if applicable. Differences between the initial projection and the annual update are billed a "Demand Deviation Charge," which is lower than the combined Demand Charges which would otherwise be applicable. A plus/minus 5% deadband is also allowed, for which no extra charge will apply. The interaction of these components is roughly equivalent to a 95% minimum demand charge before a reduced demand rate kicks in on the difference.

[13] Unlike Evergy, Ameren Missouri's proposal does incorporate time-based demand charges.

In real time, month to month, the actual demand is compared to the expected demand for the year under the annual update. That difference in demand is subject to a charge which is also lower than the combined demand charges which would otherwise be applicable.

Q. How does the Staff approach deal with the scenario where a customer was expected to use 500 MW, but used 550 MW instead?

A. Under that scenario, the deviation would be billed at the applicable demand rates, plus the applicable deviation charges and imbalance charges. A customer of this size exceeding projected demand could have significant financial implications and reliability implications for Ameren Missouri customers.

Q. How does Ameren Missouri contemplate dealing with unplanned excess demand from an LLCS customer?

A. In the tariff appended to Steven M. Wills's direct testimony as Schedule SMW-D1, paragraph 4.2 of the Customer Agreement includes a statement that "Customer's highest level of connected load to be served by Ameren Missouri under this Agreement during the term is [<insert load amount>]," with no further explanation of consequences to exceed this amount. Paragraph 4.4 of the Customer Agreement establishes a minimum demand for which the customer will be required to pay regardless of the actual demand.[14]

Q. If a customer has financial consequences for having too low of a demand and no consequences for having too high of a demand, what would a rational customer try to do?

[14] Ameren Missouri proposes, and Staff appreciates, time-based demand charges. However, it is not clear which demand counts for what for minimum bills.

A. Under these circumstances, a rational customer would err on the low side of its likely demand.

Q. Have you seen, in the past, an Ameren Missouri proposal for a 100% demand and 100% energy minimum bill?

A. Yes. That proposal, sometimes called a "take or pay" provision, was the Ameren Missouri proposal for service to Noranda in ER-2010-0036.[15] I provide more discussion of the history of Noranda, rates applicable to Noranda, and the related Ameren Missouri capacity transactions below.

Q. What are the fundamental requirements of Senate Bill 4 ("SB4")?

A. The first requirement is to bill LLCS customers the right rate, the second requirement is to mitigate harm to captive ratepayers.

Q. Can the Commission pick and choose among elements of rate structures?

A. Yes. The rate structures proposed in this case include the same basic elements of all utility rate schedules, with varying degrees of precision and transparency.

Q. What are the available options of mitigating ratepayer harm?

A. A first step is to look at the FAC and recognize that Missouri differs from other states in its FAC structure. Solutions that may work in Kansas will likely result in a utility windfall in Missouri. The next step is to not make rushed decisions in the interest of promulgating riders in this case that, if needed, can be developed in the near future. The final step is using the avoided utility windfall to mitigate the risk to captive ratepayers of bill increases caused if the additional capacity to serve new customers costs more than the revenue provided by new customers. Term lengths, termination fees, and credit or collateral

[15] Page 24, Direct Testimony of Wilbon Cooper, ER-2010-0036.

requirements are also important for the Commission to consider in the overall seriousness of a potential customer and as tools to minimize efficient breach of the contract term by the customer; the Commission is free to pick and choose, at a minimum, from the range of those features presented by the parties. Staff has recommended more conservative features for risk mitigation than other parties, and in doing so provides the Commission with a full range of options to implement the two requirements of Section 393.130.7 RSMo, which gives the Commission the responsibility to set LLCS customers' rates reflecting LLCS customers' representative share of the costs incurred to serve them, and to set LLCS customers' rates at a lever that prevents other customers' bills from reflecting any unjust or unreasonable costs arising from service to LLPS customers.

Q. Are there additional risk mitigation options?

A. Yes. An option based on lessons learned from previous large load customers would be to include an ordered provision that the rates for LLCS customers cannot be reduced from the level established in this case, and there is a presumption that in each rate case the rates for LLCS customers would increase by the system-average increase.[16] This recommendation is consistent with how Ameren Missouri modeled impacts to captive ratepayers.

Q. With Staff's recommended rate structure, risk mitigations, rider modifications and postponements, and rate floor, will captive ratepayers be protected from bill increases caused by new LLCS customers?

[16] To accommodate changes in rate design within the LLCS class, a reasonable expression of this concept would be "Ameren Missouri shall calculate the annual bill that would be applicable to a 500 MW LLCS customer taking service with a 100% load factor for 12 months under the rates authorized in this case. In future rate cases, it is presumptively just and reasonable that the rates applicable to LLCS customers shall be increased so that the annual bill that would be applicable to a 500 MW LLCS customer taking service with a 100% load factor for 12 months under those rates is increased by the same percentage amount as the overall percentage increase in utility revenues, unless a party establishes that some other amount is more appropriate. This does not prohibit changes to intraclass rate structure or rate design."

A. No. Given the cost of building new power plants, the Commission should expect that the bills of existing ratepayers will be higher than they otherwise would have been with the addition of new LLCS load. If LLCS load does not materialize or sustain and power plants have been built, those rate impacts will be higher.

Q. Did Staff develop its recommendations in this case in isolation?

A. No. While Staff has not kept any sort of one-for-one listing of similar features in other jurisdictions from those it recommends here, personnel in nearly all Staff departments have been keeping abreast of developments related to Staff's recommendations in this case. I met with auditors, engineers, economists, and other Staff professionals to integrate Staff's view of best practices into Staff's recommendations as presented in cases related to large load customers. Staff also drew on its experiences with existing and historic large load customers, and customer points of view expressed in industry and regulatory forums and filings.

PROJECTIONS OF FUTURE REVENUES AND COST OF SERVICE

Q. In her rebuttal testimony at pages 27 – 30, Ms. Palmer discusses her concern with what Mr. Wills referred to as a "risk analysis," and in particular addresses the retail rates of industrial customers. What is your response?

A. I largely agree with Ms. Palmer concerning her assessment of expectations of future rates applicable to LLCS customers. It is not reasonable to assume that LLCS customer revenues will increase at a system-average rate, or that positive regulatory lag will not absorb significant portions of LLCS customer revenues.

Q. What is the history of bill impacts by class at Ameren Missouri?

A. Exluding riders such as the FAC, RESRAM, and Missouri Energy Efficiency Investment Act (MEEIA), since April 1, 2004, rates for a residential customer using 1,500 kWh per month have increased 191%. Rates for a single phase SGS customer using 1,500 kWh per month have increased 182%. Rates for a low (25%) load factor LPS customer have increased 195%, and rates for a 100% load factor LPS customer have increased 187%. Dividing these values by the years from April 1, 2004, to the current rates which took effect June 1, 2025, indicates average annual increases of around 4%.

However, Noranda, Ameren Missouri's historic large load customer, began service at an average rate per kWh of around $0.01974/kWh on June 1, 2005, and its effective rates were last set in Case No. ER-2014-0258, at about $0.036/kWh in 2015. The Noranda rates after 10 years of service were only 19% higher than when service began, averaging increases of less than 2% per year during that time, while LPS rates had increased 37-41%, and residential and SGS rates had increased 46-55%

Based on this review, and my participation in cases related to Noranda, my response to Ms. Palmer is that it would be consistent with history for most customers' rates to increase 3-5% per year on average, but that I would not expect large customers to experience similar increases. Unless current and future Commissions operate differently than past Commissions or include customer safeguards as recommended by Staff,[17] I would expect large customer rates to be adjusted by less than system-average increases in future rate cases in response to, among other things, concerns with the continued economic viability of large customers.

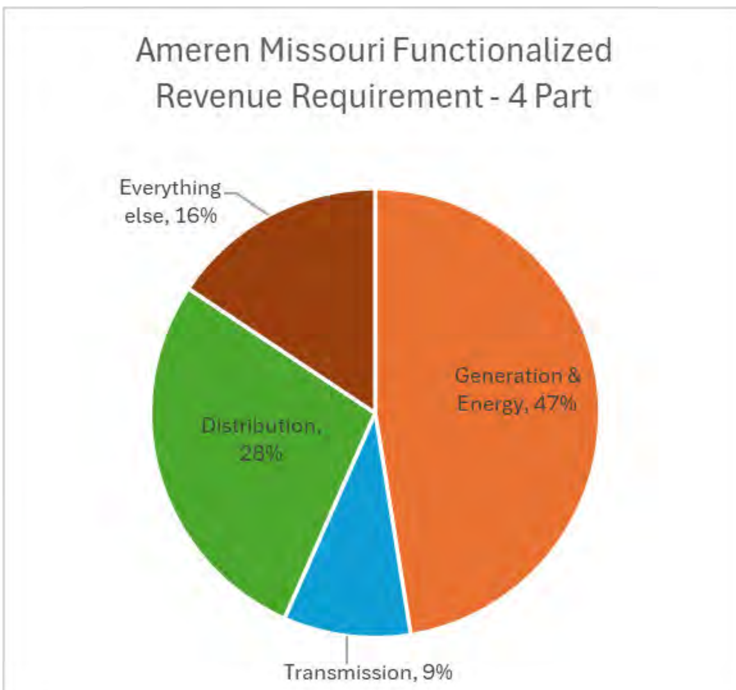
Q. What cost of service elements would you expect to be allocated to LLCS customers in rate cases?

A. I would expect that under most Class Cost of Service (CCoS) Studies, LLCS customers would receive some allocations of cost of service related to power plant capacity,

[17] Such as separate, transparent charges in the rate structure of LLCS customers, not allocating ADIT to LLCS customers, and ordering a provision in the LLCS tariff that the rates for LLCS customers cannot be reduced from the level established in this case, with a presumption that in each rate case the rates for LLCS customers would increase by the system-average increase.

energy expense, transmission, and some allocation of other costs of service like executive salaries and general plant that is proportionate to the overall cost of service allocation to LLCS customers. I would not expect LLCS customers to be allocated any cost of service related to distribution, which comprises around 28% of Ameren Missouri's net revenue requirement. Therefore, under most CCoS approaches, LLCS customers would immediately be excluded from the allocation of approximately 28% of the net cost of service that is reflected in the figure below as "everything else."

At a high level, the breakdown of Ameren Missouri's net revenue requirement is provided below:[18]



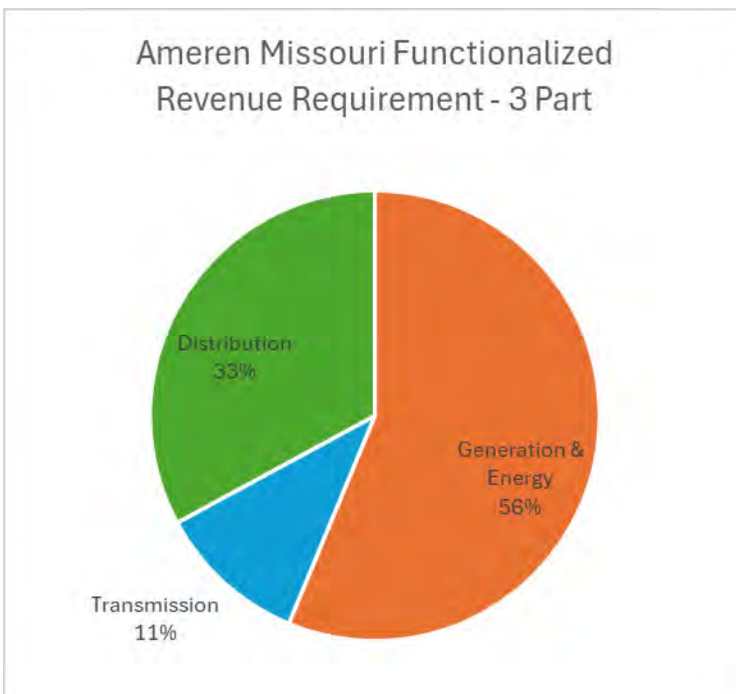
Q. What is included in "Everything Else," in this figure?

[18] This analysis is calculated relying on Staff's accounting schedules (EMS run) that reflects the agreed upon revenue requirement increase from Ameren Missouri's most recent rate case, ER-2024-0319. This run is a hypothetical construct of the agreed-to overall revenue requirement increase, and should not be interpreted as representative of the settlement position of all parties or any party, particularly in regard to the rate of return relied upon.

A. In the figure above, the "Everything Else," category includes the net revenue requirement of executive salaries, general plant, pensions, deferred income taxes, PISA, and customer programs such as Charge Ahead.

Q. What does the Revenue Requirement breakdown look like if you allocate "Everything Else," to the other three functions based on the net cost of service of each of the three major functions?

A. While analysts in a given cost of service study may differ on the exact treatment of some of the net cost of service reflected in "Everything Else," within the context of a given case and the information available in a given case, the general allocation of "Everything Else" on the basis of the overall functionalized revenue requirement is provided below:



Q. What is an important take-away from this information as it relates to the reasonableness of the assumption that LLCS rates will increase consistently with the overall rate increases as assumed by Mr. Wills and addressed by Ms. Palmer?

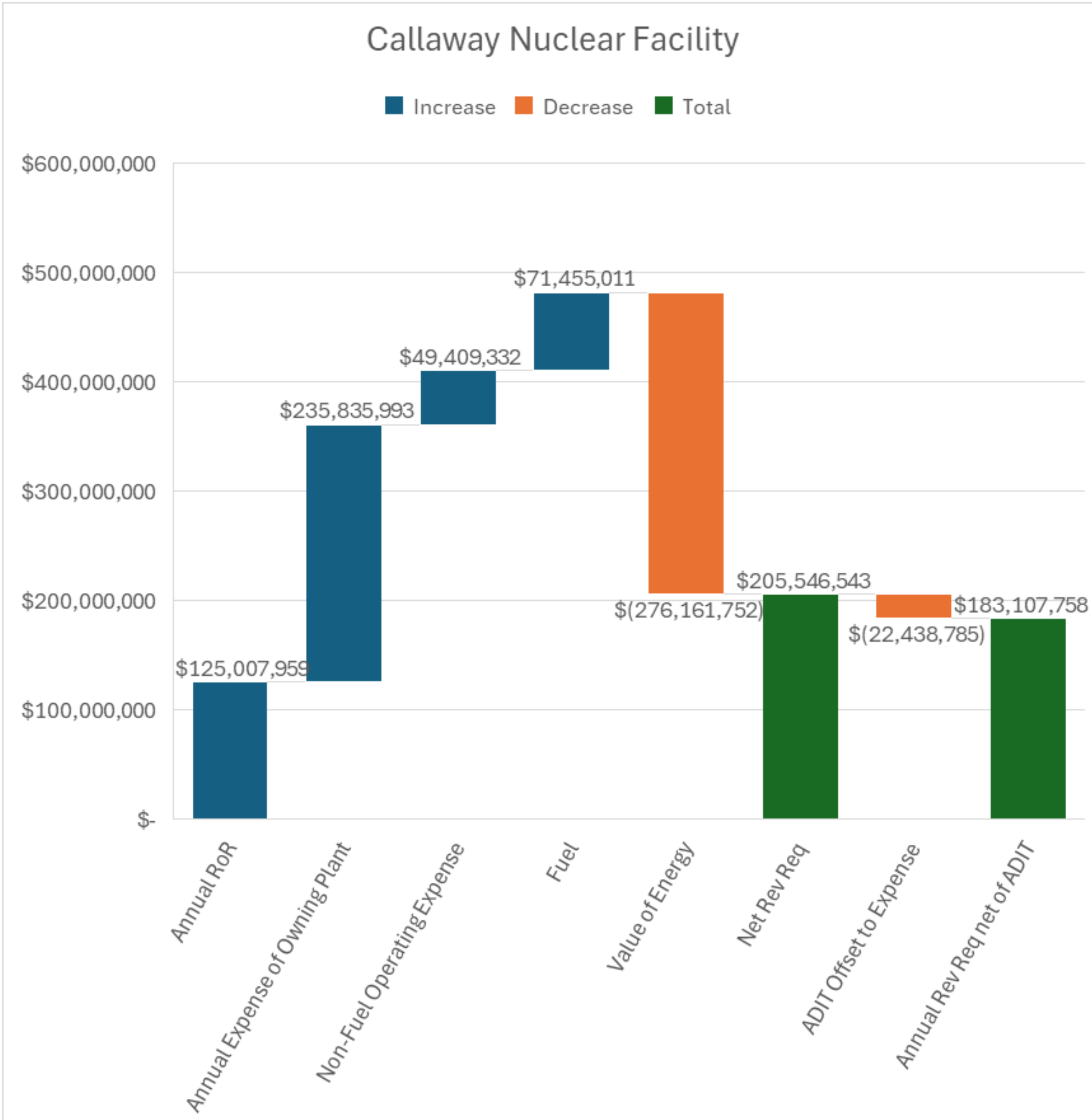
A. Under the historic approach to CCoS studies filed by Ameren Missouri and intervenors in its rate cases, LLCS customers will not be allocated any portion of 33% of the overall cost of service, which is related to distribution. This is significant because (1) this is an area in which Ameren Missouri has spent and continues to spend significant capital dollars, and (2) this is an area subject to PISA treatment, which will result in some analysts arguing that the PISA revenue requirement should be allocated to the classes on the basis of the allocation of plant subject to PISA treatment. LLCS customers will therefore also not be allocated any portion of the fixed cost allocation that is internally allocated based on distribution either.

Cost of Service of Power Plants

Q. What is the current revenue requirement for the Callaway Nuclear facility?

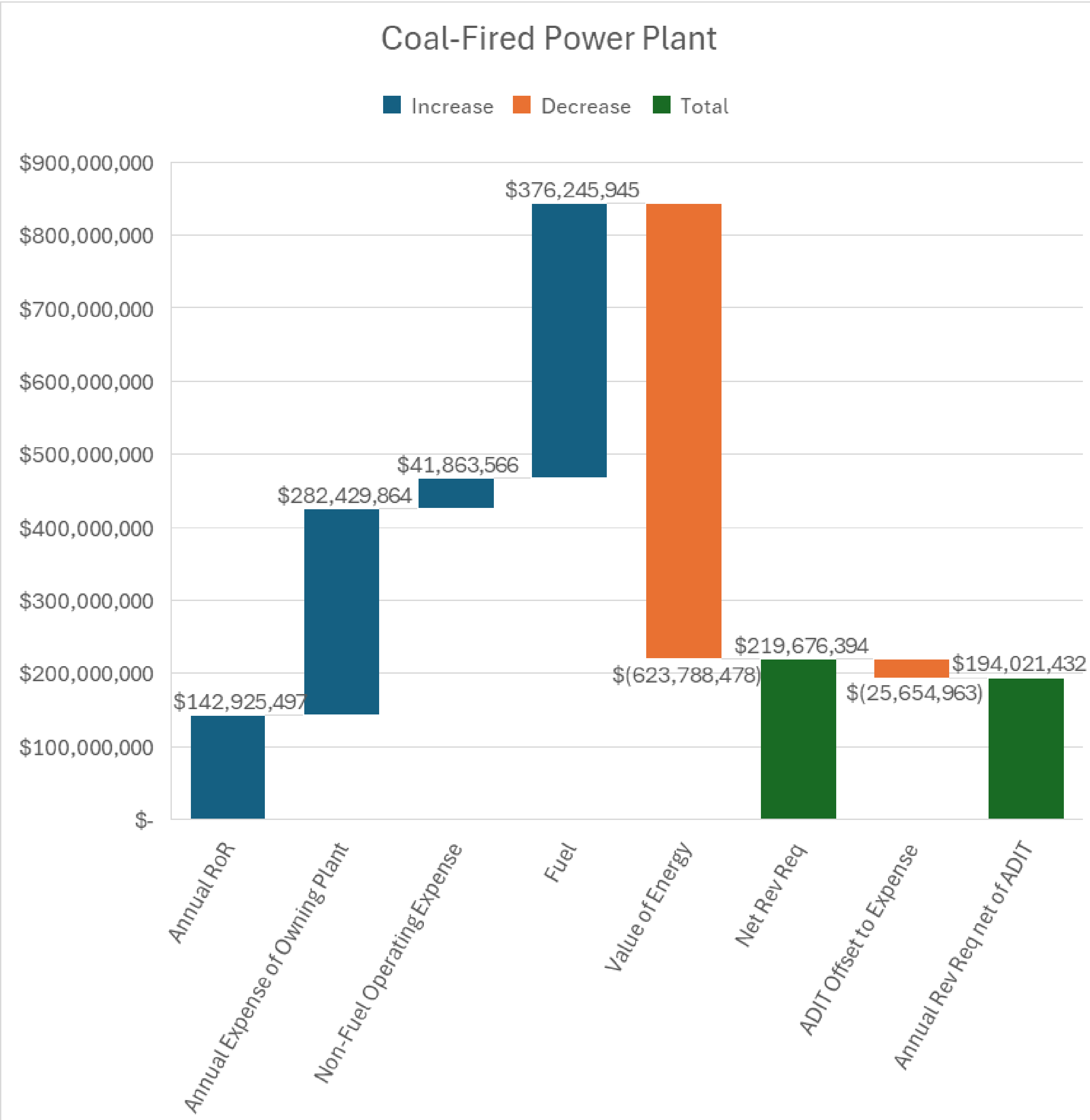
A. The annual cost of service of owning the Callaway Nuclear facility is approximately $360.6 million dollars, reflecting net ratebase of $1.755 billion. An additional $120.8 million per year is associated with operating the facility, which includes around $71.5 million in fuel. The energy generated by the Callaway Nuclear facility is worth approximately $276 million at wholesale, reflecting an 88% capacity factor with 9,482,501 MWh generated. The revenue requirement value of ADIT which could be allocated based on net ratebase to the Callaway Nuclear facility is approximately $22.4 million.[19] In other words, the net impact on Ameren Missouri's cost of service of the Callaway Nuclear facility is approximately $205.5 million, and if offset by ADIT is approximately $183.1 million. These values are illustrated in the figure below:

[19] Analysts may disagree with regard to appropriate allocation of Accumulated Deferred Income Taxes, as the ADIT balance represents the value of revenue requirement that has been effectively prepaid by ratepayers due to differences in actual income tax expense and the income tax expense included in current and historic regulated revenue requirements.



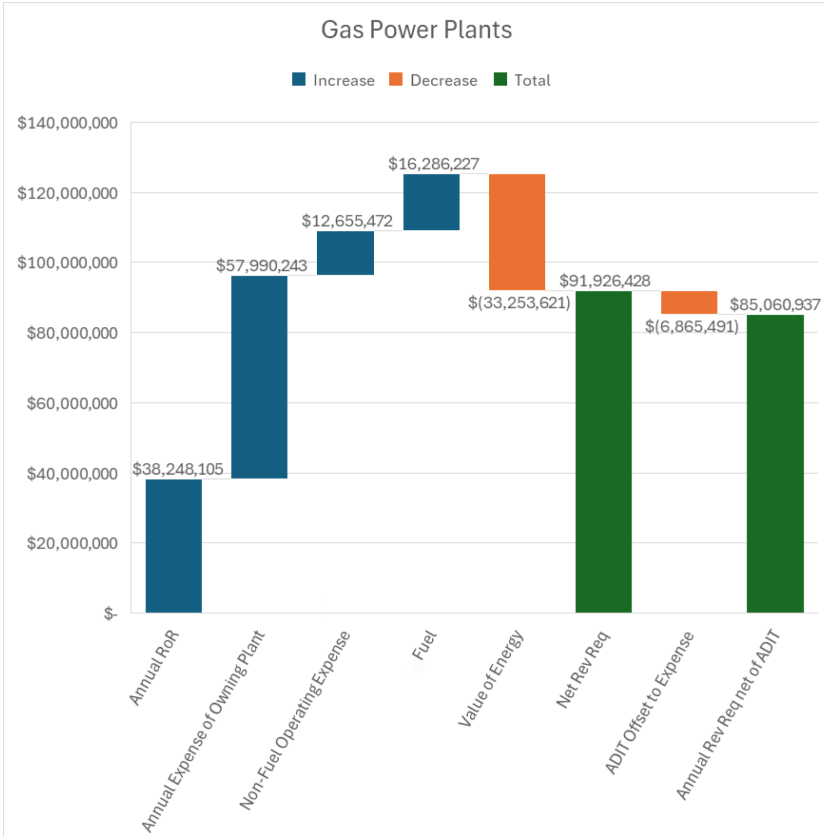
Q. What is the current revenue requirement for Ameren Missouri's coal-fired power plants?

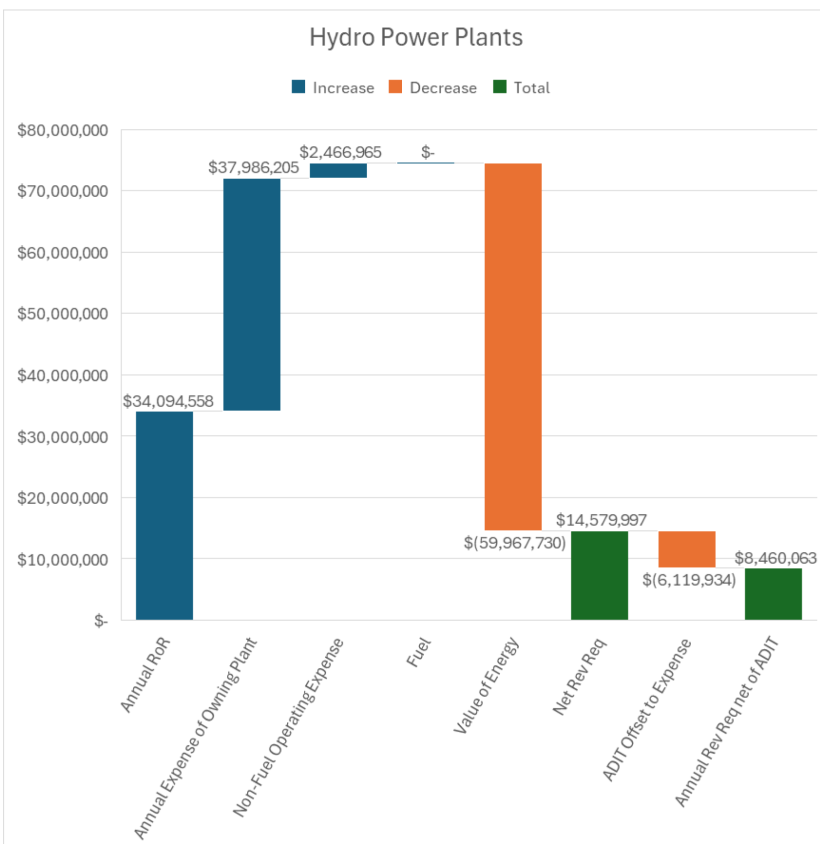
A. The following figure provides the revenue requirement components associated with coal-fired power plants:

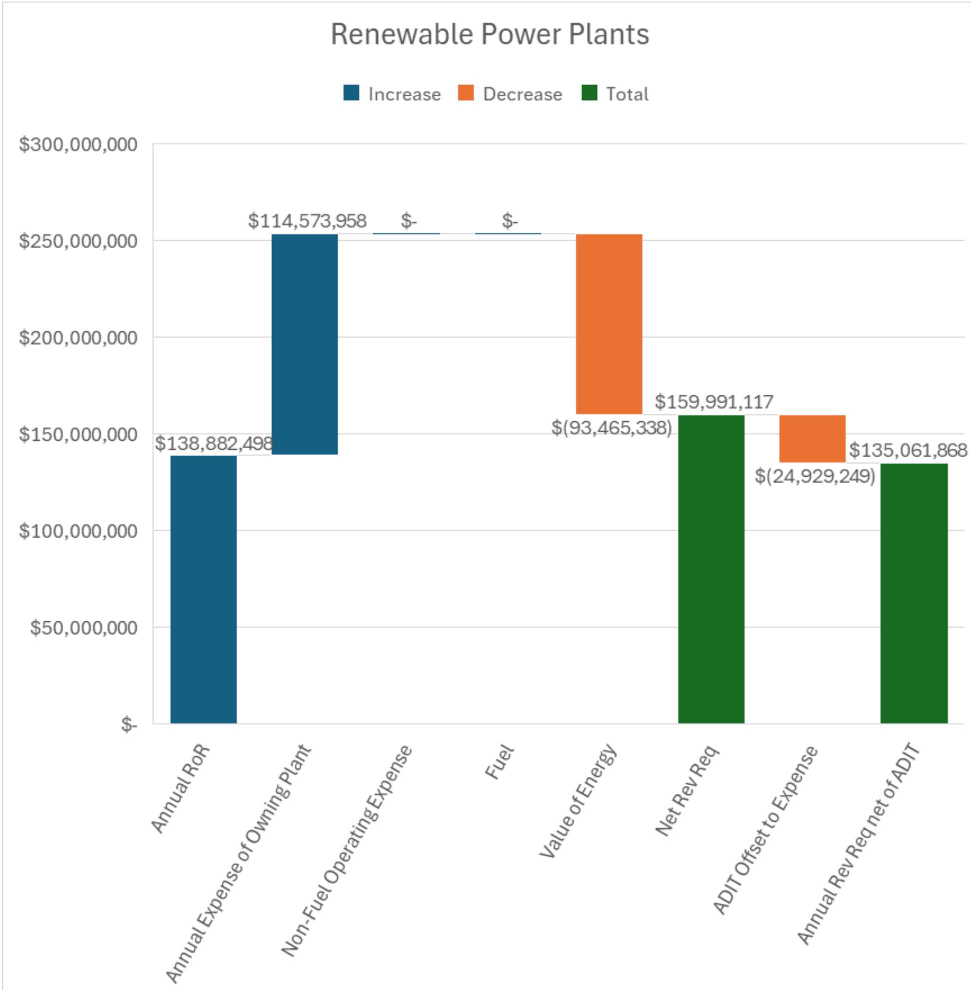


Q. What are the current revenue requirements for Ameren Missouri's hydro, gas, and renewable power plants?

A. The figures below will include those calculations. However, it should be noted that the cost of purchased power for the Taum Sauk units, and the breakdown of operational expenses between gas and renewable power plants is difficult to precisely capture.


Gas Power Plants
Increase
Decrease
Total
$140,000,000
$120,000,000
$100,000,000
$80,000,000
$60,000,000
$40,000,000
$20,000,000
$-
$38,248,105
$57,990,243
$12,655,472
$16,286,227
$(33,253,621)
$91,926,428
$(6,865,491)
$85,060,937
Annual RoR
Annual Expense of Owning Plant
Non-Fuel Operating Expense
Fuel
Value of Energy
Net Rev Req
ADIT Offset to Expense
Annual Rev Req net of ADIT


Hydro Power Plants
Increase
Decrease
Total
$80,000,000
$70,000,000
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$-
$34,094,558
$37,986,205
$2,466,965
$-
$(59,967,730)
$14,579,997
$(6,119,934)
$8,460,063
Annual RoR
Annual Expense of Owning Plant
Non-Fuel Operating Expense
Fuel
Value of Energy
Net Rev Req
ADIT Offset to Expense
Annual Rev Req net of ADIT

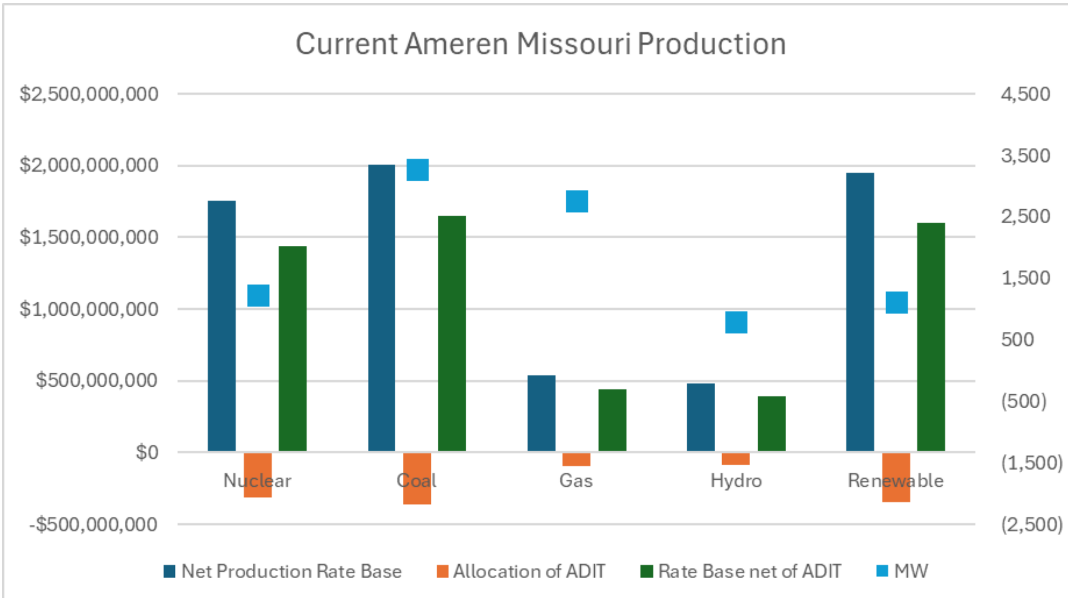


Q. Do the figures above include revenues for capacity sales associated with each type of power plant?

A. No.

Q. What amount of rate base is associated with each category of power plant, and how many MW of capacity are associated with each?

A. The figure and table below provides the original rate base for each power plant category, net of accumulated depreciation reserve. It also provides the rate base value of ADIT which would result from an allocation based on net rate base, and the net of the ADIT against the net rate base. It also includes the MW of generation for each plant type that was included in Staff's production modeling in Case No. ER-2024-0319 for the highest hour of generation, as a surrogate for accredited capacity under MISO procedures.[20]



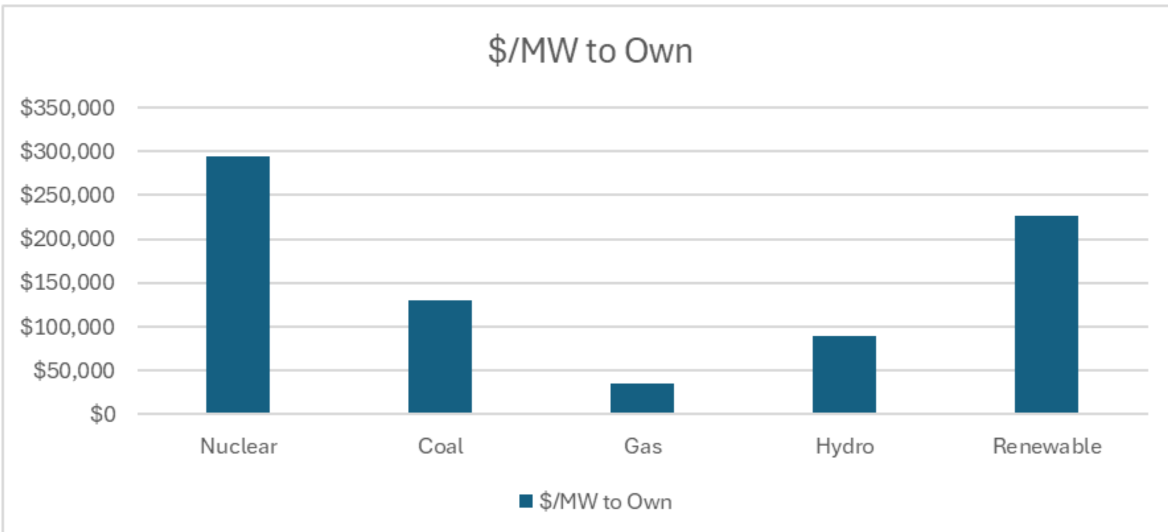
	Nuclear	Coal	Gas	Hydro	Renewable	Total
Net Production Rate Base	$1,754,743,954	$2,006,253,472	$536,890,867	$478,587,276	$1,949,501,650	$6,725,977,219
Allocation of ADIT	-$314,974,526	-$360,120,196	-$96,371,294	-$85,905,867	-$349,933,309	-$1,207,305,192
Rate Base net of ADIT	$1,439,769,428	$1,646,133,276	$440,519,573	$392,681,409	$1,599,568,341	$5,518,672,027
MW	1,228	3,278	2,769	800	1,119	9,194

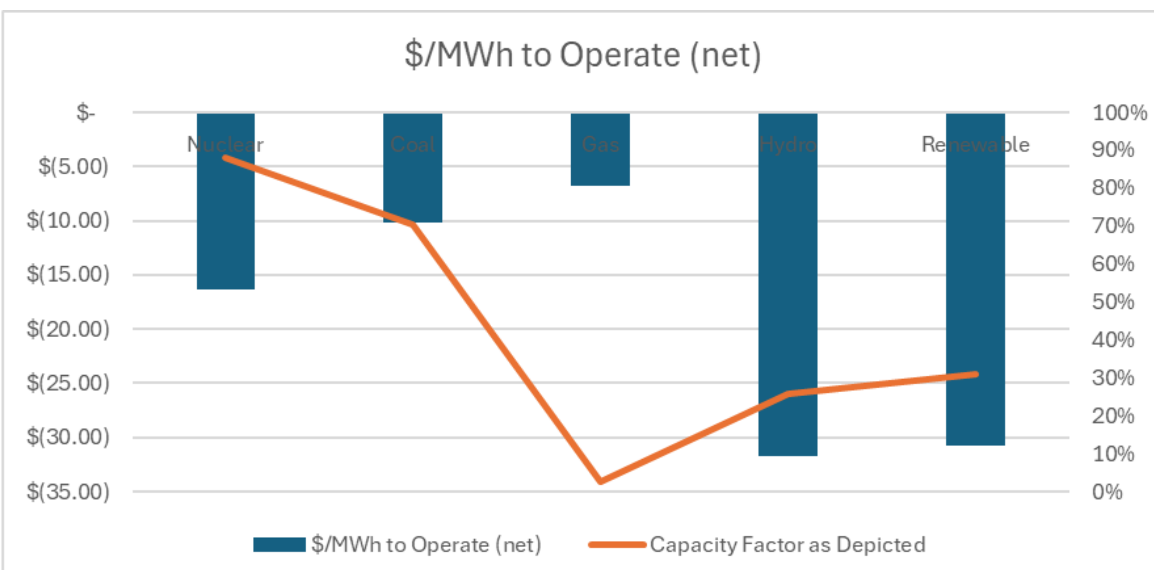
Q. For each type of power plant, what is the cost of service per MW to own the power plant and the net cost of service to operate the power plant per MWh?

A. Excluding offsets for ADIT or for capacity revenues, but including the wholesale market value of energy generated, the cost of service per MW to own power plants and the net cost of service to operate power plants per MWh are provided in the table and figures below:

[20] For non-renewable power plants, this calculation was done on a per-plant basis. For renewable powerplants, this calculation was done on a total category basis. In other words, the coal MW listed is the sum of the highest generation of each unit at each power plant, while the renewable generation is calculated by finding the hour of highest production out of the sums of production from all renewable power plants.

	Nuclear	Coal	Gas	Hydro	Renewable	Total
MW	1,228	3,278	2,769	800	1,119	9,194
MWh	9,482,501	20,263,037	637,691	1,811,364	3,041,586	35,236,178
$/MW to Own	$293,847	$129,761	$34,759	$90,118	$226,517	$131,394
Annual Expense of Owning Plant as $/MW	$ 192,049	$ 86,159	$ 20,945	$ 47,492	$ 102,396	$ 79,275
Capacity Factor as Depicted	88%	71%	3%	26%	31%	44%





Transmission Cost of Service

Q. Based on Ameren Missouri's responses to Data Requests, is Staff concerned that transmission cost of service will increase for all customers due to additions of LLCS customers, and that Ameren Missouri is not accurately portraying this publicly?

A. Yes. Ameren Missouri's public website addressing large load customers includes the following "Who is paying for the electric infrastructure upgrades needed to serve large electric customers, such as data centers? Large customers must directly pay for all the equipment and costs for constructing the infrastructure required to extend service to their location. This includes interconnection to the grid, new line extensions, switching stations, transformers, breakers and other materials."[21] However, Ameren Missouri's October 1 response to Sierra Club data request 2.6.c. asking "Explain why network upgrades that Ameren Missouri will make because of the project would not be reimbursable by the customer requesting the project," is that "Networked transmission assets are utilized to provide service generally and not just to the customer of the project." Sierra Club data request 2.6.d. asked "What allocator will Ameren use to allocate among its customer classes the costs of network upgrades that Ameren Missouri will make because of the project? Provide the allocation percentages by customer class. Explain why the Company would use this allocator." Ameren Missouri responded:

> To the extent any network upgrade in transmission is made, investments in the transmission system have historically been allocated on the basis of 12CP. The allocation percentages for this allocator from our most recent Electric Rate Case (ER-2024-0319) are:
>
> Residential – 49.67%
> Small General Service – 10.73%
> Large General Service and Small Primary Service – 31.25%

[21] Content provided on https://www.ameren.com/page/powering-mo-growth, as copied on October 16, 2025.

> Large Primary Service – 8.19%
> Lightning [sic] – 0.16%
>
> These allocators could look different with additional customers, but this is what the most recent historical allocation was. There are two main reasons the company uses 12 CP for the allocation of transmission costs. First, Transmission costs are a year round reliability source and 12 CP Does a good job mechanically reflecting that fact. Second, it creates consistency with how MISO assigns transmission costs.

Q. With that allocation approach, are captive ratepayers protected?

A. No. Even if LLCS customers will have a future 12 CP allocation of 50%, captive ratepayers will still be paying 50% of revenue requirement for network upgrades that would not have been incurred but-for the addition of those LLCS customers, or for network upgrades that are significantly more expensive than they would have been but-for the addition of those LLCS customers.

Q. Has Staff issued additional discovery related to this concern?

A. Yes. Staff DRs 0083 and 0084 relate to the website language quoted above, and to a similar public statement by Ameren Missouri,

> Will Ameren Missouri need to build more generation to meet demand from data centers? Ameren Missouri is well positioned to serve new large load customers. The company recently announced significant changes to its generation strategy, aiming to accelerate generation investments to support robust economic expansion, bolster reliability and create jobs across Missouri. The revision to Ameren Missouri's Preferred Resource Plan is designed to provide for up to 2 gigawatts of new energy demand by 2032, with a balanced mix of generation resources to deliver reliable, affordable and cleaner energy for all customers.[22]

Ameren Missouri’s October 31, 2025, responses are attached as Schedule SLKL-s2.

[22] Content provided on https://www.ameren.com/page/powering-mo-growth, as copied on October 16, 2025.

SUMMARY HISTORY OF NORANDA

Q. After the filing of its Rebuttal Report, did Staff realize that it included inaccurate information related to Noranda?

A. Yes. In an effort to rely on public information to avoid improperly revealing confidential information related to a specific former customer, I included inaccurate information in the Staff Rebuttal Report. I believe the approximate 95 MW usage that I reflected for Noranda in the graph on page 2, was related to a time when the smelter was under different ownership, and was served by Associated Electric Cooperative Inc. (AECI) instead of Ameren Missouri. Unfortunately, I did not retain the url of the source of the information that I relied upon to confirm that this was the origin of my mistake.

Q. What was the size of Noranda when it was served by Ameren Missouri?

A. ** [redacted] ** I was the Staff member responsible for these calculations in the indicated rate cases.

In 2004, Section 91.026, RSMo was enacted, which included, among other things, that:

> Notwithstanding any provisions of law to the contrary, any aluminum smelting facility shall have the right to purchase and contract to purchase electric power and energy and delivery services from any provider, wherever found or located, at whatever rates or charges as contracted for,

> and such periods or times as is needed or necessary or convenient for the operation of such aluminum smelting facility and for no other purpose, notwithstanding any past circumstances of supply.

On December 20, 2004, Ameren Missouri filed an application to begin serving Noranda's smelter in New Madrid County, Missouri, docketed as Case No. EA-2005-0180.[23] Meanwhile, a separate docket had been opened on August 25, 2003, under Case No. EO-2004-0108[24] to consider the request of the Missouri Ameren utility (known at that time as AmerenUE), to transfer ownership to an Illinois affiliate (known at that time as AmerenCIPS) of the transmission plant, distribution plant, and customers located in Illinois but served by AmerenUE, with AmerenUE retaining the Venice and Keokuk generating units.[25] In its application at paragraph 14, AmerenUE represented that

> The transfer of assets and related transactions will benefit the Missouri retail electric customers of AmerenUE, and will not harm them in any way. In particular, the transfer will provide AmerenUE's Missouri electric customers with additional generation to meet their capacity and energy needs beginning in 2004 and beyond, and will continue to provide these customers with least cost resources by which to meet their future capacity and energy needs.

The background of this transaction is summarized as follows:

> The relevant regulatory jurisdictions are Missouri and Illinois. In 1997, Illinois passed the Illinois Electric Service Customer Choice and Rate

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[23] In the Matter of the Application of Union Electric Company for a Certificate of Public Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Control, Manage and Maintain Electric Plant, as Defined in Section 386.020(14), RSMo, to Provide Electric Service in a Portion of New Madrid County, Missouri, as an Extension of Its Existing Certificated Area.

[24] In the Matter of the Application of Union Electric Company, Doing Business as AmerenUE, for an Order Authorizing the Sale, Transfer and Assignment of Certain Assets, Real Estate, Leased Property, Easements and Contractual Agreements to Central Illinois Public Service Company, Doing Business as AmerenCIPS, and, in Connection Therewith, Certain Other Related Transactions.

[25] The February 10, 2005, Report and Order in EO-2004-0108 noted that:

> The proposed transfer would make 597 MWs of additional, existing generating capacity available to serve the present and future needs of UE's Missouri load. UE estimates that the capacity increase provided by the proposed transfer would permit it to avoid new construction that would cost ratepayers about $7.7 million annually. Ratepayers would realize additional savings because the cost per megawatt-hour (MWh) of the output of UE's existing plants is significantly lower than the cost per MWh of either purchased power or power produced by gas-fired CTGs.

> Relief Law. As designed, this law provides for electric utility restructuring and introduces competition into the retail supply of electric energy in Illinois. As a result of this legislation, Ameren created AEG to hold all the generating assets of AmerenCIPS. Effectively, Illinois ratepayers are permitted to purchase electric energy and capacity from the cheapest provider. This electricity is then transmitted to the customer using the transmission and distribution assets of the relevant delivery company.
>
> Unlike Illinois, Missouri has not deregulated retail electric service. While Missouri once studied the effects of introducing similar electric restructuring legislation, progress towards a deregulated electric generation market was stalled and derailed by disasters in the experiment with deregulation of electricity in California as well as the collapse of Enron and other electric trading companies. Missouri electric utilities operate under rate base / rate of return regulation. Under this form of regulation, a utility's [sic] is allowed to reflect in retail rates its reasonable operating expenses, and is given the opportunity to earn a reasonable rate of return on its electric plant in service.
>
> As a result of the differences in regulatory schemes between Missouri and Illinois, Ameren has an incentive to divert generating costs from AEG to AmerenUE. Such diversion of generating costs provides AmerenUE the opportunity to recover such costs in its Missouri retail rates, and reduces AEG generating costs in Illinois, thereby allowing AEG to better compete and profit against other electric generators in that state. In this way, AEG generating costs, which would otherwise have exceeded the market price for electricity in Illinois and would not have been recoverable, may now be diverted to Missouri and recovered through Missouri retail rates. This diversion of generating costs from Illinois to Missouri reduces AEG's operating costs in Illinois, provides AEG a competitive advantage relative to its Illinois competitors, distorts wholesale competition in Illinois and results in inflated non-regulated profits for the Ameren Illinois affiliates, all at the expense of the Missouri regulated ratepayer.[26]

In EO-2004-0108, on December 30, 2004, the Commission ordered AmerenUE to conduct a study to determine the long-run utility costs of two scenarios:

> (1) rejection of the Metro East transfer both with and without the Noranda capacity requirements and

[26] Dissenting Opinion of Commissioner Steve Gaw in EO-2004-0108.

> (2) approval of the Metro East transfer both with and without the Noranda capacity requirements. The Commission will order that AmerenUE provide to the Commission a narrative description and summary of the reports and information consistent with each of these scenarios.[27]

The February 10, 2005, Report and Order in EO-2004-0108 found that $471/kW was appropriate for study of procurement of CTG capacity as an alternative to the Metro-East transfer, and the Commission authorized the Metro-East transfer, effective February 20, 2005.

In EA-2005-0180, on March 10, 2005, the Commission approved the Stipulation and Agreement that was filed February 24, 2005.[28] A separate order, "Re Union Electric Company," was entered in EA-2005-0180 on March 20, 2005, granting the CCN for the geographic area of the Noranda facilities, and authorizing the filing of a new tariff, the LTS Tariff, on an interim basis.

In his dissent to the Report and Order in EO-2004-0108, at pages 1-2, Commissioner Steve Gaw included the following:

> The record and pleadings in this case indicate that this decision was reached: (1) in an atmosphere of veiled threats and intimidation imposed on the Commission by the Applicant; (2) with significant evidence, some of which was available but not considered by the Commission, to conclude that this transaction could have a long-term and significant negative impact on the Missouri ratepayers of AmerenUE; (3) without reviewing and considering the pleadings and evidence of contrary parties; and (4) in a manner which arguably denies the opposing parties their due process of law. Although the majority has stated that it would protect the ratepayers from these detrimental effects in subsequent rate proceedings, such protection may be impossible if Staff's projections become reality and the detriments from this transaction exceed the benefits. For all of these reasons, I must dissent from the decision issued by the majority in the above captioned proceeding.

[27] December 30, 2024, *Order Directing Filing*, in EO-2004-0108.
[28] *Order Approving Stipulation and Agreement*, in EA-2005-0180.

And, at page 5,

> Virtually simultaneous with its Motion for Rehearing, AmerenUE sought to interject an additional issue from another case. On October 28, 2004, AmerenUE announced that it had reached an agreement to provide electric energy and capacity to Noranda Aluminum under the terms of a 15 year contract. Similar to statements regarding the Pinckneyville and Kinmundy CTs, AmerenUE again threatened that it would not execute the Noranda agreement unless the Commission approved the Metro East transfer on terms solely acceptable to AmerenUE. Given the critical economic nature of the Noranda smelting unit to the Southeast Missouri region as well as concerns regarding the long-term viability of Noranda without the access to low priced reliable electric energy, AmerenUE effectively sought to force the Commission to choose between either: (1) accepting the recognized detriments of the Metro East transfer with conditions UE then proposed and (2) the possibility of losing the Noranda smelting facility and the associated 1,100 jobs. Because of the announcement of the Noranda agreement, as well as AmerenUE's claim that the agreement was dependent on the Metro East transfer, the Commission agreed to rehear the current proceeding for the purpose of reviewing the effect of the Noranda agreement on the benefits and detriments of the Metro East transfer.

Also in the summer of 2005, for $175 million, AmerenUE purchased 850 MW of capacity at an installed capacity value of $205.88 per kW from Aquila, Inc., the merchant affiliate of the utility currently operating as Evergy Missouri West.[29] This sale resulted in after-tax losses of $99.7 million to Aquila, indicting that the cost of the units to AmerenUE was around 1/3 less than what it cost to actually buy the generators and build the power plants. AmerenUE also purchased another CTG site in 2006, located in Audrain County, Missouri, authorized in EF-2006-0276, consisting of eight GE 7001EA natural-gas-fired combustion

[29] Aquila Merchant installed ten GE Model 7EA, 75 MW combustion turbines at two locations in Illinois. Six GE 7EA turbines were installed at Goose Creek Energy Center having a combined capacity of 510 MW. Four 7EAs were installed at Raccoon Creek Energy Center having a combined capacity of 340 MW. Aquila Merchant responded to a RFP to supply turbine capacity issued by AmerenUE in the summer of 2005. The final sale price for both Raccoon Creek and Goose Creek was $175 million for all the generating equipment, substation and transmission costs. The total capacity of these two generating stations is 850 MW resulting in an installed capacity of $205.88 per kW ($175 million divided by 850,000 kW). Aquila, Inc. SEC Form 8-K filed December 16, 2005.

turbine generating units with a combined nameplate capacity of 640 megawatts, built by an NRG affiliate.[30]

Noranda began taking retail service from AmerenUE on June 1, 2005.[31]

The revenue from Noranda, and the loss of revenue from Metro East customers, was first recognized in ER-2007-0002. The rates approved in that case took effect on July 23, 2007.[32] In the 2007 rate case, AmerenUE requested, but did not receive, a Fuel Adjustment Clause.[33]

On July 4, 2008, AmerenUE filed a new rate case, docketed ER-2008-0318. AmerenUE and MIEC filed Class Cost of Service studies indicating that Noranda's rates should be reduced, on a revenue-neutral basis – by 2.6% and 16.2%, respectively.[34] In conjunction with the increase requested in this case, Noranda's position in direct testimony was that if the full 12.1% increase requested by AmerenUE were approved, its rates would be increased by only 5.8%.[35] The Commission ultimately approved a less-than system-average increase for Noranda,[36] in the rates that took effect March 1, 2009.[37] The January 27, 2009, Report and Order in ER-2008-0318, effective February 6, 2009, also authorized a Fuel Adjustment Clause for AmerenUE.[38]

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[30] EF-2006-0278, *Order Granting Application*, EF-2006-0278.
[31] Page 2, *Application for Order Allowing Intervention of Noranda Aluminum, Inc*., in ER-2007-0002, In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.
[32] *Order Granting Expedited Treatment and Approving Compliance Tariff*, Issued July 16, 2007, in ER-2007-0002.
[33] Pages 26-27, *Report and Order*, issued May 22, 2007, ER-2007-0002.
[34] Page 121, Report and Order, issued January 27, 2009, ER-2008-0318.
[35] Page 2, Class Cost of Service Direct testimony of Don Johnstone, Exhibit 754.
[36] Pages 125-126, Report and Order, issued January 27, 2009, ER-2008-0318.
[37] Order Approving Compliance Tariff Sheets, Issued February 19, 2009, ER-2008-0318.
[38] Pages 69-70, Report and Order, issued January 27, 2009, ER-2008-0318. The initial accumulation periods under the AmerenUE FAC was the period March 1, 2009 – September 30, 2009. (Page 2, Staff's Prudence Report and Recommendation, EO-2010-0255.)

On January 28, 2009, Noranda's smelter lost power due to an ice storm that damaged the transmission line relied upon by Noranda for interconnection. This resulted in the molten aluminum solidifying in the smelter pots, rendering them inoperable until the aluminum could be removed through a laborious process.

On February 5, 2009, AmerenUE filed an Application for Rehearing and Motion for Expedited Treatment in ER-2008-0318, stating that the stalling of Noranda's smelting operations resulted in "an unprecedented and significant loss of AmerenUE's retail load and the revenues associated therewith has occurred for a period that cannot at this time be determined."[39] AmerenUE went on to plead:

> Without the authorized FAC, the loss of retail revenues received from Noranda would have been offset by increased revenues from off-system sales. In other words, the Company would have simply sold the power that Noranda is no longer taking in the off-system market, and the revenues from such sales would have replaced the revenues lost from Noranda. However, pursuant to the terms of the recently-authorized FAC, 95% of the incremental off-system sales margins generated by selling MWh not taken by Noranda must be flowed through to customers. As a consequence, once the authorized FAC tariff takes effect, AmerenUE would have to bear almost all of the impact of the loss in pre-tax earnings occasioned by the devastating ice storm.[40]

And,

> To prevent this unjust and unwarranted result, and to ensure that the FAC tariff complies with § 386.266.4(1), RSMo, AmerenUE is seeking approval of a modified FAC tariff (the Modified FAC Tariff) in place of the FAC tariff that was authorized. A specimen Modified FAC Tariff (tracking the changes from the FAC tariff authorized by the Commission in the Report and Order) is attached hereto and incorporated herein by this reference as Appendix B. The Modified FAC Tariff provides that incremental off-system sales revenues made possible by MWh not taken by Noranda (but which can then be sold off-system by AmerenUE) will be retained by AmerenUE to the extent, but only to the extent, necessary to offset the loss of retail margins from Noranda due to the loss of the

[39] Page 2, Application for Rehearing and Motion for Expedited Treatment, ER-2008-0318.
[40] Page 3, Application for Rehearing and Motion for Expedited Treatment, ER-2008-0318.

> Noranda load. Under the Modified FAC Tariff, once AmerenUE has received off-system sales revenues from MWh not taken by Noranda equal to the lost Noranda margin, all additional off-system sales revenues would flow to customers (without any sharing by AmerenUE). As a consequence, customers will in any event be no worse off than they would have been if the ice storm had never occurred, but they are likely to receive additional benefits due to the additional off-system sales revenues the loss of the Noranda load makes possible. [41]

The Modified FAC tariff that AmerenUE requested be implemented was represented by AmerenUE to incorporate:

> …three discrete and straightforward changes to the FAC formula to place AmerenUE and its customers in the same position as they would have been in had no Noranda load loss occurred. First, the term "OSSR" (Off-System Sales Revenues) has been modified to exclude the revenues from off-system sales occasioned by the lost Noranda load. Second, the term SAP (Supplied kWh) has been modified to include the kWh that would have been supplied to Noranda, if the loss of load had not occurred. Finally, a new factor—"N"—has been added to the formula to flow through to customers 100% of any incremental margin which might be earned by selling the power in the off-system market instead of to Noranda.

The Commission denied AmerenUE's Application for Rehearing in its Order issued and effective February 19, 2009.[42]

On July 24, 2009, AmerenUE filed a new rate case, docketed ER-2010-0036.

The tariffs filed to initiate ER-2010-0036 included modifications to the LTS rate schedule under which Noranda was served. As explained by MIEC witness, Henry Fayne, on behalf of Noranda:

> AmerenUE has proposed that the minimum bill for Noranda would be equal to 100% of the demand and energy charges associated with its contract demand. If Noranda were to reduce load from its contract demand (the level reflected in this proceeding), AmerenUE would make such energy available for sale into MISO and would credit Noranda with any revenues received to offset Noranda's minimum bill obligation.

[41] Page 4, Application for Rehearing and Motion for Expedited Treatment, ER-2008-0318.
[42] Order Denying AmerenUE's Application for Rehearing, ER-2008-0318.

> Essentially, AmerenUE has proposed that it be guaranteed its full revenue requirement from Noranda (both fixed and variable costs) regardless of Noranda's operating level.[43]

In his direct testimony, AmerenUE witness Wilbon Cooper summarized the requested position with the succinct statement "We are proposing changes to the Rate Schedule LTS tariff that are designed to provide the Company with retail revenues from Noranda equal to those assumed in the revenue requirement in this case, no more and no less."[44] Mr. Cooper's testimony explained that Noranda, at the time of his filing, was not operating at its historic full load of 470 MW. Mr. Cooper discussed the Company's position in that case to impute revenues from Noranda as though it were operating at full load, "Since new rates from this case will likely not take effect until early next summer, including Noranda at full load in the Company's filing matches Noranda's expectation about its production at that time."[45] Mr. Cooper went on to explain the AmerenUE position that Noranda revenues at full load should be reflected in the rate calculations to avoid overcharging other customers and to avoid overrecovery by the utility, recognizing the expectation that additional retail sales to Noranda would be materializing over the coming months:

> Q. How does including Noranda at full load in the revenue requirement affect other customers?
>
> A. It means that Noranda is assigned a level of costs that equates to providing it service at full load, i.e. a greater portion of the Company's cost of service is assigned to Noranda (and away from other customer classes) than if the Company had, for example, included Noranda at its lower load level as of the end of the test year (March 31, 2009). Noranda's load as of the end of the test year was well below full load (approximately 200MW), but Noranda has been ramping up its production since then. If the Company set its revenue requirement based upon lower Noranda load, and if Noranda then increased its load

[43] Page 3, Direct Testimony of Henry Fayne, Exhibit 421, ER-2010-0036.
[44] Page 24, Direct Testimony of Wilbon Cooper, ER-2010-0036.
[45] Page 25, Direct Testimony of Wilbon Cooper, ER-2010-0036.

> after rates are set in this case, other customers would be bearing a higher portion of the Company's fixed costs through their rates while the Company would receive a higher level of revenues from Noranda than had been included in the revenue requirement calculation. The approach outlined herein takes away the upside that would have existed for the Company, and thus does not enable the Company to receive more revenues from Noranda under full load than assumed in the revenue requirement to be set in this case. This is an appropriate and symmetrical approach given the changes to the Rate Schedule LTS tariff discussed below.[46]

The First Nonunanimous Stipulation and Agreement filed in that case established that "an 'N' factor, as generally described in the direct testimony of MIEC witness Henry Fayne, with a 40,000 MWh per month trigger shall be adopted."[47] The referenced testimony is found at pages 7-8 of Exhibit 421 in Case No. ER-2010-0036:

> Q. You indicated that, if the Commission concludes that AmerenUE's risk of a Noranda curtailment should be mitigated, there are alternative approaches that can be implemented that would not impose undue risk on Noranda or AmerenUE's other customers. Would you please elaborate?
>
> A. Yes. In his testimony, AmerenUE witness Wilbon Cooper explained that the tariff change is necessary to mitigate a potential future occurrence of the loss that AmerenUE suffered as a result of the ice storm that caused a shutdown of the Noranda smelter. That loss occurred because 95% of the revenue from the sale of power, that otherwise would have been used (and paid for) by Noranda flowed to other customers through the new fuel clause. A simple alternative to the AmerenUE proposal would be to modify the fuel clause to allow the revenues from the sales of energy, that otherwise would have been used (and paid for) by Noranda, flowed to other customers through the new fuel clause. On that basis, AmerenUE would be made whole to the extent that the energy were sold, and the other customers would be held harmless; that is, other customers would be in the same position as they would have been had the consumption by Noranda not been curtailed. This approach would be more consistent with traditional ratemaking since it would be the utility, not a single customer, that would bear the risk of load fluctuations.

[46] Pages 25-26, Direct Testimony of Wilbon Cooper, ER-2010-0036.
[47] Page 2, First Nonunanimous Stipulation and Agreement, Approved by March 24, 201, Order Approving First Stipulation and Agreement, in ER-2010-0036.

In Case No. ER-2010-0036, the Commission found that Noranda pays AmerenUE approximately $140 million per year for electricity.[48] While four of the five CCoS studies filed in that case indicated that Noranda's rates should be increased, MIEC, which at that time included Noranda,[49] filed a study indicating that a $21.6 million revenue-neutral reduction to Noranda's rates was appropriate,[50] and took the position in its testimony that the full reduction to Noranda's rates was appropriate.[51] An objected-to Stipulation and Agreement would have resulted in Noranda receiving an actual rate reduction of $2.1 million (1.54%), the residential classes receiving an increase of 11.7%, and the other large customer classes receiving an increase of 9.59%.[52] "MIEC, and in particular, Noranda, attempt to justify these results by claiming that Noranda needs special rate consideration to remain competitive with other aluminum smelters in the United States, lest it be forced to close, resulting in economic devastation to Missouri."[53] The Commission ultimately ordered that the Noranda rates remain unchanged[54] in the rates that took effect June 1, 2010.[55]

In rate case, Case No. ER-2011-0028 the Commission had before it motions to compel concerning 27 of 35 data requests directed at Noranda by another intervenor, Midwest Energy Users' Association.[56] In its direct testimony, a witness for Noranda had testified "to provide information regarding the cost of electricity at other aluminum smelters and the regulatory

[48] Pages 81-82, *Report and Order*, issued May 28, 2010, ER-2010-0036.
[49] Page 5, Report and Order, issued May 28, 2010, ER-2010-0036.
[50] Page 83, Report and Order, issued May 28, 2010, ER-2010-0036.
[51] Pages 88-89, Report and Order, issued May 28, 2010, ER-2010-0036.
[52] Pages 89-90, Report and Order, issued May 28, 2010, ER-2010-0036.
[53] Page 90, Report and Order, issued May 28, 2010, ER-2010-0036.
[54] Pages 94-95, Report and Order, issued May 28, 2010, ER-2010-0036.
[55] Order Approving Compliance Tariff Sheets and Depreciation Rates, ER-2010-0036, issued June 16, 2010.
[56] Case No. ER-2011-0028, *Order Regarding MEUA's Motion to Compel Noranda Aluminum to Respond to Data Requests*, pages 1-2.

treatment other states are providing to support the continued operation of aluminum smelters."[57] In its *Reply to Response to Motion to Compel Responses from Noranda Aluminum*, Midwest Energy Users' Association included arguments for the provision of information such as, "Throughout its testimony, Noranda claims it is at a cost disadvantage as it applies to the cost electricity. In Data Request No. 12, MEUA merely seeks to discover if Noranda believes that it has offsetting cost advantages;"[58] and "Data Request Nos. 13, 14, 15 and 17 all seek Noranda admissions regarding its stock price and the LME cost of alumina. Noranda claims that such requests are designed to harass. On the contrary, MEUA seeks information related to Noranda's stock price because the recent rapid escalation in that price is contrary to Noranda's current assertions that the New Madrid smelter is financially troubled by the price electricity. MEUA seeks information related to the LME cost of alumina because, as Mr. Fayne recognizes, alumina is a commodity with all smelters being price takers. As such, any increase in the LME price of alumina will directly result in an increased profit to Noranda. Furthermore, several of the domestic smelters mentioned by Mr. Fayne have a price of electricity that is tied directly to the LME price of alumina."[59]

In Case No. ER-2012-0166, similar discovery disputes requiring Commission resolution occurred related to data requests propounded by Ameren Missouri to MIEC, related to the testimony of Kip Smith, the president and CEO of Noranda.[60] Mr. Smith's direct testimony included statements such as:

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[57] Fayne Direct, page 3, ER-2011-0028.
[58] ER-2011-0028, MEUA *Reply to Response to Motion to Compel Responses from Noranda Aluminum*, at paragraph 6.
[59] ER-2011-0028, MEUA *Reply to Response to Motion to Compel Responses from Noranda Aluminum*, at paragraph 7.
[60] ER-2012-0166, *Motion to Compel Compliance with Order Resolving Issues Presented at Discovery Conference and Request for Expedited Treatment*, page 1.

> The purpose of my testimony is to show the Commission that its decision in this case is vitally important to the New Madrid Smelter's long-term operations. The New Madrid Smelter's sustainability in Southeast Missouri is inextricably linked to the well being of the approximately 900 Noranda employees and their families and dozens of Southeast Missouri businesses and the families that they support. I hope to show the Commission that a sustainable electric rate for the New Madrid Smelter is in the public interest.[61]

Case No. EC-2014-0224 is summarized in the Report and Order as follows:

> In this case, Complainants seek a change in rate design to reduce the rate assessed to the Large Transmission Service Class, of which Noranda Aluminum, Inc. is the only customer and which is the lowest-cost rate class of all customer classes served by Ameren Missouri. This proposal asks the Commission to provide rate relief that departs from traditional cost-of service ratemaking. Complainants' request is founded on three contentions: 1) Noranda Aluminum, Inc.'s aluminum smelter is crucial to Missouri's economy; 2) the smelter cannot be sustained without the rate relief requested; and 3) all Ameren Missouri ratepayers will directly benefit from the relief requested because granting that relief is more beneficial compared to Noranda leaving the Ameren Missouri system. While there is substantial evidence in the record regarding the impact of the smelter on southeast Missouri and on the state, the evidence does not support the second and third of Complainants' contentions. Accordingly, the Commission finds that the Complainants have failed to carry their burden to show that Ameren Missouri's rate design should be modified, contrary to traditional cost of service principles, in order to give a reduced rate to Noranda Aluminum, Inc. The complaint is, therefore, denied and dismissed.[62]

In Case No. ER-2014-0258, which was filed July 3, 2014, a Nonunanimous Stipulation and Agreement was filed on October 10, 2014, to reduce the rates applicable to Noranda through the creation of a new rate schedule. The Report and Order in ER-2014-0258 was issued on April 29, 2015. As described in that Report and Order:

> Beginning in July 2014, Noranda began to experience a production slow-down due to an unusually high number of "pot" failures. The lower production means Noranda bought less electricity from Ameren

[61] ER-2012-0166, Smith Direct, page 4.
[62] Report and Order, issued August 20, 2014, in EC-2014-0224. EC-2014-0223 was filed concurrently with EC-2014-0224, and the Report and Order denying the relief sought in that case was issued October 1, 2014.

> Missouri during that period. However, Noranda anticipated returning to full production by the end of March 2015.[63]

Case No. ER-2014-0258 also considered Ameren Missouri's request in that case to recover from all ratepayers the revenue that Ameren Missouri did not recover from Noranda during the period when Noranda's operations were stalled in 2009, roughly five years earlier.[64] During the hearing, on March 10, 2015, another Nonunanimous Stipulation and Agreement was filed in Case No. ER-2014-0258, which would have resulted in treatment for Noranda which was even more lucrative than that reflected in the October 10, 2014, provisions described above. The Commission's order included findings of fact such as "Noranda uses approximately 4.2 million MegaWatt Hours (MWh) of electricity from Ameren Missouri in a year to make aluminum. Noranda uses 480 MWs of power, 24 hours per day, 7 days per week, 52 weeks per year. Every dollar per MWh change in Ameren Missouri's electricity rate represents a $4.2 million change in the pre-tax cash flow of Noranda;"[65] "If Noranda were to close, the Missouri economy would forego approximately $9 billion in economic activity over the next twenty-five years. State and local tax revenue would be reduced by approximately $350 million over those same twenty-five years. Additional unemployment benefits resulting from the closure could be as high as $9.4 million;"[66] "Noranda also has a tremendous positive impact on the Southeast region of Missouri, one of the poorest regions in the country, providing the few high paying jobs in the area;"[67] and "Noranda is by far Ameren Missouri's largest customer, representing over ten percent of the total retail sales made by the utility."[68]

[63] Page 15, Report and Order in ER-2014-0258.
[64] Pages 35-43, Report and Order in ER-2014-0258.
[65] Case No. ER-2014-0258. *Report and Order*, page 119, paragraph 2.
[66] Case No. ER-2014-0258. *Report and Order*, page 119, paragraph 3.
[67] Case No. ER-2014-0258. *Report and Order*, page 119, paragraph 4.
[68] Case No. ER-2014-0258. *Report and Order*, page 119, paragraph 5.

The Commission found:

> 10. The first step to determining whether either of the reduced rates proposed by Noranda is reasonable is to determine Ameren Missouri's incremental cost to serve Noranda. The experts also refer to incremental cost as Ameren Missouri's avoided cost, meaning the cost that Ameren Missouri would avoid if the Noranda smelter shuts down. Either term means the point at which other ratepayers would benefit from Noranda's presence on the system. At any price above that point, Noranda is making a contribution to Ameren Missouri's fixed costs. At a price below that point, Noranda would not be making a contribution to Ameren Missouri's fixed costs and Ameren Missouri's other ratepayers would be better off without Noranda on the system.
>
> 11. Incremental cost is largely influenced by the amount at which Ameren Missouri could sell power on the open market if it could no longer sell that power to Noranda. MIEC's witness, James Dauphinais, testified that the incremental cost would be between $28.03 and $29.39 per MWh. Staff's witness, Sarah Kliethermes, calculated incremental cost at $31.50 per MWh. In his rebuttal testimony, Ameren Missouri's witness, Matt Michels, calculated that point at either $32.77 per MWh or $34.13 per MWh. At the hearing, he testified that for the period through May of 2017, the incremental cost would likely remain below $32.50 per MWh.
>
> 11. [sic] The actual future incremental cost is uncertain because it depends on the spot energy market prices and annual capacity market prices that will occur in the future.
>
> 12. In setting a rate for Noranda, it is important that the rate be set, and remain, above the incremental cost. Below that cost, Noranda would not be covering any part of Ameren Missouri's fixed costs. If Noranda is not making any contribution to fixed costs, there is no justification for allowing it to pay a reduced rate and other ratepayers would be better off if the smelter closed. But, so long as Noranda's rate remains above the incremental cost, Noranda will make a contribution to Ameren Missouri's fixed costs and other customers will pay a lower rate than they would if the smelter closed and went off Ameren Missouri's system.
>
> 13. A rate below fully allocated cost of service and above incremental cost of service is only appropriate if the smelter will likely leave Ameren Missouri's system if not allowed a lower electric rate. The future viability of the smelter, and thus the likelihood Ameren Missouri

> would retain Noranda's load, is largely dependent on the price of aluminum metal on the world market.[69]

Paragraphs, 14 – 31, at pages 122 – 126, make various findings related to the trading prices of aluminum on the London Metal Exchange, the cyclical demand for aluminum, the production capacity of aluminum, aluminum pricing projections, "stress tests," conducted by Noranda, Ameren Missouri's criticisms of those tests, the views of potential lending partners of Noranda, Noranda's historic operating performance, Noranda's refinancing abilities, Noranda's debt and leverage ratio, Noranda's ownership, and the cost of electricity per MWh of other aluminum smelters.

The Commission reached the conclusions of law that:

> F. The evidence in this case shows that Noranda is a unique customer because it uses much more electricity than any other Ameren Missouri customer. It uses that electricity at a very high load factor. It is so unique that it has had its own rate classification for many years. G. Under these circumstances, a rate for Noranda that is less than its fully allocated cost, but more than its incremental cost is just and reasonable within the meaning of Section 393.130, RSMo (Cum. Supp. 2013), and is not unduly or unreasonably preferential. [70]

The "Decision" begins:

> The Commission will start from a premise that no one really disputes; Noranda is significant to this state, to Ameren Missouri, and to its customers. Noranda's aluminum smelter near New Madrid, Missouri has a huge economic impact on a region of the state, known as the Bootheel, that is economically depressed. It buys staggeringly large amounts of electricity every hour of every day. It is by far Ameren Missouri's largest customer, by itself buying over ten percent of all the electricity Ameren Missouri sells. For many years, Noranda has come before this Commission in every Ameren Missouri rate case and proclaimed that it needs low cost electricity to remain viable. Sometimes the Commission has made decisions that Noranda would find favorable; sometimes it has not. Most recently, less than a year ago, the Commission denied Noranda's request for a reduced rate in a complaint

[69] Case No. ER-2014-0258. *Report and Order*, pages 120-122.
[70] Case No. ER-2014-0258. *Report and Order*, page 129.

> case decided while this case was pending. The Commission denied that request because Noranda failed to meet its burden of proof to show that its current rate was not just and reasonable. But Noranda continued its quest for a lower rate in this rate case, again asking for a rate that is below Ameren Missouri's fully allocated cost to serve. This time the Commission reaches a different result because additional evidence and argument was presented. The additional evidence describes a looming problem for Noranda: it must seek to refinance its existing debt in 2017 and 2019. Noranda presented various scenarios based on the price of aluminum in which it would run out of liquidity (cash and available credit) in the next few years. Those scenarios were criticized a not the most likely to occur, and indeed, they are not intended to be forecasts of aluminum prices. Rather, they are scenarios of what would happen if aluminum prices, which are volatile, were to drop. They are worst case scenarios, but sometimes the worst happens.[71]

The Commission went on to authorize a new "Industrial Aluminum Smelter," rate class, IAS, with a substantial rate reduction to $36/MWh, a limitation of the amount that Noranda would pay under the FAC, and a limitation to the amounts that the IAS rates could be increased in future rate cases.[72] The Commission also ordered that:

> The IAS customer shall file a monthly certification of compliance and quarterly surveillance reports demonstrating that the customer has fulfilled the requirement that employment at the New Madrid smelter meets or exceeds a daily average of 850 full-time equivalent personnel, either direct employees or contract personnel, and specifically noting instances where the employee count goes below the required average because employees have voluntarily left the customer's employ and the IAS customer is actively seeking to fill those positions, or due to force majeure or other events considered by the Commission to be outside the IAS customer's control.[73]

Additional conditions required Noranda to make capital expenditures in Missouri, continued employment levels, limitations on payment of dividends by Noranda, or changes in ownership of Noranda.[74]

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[71] Case No. ER-2014-0258. *Report and Order*, page 130.
[72] Case No. ER-2014-0258. *Report and Order*, pages 133-134.
[73] Case No. ER-2014-0258. *Report and Order*, pages 135-136.
[74] Case No. ER-2014-0258. *Report and Order*, pages 136-137.

On February 1, 2016, ten years and seven months after Ameren Missouri began serving Noranda, Noranda and other individual ratepayers filed EC-2016-0199, "In the Matter of Complainants' Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Industrial Aluminum Smelter (ISA) Tariff to Decrease that Rate for Electric Service." The complainant requested an emergency reduction to the rate to Noranda, "with the understanding that the rates for customers other than Noranda likely will be higher as a result of this action."[75] On June 1, 2016, eleven years to the day after Ameren Missouri began serving Noranda, MIEC filed for dismissal of its complaint, noting that "Unfortunately, Noranda ceased smelting operations at the New Madrid smelter earlier this year and has filed for bankruptcy."[76]

Q. What are the differences in the circumstances of AmerenUE/Ameren Missouri prior to taking on Noranda as a customer versus today?

A. AmerenUE had sufficient capacity to serve Noranda in 2005 due to its discontinuance of service to Metro East customers. AmerenUE took advantage of market conditions to acquire even more capacity as other non-regulated entities sold off power plants below the cost of constructing new generation and even below their own book costs. Today, Ameren Missouri is not long on capacity, and the cost of building new power plants is at an all time high.

Q. What are the similarities that you expect this Commission to encounter in proceedings related to serving large load customers going forward?

A. I expect intense disputes over calculating the cost of service of serving large load customers. I recommend Staff's rate structure not only as being generally reasonable, but also

[75] EC-2016-0199, *Rate Design Complaint and Motion for Expedited Treatment*, page 1.
[76] EC-2016-0199, *Voluntary dismissal of Complaint*, page 1.

as a means to lessen those disputes going forward. I also expect LLCS customers to intervene in Commission cases with pleas for reduced rates related to the economic viability of those LLCS customers' businesses. Based on Noranda's closure and bankruptcy, I also would not be surprised by the closure of businesses that historically had seemed incapable of bankruptcy due to their size and economic importance.

Q. Are there any other items from Noranda's history that are particularly relevant?

A. Yes. AmerenUE was acutely aware of the massive shifts in the FAC caused by the loss of Noranda's load, and without alteration, the FAC will operate symmetrically to cause massive increases in revenue recovered through the FAC when new large loads are added. The N Factor was implemented in the FAC to address these risks, and a similar mechanism should be adopted to mitigate those risks with LLCS customers, if LLCS customers are not fully excluded from the FAC. AmerenUE requested full take or pay treatment from Noranda to address risk of future changes in load, which is far more restrictive than the demand charges recommended by Staff in this case.

<u>CONCLUSION</u>

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

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Surrebuttal Testimony of Sarah L.K. Lange;* and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 29th day of October 2025.

Dianna L. Vaught
Notary Public

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2027
Commission Number: 15207377

Large Load Customer Service

Schedule LLCS

Customers eligible for service on the LLCS rate schedule are required to take service on this rate schedule.

Applicability:

Any customer taking service at 34 kV or greater except those served under the Large Primary Service rate schedule prior to January 1, 2026, or any customer with an expected 15-minute customer Non-Coincident Peak (NCP) of 25 MW or greater at a contiguous site (whether served through one or multiple meters) shall be subject to this Schedule LLCS.

In the event that a customer with a demand that did not exceed 25 MW prior to January 1, 2026, (1) increases its demand to 29 MW or greater, or (2) requires installation of facilities operating at transmission voltage to accommodate increases in its demand, Ameren Missouri shall expeditiously work with such customer to execute a service agreement and fully comply with the provisions of this Schedule LLCS within 6 months of (1) the customer's notice that such customer's demand is expected to equal or exceed 29 MW or (2) Ameren Missouri's determination that transmission facilities are required.

Other Tariff Applicability:

Customers taking service under Schedule LLCS are not eligible for service under or participation in:

1. The LPS Optional Time-of-Day Adjustment,
2. Charge Ahead programs,
3. Rider B (discounts for customer-owned substations),
4. Rider D (temporary service),
5. Rider E (supplementary service),
6. Rider F (shut-down service),
7. Renewable Solutions Program,
8. Economic Development Incentive, or Economic Development and Retention Rider, or Economic Re-Development Rider,
9. Community Solar Program,
10. Standby Service Rider,
11. Renewable Choice Program,
12. Any compensated demand response or curtailment programs.

Service Agreement:

The form of the application for LLCS service shall be the Company's standard written application form *[which shall be approved by the Commission in this or another proceeding prior to utilization].* This form shall include:

A. The customer's full corporate name and registration information, and that of any and all parent companies.
B. A description of all terms of the Interconnection and Facilities Extension infrastructure and monetary terms, with a statement of the value of Customer Specific Infrastructure to be used in calculating the Facilities Charge.
C. The anticipated load, by month and year, for a minimum of 15 years. This shall include:
    a. A description of weather sensitive load, in monthly kW and monthly kWh,
    b. A description of non-weather sensitive load, in monthly kW and monthly kWh,
    c. An explanation of the variables driving changes in non-weather sensitive load, in monthly kW and monthly kWh,
    d. A commitment to provide updated load-forecasts for the upcoming year by January 1 of that year, in monthly kW and monthly kWh, (Service Agreement Annual Update)
    e. A commitment to notify Ameren of any anticipated deviations of +/-10% or more of previously-anticipated load as soon as such potential deviations become anticipated, the Service Agreement Annual Update,
    f. A commitment to cooperate in daily load forecasting.
        i. Information for load management purposes, including,
            1. Contact information for the person or persons responsible for the LLCS customer's load forecasting,
            2. Contact information for the person or persons responsible for executing curtailment of the LLCS load,
            3. A commitment to maintain updated contact information.
D. A pledge of collateral or other security as ordered by the Commission in this proceeding, which shall equal or exceed the indicated termination fees.
E. A commitment to pay or cause to be paid any applicable termination charges, as defined in the LLCS tariff. In the event that any additional termination provisions may be necessary or appropriate to address additional risk with a particular LLCS customer, those provisions shall be defined in the Service Agreement.
F. The minimum term of service for a customer qualifying for service under LLCS shall be 10 years, following a ramp-up period of up to 5 years.
G. Details pertinent to calculation and verification of rates for the Capacity Cost Sufficiency Rider, if applicable.
H. Any applicable terms for renewal or extension of the Service Agreement term.
I. Any applicable terms for transfer of capacity to other LLCS customers
J. Ameren Missouri is prohibited from constructing interconnection facilities for any potential LLCS customer, making upstream transmission investments to facilitate service to that customer; or building or acquiring power plants, or energy contracts,

or capacity contracts to serve that customer, unless and until it is authorized to do so by the Commission.

Optional Agreement for Payment of Actual MISO Charges:

The Service Agreement may include terms specifying that the LLCS customer agrees to pay all charges received by Ameren Missouri for service at the LLCS customer's commercial pricing node, including but not limited to charges for the day ahead market, the real time market, all ancillary services, and all other charges applicable under MISO's OATT, including administrative and transmission charges. However, these charges will not include any capacity auction charges or revenues.

Ameren Missouri shall provide a copy of such charges to the LLCS customer no later than 1 business day after received by Ameren Missouri, including any revisions, rebills, or other modifications which may be presented by MISO to Ameren Missouri.

The customer shall pay the full amount of each such charges no later than 21 business days after the charges were provided to the customer by Ameren Missouri.

Customers may operate behind the meter generation as detailed in the terms of this Optional Agreement.

If a customer enters into this Optional Agreement as described above, the customer shall not be billed the otherwise applicable Wholesale Energy Charge.

Table of Rates

Charge	Rate	Determinant
Customer Charge	$10,000	$/Customer
Low Income Pilot Program Charge	$ 291.99	$/Customer
Facilities Charge	$ 0.0225	$/$ of Assets
Demand Charge 1 - Charge for Generation Capacity Cost of Service	$ 16.60	$/kW during demand window
Demand Charge 2 - Charge for Transmission Capacity Cost of Service	$ 4.79	$/kW during demand window
Energy Charge	$ 0.051	$/kWh
Alternative to Energy Charge	Execution of an Optional Agreement for Payment of Actual MISO Charges	
RES compliance charge	**_**	$/kWh
Variable Fixed Revenue Contribution	23.4%	Percent of other charges
Stable Fixed Revenue Contribution	23.4%	Percent of other charges
Demand Deviation Charge	$11.3475	$/kW of deviation
Imbalance Charge, Lesser of:	$11.3475	$/kW of deviation
Or, Spring	TBD	
Or, Summer	TBD	
Or, Fall	TBD	
Or, Winter	TBD	
EDI Responsibility Charge	$ -	$/kWh
Capacity Shortfall Rate, if applicable	TBD	$/kW
Capacity Cost Sufficiency Rider, if applicable	TBD	$/Month
Reactive Demand Charge	$ 0.4481	$/kVar

Treatment of LLCS Customer Revenues

A. All revenue from the Charge for Generation Capacity, the Variable Fixed Revenue Contribution Charge, the Stable Fixed Revenue Contribution Charge, the Demand Deviation Charge, the Imbalance Charge, and the RES Compliance Charge will be recorded to a regulatory liability account. The resulting regulatory liability will be treated as an offset to production ratebase with a 50 year amortization. The revenue recorded to the regulatory liability account will not be treated as revenue in setting rates.

B. Until the first rate case recognizing a new LLCS customer at its anticipated full requirements, revenue from the Transmission Capacity Cost of Service Charge that is in excess of the level of revenue from that charge that has been recognized in rates will be recorded to a regulatory liability account. The resulting regulatory liability will be treated as an offset to transmission ratebase with a 50 year amortization. Normalized transmission revenues will be reflected in revenue in setting rates.

C. All revenue billed under Imbalance Charge, Capacity Shortfall Rate, and the Capacity Cost Sufficiency Rider will be used to offset expense associated with the increased cost of service caused by the LLCS customer in any applicable rate case or through the FAC, if applicable.

D. Revenue from the Energy Charge or revenue under an Optional Agreement for Payment of Actual MISO charges shall be deferred as a regulatory liability and incorporated into the FAC in a future general rate case. In the event the FAC is modified to exclude all costs and expenses associated with an LLCS customer, revenue from these charges will be treated as ordinary revenue.

Early Termination:

In the event that an LLCS customer's monthly load (in kWh) is 50% or less of its expected load under its updated contract load for 3 consecutive months, the customer will be required to pay, or cause to be paid, all amounts expected for the remainder of the contract under the following charges: Facilities Charge, Demand Charge for Generation Capacity, Demand Charge for Transmission Capacity, Variable Fixed Revenue Contribution, and Stable Fixed Revenue Contribution.

A. If a customer anticipates a temporary closure or load reduction related to retooling, construction, or other temporary causation, this anticipated reduction shall not trigger the termination charges described above until the anticipated load reduction has exceeded the anticipated duration by three months;

B. The amount due under the Variable Fixed Revenue Contribution Charge in the event of early termination shall be due at the level associated with normal usage in the most recent applicable rate proceeding. If a rate proceeding has not occurred establishing normal usage, or if the customer was not recognized at the anticipated contract maximum load in the prior rate proceeding, the amount due under the Variable Fixed Revenue Contribution Charge shall be at the level associated with the contract projected usage;

C. In the event an LLCS customer either declares bankruptcy, the facility is closed, or is more than 5 business days late in payment of a properly-rendered bill for service, termination charges are immediately due;

D. Except in the case of bankruptcy, closure, or lack of timely payment, termination charges are due on the due date of the bill for the third month of 50% or lower usage;

E. The portion of termination charge revenue associated with the Facilities Charge shall be recorded as a regulatory liability, and treated as an offset to transmission plant. The amortization period for this regulatory liability shall be set to coincide as closely as is practicable with the depreciable life of the transmission-related infrastructure associated with the LLCS customer;

F. The remaining termination charge revenue shall be recorded as a regulatory liability and treated as an offset to production ratebase with a 50 year amortization;

G. These termination provisions can be waived or varied by the Commission if the Commission determines that it is just and reasonable to do so upon application of Ameren Missouri and an opportunity for hearing;

H. Provisions contained herein supersede the Termination of Service provisions of the Rules and Regulations of the generally-applicable tariff.

Other Terms:

A. LLCS customers shall be billed on a calendar month basis.
B. LLCS bills shall be rendered by the fifth business day of the following calendar month, except as otherwise specified in an Optional Agreement.
C. LLCS bills shall be paid by the fifteenth business day of the month issued, except as otherwise specified in an Optional Agreement.
D. Demand is measured as four times the sum of the energy consumed in three consecutive five minute intervals in which the most energy is consumed during the applicable periods. - winter months between 6:00 AM and 11:00 AM and between 5:00 PM and 9:00 PM,
   -spring, summer, and fall months between 3:00 PM and 10:00 PM.
E. The Demand Deviation Charge is calculated based on the difference in a given month's demand forecast in the initial Service Agreement and the current Service Agreement Annual Update, except that differences of +/- 5% of the Service Agreement amount are not subject to charge.
F. The Imbalance Charge is calculated based on the difference in a given month's actual demand and the level of demand for that month in the current Service Agreement Annual Update.
G. The Variable Fixed Revenue Contribution will be applied to the actual billed amounts for the Customer Charge, the Facilities Charge, the Wholesale Energy Charge, whether billed as a flat rate or under the Optional Agreement, and the RES Compliance Charge. The Stable Fixed Revenue Contribution Charge applies to the greater of the rate for the Generation Capacity Charge rate multiplied by the updated contract demand for the month OR the actual charge calculated for the Generation Capacity Charge, and to the greater of the rate for the Transmission Capacity Charge Rate multiplied by the updated contract demand for the month OR the actual charge calculated for the Transmission Capacity Charge.
H. Deferral accounts associated with LLCS customers may be consolidated in a general rate case for administrative convenience, with the resulting amortization period to approximate a weighted average of the remaining amortization periods of the consolidated accounts.
I. Service on this schedule is limited to 33% of Ameren Missouri's annual Missouri jurisdictional load.
J. Prior to execution of a Service Agreement with a prospective LLCS customer, Ameren Missouri shall ensure that it has adequate capacity available for resource adequacy calculations to serve all existing customers and the prospective LLCS customer. In the event Ameren Missouri executes a Service Agreement without adequate capacity, Ameren Missouri's existing customers shall be held harmless from any MISO or other RTO capacity charges, and held harmless from any penalties assessed by any entity related to those capacity shortfalls.
K. Capacity Cost Sufficiency Rider
   In the event that Ameren Missouri does not have sufficient capacity to reliably serve a requesting LLCS customer and its other load in a given season of a

given year of the anticipated Service term, Ameren Missouri may obtain contractual capacity to reliable serve the requesting customer. Ameren Missouri shall file an ET case and tariff with no less than 45 days effective date, and shall file testimony explaining the potential LLCS customer, that customer's energy and capacity needs, and the capacity arrangements applicable to reliably serving that customer. Ameren Missouri may seek a protective order for portions of the testimony as appropriate, but any Capacity Cost Sufficiency Rider Rate to be charged to any LLCS customer must be contained in a published tariff. The Capacity Cost Sufficiency Rider tariff shall contain terms related to treatment of revenues generated by the rider to prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers.

L. Interconnection and Facility Extension

a. When applying for service, a prospective LLCS customer shall be responsible for prepayment of the transmission extension, which shall consist of all substations, conductors, devices, poles, conduits, transformers, and all appurtenant facilities and meter installation facilities installed by Company or for which the Company is financially responsible for installation, whether or not under the functional control of the Company, including any and all equipment necessary to ensure adequate power quality with the addition of prospective LLCS customer's load.

b. Prior to construction of any electrical facilities for service to a prospective LLCS customer, the Company and the prospective LLCS customer shall prepay an estimate of the construction costs of the required facilities, including the cost of all materials, labor, rights-of-way, trench and backfill, together with all incidental underground and overhead expenses connected therewith.

(1) The prospective LLCS customer will be responsible for nonrefundable charges for infrastructure that is owned and under the functional control of Ameren Missouri, which would not have been constructed but-for the provision of service to the prospective LLCS customer.

(2) The prospective LLCS customer will be responsible for refundable charges that may be reimbursed to that LLCS customer during the five years following completion of the transmission extension, and shall consist of (a) the portion of charges for infrastructure that is owned and under the functional control of Ameren Missouri, which has been constructed in excess of the level of infrastructure that would not have been constructed but-for the provision of service to the prospective LLCS customer, and (b) the portion of charges for infrastructure that is not under the functional control of Ameren Missouri, but for which Ameren Missouri is compensated by entities other than its Missouri retail ratepayers.

(3) To the extent that future prospective customers request service which utilizes the infrastructure referenced in part 2 within five years

following the completion of construction, payment for such infrastructure, when obtained, shall be provided to the LLCS customer who initially funded such infrastructure.

(4) Upon completion of construction, Ameren Missouri shall prepare a reconciliation of the actual construction costs and estimate construction costs, which shall promptly be refunded to, or paid by, the LLCS customer, as applicable.

Ameren Missouri's
Response to MPSC Data Request - MPSC
ET-2025-0184
Large Load Tariff - Customers

No.: MPSC 0083

Please refer to the following statement as copied from <https://www.ameren.com/page/powering-mo-growth> on October 16, 2025, "Who is paying for the electric infrastructure upgrades needed to serve large electric customers, such as data centers? Large customers must directly pay for all the equipment and costs for constructing the infrastructure required to extend service to their location. This includes interconnection to the grid, new line extensions, switching stations, transformers, breakers and other materials." Please confirm that Ameren Missouri's direct proposal in this case does not require a large customer to directly pay for any transmission system investments made to provide service to that large customer that exist above the interconnection of that large customer and the transmission grid.

RESPONSE

Prepared By: Steven M Wills
Title: Senior Director, Regulatory Affairs
Date: October 27, 2025

Confirmed.