Exhibit:	
Issue(s):	*LLPS Rate Structure and Design, System Support Rider*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal Testimony*
Case No.:	*EO-2025-0154*
Date Testimony Prepared:	*September 12, 2025*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

EVERGY METRO, INC.,
d/b/a Evergy Missouri Metro

and

EVERGY MISSOURI WEST, INC.,
d/b/a Evergy Missouri West

CASE NO. EO-2025-0154

Jefferson City, Missouri
September 2025

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

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SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

CASE NO. EO-2025-0154

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 July 25, 2025?

A. Yes.

SUMMARY

Q. What is the purpose of your surrebuttal testimony?

A. I will provide corrections and clarifications related to the Staff Rebuttal Report and recommended Large Load Power Service ("LLPS") tariff, including an updated recommended LLPS tariff[1]. I will also respond to the rebuttal testimonies of various parties.

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. A summation error in Staff's main rate workpaper resulted in the exclusion of some elements of revenue requirement from the recommended rates,[2] and certain revenue requirement components were

[1] Attached as Schedule 1.
[2] Staff appreciates Data Center Coalition (DCC) Data Request (DR) 231, which brought this issue to its attention.

inadvertently omitted from Staff's calculation.[3] Corrected rates for both utilities are included in Schedule 1 to this testimony.

2. Some imprecise language was used for referencing the annual update process, which led to difficulty in understanding the calculation of demand deviation and imbalance charges. More complete explanation is incorporated in Schedule 1.[4]

3. Staff failed to include intended language concerning the ability to explicitly reassign contract capacity, which impacts calculation of demand deviation charges, imbalance charges, and termination charges.[5] Staff also failed to note the need for term extension or renewal provisions, which are incorporated into Corrected Tariff A.

4. Staff failed to include details in the tariff discussed in the Report, such as the time of use periods and other details, including the calculation of demand deviation and imbalances charges.

5. Staff, through review of rebuttal testimonies concerning various riders and discussion with OPC concerning FAC[6] operational details, has developed an alternative approach to the FAC treatment of LLPS customers and the billing of wholesale energy expense which would enable customer-sited generation and response to market energy and transmission congestion, and also better align risks related to market energy prices and transmission congestion. This revised recommendation is presented in Schedule 1, and discussed below, in the section "Rate Structure, Rate Design, and Pricing." It is consistent with Staff's recommended tariff design filed in Ameren Missouri's case, Case No. ET-2025-0184, in Staff's Rebuttal Report, filed 9/5/2025.

GENERAL POLICY ISSUES DISCUSSED IN REBUTTAL

Q. Did parties file rebuttal testimony that adding large customers may benefit the bills of existing customers?

A. Yes.

Ameren Missouri's witness Steven M. Wills testifies in his rebuttal testimony that,

I fully expect based on my general experience with such costs in the region and an awareness of Evergy's base retail rate levels that the base

[3] Staff appreciates DCC DR 234, which brought this issue to its attention.
[4] Staff appreciates DCC DRs 229 and 230, which brought this issue to its attention.
[5] Staff appreciates Google DR 211, which brought this issue to its attention.
[6] Fuel Adjustment Clause (FAC).

> retail tariff charges that will apply to large load customers will likely cover those types of incremental costs and likely leave some revenues to make some level of contribution to the fixed costs of Evergy's total electric system.[7]

In her rebuttal testimony on behalf of Renew, Jessica Polk Sentell, states,

> Furthermore, we are strongly supportive of customers having the choice (or in this case, choices) to adjust their energy consumption (amount and generation sources) according to their company's needs. The choices enabled by these tariff riders essentially create customer-specific pricing and customer-specific generation resources for LLPS customers. And while these rates will overall have a neutral or positive impact for LLPS customers, Evergy does not want or foresee them negatively impacting non-participating or non-LLPS customers. In fact, Evergy says these programs will help ensure new large-load customers will "pay their share" and "protects existing and non-large load customers, and minimizes the risk of cost shift."[8]

In her rebuttal testimony, Dr. Carolyn A. Berry, on behalf of Google, states,

> Large load customers, particularly those with high load factors, offer both operational and economic advantages to the electric system. Due to their consistent and predictable energy consumption, these customers support more efficient operation and planning of the electric utility grid. Their steady energy demand profiles, for example, enable utility system planners and grid operators to better optimize existing generation and transmission infrastructure, which in turn, can delay new infrastructure investments and improve overall system efficiency.[9]

Dr. Berry also testifies that,

> Additionally, the consistent energy usage of large load customers helps to distribute fixed costs across a larger energy volume, contributing to a lower average cost per kWh for all customers. Many large industrial consumers also engage in demand management, further enhancing grid stability and reliability. In essence, these customers provide a stable base load enhancing the economic and operational health of the electric utility system.[10]

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[7] Wills Rebuttal, page 6. Note, the testimonies of Mr. Wills and Mr. Arora include support for the Ameren Missouri Large Load Customer tariff additions to its Large Power Service rate schedules and related materials that are the subject of ET-2025-0184. Staff will not respond to those elements as the support of the Ameren Missouri requested treatment and Staff's response are properly addressed in Case No. ET-2025-0184, not Case No. EO-2025-0154.
[8] Sentell Rebuttal, 16th page of unpaginated pdf file.
[9] Berry Rebuttal, page 8.
[10] Berry Rebuttal, page 8.

Ameren Missouri witness Ajay K. Arora testifies that "I generally agree with Mr. Gunn's description of the overall large load customer landscape and agree that these customers present a historic opportunity for the state."[11]

Q. Will adding Large Load Power Service ("LLPS") customers lower electric rates for other customers of Evergy Missouri Metro ("EMM") and Evergy Missouri West ("EMW")?

A. Probably not.

Q. Why won't adding LLPS customers lower the electric rates for other EMM and EMW customers?

A. LLPS customers may produce more state and local tax revenue. LLPS customers may spur economic development. LLPS customers may do a lot of things, but LLPS customers almost certainly will not lower electric rates for other EMM or EMW customers, nor should Commissioners expect that EMM or EMW rates for other customers will be lower than they otherwise would be because of revenue that LLPS customers will provide. The cost of building new power plants is very, very high. The ongoing cost of service that new power plants will cause is very, very high. Existing power plants will at one point or another retire, which will necessitate building expensive new power plants even if LLPS customers are not added; however, adding LLPS customers will require building more new power plants, building bigger new power plants, or building new power plants sooner. It is not mathematically possible to have an outcome where so many expensive new things can be built that the expensive new thing somehow becomes cheaper than the existing cheaper thing.

Q. Is a reduction to the average cost of energy the same thing as reducing the average cost of energy for existing customers?

[11] Arora Rebuttal, page 5.

A. No. A utility can decrease the average cost of energy on an annual $/kWh basis, while its existing customers' rates actually increase, if it sells energy to its new customers cheap enough. As a simple example:

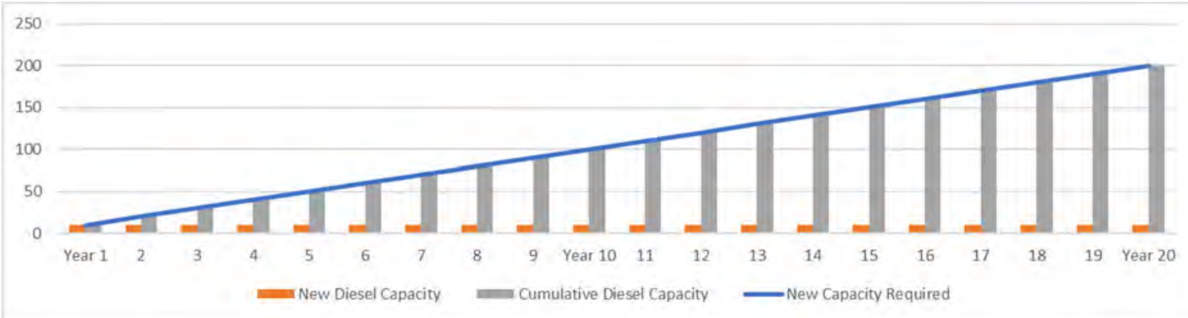
- Assume a utility has a total cost of service of $100,000 per year, and sells 1 million kWh per year at a rate of 10 cents per kWh.
- The utility begins serving a new customer on a special rate. It costs $30,000 to serve the new customer, and the new customer pays a rate of 5 cents per kWh for 500,000 kWh per year, which produces $25,000 in annual revenue.
- Nothing else changes, and the utility seeks and receives an increase in the 10 cent rate to increase it to 10.5 cents per kWh, to make up for the $5,000 shortfall caused by the new customer.
- In this example, the average cost of energy for the utility actually goes down, from 10 cents per kWh to 8.67 cents per kWh, even though the rates paid by everyone except the new customer went up.

This difference in the average cost of energy and the rate impacts for existing customers is exactly what the Commission needs to think critically about in this case. New LLPS customers may literally reduce the average cost of energy in that many, many, kWh of energy will be sold to LLPS customers at a low rate under Evergy's proposals; however, rates for other customers will be going up to offset increased cost of service for expensive new power plants.

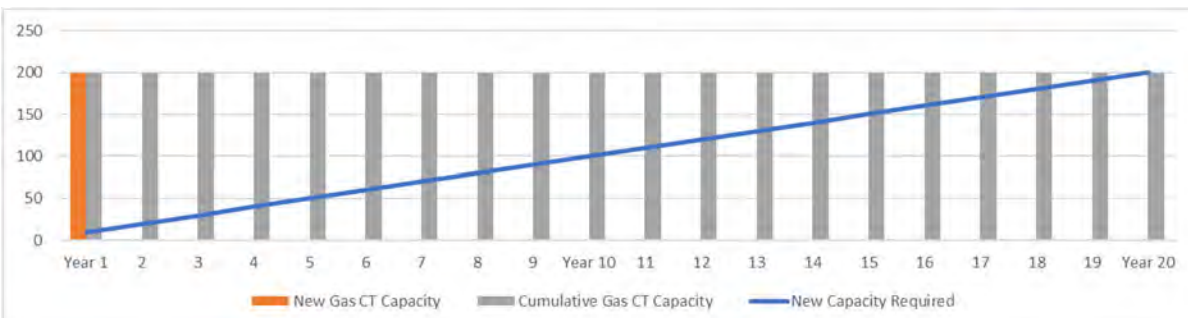
Q. Are economies of scale relevant to whether or not an LLPS customer could cause the rates of other customers to rise less than they otherwise would?

A. Yes. An example where this would make sense is as follows:

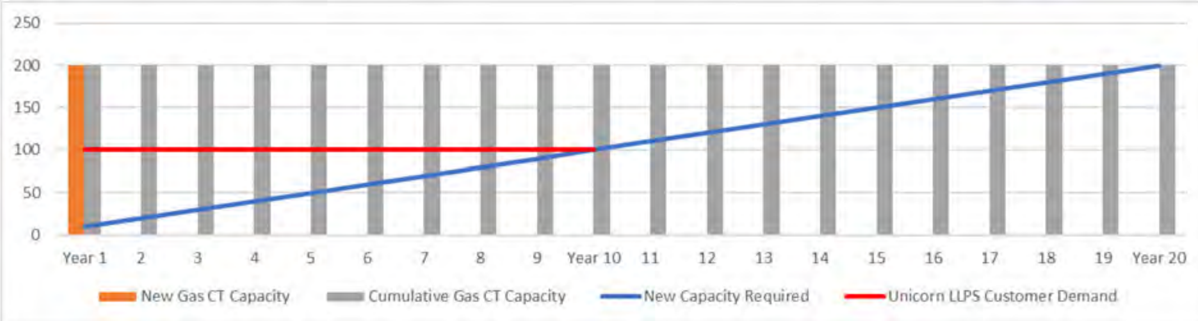
Hypothetically, a utility needs 10 MW to meet its resource adequacy requirements for the coming year. It buys a 10 MW diesel generator for $12 million, or $1.2 million per MW. The following year, it needs 10 more MW to meet its requirements, and buys another 10 MW diesel generator. This process repeats until 200 MW of diesel generators have been bought.



It probably would be better to build an efficient 200 MW gas-fired combustion turbine for $100 million, at $0.5 million per MW, rather than to install 20 separate diesel generators at a total cost of $240 million. However, installing 200 MW of gas combustion turbine ("CT") capacity in year 1 leaves a lot of excess capacity for the first 19 years of that plant's life, as shown below.



In a perfect world, a "unicorn" LLPS customer would need exactly 100 MW of capacity, for exactly 10 years, and those years of customer demand and excess capacity would exactly line up, and rate case timing would exactly work out, and the LLPS customer will pay more revenue for the energy they consume and for their capacity requirements than the market value of that capacity and energy, and all customers would be better off from the perspective of their electric bills than if the LLPS customer had not come onto the system.



It is unlikely that reality would precisely fit the facts of this scenario.

Rising Costs of Power Plants

Q. Why is it unlikely that the benefits Mr. Wills, Ms. Polk Sentell, Dr. Berry, and Mr. Arora allude to would occur?

A. On a dollar per MW basis, the rate base of a new power plant built in 2030 will be much higher than the rate base of an old power plant kept in operation since the 1970s. Adding new power plants to serve new LLPS load, given the size of LLPS customers, will be immensely expensive. As noted by Dr. Marke "In this case, the concern is that the pipeline demand for service is roughly the equivalent of building out a brand-new utility."[12]

Q. What is the cost of existing power plants for EMM and EMW?

A. EMM currently serves just under 2,000 MW of total load with just over $2 billion dollars of Missouri jurisdictional net production rate base. EMM's power plants cost about $3.5 billion to build (Missouri jurisdictional), and have accrued around $1.5 billion in Missouri jurisdictional depreciation reserve. Dividing these values out results in average rate base value of about $1 million per MW for the existing EMM fleet.

[12] Marke Rebuttal, pages 17 – 18.

EMW currently serves just over ** [redacted] ** MW of total load with under 1 billion dollars of net production rate base. EMW's power plants cost under $1.45 billion to build, and have accrued around $0.5 billion in depreciation reserve. Dividing these values out results in average rate base value of about ** [redacted] ** per MW for the existing EMW fleet.

Q. What is happening to the cost of power plants?

A. The cost to build a new power plant is increasing. In this increasing cost environment, the rates for new LLPS services must be increased to potentially obtain the benefits alluded to by Mr. Wills, Ms. Polk Sentell, Dr. Berry, and Mr. Arora.

For 2023, the Energy Information Administration reported average construction cost of $1.6 million per MW for photovoltaic power plants, $1.3 million per MW for batteries, and $1.7 million per MW for wind. For simple cycle combustion turbines, the reported cost for 2023 was $562 thousand per MW. For combined cycle units, the CT portion was $782 thousand and the Heat Recovery Steam Generator ("HRSG") portion was $1.122 million.[13]

However, the cost of power plants has risen since 2023, and will likely continue to rise. In fact, on July 31, 2025, the Commission authorized three certificates of convenience and necessity for new EMW power plants, at an expected cost of $2.22 million per MW for the Viola combined cycle project, $2.25 million per MW for the McNew combined cycle project, and $1.9 million per MW for the Mullin Creek 1 project.[14] The same day, the Commission authorized EMW to proceed under CCNs[15] for Sunflower Sky Solar at a cost per installed MW of ** [redacted] ** and Foxtrot Solar at a cost per installed MW

[13] https://www.eia.gov/electricity/generatorcosts/, accessed 7/31/2025.
[14] These values do not include Allowance for Funds Used During Construction (AFUDC) or other statutorily-available treatments, EA-2025-0075. EMW was authorized to proceed with a 50% share in Viola, a 50% share of McNew, and a full 100% of Mullin Creek 1.
[15] Certificate of Convenience and Necessity ("CCN")

of ** [redacted] **.[16] While specific future accredited capacities are not known at this time, using a generous 60% summer capacity valuation, this works out to an average of ** [redacted] ** per available MW.

The CCNs approved on July 31 for EMW will provide approximately 1,249 MW of accredited capacity, at a total cost of ** [redacted] **, for an average of ** [redacted] ** per MW.

** [redacted]

**

[16] Excluding AFUCD, EA-2024-0292.

Q. Based on the only LLPS customer projections available from Evergy, what kind of capacity will be required to serve new LLPS load?

A. Evergy's partial response to relevant Staff data requests, provided after objection, indicates that ** [redacted].

[redacted]

[redacted]

[redacted] **

Q. The Commission approved CCNs for five new EMW power plants on July 31, 2025. Will those CCNs increase EMW's available capacity enough to serve new LLPS load?

A. No, not if the projections are accurate.

Q. Does the discussion above account for the values of energy produced, the value of excess capacity, the cost of fuel, the value of renewable energy credits, regulatory lag, AFUDC, or other items that will ultimately be addressed in customer rates?

A. No. It also does not account for the increases in retail cost of service that will be caused through application of regulatory accounting matters such as increased rate base through the application of deferrals associated with Plant in Service Accounting (PISA) or Construction Work in Progress (CWIP).

Q. Won't sales of energy and capacity from new power plants provide revenues, no matter what happens with LLPS customers?

A. Yes, but no reasonable projection results in newly-constructed power plants in Missouri or Kansas producing enough revenue to offset its cost of service in today's energy and capacity markets. Were that the case, we would see independent power producers building new natural gas power plants, which is not happening in this area.

Q. Given the concerns with the increases in the cost of building a power plant since the 1970s, wouldn't it be reasonable to just make the LLPS customers pay for the power plants they are causing?

A. That could be reasonable. That is also immensely impractical. Staff's recommended approach of requiring LLPS customers (1) to pay a proportionate share of capacity costs based on that customer's projected demand for their service term and (2) essentially setting other rate elements to recover the variable expense of serving that customer to be billed with closely related determinants is a reasonable compromise to provide the LLPS customer that does materialize with a fair rate, while not setting an inappropriate below-cost rate to attract customers who will cause more increases to the cost of service than revenues that will be provided to offset those increases.

Q. Why would this be impractical?

A. It would require a running counterfactual revenue requirement calculation of what the cost of service would have been without LLPS customers, and it would also require determining what plants are caused by LLPS customers.

Q. Does Evergy have incentives to argue that a new power plant is not caused by a new LLPS customer?

A. Yes. The PISA statute, Section 393.1400, RSMo., exempts from PISA eligibility "rate-base additions that increase revenues by allowing service to new customer premises." The Commission cannot rely on Evergy to identify new power plants built to serve new LLPS customers, because doing so will cost Evergy the lucrative legislative treatment that it has obtained.

Attracting customers

Q. Google witness Dr. Berry testifies that

> The SSR addresses a different concern: that large load, simply by virtue of coming onto the system, could potentially harm other customers. The notion is that the cost of resources built to accommodate large load will somehow be paid, in part, by existing customers– meaning that large load will not pay its fair share of costs. Ultimately this boils down to a conviction that the existing cost allocation framework does not work when a large load is added to the system.[17]

[17] Berry Rebuttal, page 32.

DCC witness Shana Ramirez testifies,

> From a system reliability perspective, their presence may support and even accelerate necessary utility investments in aging infrastructure, ultimately enhancing service quality for all customers.[18]

And,

> Multi-year service commitments from large load customers enhance the utilization of both existing and new generation and transmission assets. These customers also contribute stable, long-term demand, which supports more efficient resource planning and system modernization efforts. [19]

And,

> Financially, large loads can increase and stabilize utility revenues by expanding overall system usage. A higher total sales volume allows the utility to distribute fixed system costs across more kilowatt-hours, which may help reduce costs for other ratepayers.[20]

And,

> From a policy and compliance standpoint, many large load customers are actively pursuing ambitious sustainability objectives. This creates opportunities for meaningful collaboration on clean energy procurement, energy efficiency initiatives, and innovative grid solutions.[21]

And,

> Furthermore, large, consistent loads may catalyze the deployment of emerging technologies, such as advanced geothermal or nuclear power, hydrogen-based fuels, and grid-scale energy storage as well as supporting a variety of grid-enhancing technologies. By serving as anchor customers or project sponsors, these entities can help advance alternative pathways to achieving the utility's clean energy and decarbonization goals especially if they are willing to take on more risk such as supporting first-of-a-kind technologies that is not appropriate for a utility to bear but could provide future benefits when those technologies are potentially de-risked. [22]

[18] Ramirez Rebuttal, page 8.
[19] Ramirez Rebuttal, page 8.
[20] Ramirez Rebuttal, page 8.
[21] Ramirez Rebuttal, page 8.
[22] Ramirez Rebuttal, pages 8 - 9.

Shouldn't it be the goal of the Commission to set LLPS terms and rates to attract LLPS customers?

A. No. The rates should be set to be fair and to comply with the statutory requirements that LLPS rates be set to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[23] There will be jurisdictions with lower rates and with differing terms for various reasons ranging from different capacity costs, different energy costs, and different legal frameworks. Missouri should not launch a race to the bottom.

Q. Doesn't the existing cost allocation framework work when a large load is added to the system?

A. No. The existing cost allocation framework does not work when a large load is added to the system. Particularly the existing framework will not comply with the new requirement of Section 393.130.7. It will almost certainly be necessary to handle cost of service allocation to LLPS customers as a first stage of future class cost of service studies, akin to how wholesale load has been treated historically.

Q. Mr. Arora testifies that, "I agree that customers like these 'shop their loads' and that they do so nationally, as Mr. Gunn notes on pages 9-10 of his Direct Testimony."[24] And Ms. Sentell testifies on page 12 of her unpaginated Rebuttal that "Access to renewable energy generation options is increasingly vital to a region's competitive economic development. Offering customers options to purchase renewable energy is one way for Evergy

[23] Section 393.130.7, RSMo., effective August 28, 2025, enacted pursuant to SB 4.
[24] Arora Rebuttal, page 5.

to draw corporate customers to the region, as well as prevent large load customers from leaving or seeking to expand outside Evergy's service territory." How do these concerns reconcile with the testimony of Dr. Marke that, "In this case, the concern is that the pipeline demand for service is roughly the equivalent of building out a brand-new utility. If the investment is made to meet that demand but those new customers don't materialize, go out of business, or significantly reduce their energy usage the investments built to serve them may become stranded assets. In that case, either ratepayers, shareholders or both will be left footing that bill."[25] and with the load projections Evergy has provided for potential LLPS customers?

A. There is a strange disconnect between simultaneously preparing for a massive load onslaught by building out capacity on the one hand, and carving out lucrative pricing terms or rider treatments on the other. This was discussed in Staff's Rebuttal Report but bears repeating: EMW and EMM have an obligation to serve customers and some of those customers may be very large, but there is no requirement that those customers be provided a sweetheart deal or get any sort of wish list of capacity composition. As discussed above, there may be LLPS customers who fill capacity gaps who will result in the rates for future ratepayers being lower than they would be without those LLPS customers as EMM and EMW build new capacity anyway. However, there is almost certainly no LLPS customer who will pay EMM or EMW more than the net cost of service that customer will cause if EMM or EMW build a new expensive power plant just to have enough capacity to serve LLPS customers. Were that the case, customers of this size, sophistication, and access to capital would likely simply build their own power plant for their own needs and not participate in any retail utility or wholesale marketplace while paying a utility the rate of return on a power plant investment, and in that

[25] Marke Rebuttal, pages 17 – 18.

case those customers could build the form of capacity – renewable, gas, coal, diesel, or nuclear - that best fits that customers corporate commitments or aspirations.

Acceleration Component of SSR and Election of Statutory Accounting Benefits

Q. Google witness Dr. Berry testifies that

> The Company assumes that a resource that is built now for large loads would have been built in the future even without large loads. This is highly unlikely. Resource planning in a world without LLPS customers would be very different. It is more likely the resource would never be built if there was no large load. There is no acceleration, rather the Company would build a different set of resources.
>
> Additionally, the Company's methodology assumes that the non-LLPS customers will pay a constant pro-rata share of acceleration costs over the entire period and that the pro-rata share is the same in the future with large load and the future without it. In reality, the pro-rata shares will1 change annually as LLPS customers ramp into their contract capacity and new LLPS customers come on the system. In a future with no LLPS customers, other customers would be responsible for bearing 100% of the costs of all new resources built by the Company to serve them.
>
> Another serious flaw is the omission of the benefits provided to non-LLPS customers. LLPS customers will pay their pro-rata share of all existing resources, reducing the amounts that non-LLPS customers will have to pay. This error reflects the misguided use of a marginal impact analysis within an average embedded cost methodology. The marginal impact analysis does not take into account the full range of effects from the incorporation of LLPS customers into the customer mix.[26]

Do you agree?

A. I agree that resource planning and the actual utility fleets to be built over the coming decades would look very different if LLPS customer do not and will not exist. I also agree that the proposed SSR[27] Acceleration Component is not calculated reasonably. However, I cannot agree that benefits provided to non-LLPS customer were omitted from Evergy's

[26] Berry Rebuttal, pages 33 - 34.
[27] System Support Rider (SSR).

analysis, because at Evergy's proposed rates and revenue treatments, there are no rate benefits provided from LLPS customers to captive ratepayers. Rather than a device such as the Acceleration Component, it is better to set an appropriate demand charge from the outset, as recommended by Staff, and to use the revenues generated by that charge to offset the new rate base caused by LLPS customers.

Q. Dr. Marke testifies that he supports the SSR and that:

> I can't imagine a reasonable argument against it. Especially considering the passage of SB4 and the statutory language of § 393.130(7), RSMo 2025:
>
> > The schedules should reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers.[28]

Can you think of a reasonable argument against the SSR?

A. Yes. While I agree that the rates proposed by EMM and EMW would not produce revenues that comply with Section 393.130(7), RSMo 2025 without AT LEAST additional revenue through the SSR, that is a problem with the underlying rate structure and the pricing requested by EMM and EMW. It is better to fix the LLPS rate structure and pricing than it is to layer on an SSR. Shortcomings of the SSR – reasonable arguments against it – include that the calculation of the rate is very subjective, the determinants that the SSR rate would apply to are subject to Evergy's discretion, and much of the revenue collected under the SSR as proposed by Evergy would be retained by shareholders and would not be reflected in the revenue requirements of EMM and EMW as needed to prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLPS customers.[29]

[28] Marke Rebuttal, page 24.
[29] Section 393.130(7), RSMo. 2025.

Q. DCC witness Mr. Kevin C. Higgins provides criticisms of the calculation of the SSR acceleration component as items to correct in ordering approval of the SSR acceleration component, at pages 19 - 26 of his Rebuttal Testimony. Should the Commission correct the calculation of the SSR acceleration component?

A. No. First, Mr. Higgin's recommendations are not improvements. But, in the broader sense, it is not reasonable to fix the SSR acceleration component, it is reasonable to set appropriate LLPS rates and terms that don't rely on an external device such as the SSR acceleration component.

As noted by Google witness Dr. Berry, Evergy's initial SSR calculation requires the creation of a hypothetical ratemaking environment with excessive reliance on projections and assumptions.

> To perform the SSR calculation, the following assumptions need to be chosen:
> - Resource to be accelerated
> - Resource costs, both if built now and if built at a future date
> - Acceleration period (the number of years in the future that the resource would have been built if there were no large load)
> - Discount rate
> - Term over which the resource costs will be recovered
> - Customer consumption profiles (peak load of LLPS customers and other customers to determine the allocation of costs).[30]

Reliance on these myriad assumptions and their interactions is not reasonable. To say the least, these assumptions can be subjective and the review of these assumptions can be contentious. Mr. Higgins' additions to the SSR acceleration rate calculation – especially projecting future fuel and energy values and future dispatches -- exacerbates these problems.[31]

[30] Berry Rebuttal, page 37.
[31] Higgins Rebuttal, page 22.

Similar complications undermine the option to rely on vintage pricing or assigning the cost of service to specific plants to specific LLPS customers, as Mr. Higgins discusses vintage pricing at pages 27 – 29 of his rebuttal testimony, and Dr. Berry at page 38 of her rebuttal testimony.

Q. Is there an additional complication to plant assignments or vintage pricing?

A. Yes. Evergy has significant financial incentives to claim that a given power plant is built to serve all customers, and that it was not built to serve LLPS customers or other new load.

Q. Dr. Berry testifies that,

> It will never be the case, under the embedded cost of service approach, that a new resource will be built to serve a specific LLPS load. If that were the case, the cost of the new resource could be assigned to the new load and customers would be protected. (The Company, however, has not offered a direct assignment option.)[32]

DCC witness Kevin C. Higgins testifies as follows:

> As a threshold matter, characterizing the revenue requirement impacts of load growth in terms of "acceleration" does not comport well with what actually occurs with load growth. Unless a utility has excess capacity or allows customers to acquire generation supplies from third-party providers, substantial load growth will change a utility's resource portfolio. As such, we would expect a growing utility to acquire additional resources, as distinct from simply accelerating resources. The acquisition of additional resources would result in a change in revenue requirements, but any net change in rates would result from the interplay of the increase in revenue requirements and the increase in billing determinants associated with the new load. Incremental load results in incremental resources; it does not really result in accelerated resources. Conceptually, the "acceleration" concept does not reasonably describe what happens with load growth.

Do you have any insight as to why Evergy took the "acceleration" approach instead of assigning plants to new customers?

[32] Berry Rebuttal, page 36.

A. Yes. Administratively, assigning plants to specific customers would be very, very, difficult to implement over time. However, there are two other reasons for Evergy to choose the "acceleration" approach over plant assignments. First, if EMM or EMW stated that they were adding a power plant to enable service to a new customer, then under current Missouri law that power plant would not be eligible for lucrative regulatory mechanisms. The PISA statute, Section 393.1400, RSMo., exempts from PISA eligibility "rate-base additions that increase revenues by allowing service to new customer premises." The Commission cannot rely on Evergy to identify new power plants built to serve new LLPS customers, because doing so will cost Evergy the lucrative legislative treatment that is has obtained.

Second, the variability of the SSR in terms of its calculation and the determinants to which it applies gives significant ability to Evergy to pick and choose customers of EMM and EMW, and to maximize positive regulatory lag to its benefit.[33] If instead, EMM and EMW charged LLPS customers for the actual revenue requirements of new power plants, the resulting rates would probably be higher than what LLPS customers are willing to pay, because it would be cheaper for those customers to build their own power plants and avoid paying a third party – Evergy - a return on that investment.

Q. To effectuate Dr. Berry's assertion that "LLPS customers will pay their pro-rata share of all existing resources, reducing the amounts that non-LLPS customers will have to pay,"[34] what would have to be true?

[33] DCC witness Kevin C. Higgins testifies against the acceleration component of the SSR, noting that "the rate proposed is ** [redacted]. ** Higgins Rebuttal, pages 17 - 18.

[34] Berry Rebuttal, pages 33 - 34.

A. It would have to be true that the resources to serve the LLPS customers are included in the rates the LLPS customers pay, and it would have to be true that offsets to rate base paid for by non-LLPS customers are not unreasonably allocated to the benefit of LLPS customers. Specifically, Accumulated Deferred Income Taxes (ADIT) should not be used to offset the demand rates of LLPS customers.

Q. What is ADIT?

A. 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 LLPS 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.

Q. What is demonstrated by the iterations of the net present value analysis presented by Mr. Higgins at pages 22 – 26 of his rebuttal testimony?

A. Frankly, these iterations demonstrate that a net present value calculation, or the differences between net present value calculations, can be manipulated to provide essentially any answer one may seek. Staff has frequently cautioned against reliance on NPV calculations for ratemaking or for approving CCNs. Other options would include using a simple cycle gas turbine, which would likely have slightly lower initial capital costs, and significantly lower energy value and fuel costs, or using a wind farm, which would have exponentially higher capital costs, lower energy value, and no fuel costs.

TARIFFS

Rate Structure, Rate Design, and Pricing

Q. DCC witness Kevin C. Higgins testifies that he supports the LLPS rate structure and pricing requested in Mr. Lutz direct testimony, with the exception of the SSR.[35] Specifically, Mr. Higgins testifies,

> Schedule LLPS was derived using the otherwise applicable Schedule LPS for both the Missouri Metro and Missouri West service territories as a baseline. The initial monthly pricing proposals for both the Missouri West and Missouri Metro Schedule LLPS rate plans are presented in Table 6 in the Direct Testimony of Evergy witness Lutz. The proposed LLPS rate designs represent a simplification and improvement over the otherwise complex "hours use" rate designs currently used for Schedule LPS in both the Missouri Metro and Missouri West service territories. In the LLPS rate design, capacity-related costs are removed from the hours-use energy blocks and transferred to the production demand charge. Transmission and substation-related costs are recovered in a separately stated Grid charge. I support these changes and recommend approval of the Schedule LLPS initial monthly pricing proposed by Mr. Lutz, with the exception of the System Support Rider, which I will discuss later in my testimony.

Does the direct rate structure requested by Evergy offer an improvement of the hours use rate structure of the LPS tariff?

A. No. Staff's time-based approach is an improvement over hours use because it better aligns the price signal of the cost of consuming a kWh of energy with the cost of that

[35] Higgins Rebuttal, pages 8 - 9.

kWh of energy, based on the time of year and the time of day the energy is consumed. However, the Evergy flat approach is significant step backward. The Evergy approach of a flat price for each kWh removes customer incentives to manage timing of energy consumption, and opens possibilities of price arbitrage, particularly if coupled with any of the proposed Riders for which Staff has recommended rejection. This is because while all energy rates are set on an assumption that the highs and lows of the market average out over time, for customers of this size and sophistication it is important to be especially mindful of likely periods when EMM or EMW will be selling energy for \$20-\$30/MWh, while purchasing that energy for \$200/MWh during times of high market energy prices.

Q. Reflecting on this concern, are there other options?

A. Yes. While FAC interactions would need to be addressed, a concept with good potential is as follows:

1. Because of legal concerns with the filed rate doctrine, Staff is reluctant to recommend that energy cost recovery be based on after the fact billing of actual wholesale energy expense; rather, a published energy rate is necessary for LLPS customers.[36]

2. If customers are given the option to enter into an agreement with EMM or EMW to accept direct billing of wholesale energy expense for that LLPS customer's load node, including day ahead, real time, and ancillary charges, many would choose that option. This would also facilitate:

a. Direct customer management of energy costs by avoiding high cost times and maximizing low cost times, for an overall response comparable to demand response,

b. Improved price signals for responses to any utility-required curtailments, and

[36] An approach similar to the PGA could potentially be legally applied to LLPS customers as a class.

c. Ability for the customer to more accurately balance the expenses incurred for serving its load with the revenues that may be generated through off-site customer-controlled renewable generation.

3. With this option available to customers, it would be reasonable to set the published tariff energy rates at a higher level than recommended in Staff's Rebuttal Report. This is necessary because customers who expect to perform "worse than average" would chose the published rate over the actual wholesale expenses.

4. LLPS customer load would need to be excluded from the FAC, and it would be fully fair to do so because EMM or EMW, respectively, would be receiving the exact revenue from LLPS customers to cover the day-ahead, realtime, and ancillary expenses of serving those customers. This treatment would significantly address the problems Staff raised in its rebuttal with regard to the future need for an FAC "Reverse N Factor," and "N Factor."

5. The recommended 20% contribution to the overall cost of service sized off of the energy charges and other applicable charges through the Fixed Revenue Contribution Charges would remain. Some elements of Staff's recommended revenue treatments through regulatory assets would require modification, as detailed in the revised tariff, Schedule 1.

Staff has prepared revisions to its recommended tariff, attached as Schedule 1, to incorporate these concepts.

Q. Conceptually, how could this rate approach deal with the customer-oriented concerns in the Customer Capacity Rider (CCR) and the Clean Energy Choice Rider (CEC)?

A. If a customer chooses to participate in this pricing option, for a remotely-located energy resource, this treatment would align the energy pricing relationship of the resources, across the market, as adjusted for congestion and distance by the market. This could enable customers to match usage to distant resource output, in real time, to the extent the customer chooses for economic or social policy reasons. Staff continues to recommend the Commission reject both proposed riders CCR and CEC; however, Staff does not object to EMM or EMW entering reasonable PPAs[37] for output of customer-owned or customer-controlled generation. Essentially,

1. The customer will pay the required demand charges under the LLPS tariff based on the amount of capacity EMM or EMW must keep available for that customer under resource adequacy requirements,

2. EMM or EMW will pay the customer some capacity value for some capacity amount determined through prudent utility decision-making for that generation,

3. The customer uses the energy they want to use when they want to use it, which may or may not be influenced by what the resource is generating wherever it is located, and the wholesale market governs the treatment of each,

4. Other ratepayers receive the benefit of a 20% markup of the value of the energy the LLPS customer consumes, through the Fixed Revenue Contribution Charges so that the customer is making a contribution towards cost of service like Evergy's office buildings, and executive salaries, and

5. EMM and EMW may include specific terms in the PPA and/or customer agreement to satisfy the customers' or some third parties' standards related to claiming renewable energy usage, net zero compliance, etc., so long as such terms are otherwise prudent.

[37] Purchased Power Agreement (PPA).

Q. If a customer chooses to participate in this pricing option, conceptually, how could this rate approach deal with the customer-oriented concerns in the Demand Response & Local Generation Rider (DRLR)?

A. For a locally-sited energy resource, this treatment would align the energy pricing relationship of the resources with the LLPS customer's billing. This could enable customers choosing to meet energy needs with the local resource instead of the market energy availability.

For example, if a renewable resource is located behind the meter the customer is enabled to receive the full energy market value of that generated energy. If a diesel genset or other dispatchable generation is located behind the meter, it enables the customer to strategically participate in economic self-dispatch or demand response-type activities by receiving the full energy market value of that energy or offset to its energy requirements.

Staff continues to recommend the Commission reject the DRLR, however this rate option opens the door for a simple term in the LLPS tariff enabling behind-the-meter generation that otherwise complies with applicable law and regulation. Essentially,

1. The customer will pay the required demand charges under the LLPS tariff based on the amount of capacity EMM or EMW must keep available for that customer under resource adequacy requirements,
2. The customer uses the energy they want to use when they want to use it,
3. Other ratepayers receive the benefit of a 20% markup of the value of the energy the LLPS customer consumes through the Fixed Revenue Contribution Charge, so that the customer is making a contribution towards cost of service like Evergy's office buildings, and executive salaries, and

4. EMM and EMW may include specific terms in the PPA and/or customer agreement to satisfy the customers' or some third parties' standards related to claiming renewable energy usage, net zero compliance, etc., so long as such terms are otherwise prudent.

Q. Should capacity value be provided for local or remote customer-controlled generation, or should the otherwise applicable demand charges be reduced by offsetting the determinants used in billing?

A. The only way it would be could be reasonable to modify the otherwise applicable demand charges would be if the "firm" capacity of the customer was limited to the amount not subject to offset, and if EMM and EMW include hold-harmless requirements for captive ratepayers to curtail LLPS customer loads to that firm level when the peaks applicable to resource adequacy requirements could be set.

Q. Can you summarize the rates and rate treatments recommended by Staff?

A. Yes.

Charge	EMM Rates	EMW Rates	Determinant	Revenues Deferred Until Recognized in Rate Case - To be Ordered in this Case	Ongoing Revenue Deferral - To be Reflected in Tariff	Include in Revenue Contribution?	Include in Termination?
Customer Charge	$10,000	$10,000	$/Customer			Variable	
Facilities Charge	$ 0.0107	$ 0.0065	$/$ of Assets			Variable	Yes
Demand Charge 1 - Charge for Generation Capacity Cost of Service	$ 17.55	$ 8.16	$/kW during demand window	Yes	Yes	Stable	Yes
Demand Charge 2 - Charge for Transmission Capacity Cost of Service	$ 3.00	$ 5.81	$/kW during demand window	Yes		Stable	Yes
Energy Charge	$ 0.055	$ 0.053	$/kWh	Yes	Not if excluded from FAC	Variable	Yes
Alternative to Energy Charge	Execution of an Optional Agreement for Payment of Actual RTO Charges						
RES compliance charge	$ 0.00033	$ 0.00040	$/kWh		Yes	Variable	
Variable Fixed Revenue Contribution	24.77%	24.77%	Percent of other charges	Yes	Yes		Yes
Stable Fixed Revenue Contribution	24.77%	24.77%	Percent of other charges	Yes	Yes		Yes
Demand Deviation Charge	$8.9177	$8.9177	$/kW of deviation	Yes	Yes		
Imbalance Charge	$8.9177	$8.9177	$/kW of deviation	Yes	Yes		
EDI Responsibility Charge	$ -	$ -	$/kWh				
Capacity Shortfall Rate, if applicable	TBD	TBD	$/kW	Yes, if Applicable			
Capacity Cost Sufficiency Rider, if applicable	TBD	TBD	$/Month	Yes, if Applicable			
Reactive Demand Charge	$ 0.99294	$ 0.46000	$/kVar				

New Cost of Service Related to LLPS Customers

Q. In her surrebuttal, Staff expert Claire M. Eubanks, P.E. provides recommendations concerning Dr. Marke's rebuttal recommendations concerning additional studies and potential increases in costs of service that may be caused by LLPS customers. How should any increases in cost of service associated with Dr. Marke's recommendations be treated?

A. Staff recommends that any expenditures associated with Dr. Marke's recommendations be tracked for future recovery from LLPS customers.

Q. In general, how should this cost of service be recovered?

A. In general, cost of service related to studies and monitoring of LLPS load should be recovered through the LLPS customer charge. Cost of service related to power quality or related issues should be recovered through an appropriate determinant such as a separate NCP demand charge or potentially the reactive demand charge, depending on the causation.

Creation of LLPS Class

Q. In his rebuttal on page 10, Mr. Wills notes that in the pending Ameren Missouri ET-2025-0184 filing, Ameren Missouri chose to price service for Large Load Customers at the existing rates published in its Large Power Service Rate schedules. Dr. Berry, on behalf of Google testifies that "It would be prudent to wait until there are sufficient customers eligible to take service under the LLPS rates, and then determine the rates in a rate case under the accepted cost of service and rate-making methodologies."[38] What is Staff's response?

A. While generally Staff will address the Ameren Missouri rate structure in the Ameren Missouri docket, Dr. Berry frankly presents an idea that does merit some consideration

[38] Berry Rebuttal, page 49.

– that is – that LPS rates are not the destination, but a waypoint. Staff's recommended rate structure and rate design matches the sophistication of LLPS customers to the complexity of the cost of service these customers cause. Staff's recommended revenue treatment captures the revenue provided by these customers prior to recognition in a rate case as a tool to offset the long-term increases to the overall utility cost of service, both to work towards compliance with Section 393.130.7, RSMo., and also to reduce the significant long-term stranded asset risk that is introduced to captive rate payers by utility pursuit of very large customers. However, if for whatever reason, the Commission does not adopt this revenue retention approach, it could be reasonable to use the existing LPS rate schedule rates for service of LLPS customers until a rate case occurs to recognize these customers. This is not Staff's recommendation, but it is an acknowledgement that it is extraordinarily difficult to design reasonable rates for unknown customers with unknown characteristics, outside of a rate case with a fully developed cost of service calculation.

Q. If the Commission does order use of LPS rates as a waypoint to creation of an LLPS tariff in a future rate case, is there anything especially important to include in the Order?

A. Yes. All terms related to connecting a new customer and the prepayment of those facilities by the LLPS customer must be ordered in this case. Deferral of all LLPS revenues and direct expenses should also be ordered for consideration in a future rate cases. Subaccounts should be created to facilitate future treatment options for both capital and expense values. And the Commission should order that all load projections used, annual, monthly, hourly, and sub-hourly, be retained, as well as all actual load and demand data.

These requirements are particularly applicable to the development of charge components for transmission services and ancillary services, as the predictability and quality of load reporting result in the cost of service for those activities to range from $0.00 to millions of dollars per month. Many of these expenses will flow through the FAC and be socialized to all customers of EMM or EWM, respectively.

Applicability

Q. Google witness Dr. Berry acknowledges that it may be reasonable to include customers as small as 25 MW in the LLPS class in her rebuttal testimony at page 16, and discusses not changing requirements on existing customers through page 19. Is this consistent with Staff's recommendations?

A. Yes. Staff's recommended LLPS floor is 25 MW, and Staff's applicability language recommendations included a grandfathering clause to exempt existing customers served on other tariffs from the LLPS requirements.

Collateral and Termination

Q. DCC witness Shana Ramirez discusses at pages 21 - 22 of her rebuttal testimony possible collateral requirement calculation, including the inconsistency between the requirements described in Mr. Lutz's direct testimony, and in the tariff drafts attached to his direct testimony. Would either provision protect Missouri ratepayers?

A. No. Neither the two-year nor the three-year approach would meaningfully protect Missouri ratepayers. Rather, either approach would give EMM or EMW notice to file a rate case timed so that the revenue that is no longer recovered from an LLPS customer can be recovered from other captive Missouri ratepayers.

Q. Why wouldn't ratepayers be protected under either approach?

A. EMM or EMW will be building new power plants to serve LLPS customers, and EMM and EMW have discretion in rate case timing, including the timing of true-up cut offs.

It would be reasonable to expect that if EMM or EMW receive notice that a customer will terminate, that the respective utility will time its case so that the customer actually terminates just before the true-up cutoff of the case. The utility would then expect, and the Commission would likely order, the determinants and revenues in the case to be modified to exclude the terminating customer. This will result in captive ratepayers paying for the capacity that the LLPS customer will not be using, offset only by an amortization of the value of the termination fee. In other words, the utility would bear no risk and no financial harm from the LLPS customer's departure, while captive ratepayers pay for the capacity built to serve that LLPS customer.

Demand Provisions

Q. Google witness Dr. Berry testifies that,

> I recommend that the Commission approve a 70% minimum demand charge for the Demand Charge, Grid Charge, and Reactive Adjustment Charge. This is for several reasons: minimum demand charges will be applied to multiple kW charges, the risk of stranded costs are reduced given current and projected market conditions in SPP, the Company has not yet built capacity to service LLPS customers, and a 70% minimum demand charge more evenly balances the risks to the Company, LLPS customers, and other customers. Additionally, the company has not presented any cost-based evidence to support its proposed 80% minimum. Finally, a 70% minimum demand charge would preserve greater flexibility for LLPS customers to manage their demand and effectively participate in demand response, which can provide benefits for overall grid reliability and mitigate costs for all customers on the system.
>
> I additionally recommend that the Commission reject the Company's proposed minimum demand charges for the SSR and the Company Transmission Delivery Charge. These proposed charges were not included in the Company's initial filing preventing adequate review. Beyond this procedural flaw, and as I detail later in my testimony, I

> recommend the complete rejection of the SSR itself, which would inherently include any associated minimum demand charges.[39]

DCC witness Kevin C. Higgins testifies the LLPS minimum demand charge should be reduced to 70% of the contract capacity,[40] and that additional flexibility should be provided in reducing the contract capacity. [41]

Do these provisions protect ratepayers or the utility? [42]

A. These provisions work together so that the utility will get four years of at least 90% revenue from an LLPS customer before ratecase recognition, and an additional year of full revenues. Then, if a customer provides notice that it is going to reduce its capacity, the utility will request that reduction be normalized into the billing determinants and revenue calculation through a ratecase. The utility needs notice of that reduction to file a ratecase to recognize that reduction. Similar to the discussion of termination provisions, this term provides insulation against risk to Evergy, and minimal protection to captive ratepayers.

Q. Google witness Dr. Berry testifies that,

> The Company informed stakeholders through discovery that it planned to include these additional changes in the LLPS tariff. There has been no analysis provided by the Company regarding the need or impact of either a minimum SSR or Transmission Delivery Charge. Given that the Company added these requirements late in the process, providing no time for adequate review, I recommend that the Commission reject the Company's back-door proposal for a minimum SSR Charge and minimum Transmission Delivery Charge.[43]

How does Staff respond to the informal introduction of these charges, and to the concepts of the charges themselves?

[39] Berry Rebuttal, page 26.
[40] Higgins Rebuttal, pages 10 - 12.
[41] Higgins Rebuttal, pages 12 - 14.
[42] With regard to early termination fees, Dr. Marke recommends: "… that minimum charges include 90% of the contract capacity ..." Marke Rebuttal, page 16.
[43] Berry Rebuttal, page 22.

A. Staff has been generally troubled by the ongoing uncertainty around what Evergy actually intends for the tariffs at issue in this case to say, how customers will generally be treated, and how various provisions will ultimately interact. Conceptually, a well-designed transmission charge with a minimum demand is consistent with Staff's recommended rate structure. However, Staff does not know if the charges Evergy has conceptualized for EMM and EMW are or are not well-designed, and they are not actually before the Commission at this point. Conceptually, a minimum SSR charge could mitigate one aspect of Staff's concerns with the SSR, however, simply implementing a reasonable LLPS rate structure and rate design is Staff's preferred resolution.

Economic Development Discount Availability

Q. DCC witness Kevin C. Higgins testifies it would be preferable to disallow application of economic development discounts to LLPS customers rather than implement the cost recovery component of the SSR.[44] Do you agree?

A. Yes. Not only is this approach consistent with the existing MKT and SIL tariffs for EMW customers, it is also consistent with Staff's recommended treatment for Empire LLCS customers, and with Ameren Missouri's requested treatment for LLCS customers.[45]

Optional Riders

Q. Renew witness Ms. Sentell's rebuttal testimony states, "[n]ot only will CER help customers reach their own sustainability goals, it will also… help cover the costs of adding said sustainable generation to Evergy's grid."[46] Staff sent DR 140 asking in part:

[44] Higgins Rebuttal, page 15, and page 26.
[45] Wills Rebuttal, page 15.
[46] Sentell Rebuttal, PDF page 7.

> In reference to subpart 1 above, if a CER customer terminates service and cannot "cover the costs of adding said sustainable generation," does Ms. Polk have any concerns with the potential for non-CER customers covering the costs of the clean energy resources requested by the CER customer?

Ms. Sentell responded to DR 140 stating:

> I do not have concerns regarding CER customers terminating service and non-CER customers covering these costs as these terms should be included in the CER customers' contracts, which would be a standard business practice. As with any business agreement, it would logically be the case that such terms are included and agreed to before service commences. Furthermore, it is explicitly stated in the CER Tariff that: Should a Requesting Customer terminate its service at any point after the Company has executed a Clean Energy Preferred Resource Plan specific to the Requesting Customer and before the Cost Differential of the Clean Energy Preferred Resource Plan (or allocated portion) has been fully paid, the Requesting Customer shall be required to pay the outstanding Cost Differential as a single payment, and shall be subject to any additional terms and conditions set forth in a separate commercial agreement…

Staff sent Evergy DR 63 asking in part, "[i]f the customer does not pay the outstanding cost differential, will other customers have to bear the cost?" Evergy responded, "[i]t is difficult to say for certain given the range of possible remedies, but under extreme conditions, it is plausible that the cost differential could ultimately be recovered from other non-sponsoring customers."

How will customers bear the cost of resources added to meet the desires of an LLPS customer?

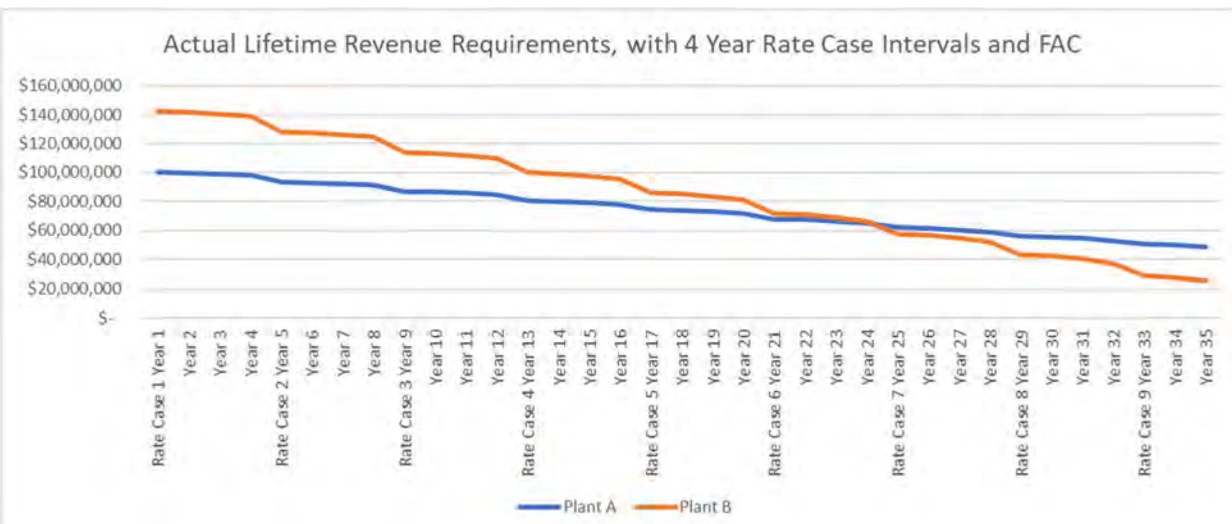
A. Evergy's use of differences in the Net Present Value of Revenue Requirement does not protect captive ratepayers, and ratepayers will bear the costs of resources added to meet the desires of an LLPS customer.

Q. How does use of NPVRR distort the actual harm to captive-ratepayers of the proposed CER or similar programs?

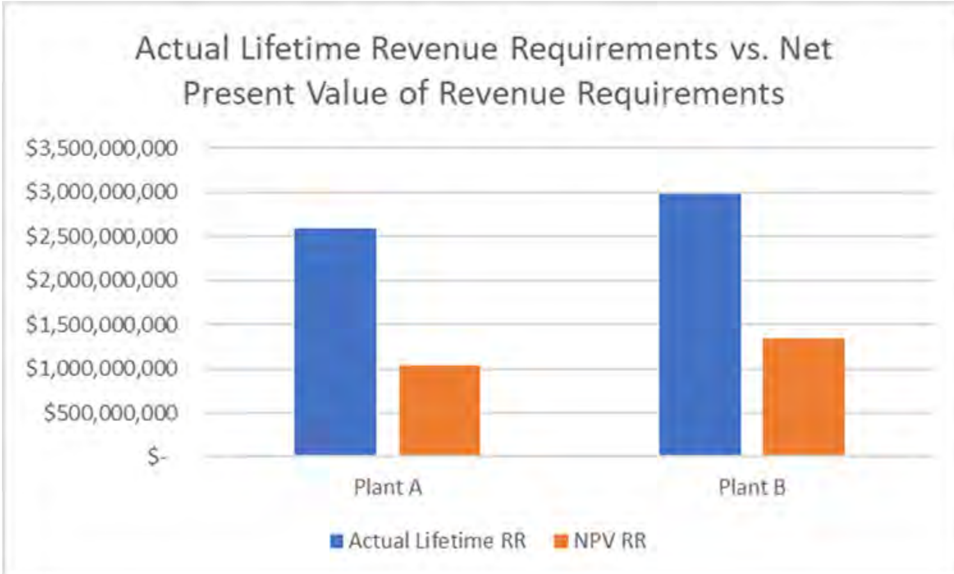
A. Using upfront payments from LLPS customers based on the NPVRR difference of alternative resource plans will not fairly compensate captive ratepayers for the long-terms change in resource plan.

As an illustration:

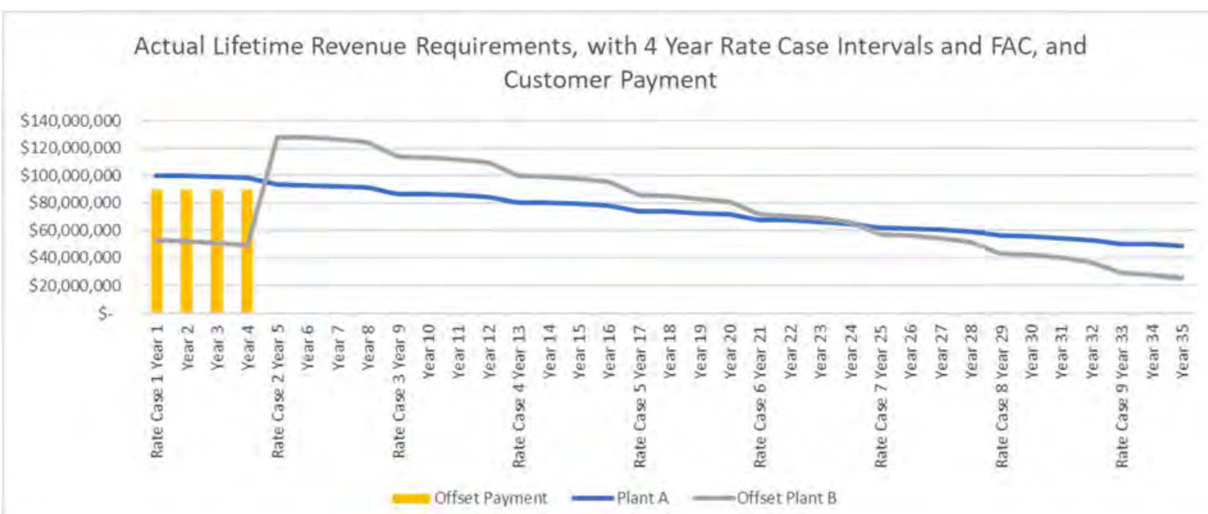
Assume EMW can build either a gas plant with an initial rate base value of $750 million and a starting revenue requirement of $100 million, or a solar plant with an initial rate base value of $1.3 billion and a starting revenue requirement of about $142 million. The actual stream of revenue requirements from Plant A, assuming 4 year rate case intervals, is about $2.6 billion. For Plant B, the equivalent amount is about $3 billion, a difference of $391 million.



However, the net present value of these differences would only be about $299.5 million, as Plant A has a NPVRR of $1.04 billion, and plant B has a NPVRR of about $1.34 billion.



If a LLPS customer who desired that Plant B be constructed instead of Plant A made four payments of $89,443,932 in each of the first four years of Plant B, then the NPVRR of Plant B minus the customer payments would exactly match the NPVRR of Plant A. However, looking at the stream of revenue requirements, the symmetry of the payments to ratepayers is doubtful:



For twenty of the thirty-five years, ratepayers would pay rates that are higher than they would pay with Plant A. Over the lifetime of the plant, ratepayers would pay $33.375 million more under the "Offset Plant B" scenario than the Plant A scenario, although the NPVRR of the two is identical. In other words, the Commission should not substitute an NPVRR analysis for its own good judgement.

Q. With regard to the Customer Capacity Rider, Google witness Dr. Berry testifies that "All contracting is subject to the Company's capacity need and at its complete discretion," and "No capacity from the customer-owned resource is assigned directly to the large load customer."[47] Do you agree with these concepts as applied?

A. No. In fact, the interaction of the proposed CCR and the LLPS billing determinants is one of Staff's concerns with the CCR. It is not reasonable to decrease what a LLPS customer is billed from its actual metered demands. The utility is still responsible to meet resource adequacy requirements for the total load, regardless of the performance of a particular resource.

<u>CONCLUSION</u>

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

[47] Berry Rebuttal, pages 42 - 43.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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 9th day of September 2025.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2029
Commission Number: 12412070

D. Suzie Mankin
Notary Public

Schedule LLPS

Customers eligible for service on the LLPS 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 Power, Special Rate for Incremental Load Service, or Special High-Load Factor Market Rate rate schedules prior to January 1, 2026, or any customer with an expected 15-minute customer Non-Coincident Peak (NCP) of 25 kW or greater at a contiguous site (whether served through one or multiple meters) shall be subject to this Schedule LLPS. [Note, for the EMM tariff, only the Large Power rate schedule reference is applicable.]

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, unless such customer is served on the Special Rate for Incremental Load Service or Special High-Load Factor Market Rate rate schedules, or (2) requires installation of facilities operating at transmission voltage to accommodate increases in its demand, EMM/EMW shall expeditiously work with such customer to execute a service agreement and fully comply with the provisions of this Schedule LLPS within 6 months of (1) the customer's notice that such customer's demand is expected to equal or exceed 29 MW or (2) EMM/EMW's determination that transmission facilities are required.

Other Tariff Applicability:

LLPS customers are required to participate in the following riders:
- Fuel Adjustment Clause
- Tax and License Rider
- Renewable Energy Standard Rate Adjustment Mechanism Rider. [EMW only]
- Securitized Utility Tariff Rider [EMW only]

LLPS customers are not eligible to participate in the following riders:
- Underutilized Infrastructure Rider
- Economic Development Rider
- Large Power Off-Peak Rider
- Limited Large Customer Economic Development Discount Rider
- Standby Service Rider
- Voluntary Load Reduction Rider
- Curtailable Demand Rider
- Demand Side Investment Mechanism Rider
- Market Based Demand Response

[This list prepared based on EMW tariff names]

Service Agreement:

The form of the application for LLPS 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 [EMM/EMW] 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 LLPS customer's load forecasting,
            2. Contact information for the person or persons responsible for executing curtailment of the LLPS 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 LLPS tariff. In the event that any additional termination provisions may be necessary or appropriate to address additional risk with a particular LLPS customer, those provisions shall be defined in the Service Agreement.
F. The minimum term of service for a customer qualifying for service under LLPS 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 LLPS customers.
J. [EMM/EMW] is prohibited from constructing interconnection facilities for any potential LLPS 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 RTO Charges:

The Service Agreement may include terms specifying that the LLPS customer agrees to pay all charges received by [EMM/EMW] for service at the LLPS 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 SPP's OATT, including administrative and transmission charges. However, these charges will not include any capacity auction charges or revenues.

[EMM/EMW] shall provide a copy of such charges to the LLPS customer no later than 1 business day after received by [EMM/EMW], including any revisions, rebills, or other modifications which may be presented by SPP to [EMM/EMW].

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 [EMM/EMW].

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	EMM Rates	EMW Rates	Determinant
Customer Charge	$10,000	$10,000	$/Customer
Facilities Charge	$ 0.0107	$ 0.0065	$/$ of Assets
Demand Charge 1 - Charge for Generation Capacity Cost of Service	$ 17.55	$ 8.16	$/kW during demand window
Demand Charge 2 - Charge for Transmission Capacity Cost of Service	$ 3.00	$ 5.81	$/kW during demand window
Energy Charge	$ 0.055	$ 0.053	$/kWh
Alternative to Energy Charge	Execution of an Optional Agreement for Payment of Actual RTO Charges		
RES compliance charge	$ 0.00033	$ 0.00040	$/kWh
Variable Fixed Revenue Contribution	24.77%	24.77%	Percent of other charges
Stable Fixed Revenue Contribution	24.77%	24.77%	Percent of other charges
Demand Deviation Charge	$8.9177	$8.9177	$/kW of deviation
Imbalance Charge	$8.9177	$8.9177	$/kW of deviation
EDI Responsibility Charge	$ -	$ -	$/kWh
Capacity Shortfall Rate, if applicable	TBD	TBD	$/kW
Capacity Cost Sufficiency Rider, if applicable	TBD	TBD	$/Month
Reactive Demand Charge	$ 0.99294	$ 0.46000	$/kVar

Treatment of LLPS 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 LLPS 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 LLPS 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 SPP 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 LLPS customer, revenue from these charges will be treated as ordinary revenue.

Early Termination:

In the event that an LLPS 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 LLPS 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 LLPS 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 [EMM/EMW] 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. LLPS customers shall be billed on a calendar month basis.
B. LLPS bills shall be rendered by the fifth business day of the following calendar month, except as otherwise specified in an Optional Agreement.
C. LLPS 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.
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 LLPS 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 [EMM/EMW]'s annual Missouri jurisdictional load.

J. Prior to execution of a Service Agreement with a prospective LLPS customer, [EMM/EMW] shall ensure that it has adequate capacity available for resource adequacy calculations to serve all existing customers and the prospective LLPS customer. In the event [EMM/EMW] executes a Service Agreement without adequate capacity, [EMM/EMW]'s existing customers shall be held harmless from any SPP 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 [EMM/EMW] does not have sufficient capacity to reliably serve a requesting LLPS customer and its other load in a given season of a given year of the anticipated Service term, [EMM/EMW] may obtain contractual capacity to reliable serve the requesting customer. [EMM/EMW] shall file an ET case and tariff with no less than 45 days effective date, and shall file testimony explaining the potential LLPS customer, that customer's energy and capacity needs, and the capacity arrangements applicable to reliably serving that customer. [EMM/EMW] may seek a protective order for portions of the testimony as appropriate, but any Capacity Cost Sufficiency Rider Rate to be charged to any LLPS 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.