Exhibit No.:	
Issue(s):	*Limited Large Customer Service Recommendation, Class Cost of Service, Rate Design*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2024-0261*
Date Testimony Prepared:	*July 21, 2025*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

SARAH L.K. LANGE

THE EMPIRE DISTRICT ELECTRIC COMPANY,
d/b/a Liberty

CASE NO. ER-2024-0261

Jefferson City, Missouri
July 2025

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Executive Summary

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, and my business address is 200 Madison Street, Jefferson City, Missouri 65101.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Public Service Commission ("Commission") as an Economist for the Tariff/Rate Design Department, in the Industry Analysis Division.

Q. Please describe your educational and work background.

A. Please see Schedule SLKL-d1.

Q. What is the purpose of your direct testimony?

A. I will present the results of Staff's class cost of service ("CCOS") study, and provide Staff's recommended implementation of effectuating an increase of Empire's[1] currently tariffed rates to collect $635,918,398 from its customers, an increase of $122,187,476 (23.78%%) from its current retail revenues of $513,730,922, including $384,359 for EDR[2] Factor-Up.

I will also provide

- Staff's recommendations for the large load tariff required under SB 4,
- An update on Empire's rate modernization process, recommended next steps, and recommended changes to demand charge determinants, and
- Staff's recommendation to freeze the Residential EV Pilot to new customers.

[1] The Empire District Electric Company, d/b/a Liberty ("Empire" or "Company").
[2] Economic Development, Rider ("EDR").

Class Cost of Service and Class Revenue Responsibility Summary

Q. What is a CCOS study?

A. A CCOS study compares the revenue that groups of customers provide against the total cost of providing service for a year, as assigned and allocated among those customers. For purposes of analyzing CCOS study results, the results are generally expressed by subtracting expenses from revenues, and calculating the rate of return provided by the remaining revenues. A CCOS study can be a useful tool in determining how rates should be designed at the conclusion of a general rate case.

Q. What cost studies has Staff performed for this case?

A. Staff has prepared a functionalized cost of service study, which categorizes the cost of service presented in Staff's direct-filed accounting schedules.[3] That study is discussed in the testimony of Marina Gonzales. Ms. Gonzales also discusses the level of revenue provided by each class through the rates published in that class's rate schedule, as well as other revenues provided by, allocated to, or allocated against each class. As community solar programs, economic development riders, and other discrete revenue sources have been added to utility tariffs, further clarification has become necessary.[4]

My testimony will discuss Staff's preparation of Staff's independently calculated distribution classification. Staff's recommended revenue responsibility shifts are based off of Staff's study using these classifiers, as applied to Staff's direct-filed accounting schedules.

[3] For example, Transmission, Distribution, Production (by sub-function), and Administrative & General.
[4] This distinction is important in that applying a seemingly equal-percentage adjustment to revenues which include additional revenues not subject to increase in a given case will not produce an equal-percentage increase to the rates in each class's rate schedules.

Staff has also prepared a comparison study using the distribution classification calculated by Empire, as applied to Staff's direct-filed accounting schedules. That study is discussed in the testimony of Dr. Hari K. Poudel, PhD.

Q. How does Staff recommend any rate increase in this case be allocated to the customer classes?

A. As discussed in the testimony of James A. Busch, given the circumstances surrounding this case and the roll out of Empire's "Customer First" billing system and software, Staff recommends that any increase be allocated to the classes on an equal percentage basis prior to consideration of Mr. Busch's recommended Customer First disallowance, and that the Customer First disallowance then be applied entirely to the residential class.[5]

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$ 248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Revenue Responsibility Adjusted for Customer First	$ 298,780,247	$ 78,067,727	$144,817,781	$ 13,523,818	$ 86,549,643	$ 5,948,851	$ 8,319,465
Increase	$ 50,056,393	$ 16,718,897	$ 31,014,014	$ 2,896,246	$ 18,535,374	$ 1,273,999	$ 1,781,687
Percent Increase to "Average" Customer Bill	20.13%	27.25%	27.25%	27.25%	27.25%	27.25%	27.25%

This approach can be taken by the Commission regardless of any class cost of service study results presented in this case.

Q. What are the results of Staff's CCOS Study?

A. Staff's CCOS study results, without reflecting the Customer First disallowance recommended by James A. Busch, are set out below:

[5] To the extent the disallowance exceeds the increase applicable to the Residential class, Residential rates should be held constant, with the remaining disallowance being applied against the increase applicable to the General Service class. The Customer First disallowances recommended by Matt Young and Melanie Marek would be spread to all customer classes.

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Required Revenue	$337,044,437	$ 69,899,603	$136,292,514	$ 11,943,112	$ 83,413,729	$ 6,230,146	$ 8,436,792
Study Results Increase to Adjustable Rates	$ 89,161,774	$ 8,758,256	$ 22,873,633	$ 1,215,759	$ 14,027,757	$ 1,571,104	$ 1,921,125
% Increase	36%	14%	20%	11%	21%	34%	29%
Equal Percent Increase	$ 67,553,443	$ 16,662,353	$ 30,909,123	$ 2,886,451	$ 18,472,687	$ 1,269,691	$ 1,775,662
Over/(Under) Contribution $	$ (20,767,141)	$ 8,111,580	$ 8,420,377	$ 1,570,911	$ 3,073,227	$ (285,603)	$ (123,352)
Over/(Under) Contribution %	-21.54%	41.51%	22.91%	49.22%	14.39%	-19.74%	-4.39%
5% Tolerance	$ 4,821,149	$ 977,046	$ 1,838,078	$ 159,584	$ 1,068,134	$ 72,336	$ 140,469

Q. What revenue responsibility does Staff recommend for each class if the recommendation above is not adopted?

A. Staff recommends that the Customer First disallowance be used to offset the otherwise applicable increase to residential customers. The average increase to the rates to be set in this case is 23.78%. Staff's CCOS results indicate that Lighting customers receive that system average increase, that Residential and Transmission customers receive an above-average increase, and that General Service ("GS"), Large General Service ("LGS"), Small Primary Service ("SPS"), and Large Power Service ("LPS")customers receive a below-average increase. Those calculations are summarized below:

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Required Revenue	$337,044,437	$ 69,899,603	$136,292,514	$ 11,943,112	$ 83,413,729	$ 6,230,146	$ 8,436,792
Revenue Responsibility Adjusted for Customer First	$315,570,519	$ 71,075,289	$139,206,022	$ 11,977,731	$ 83,592,758	$ 6,177,749	$ 8,318,331
Increase	$ 66,846,665	$ 9,726,459	$ 25,402,255	$ 1,350,158	$ 15,578,489	$ 1,502,897	$ 1,780,553
Percent Increase to "Average" Customer Bill	26.88%	15.85%	22.32%	12.70%	22.90%	32.15%	27.23%

However, the following factors are relevant to the Commission's determination of how to implement any rate increase ordered in this case:

1. The distribution treatment in Staff's CCOS shifts cost responsibility toward residential and small customer classes and away from larger classes (as discussed in detail in the respective sections).
2. The production allocation is not Staff's recently-recommended approach, and it tends to overallocate cost responsibility toward residential and small customer

classes and away from larger classes (as discussed in detail in the respective sections), but Staff has used it in this case because:

a. Concerns with the billing issue undermine Staff's preferred approach, and

b. To minimize disputes in this already very complex case.

3. A CCOS is a guide, not a precise answer, and

4. Most importantly, policy considerations such as affordability, rate shock, etc., are well within the Commission's discretion and should be the final and conclusive factor in its ordered rate design. Therefore, Staff recommends that the Commission consider Staff's indicated residential class increase as the absolute ceiling in issuing its ordered rate increase implementation.

Rate Design Summary

Q. What are Staff's residential rate design recommendations?

A. As discussed by Dr. Poudel, Staff calculated the cost of service for the residential customer charge as between approximately $9.61 and $10.61 per customer per month. This value reflects the disallowances recommended by Staff witnesses Matthew R. Young and Melanie Marek. However, reducing the customer charge while increasing rates considerably will exacerbate rate shock. To mitigate rate shock, Staff recommends retaining the existing customer charge, or increasing the customer charge by the overall percentage increase applicable to the residential class.

Staff recommends equal percentage increases to the residential energy charges, and retention of the current level of the Off-Peak kWh credit rate.

Q. What does Staff recommend concerning non-residential rates?

A. Ms. Gonzales recommends equal percentage increases to each rate element within each class, except as discussed below concerning restructuring of demand charges.

I will discuss Staff's recommendation to restructure the demand charges (other than facilities demand) for all non-residential rate schedules from a customer non-coincident peak determinant to use of a time-based determinant in this case. I will also discuss rate modernization recommendations for non-residential customers for future cases.

Other Recommendations

Q. What other specific recommendations do you make in this testimony?

A. I recommend creation of a new rate schedule, "Large Load Customer Service." I also I recommend:

-continued progress on modernization of Empire's non-residential rate schedules;

-appropriate monitoring related to reactive demand determinants and rates;

-that Empire review its billing system capabilities and determine whether it anticipates any challenges in modifying its rates to explicitly bill customers served at a different voltage from what is typical for a rate schedule,

-elimination of the Optional Time of Use Adjustment, as there are currently no customers participating in this tariff, and rate modernization will be a better avenue for potential customers; and

-Freezing Empire's Residential EV Charger Pilot program.

<u>393.130.7 Tariffs for Large Load Customers</u>

Q. Will SB 4 be in effect when rates ordered in this case become effective?

A. Yes. SB 4 will become effective on August 28, 2025.

Q. What will Section 393.130.7 require as of August 28, 2025?

A. Section 393.130.7 is a subsection added by SB 4 and will require Empire to develop tariffs applicable to customers with peak demand of 50 MW or more, with rates that "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." The Commission may also order similar tariffs applicable to customers with a peak demand of less than 50 MW.[6]

Q. Has Staff prepared a tariff intended to effectuate this language?

A. Yes. Staff has prepared a rate schedule, Large Load Customer Service ("LLCS"), based on industry best practice and its review of the risks, costs, and expenses associated with service to customers in excess of 25 MW. The draft tariff is attached as Schedule SLKL-d2, and is described in more detail below. In general, Staff's approach is to thread the needle of setting just and reasonable rates for these customers who are significantly different than Empire's existing customers and which will cause significant risks for future excess capacity.

Staff has developed this recommended rate structure by identifying the cost of service which will vary with the addition of an LLCS customer, and identifying the determinant that causes variation in the cost of service. Rate structure is typically a balance between customer understandability, ease of administration, and the alignment of cost/expense recovery with cost/expense causation. However, LLCS customers are sophisticated customers who can tolerate and understand the more complex billing structure which enables greater transparency.

[6] Section 393.130.7 provides:

> Each electrical corporation providing electric service to more than two hundred fifty thousand customers shall develop and submit to the commission schedules to include in the electrical corporation's service tariff applicable to customers who are reasonably projected to have above an annual peak demand of one hundred megawatts or more. 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. Each electrical corporation providing electric service to two hundred fifty thousand or fewer customers as of January 1, 2025, shall develop and submit to the commission such schedules applicable to customers who are reasonably projected to have above an annual peak demand of fifty megawatts or more. The commission may order electrical corporations to submit similar tariffs to reasonably ensure that the rates of customers who are reasonably projected to have annual peak demands below the above-referenced levels 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.

This increased transparency facilitates compliance with the statutory requirement that these customers be billed rates that "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,"[7] and also provides for cleaner calculations of rates in future rate cases.

Under Staff's recommended structure and design, the LLCS rate will be set to essentially the floor for economic development recipients established by Section 393.1640, RSMo in that LLCS rates will be set to collect 120% of the cost of service that varies with the addition of a new LLCS customer. The intent of this provision is so that LLCS customers contribute toward the "fixed costs," within the Empire revenue requirements.[8] While analysts will disagree on how to most reasonably recover this revenue requirement in a given case, there is no dispute that all customers will bear some portion of this revenue requirement. Staff's recommended LLCS rate schedule and design attempts to quantify the revenue requirement components that will vary due to LLCS customers and to separately bill for each component. The recommended rate structure then incorporates a charge element to recover 20% of those variable bill charges, so that LLCS customers contribute to the "fixed cost" recovery of the utility.

Q. What are the general components of Staff's recommended rate structure?

A. Staff's recommended tariff sets out:

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[7] Section 393.130.7, RSMo.

[8] "Fixed cost" is an often used, but not particularly useful, term. The initial screen for identifying a "fixed cost" would be to consider any revenue requirement component that does not vary directly with changes in the utility's overall load, overall demand, or overall number of customers to not be "fixed," with those remaining revenue requirement components – such as computer systems, computer software, office buildings, office furniture, management employees, investor relations costs and expenses, other overheads, and the revenue requirement associated with policy-driven activities, such as solar rebates, electric vehicle charging stations, and supports for low-income rate payers. These revenue requirement components do not relate to the often-referenced utility functions of "production/generation,", "transmission," or "distribution," but are to be recovered by the utility from its ratepayers.

1. Applicability requirements,
2. Interconnection and facility extension requirements,
3. Requirements for a Service Agreement with commitments to facilitate Empire's obligations as a Load Serving Entity,
4. A transparent rate structure with the following charges:

Charge	Rate	Determinant for Charge
Customer Charge	$ 10,000	$/Customer
Facilities Charge	$ 0.03148	$/$ of Assets
Demand Charge 1 - Charge for Generation Capacity Cost of Service	$ 22.04	$/kW during demand window
Demand Charge 2 - Charge for Transmission Capacity Cost of Service	$ 5.52	$/kW during demand window
Energy Charges		
Summer Off Peak	$ 0.0210	$/kWh
Summer Intermediate	$ 0.0313	$/kWh
Summer On Peak	$ 0.0460	$/kWh
Fall Off Peak	$ 0.0204	$/kWh
Fall Intermediate	$ 0.0342	$/kWh
Fall On Peak	$ 0.0540	$/kWh
Winter Off Peak	$ 0.0286	$/kWh
Winter Intermediate	$ 0.0339	$/kWh
Winter On Peak	$ 0.0372	$/kWh
Spring Off Peak	$ 0.0165	$/kWh
Spring Intermediate	$ 0.0300	$/kWh
Spring On Peak	$ 0.0492	$/kWh
Load-servicing charge (Summer)	$ 0.0020	$/kWh
Load-servicing charge (Non-Summer)	$ 0.0010	$/kWh
RES compliance charge	$ 0.0004	$/kWh
Variable Fixed Revenue Contribution	24.36%	Percent of other charges
Stable Fixed Revenue Contribution	24.36%	Percent of other charges
Demand Deviation Charge	$ 107.02000	$/kw deviation (more than =/- 5%)
	$ 8.91770	$/kw deviation (less than =/- 5%)
Imbalance Charge	$ 8.91770	$/kW of deviation
EDD Responsibility Charge		$/kWh
Capacity Shortfall Rate, if applicable		$/kW
Capacity Cost Sufficiency Rider, if applicable		$/Month
Reactive Demand Charge		$/kVar

5. Revenue treatment recommendations to promote the statutory requirement that the LLCS customer pay rates that reflect their representative share of the costs incurred to serve LLCS customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLCS customers.

6. Termination charges to promote the statutory requirement that the LLCS customer pay rates that reflect their representative share of the costs incurred to serve LLCS customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLCS customers, and

7. Other strategies to mitigate the risks of unreasonable rate increases to non-LLCS customers caused by Empire's managerial decisions related to LLCS customers.

Q. Is Staff imputing revenues into this case for LLCS customers?

A. No. Staff has not imputed revenues in this case. Because revenues are not imputed, if and when Empire begins serving a LLCS customer, it will begin overearning, absent reasonable accounting treatment. This is because the energy expense for a LLCS customer will be recovered through the FAC[9], and Empire's rates to other customer classes are already designed to recover Empire's full cost of service. Staff's recommended LLCS tariff includes provisions for revenues not offset by direct changes in Empire's cost of service between rate cases to be recorded to regulatory liability accounts. This approach does not harm Empire or the LLCS customers, but does prevent unreasonable profiting. This approach also works to reduce the risks for non-LLCS customers, in that the liabilities are used to offset the increased production ratebase which will be caused by the significant load growth associated with LLCS customers.

[9] Fuel Adjustment Clause ("FAC").

Changes to Be Made to Other Empire Tariff Provisions

Q. What other tariff changes are necessary?

A. Other areas of the tariff will require modification to refer LLCS customers to the LLCS tariff for differing treatment, including:

1. The Empire line extension tariff should include a statement that the provisions of that tariff do not apply to LLCS customers, and the Transmission Extension provisions of the LLCS tariff govern.

2. The Emergency Conservation Procedures tariff should include a statement that LLCS customers are not considered critical services, and that they are subject to curtailment pursuant to the provisions of the Emergency Conservation Procedures tariff.

3. As addressed in greater detail below, and in the CCOS/RD testimony of Brooke Mastrogiannis, it will be necessary to modify the Empire FAC to prevent unreasonable results associated with the addition or cessation of LLCS customers.

Q. Is Staff proposing tariff changes or riders to enable LLCS customers to influence Empire's resource planning or to offset some level of usage or demand with energy from selected resources, or any other type of renewable attributes program?

A. No. While Staff appreciates that some entities who would consider Empire's service territory for service under the LLCS tariff may have a desire to change Empire's generation fleet directly or indirectly, Staff cannot recommend that a customer's Environmental, Social, and Governance ("ESG") goals substitute in whole or in part for Empire's prudent production fleet planning, or for the Commission's role in approving Empire's prudent production fleet planning contemplated in the provisions of SB 4 related to integrated resource planning.

Q. Does anything prohibit a customer of Empire from seeking out contracts with an independent power producer, or even owning its own generation in the Southwest Power Pool ("SPP") or any other market?

A. No.

Q. Should demand response options be incorporated into the LLCS tariff?

A. At this time, Staff does not recommend that the LLCS tariff incorporate demand response provisions. While in the future a reliable approach to demand response may be developed for customers of this size, at this time, Staff recommends that curtailments and interruptions to LLCS customers be addressed, to the extent necessary for reliability and safety, through Empire's Emergency Conservation Procedures.

Applicability Provisions

Q. What does Staff recommend for the Applicability section of Empire's LLCS tariff?

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A. Staff's recommended provisions are:

> **Applicability:**
> Any customer taking service at 34 kV or greater except those served under the Small Primary rate schedule, Large Power rate schedule, or the Transmission Service rate schedule 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 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, Empire 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) Empire's determination that transmission facilities are required.
>
> **Customers eligible for service on the LLCS rate schedule are required to take service on this rate schedule.**
>
> **Other Tariff Applicability:**
> Customers taking service under Schedule LLCS are not eligible for participation in:
> 1. Interruptible Service, Rider IR
> 2. Optional Time of Use Adjustment, Rider OTOU
> 3. Economic Development, Rider EDR
> 4. Limited Large Customer Economic Development, Rider SBEDR
>
> **Customers taking service under Schedule LLCS are required to take service under:**
> 1. Fuel Adjustment Clause, Rider FAC
> 2. Securitized Utility Tariff Charge, Rider SUTC
> 3. Charges pursuant to any authorized program under the authority of the Missouri Energy Efficiency Investment Act.

Q. Why is 25 MW a reasonable floor for the LLCS tariff?

A. In response to discovery in the Evergy LLPS case, File No. EO-2025-0154, Staff learned that 25 MW is an industry standard demarcation for customers that must practically be served at transmission voltage. This is consistent with trends that Staff has observed in utility infrastructure. This is also larger than any customer Empire has ever had, and is generally consistent with the demand of a customer for whom a utility would seek a special contract or develop a tariff with that particular customer in mind.

While SB 4 establishes a floor of 50 MW for Empire's large load customer class, it includes the option for the Commission to set a lower floor. Recently, SPP has defined "High Impact Large Loads," as "Any commercial or industrial individual load facility or aggregation of load facilities at a single site connected through one or more shared points of interconnection or points of delivery that can pose reliability risks to the grid. HILLs are deemed Non-Conforming Loads. A load may be considered a HILL if the point of interconnection kV level is:

69 kV or below and the HILL peak demand is 10 MW or greater

Greater than 69 kV and the HILL peak demand is 50 MW or greater"[10]

Under SPP's tariff, Non-Conforming Loads require additional compliance and forecasting obligations of the associated retail utility.

Q. Why should LLCS customers be ineligible for participation in economic development discount riders?

A. Consistent with the request of Ameren Missouri in EA-2025-0238, Staff recommends that the Commission exercise the discretion it is afforded under Section 393.1640 to exempt LLCS customers from the availability of economic development discounts.[11] If LLCS rates are set to meet the statutory requirement that LLCS rates be set to

[10] Southwest Power Pool, Large Load Stakeholder Engagement Forum at Slide 22, July 1, 2025, available at https://spp.org/Documents/74189/Large%20Load%20Stakeholder%20Engagement%20Forum%20Meeting%20Materials%2020250701.zip .

[11] For example, Section 393.1640 provides in part, "[u]nless otherwise provided for by the electrical corporation's tariff, the applicable discount shall be a percentage applied to all base-rate components of the bill," and "[t]he electrical corporation may include in its tariff additional or alternative terms and conditions to a customer's utilization of the discount, subject to approval of such terms and conditions by the commission."

"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," then it is not reasonable to immediately reduce those rates by 40%, or other customer classes' rates will necessarily reflect unjust and unreasonable costs caused by LLCS customers. This is because the statutory economic development discount – once recognized in a rate case – does not reduce utility revenue. Rather, the revenue not paid by customers receiving a discount is added to the revenue requirement of all customers.

Complicating any potential application of the statutory economic development discount to LLCS customers is that Section 393.1640 is also clear that the customer receiving the discount must meet variable costs and provide a contribution to fixed costs, specifying, "the cents-per-kilowatt-hour realization resulting from application of any discounted rates as calculated shall be higher than the electrical corporation's variable cost to serve such incremental demand and the applicable discounted rate also shall make a positive contribution to fixed costs associated with service to such incremental demand. If in a subsequent general rate proceeding the commission determines that application of a discounted rate is not adequate to cover the electrical corporation's variable cost to serve the accounts in question and provide a positive contribution to fixed costs then the commission shall increase the rate for those accounts prospectively to the extent necessary to do so." In other words, if the LLCS rate is set appropriately, then a customer's bill is reduced by the economic development discount, the discount would be unreasonably paid for by other customers (in contravention of SB 4), and then in the next case the LLCS rates would be raised to make up for the discount. This result is impractical, unreasonable, illegal, and unnecessary.

Interconnection and Facility Extension

Q. What are the appropriate requirements for LLCS customer requests for interconnection akin to line extension requests for smaller customers?

A. Staff recommends that the LLCS tariff specify the following with regard to the requirement of prepayment of the costs of interconnection and facility extension:

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 Empire, 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 Empire, 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 Empire, but for which Empire 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, Empire 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.

Q. Why is this treatment appropriate?

A. Customers taking service at 25 MW and/or at transmission voltage will require interconnection facilities in the tens of millions of dollars. If treatment other than that recommended by Staff is adopted, and if an LLCS customer does not take service for the full expected term with adequate rates, other customers will bear unreasonable costs associated with service of LLCS customers.

Service Agreement and Description of Expected Demands and Loads

Q. What are appropriate requirements for inclusion in the required LLCS Service Agreement?

A. Staff's recommended tariff provisions are:

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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. 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,
   e. A commitment to notify Empire of any anticipated deviations of +/-10% or more of previously-anticipated load as soon as such potential deviations become anticipated;
   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.
C. A pledge of collateral or other security as ordered by the Commission in this proceeding, which shall equal or exceed the indicated termination fees.
D. 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.
E. 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.
F. Details pertinent to calculation and verification of rates for the Capacity Cost Sufficiency Rider, if applicable.

Q. Why is it necessary for Empire to have accurate day-to-day load forecasts from LLCS customers?

A. SPP requires day-to-day load forecasts for each non-conforming load. Even if a given LLCS customer were not to be determined by SPP to be a non-conforming load, accurate daily load forecasts are necessary to mitigate real time market exposure in the SPP Day 1 marketplace. While there may be an implicit assumption that LLCS load will be steady and come with a high load factor, this is not a justified assumption and is contrary to Staff's expectations. Data center loads can be quite weather sensitive in climates such as Missouri in that cooling can be a major end use due to the waste heat produced by computing equipment. Customer use cases and managerial decisions can also drive inconsistencies in the day-to-day energy consumption of data centers. It is Staff's experience that while certain manufacturing or metallurgical processes result in a very high load factor (90%+), others can be very poor load factor, and can have dramatic swings in the energy consumed hour-to-hour over the course of a day. For example, electric arc furnaces can be turned on or off as needed to match the availability of applicable raw material, or to coincide with demand through a just in time approach. This modern dispatchable smelting technology is in contrast to blast furnaces or pot lines which require constant and consistent energy. Staff is also aware of other use cases which may result in week-to-week or seasonal swings in the customer's demand or required energy level. For example, just in time manufacturing may involve temporary layoffs of a given manufacturing shift, or national and international companies may shift production or processing among various locations.

Staff's assessment of day-to-day variability in energy requirements is not intended as a qualitative judgement, rather, it is to emphasize the potential for variability in energy requirements, which drives exposure to the SPP Day 2 market. This is because Load Responsible Entities such as Empire are required to provide forecasted load for the next day to the SPP so that the SPP can efficiently dispatch resources to meet that aggregated load. Tight coordination between the LLCS customer and utility personnel can mitigate this exposure through simply relaying that an evening shift is being suspended, a batch of metal will be smelted at 4:00 pm instead of the normal 2:00 pm, or that 5 MW of HVAC equipment will be expected to kick on to maintain appropriate temperatures in a server building.

Q. Why is it necessary for Empire to have accurate long term and mid term load forecasts from LLCS customers?

A. Given the size of potential LLCS customers relative to current customers and the headroom in Empire's capacity positions, it is important to have reasonable expectations of the energy and capacity requirements of an LLCS customer over the expected duration of that customer's service requirements. Given the need for Empire to comply with current and potential future resource adequacy requirements, it is important for the utility to have reasonably accurate demand forecasts for purposes of satisfying resource adequacy requirements. Overestimated demand will result in harm to customers due to over-procurement of capacity, and SPP will assess penalties for inadequate capacity relative to load.

Regarding the requirements in items 1, 3, 4, 5, and 6 of the Staff recommended service agreement, it is anticipated that Empire will have to build or otherwise acquire capacity to serve LLCS customers. Generally, production assets have lives measured in decades, with revenue requirement impacts to match. While the details of Staff's recommended termination provisions will be discussed below, the risk of underutilized generation assets or long-lived contractual capacity arrangements exceeding the service requirement of an LLCS customer falls on captive ratepayers.[12]

[12] Staff is not opposed to development of a reasonable risk-sharing arrangement so that shareholders bear some or all of the long-term risk of underutilized assets.

Q. Is it appropriate to assign the costs of meeting immediate LLCS capacity needs to a given LLCS customer?

A. Yes. Staff recommends that in the event that Empire requires capacity arrangements to serve LLCS load, Empire should seek to expeditiously promulgate a tariff so that those additional expenses can be appropriately recovered from the LLCS customer causing the need for additional capacity. Staff's recommended tariff language is provided below:

Capacity Cost Sufficiency Rider: In the event that Empire 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, Empire may obtain contractual capacity to reliably serve the requesting customer. Empire 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. Empire 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.

Recommended Rate Elements and Derivations

Q. What is Staff's recommended Customer Charge for LLCS customers?

A. While it is Staff's understanding that Empire does have employees who are available to discuss large load customer service with large load customers, Empire currently does not have dedicated staff to interface with customers for load forecasting to the SPP or otherwise to attract or service LLCS customers. Further, Empire does not currently have LLCS customers, and necessarily does not incur charges for metering or billing those customers.

For purposes of setting rates in this case, Staff can offer an informed estimate of approximately one full-time employee being required per customer. Staff expects that one forecasting employee will likely interface with up to three LLCS customers, and that one customer-service oriented employee will likely interface with up to five LLCS customers, once multiple LLCS customers are served. Using these assumptions and round numbers, for purposes of setting an initial rate, Staff recommends the LLCS customer charge be initially set at $10,000 per customer per month.

Q. What is Staff's recommended Facilities Charge for LLCS customers?

A. Although under Staff's recommended LLCS approach, LLCS customers will prepay the capital cost of interconnection facilities, it is appropriate to include a charge to recover the ongoing Operations & Maintenance ("O&M") expenses, insurance expense, and property taxes associated with LLCS infrastructure that is reflected in the Empire revenue requirement.

Different LLCS customers will require different demand-carrying capabilities of infrastructure, but there may also be significant differences in the length of required conductors and the number and size of required transmission poles. For example, more assets may be required to serve a 100 MW customer who locates 10 miles from an adequate transmission line and requires crossing bodies of water or difficult topography than a 500 MW customer who locates adjacent to an existing transmission substation with adequate capacity. The expenses described above will vary more directly relative to the dollars of assets required by each customer than the demand of either customer.

Therefore, Staff recommends the Facilities Charge be charged based on the dollar value of customer-specific infrastructure. This value will be specified in the Service Agreement.

The rate will be set based on the proportion of those transmission expenses for Empire as a whole to its gross transmission plant. Staff does not intend to require individual tracking of these expenses per customer, rather the rates will be set based on the total applicable expenses for all transmission assets, divided by the total transmission plant for each utility, divided by 12.

A simple example would be if a utility had $100,000,000 in transmission assets and the annual property tax, insurance, and O&M expense for those assets was $10,000,000, then the facilities charge rate would be $0.0083/$ of Assets.[13] Under this design, if a new LLCS customer required construction of a $10,000,000 transmission asset, then that customer would be required to pay $83,333 per month to cover the expenses associated with owning and operating a transmission asset of that value. If a different customer required construction of a $5,000,0000 transmission asset, then that customer would be required to pay $41,667 per month.

Staff estimates reasonable rates for the Facilities Charge at this time to be $0.03148 $/$ of Assets. For an LLCS customer requiring $30,000,000 of infrastructure, this charge would produce about $11.3 million in annual revenue.

Billing Demand Charges

Q. How does Staff recommend LLCS customers be billed for their demand requirements?

A. In the interest of transparency, and to accurately apply charges to appropriate determinants and deviations from expectations, Staff recommends several separate demand charges. The monthly charges which would apply to each customer each month would recover

[13] $10,000,000 in expense divided by $100,000,000 in ratebase = $0.10. $0.10 / 12 months = $0.083.

the cost of service associated with generation capacity and transmission capacity. Additional charges should be developed to accommodate differences in the initially-forecast demands and the current-year updated forecast, and for differences in the current-year updated forecast demands, and the actual experienced demands. Staff also recommends a separate charge be included (at an initial rate of $0.00) for the potential recovery of revenue associated with any SPP action through which Empire ratepayers become responsible for payments associated with capacity shortfalls. The demand charges related to demand differences are discussed in the concurrently filed testimony of J Luebbert.

Charge for Generation Capacity Cost of Service

Q. What are reasonable approaches to pricing the cost of service of generation capacity for LLCS customers?

A. Staff considered the theoretical reasonableness of several bases for deriving a reasonable rate for the generation capacity requirements of LLCS customers.

Reasonable bases include:

1. The entire revenue requirement of the most recent generation asset addition, divided by the estimated LLCS demand determinant. For example, if a new 500 MW Combined Cycle gas unit has a first-year revenue requirement of $170,000,000; and if there is 300 MW of LLCS load, then the rate per kW of LLCS demand each month would be $47.22.
2. The portion of the revenue requirement of the most recent generation asset addition, prorated by total estimate LLCS demand determinants, plus a reserve margin. For example, if a new 500 MW Combined Cycle gas unit has a first-year revenue requirement of $170,000,000; and if there is 300 MW of LLCS load, then accounting for a 10% reserve margin, the LLCS load should be responsible for 67% of the plant's revenue requirement – which would be $112,200,000. Using this approach, the rate per kW of LLCS demand each month would be $31.17.
3. A Cost of New Entry ("CONE") calculation, on a kW-Month basis; the current SPP CONE calculation $85.61 /kw-year or $7.13 per kW-month, which would yield a rate of $8.20/kW, accounting for a reasonable reserve requirement estimate.

4. The cost of owning and operating the actual generation fleets of Empire, excluding the cost of fuel and fuel-related operating expenses, divided by the capacity requirements of existing ratepayers.

Q. What concerns does Staff have with potential pricing of generation capacity cost of service for potential LLCS customers in this case?

A. Staff determined that it would be unreasonable to offset the cost of owning and operating current generation fleets with revenues currently produced through the operation of those fleets, and that any approach which did so would fail to comply with SB 4.[14] The existing Large Power Service rates, under which the net revenues associated with energy sales are netted against the gross cost of service otherwise calculated for each class, would therefore not be an appropriate starting point for LLCS rates.[15]

Q. What is the difference between the gross cost of generation capacity and the net cost of generation capacity?

A. The difference between the gross and net costs of generation capacity are the revenues obtained by selling generated energy into the wholesale capacity market. In a given rate case, the net expense or revenue associated with fuel to generate energy, energy market revenues from the utility's generation, and the expense of wholesale energy to serve load are typically netted for resolution of revenue requirement issues and for setting the FAC base. However, increasing load will increase wholesale energy market expenses. Since the net effect

[14] While it could be reasonable and compliant with SB 4 to develop an LLCS rate that allocates the full revenue responsibility for new generation facilities prompted by load growth and that rate could be reasonably offset by the net revenues associated with those new generation facilities, this approach would be difficult and potentially impossible to administer over time.

[15] While in rate cases parties disagree about the appropriate allocation of generation revenue among customer classes, both parties' allocation approaches allocate generation revenue to the Large Power Service class which reduces the otherwise-applicable revenue requirement for that class.

of adding significant load is increasing the net expense or reducing the net revenue, it is not reasonable to allocate the revenue to the customer causing the revenue reduction.[16]

Q. Did Staff consider tying the revenue requirement for generation plant built to serve LLCS customers to the LLCS cost of service?

A. Yes. While it is reasonable and could be compliant with SB 4 to develop an LLCS rate that allocates the full revenue responsibility for new generation facilities prompted by load growth and that rate could be reasonably offset by the net revenues associated with those new generation facilities, this approach would be difficult and potentially impossible to administer over time. Because a customer of the size that is subject to the LLCS tariff could necessitate the addition of an entire new power plant, or a significant portion of a new large power plant, it could be reasonable to allocate the cost of that plant (net of the revenues produced by that plant) to the LLCS customer(s). However, as plants are built and retired over time, and as other customer classes grow and contract over time, it would be difficult-to-impossible to track where revenue responsibility for a given plant should appropriately lie. Further, at this time, generally, a simple cycle natural gas combustion turbine would be the least costly means of meeting additional capacity requirements caused by an LLCS customer; however, overall system needs should dictate the appropriate plant addition which may be a combined cycle or other more expensive capacity.

Q. How did Staff calculate its recommended generation capacity demand rate?

[16] Staff does not allocate fuel or net market expense to the LLCS class in its demand charge quantification. Staff does recommend that LLCS customers be billed an energy charge based on the wholesale cost of energy to serve LLCS customers.

A. Staff calculated the recommended generation capacity demand rate based on the production cost of service, excluding fuel and variable labor, and without allocated overheads, divided by Empire's summer coincident peak demand determinates.

	Generation Demand
Plant	$ 1,638,195,110
Reserve	$ 436,514,372
Adjustments	$ 18,045,325
Ratebase	$ 1,219,726,063
Return on Ratebase	$ 85,673,559
Depreciation	$ 51,317,964
Expenses	$ 70,174,551
Revenues	$ -
Income Tax	$ 18,670,697
Cost of Service	$ 225,836,770
Annual kW at CP	10,245,506
Rate	$ 22.04

This charge should be expected to increase in any rate case in which Empire incorporates new generation. Empire's current net rate base is approximately $1.2 billion, and expected revenue requirement for additional generation is in the range of $25 – $35 or more per kW-month. If Empire essentially doubles its current generation ratebase through the addition of new generation, the associated rate increases will affect both LLCS and non-LLCS customers.

Charge for Transmission Capacity Cost of Service

Q. What should the Transmission Capacity Charge recover?

A. The intent of this charge is to recover the net cost of service for transmission for all customers, including the LLCS customer. While the LLCS customers will each have some level of customer-specific transmission facilities, and additionally cause specific transmission expenses, these customers will also rely on the interconnected transmission system and should contribute towards the cost of service associated with building, owning, and operating transmission lines, and with the RTO[17]-related costs of participating in the shared transmission system. Because Empire builds transmission not only to serve its own load, but also through participation in the RTO, it is reasonable to offset the Transmission Capacity cost of service by those revenues. In future general rate cases, the LLCS allocation of these costs will ideally calculated through the CCOS study. Historically, transmission costs, revenues, and expenses have been allocated using the 12 monthly CPs. In this case, Staff bases the initial charge development using the summer utility CP, resulting in a rate of $5.52 $/kW.

Energy Charges

Q. How should LLCS energy charges be structured?

A. In the interest of transparency, Staff recommends discrete charges for day-ahead energy and for several other cost of service elements which vary directly with the amount of energy consumed by a customer. Those other elements are expenses associated with real-time deviations, RES[18] compliance, and economic development discount responsibility.

Charges for Day Ahead Energy Expense

Q. How should the charge for day-ahead energy expense be designed?

A. Staff recommends time-based energy charges to recover day-ahead energy expense associated with procurement of energy for LLCS customers, for several reasons:

1. It most clearly relates revenue responsibility and cost causation.
2. While Staff's recommended rates are cost-based and are not intended to drive behavioral changes, these rates do not encourage consumption at times when energy costs are high, and do not discourage consumption at times when energy costs are low.

[17] Regional Transmission Organization ("RTO").
[18] Renewable Energy Standard ("RES").

3. It encourages, but does not require, shifting energy consumption to periods when energy costs are low, and away from period when energy costs are high. For customers with variable loads related to manufacturing or metallurgy, extensive energy use can be targeted to times with lower rates to the extent the customer chooses. Some customers may find thermal energy storage to be cost-effective.
4. If an LLCS customer has a perfect load factor, they will not be harmed. If an LLCS customer has usage peaks which coincide with times of low energy prices, they will experience a lower bill than if on a flat rate; and if an LLCS customer has usage peaks which coincide with times of high energy prices, they will experience a higher bill than if on a flat rate.
5. Times of high energy prices generally coincide with times of high generation and transmission demand. Times of low energy prices generally coincide with times of system under-utilization.

Q. How will Empire procure the energy required by LLCS customers?

A. Every kWh of energy that Empire sells to any retail customer must be purchased through the SPP integrated marketplace.[19] Every additional kWh of load results in an overall increase in purchased power expense net of revenues.[20] Every kWh of energy required by an LLCS customer will cause Empire to purchase an additional kWh of energy through the integrate market in the interval in which it is needed, at the price of the Locational Marginal Price ("LMP") at the interconnection node.[21] If a transmission constraint exists between the

[19] The relatively small amounts of generation from net metered solar and from utility sources such as the St. Joe Landfill gas plant or small solar sites does offset load requirements at the distribution level.

[20] For financial reporting purposes, FERC requires that utilities report the value of the net amount of energy transacted in a given interval, as opposed to the actual value of both the energy sold and the energy purchased. Therefore, in a given interval the expense of the energy for Empire's load may be booked as a purchased power expense, or as a net negative energy revenue. Each day, generators owned by its market participants, including Empire, are bid into the market, and SPP chooses which ones to dispatch to serve its system-wide load on a least-cost basis. System-wide generation is dispatched on a system-wide least cost basis, and any one utility's load will only coincidentally cause an increase in that utility's instructed generation if that utility's generation happens to be next in the cost-ordered stack. While additional load may result in additional generation sales, or in increased LMPs for generation sales transactions, this relationship is coincidental, at best.

[21] While a single load node LMP is reported, the reported LMP is actually an average of the LMPs at each interconnecting node, weighted by the load transacted at that node. For example, if in a given interval Empire requires 100 MWh at Node A, transacted at $20, and 50 MWh at Node B, which is congested, transacted at $100, then the published LMP would be calculated as 100 * $20 = $2,000, 50 * $100 = $5,000, then $7,000 / 150 = $46.67/MWh.

node at which energy is required and the nodes at which the lowest-priced energy could be generated, then the price of energy at the interconnecting load node will be increased to account for redispatch of energy at a location that can serve the load despite the transmission constraint.

Q. Will Empire's LLCS customers increase the cost of wholesale energy for all customers, even if the LLCS customer pays the full wholesale energy expense at its interconnection node?

A. Likely yes. No Missouri utility has experience with a single interconnecting load the size of contemplated LLCS customers. Depending on the location of the specific constraint in a given interval, these constraints could raise the LMPs of other regional load nodes too.[22]

While there is no realistic way to cap the impact of transmission constraints caused by LLCS customers throughout the service territory, Staff recommends requiring Empire to register each LLCS customer through the SPP as a separate load to facilitate isolation of the cost of the constraint to the LLCS class. This recommendation is further discussed by Staff witness J Luebbert.

In the future, the LLCS energy charges should be calculated using the nodal prices at LLCS interconnections. For this case, Staff relies on the historic weighted load LMP for Empire.

Q. How did Staff calculate the applicable time-based energy rates in this case?

A. Staff relied on historic average wholesale energy levels.

The historic seasonal average around-the-clock Day-Ahead LMPs are summarized in the table below:

[22] Eventually, it is likely that transmission solutions will be developed to address major constraints. The cost of these solutions should be allocated to the LLCS class.

	Raw Averages			
	Empire			
	Summer	Fall	Winter	Spring
2024	$ 28.12	$ 26.18	$ 38.40	$ 20.80
2023	$ 34.24	$ 27.70	$ 27.27	$ 24.43
2022	$ 85.60	$ 66.59	$ 55.57	$ 62.06
2021	$ 42.15	$ 49.61	$ 211.67	$ 29.81
2020	$ 24.00	$ 32.41	$ 23.92	$ 18.71
2019	$ 23.95	$ 25.95	$ 25.88	$ 31.10
2018	$ 29.28	$ 32.65	$ 34.48	$ 27.19
2017	$ 27.76	$ 31.02	$ 28.30	$ 28.47
2016	$ 27.43	$ 27.77	$ 23.69	$ 17.95

To develop reasonable energy rates for this case, Staff next adjusted these values to 2025, using a 2% annual inflation factor.

	Inflation Adjusted			
	Empire			
	Summer	Fall	Winter	Spring
2024	$ 28.12	$ 26.18	$ 38.40	$ 20.80
2023	$ 35.61	$ 28.81	$ 28.36	$ 25.40
2022	$ 90.74	$ 70.58	$ 58.90	$ 65.79
2021	$ 45.53	$ 53.58	$ 228.60	$ 32.20
2020	$ 26.40	$ 35.65	$ 26.31	$ 20.58
2019	$ 26.82	$ 29.06	$ 28.99	$ 34.83
2018	$ 33.37	$ 37.22	$ 39.30	$ 31.00
2017	$ 32.21	$ 35.98	$ 32.83	$ 33.02
2016	$ 32.36	$ 32.77	$ 27.95	$ 21.18

Staff found the average excluding the minimum and maximum value for each season from the simple average. Staff then found 75% of the simple average, and 125% of the simple average to filter outlier prices:

	Calculations			
	Empire			
	Summer	Fall	Winter	Spring
Simple Average	$ 39.02	$ 38.87	$ 56.63	$ 31.64
75% of Average	$ 25.07	$ 27.11	$ 27.29	$ 21.26
125% of Average	$ 41.79	$ 45.19	$ 45.49	$ 35.43

Where a price fell outside of this range, Staff replaced the actual price with the 75% or 125% value, as applicable:

	Filtered Results			
	Empire			
	Summer	Fall	Winter	Spring
2024	$ 28.12	$ 36.15	$ 38.40	$ 28.35
2023	$ 35.61	$ 28.81	$ 28.36	$ 25.40
2022	$ 33.43	$ 36.15	$ 36.39	$ 28.35
2021	$ 33.43	$ 36.15	$ 36.39	$ 32.20
2020	$ 26.40	$ 35.65	$ 36.39	$ 28.35
2019	$ 26.82	$ 29.06	$ 28.99	$ 34.83
2018	$ 33.37	$ 37.22	$ 39.30	$ 31.00
2017	$ 32.21	$ 35.98	$ 32.83	$ 33.02
2016	$ 32.36	$ 32.77	$ 27.95	$ 28.35

The Seasonal Average calculations are set out below, with the Revised Average 2 calculations being the simple average of the filtered prices:

	Seasonal Average Energy Cost per MWh			
	Empire			
	Summer	Fall	Winter	Spring
Simple Average	$ 39.02	$ 38.87	$ 56.63	$ 31.64
Revised Average 1	$ 33.43	$ 36.15	$ 36.39	$ 28.35
Revised Average 2	**$ 31.31**	**$ 34.22**	**$ 33.89**	**$ 29.98**

Q. What are the time periods, by season, Staff found as reasonable for the time-differentiated energy charges?

A. Staff reviewed the percentage of peak for each hour, by season, of the most recent two years of energy prices. The recommended periods are illustrated and set out below:

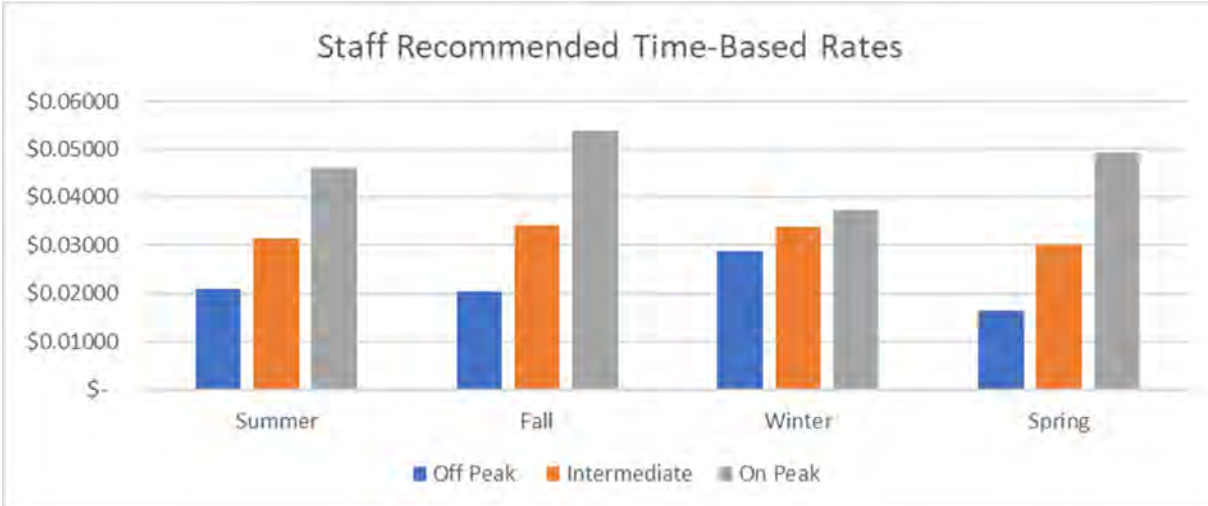
	Hour:	Midnight	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
2024	Winter	57%	61%	59%	58%	61%	67%	81%	97%	100%	99%	100%	90%	79%	73%	67%	64%	64%	76%	94%	87%	81%	78%	72%	65%
2023	Winter	57%	60%	58%	58%	60%	67%	79%	93%	96%	93%	100%	95%	83%	78%	73%	71%	70%	77%	98%	93%	84%	82%	76%	70%
2024	Spring	43%	41%	33%	31%	31%	38%	51%	62%	68%	89%	98%	86%	84%	84%	88%	90%	92%	95%	100%	98%	99%	91%	72%	59%
2023	Spring	42%	41%	37%	35%	38%	46%	61%	74%	83%	95%	100%	91%	87%	89%	90%	91%	93%	96%	98%	100%	99%	91%	73%	61%
2024	Summer	37%	36%	32%	29%	27%	28%	31%	33%	38%	47%	50%	53%	61%	70%	81%	87%	94%	100%	96%	86%	72%	60%	51%	43%
2023	Summer	36%	34%	30%	28%	27%	28%	30%	33%	37%	46%	50%	55%	63%	69%	80%	87%	95%	100%	91%	82%	70%	59%	50%	42%
2024	Fall	34%	33%	30%	29%	30%	32%	41%	50%	51%	54%	68%	60%	60%	65%	72%	77%	86%	96%	100%	85%	65%	55%	48%	42%
2023	Fall	43%	42%	38%	35%	39%	41%	51%	66%	73%	78%	86%	81%	76%	76%	82%	86%	90%	97%	100%	91%	78%	67%	60%	53%

	Winter				Spring, Summer, & Fall			
	$Start_1$	End_1	$Start_2$	End_2	$Start_1$	End_1	$Start_2$	End_2
Off Peak	11:00 PM	6:00 AM			10:00 PM	8:00 AM		
Intermediate	2:00 PM	6:00 PM			8:00 AM	3:00 PM		
On Peak	6:00 AM	2:00 PM	6:00 PM	9:00 PM	3:00 PM	10:00 PM		

Q. What is the cost of energy for each period, and what rates result for each period?

A. Those values are provided in the following table, and illustrated in the accompanying graph:

	Seasonal Average Energy Cost per MWh			
	Summer	Fall	Winter	Spring
Revised Average 2	$ 31.31	$ 34.22	$ 33.89	$ 29.98
Period	**Summer**	**Fall**	**Winter**	**Spring**
Off Peak	$ 21.01	$ 20.39	$ 28.63	$ 16.52
Intermediate	$ 31.31	$ 34.22	$ 33.89	$ 29.98
On Peak	$ 46.01	$ 53.97	$ 37.23	$ 49.22
Off Peak	$ 0.02101	$ 0.02039	$ 0.02863	$ 0.01652
Intermediate	$ 0.03131	$ 0.03422	$ 0.03389	$ 0.02998
On Peak	$ 0.04601	$ 0.05397	$ 0.03723	$ 0.04922



Other Energy-based Charges

Q. How should the Load-Servicing Energy Charge be designed?

A. This charge will recover the cost of service associated with real time deviations, ancillary services, and those transmission expenses that vary with load versus demand. In the future, it could be reasonable to refine this rate to recover LLCS-specific deviations to reflect increased load-forecasting risk. Staff is willing to work with Empire and other parties to establish realistic rates for the variation between the loads it provides to the SPP for day-ahead dispatch and the actual loads experienced by each in real time. However, as discussed by J Luebbert, the addition of an LLCS customer's load variability could significantly impact the historic relationship between load and real time and ancillary services expenses. Staff recommends these rates be set at initial rates of $0.002 $/kWh for the summer billing season, and $0.001 $/kWh for all non-summer billing seasons. If a separate load node is established for each LLCS customer as Staff recommends, these rates should be based on the collective net deviation expense of the LLCS class across all LLCS load nodes.

Q. What will the Missouri RES charge recover?

A. This charge will recover the approximate value of Renewable Energy Certificates associated with requirements under the Missouri Renewable Energy Standard ("RES"). Among other things, the RES requires that Empire must generate or purchase renewable energy, or purchase Renewable Energy Certificates ("REC"), equal to at least 15% of its load for years after 2021.[23] Staff recommends that each kWh of LLCS load be billed at a rate equal to 15% of the value of a REC as established in each rate case.

Q. What is a reasonable dollar amount to use for the value of a REC at this time for purposes of this charge?

A. At this time, a value of $2.73 is reasonable, as this is reflective of the current REC purchase rate in Empire's tariff.[24] This results in a RES compliance charge of $0.0004/kWh.

Q. What should the Economic Development Discount ("EDD") Responsibility Charge recover?

A. The EDD Responsibility Charge will be designed to recover the value of the discounts allocated to the LLCS class in future rate cases. Missouri statute 393.1640.2. states:

> In each general rate proceeding concluded after August 28, 2022, the difference in revenues generated by applying the discounted rates provided for by this section and the revenues that would have been generated without such discounts shall not be imputed into the electrical corporation's revenue requirement. Instead, such revenue requirement shall be set using the revenues generated by such discounted rates and the impact of the discounts provided for by this section shall be allocated to all the electrical corporation's customer classes, including the classes with customers that qualify for discounts under this section through the application of a uniform percentage adjustment to the revenue requirement responsibility of all customer classes.

[23] Section 393.1030, RSMo.
[24] Renewable Energy Purchase Program, P.S.C. Mo. No. 6 Sec. 4 5th Revised Sheet No. 7a.

At this time, the EDD Responsibility Charge rate should be set at $0.00, as such an allocation will only occur at the conclusion of a general rate case in which LLCS customers are recognized.

Other Demand Charges

Q. What is the intent of the Capacity Shortfall charge, if applicable?

A. SPP enforces resource adequacy. If a utility serving one or more LLCS customers faces a capacity shortfall penalty, an expedited proceeding should be held to decide whether or not that penalty should be assessed directly to one or more LLCS customers. The basis for this charge is addressed in the concurrent testimony of J Luebbert.

Q. What is the Capacity Cost Sufficiency Rider?

A. As explained in the recommended tariff language above, Staff recommends that in the event that Empire requires capacity arrangements to serve LLCS load, Empire should seek to expeditiously promulgate a tariff so that those additional expenses can be appropriately recovered from the LLCS customer causing the need for additional capacity. This charge would be reflected on that customer's bill as the "Capacity Cost Sufficiency Rider."

Q. Does Staff recommend additional demand-related charges?

A. Yes. Staff also recommends inclusion of distinct charges to accommodate differences in the initially-forecast demands and the current-year updated forecast, and for differences in the current-year updated forecast demands, and the actual experienced demands. These charges are discussed in the concurrent testimony of J Luebbert.

Q. What is the reactive demand charge?

A. The reactive demand charge is intended to recover costs and expenses associated with the correction of voltage stability issues caused by customers requiring reactive demand in excess of the power the customer requires.[25] Unlike other Missouri electric utilities, Empire does not currently bill a reactive demand charge to other customer classes. Therefore, Staff suggests this rate initially be set at a rate of $0.00/kVar, pending further study and a future rate case. However, Staff recommends that this rate be established now, so that Empire may include it in the programming of the LLCS rates in the billing system, and to facilitate retention of determinants of any LLCS customers who may take service.

Staff understands that due to retirement of rotating mass generation units such as large coal plants, additional challenges have arisen in grid management related to voltage stability. Currently, Empire does not bill a separate reactive demand charge for its large customers, unlike Ameren Missouri, Evergy Missouri Metro, or Evergy Missouri West. However, due to regional coal retirements and the introduction of large loads, Staff encourages Empire to monitor this situation, and requests the Commission order Empire to provide a study of the cost of reactive demand management, and how those costs may vary with load type, in its particular location within the SPP footprint. Staff suggests a reasonable time for the submission of such study would be approximately two years after this case is concluded.[26]

Charges for Contributions to Fixed Cost Recovery

Q. Will the charges discussed above result in contributions from LLCS customers to Empire's fixed costs?

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[25] Note, Staff is recommending that LLCS customers pay upfront for voltage support infrastructure that is necessary due to maintain power stability on the grid with the inclusion of the new load. That infrastructure may be located before or after the customer's metering point. If a customer does prepay for voltage support infrastructure and the metering point is "downstream" of that infrastructure, then the load subject to the charge should be prorated accordingly to avoid double-charging. Staff expects to cooperate with Empire and other stakeholders to develop and refine appropriate tariff language to address this issue.

[26] Such study should also consider the appropriateness of incorporating a reactive demand charge into other rate schedules.

A. Effectively, with the possible exception of the transmission demand charge, no. The charges discussed above do not reflect any of Empire's day-to-day costs of doing business, such as computer systems, computer software, office buildings, office furniture, management employees, investor relations costs and expenses, other overheads, and the revenue requirement associated with policy-driven activities, such as solar rebates, electric vehicle charging stations, and supports for low-income rate payers.

Q. Does Staff recommend that the LLCS rate structure include charges to cause the LLCS customers to contribute towards Empire's fixed costs?

A. Yes. Staff's recommended structure includes two charges so that the LLCS rate will be set to essentially the floor for economic development discount recipients established by Section 393.1640, and so that, with appropriate accounting treatments, these rate schedules will reasonably ensure LLCS 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 LLCS customers. To account for income tax, the bill components will actually need to be multiplied by 24.36% to accomplish a 20% contribution to "fixed costs."

Q. How should the fixed cost recovery charges be designed?

A. Staff recommends two separate Fixed Cost Recovery charges. The Variable Fixed Revenue Contribution charge will be calculated using the actual demand or usage calculated charge for a given month. The Variable Fixed Revenue Contribution charge will be applied to the actual billed amounts for the Customer Charge, the Facilities Charge, Energy Charges (including the Day Ahead, Load Servicing, and RES Compliance Charges, but not the EDD Responsibility Charge), and the Reactive Demand Charge (when applicable).

The Stable Fixed Revenue Contribution Charge will be applied to only the Demand Charge amounts. This charge calculation varies in that it recovers for the greater of actual demand in a month, or contracted demand for that month. Specifically, 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.

Additional Staff-Recommended Tariff Provisions and Regulatory Treatments

Q. Are there other details to include in the LLCS tariff as necessary definitions and service specifications that would be expected in any rate schedule?

A. Yes. Staff's recommended LLCS tariff also includes basic provisions, as set out below:

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.
C. LLCS bills shall be paid by the fifteenth business day of the month issued.
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.

Q. Are there important policy-related terms to include in the LLCS tariff?

A. Yes. Staff also recommends that the LLCS tariff address Revenue Treatment, Termination Charges, and specific provisions to provide some rate mitigation to captive ratepayers. The effects of positive and negative regulatory lag must be considered in establishing rates that will reasonably ensure LLCS 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 LLCS customers. The recommended revenue treatments, termination charges, and risk mitigation strategies interplay, as well as Staff's recommendations concerning the FAC.

Regulatory Lag Considerations

Q. All else being equal, would Empire experience significant positive regulatory lag with the addition of an LLCS customer?

A. Yes. Due to the inherent lag between when an LLCS customer begins paying its bills, and when that revenue is recognized in a rate case, Empire will experience positive regulatory lag. This lag is different than ordinary positive lag associated with customer growth for the following reasons:

1. Scale,
2. Lack of offsetting revenue requirement increases, and
3. The statutory requirement that LLCS 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 LLCS customers cannot be effectuated until those revenues are realized in a rate case to the benefit of other customers.

Q. Why is the scale of LLCS customers relevant?

A. It is the prerogative of Empire management to time rate cases to maximize shareholder benefit. With ordinary customer growth, offsetting increases to revenue requirement would negate some of the positive benefits of regulatory lag to shareholders. However, LLCS customer growth will be offset by increases in revenue requirement to a much smaller extent than normal customer growth, on a $/kWh basis, and the quantity of kWh associated with LLCS customers dwarfs that of any other customer of Empire's.

Q. What causes the difference between LLCS customers and other customers related to increase in revenue requirement?

A. When a new home or business begins taking service, not only is the scale of revenue growth much smaller than will be the case for an LLCS customer, but also there are more offsetting increases to revenue requirement. For an LLCS customer, Empire will not be paying for some or all of the costs to install a meter, a service line, or a line transformer. Nor will Empire be paying for the accumulated need to expand distribution systems or substations to serve customers collectively with the addition of an LLCS customer. Rather, the LLCS customer will be prepaying for its transmission interconnection, its meter, and any infrastructure in between. This required customer contribution is reasonable and appropriate, but it also distinguishes LLCS growth from ordinary customer growth.[27]

Q. Will capacity costs or expense offset the positive regulatory lag if Empire acquires capacity to serve a new LLCS customer?

A. Additional capacity may be built, acquired through a contract for a specific asset, or acquired through other contractual arrangements.[28] If the capacity is built, it is unlikely that there would be a timing scenario where a rate case would capture the increased revenues from a new LLCS customer prior to capturing the increased revenue requirement associated with the new generation asset. This is, first, because that timing would be unlikely to be chosen by Empire, who controls the pace of construction activities and has discretion in the timing of

[27] Some amount of expenses will increase associated with ownership and operation of these customer-contributed facilities.

[28] If the terms of those contracts or capacity arrangements are less than one year, those expenses are included in the FAC, and the FAC will limit the increase in expenses that offset the positive regulatory lag.

customer additions; and second, for the practical reason that if Empire needs to build additional capacity to serve the full load of an LLCS customer, then Empire will not be serving that LLCS customer at full load until that capacity addition is up and running unless some other arrangement is in place, or unless SPP penalties are incurred.

If Empire were to make a contractual arrangement of more than one year for capacity to enable service of an LLCS customer while constructing a new generation asset, then the utility may be shielded from negative regulatory lag associated with that asset. Empire is substantially shielded from negative regulatory lag associated with construction of renewable generation (unless that rate-base addition increases revenues by allowing service to new customer premises) under the provisions of Section 393.1400 related to Plant in Service Accounting ("PISA"). Recently enacted SB 4 allows the same protection from negative regulatory lag for new natural gas generation units, effective August 28, 2025.

It is important to note that Empire will be recovering the full cost of owning and operating its generation fleets from existing customers at the conclusion of this rate case. If a new LLCS customer begins paying for the generation fleet – as they should – then Empire will over-recover that amount. As a very simple example, consider four friends who decide to buy a $20.00 pizza. Each of the four hands $5 to the cashier. Just then a fifth friend walks in and joins them. Should this newcomer also give the cashier $5? Or should the newcomer give $1 to each of those who already paid? Empire is in the position of the restaurant manager, who would be pleased to accept a $5.00 gratuity on that $20.00 pizza. As described below, reasonable accounting authority should be ordered to ensure a fair outcome for the existing rate payers, and to avoid unreasonable accumulation of positive regulatory lag to the benefit of Empire shareholders.

Q. What changes to cost of service will Empire incur that would offset the revenues of new LLCS load?

A. In most cases, the only cost of service components that will offset the revenues of new LLCS load will be wholesale energy expenses and load and demand-allocated RTO expenses. Notably, Empire has substantial protection from these expense increases through the operation of the FAC, as discussed below.

Modifications to the Fuel Adjustment Clause to Address Regulatory Lag and LLCS Customers

Q. As Empire sells additional energy to a new LLCS customer, what happens to all ratepayers through operation of Empire's FAC?

A. While the exact percentage of the increased wholesale energy cost that is recovered through the FAC will vary based on the relationship of the cost and revenue components and the percentage increase in load, due to the FAC some amount of the wholesale cost of energy for serving new load will be distributed to all customers through the FAC, in addition to the full recovery of the wholesale cost of energy which occurs through the rates of the new LLCS customer.

Q. Are changes to the FAC necessary and appropriate to ensure that Empire does not unreasonably retain revenues associated with the portion of each energy charge equal to the FAC Net Base Energy Cost ("NBEC")?

A. Yes. The detailed changes to the FAC are described by Brooke Mastrogiannis. In general, every kWh of energy sold at retail recovers the NBEC, with additional revenue accruing to the utility. When retail sales are greater than the level used in setting NBEC, the utility ultimately recovers extra revenue relative to the rate case, and when retail sales are lower than the level used in setting NBEC, the utility ultimately recovers lower revenue relative to the rate case.

Q. Why is it appropriate to treat sales growth related to LLCS customers differently than other sales growth?

A. Typically, the utility retains the benefit of, or absorbs the reduction of, changes in sales levels between rate cases as a regulatory lag phenomenon. However, LLCS customers present unprecedented risks to other customers, as described above, and Empire has nearly unilateral control of its rate case timing, as well as significantly more information than Staff, OPC[29], or other stakeholders concerning the timing of LLCS customer load changes. Because the risk of serving LLCS customers is distributed to all customers through the FAC, with little if any risk retained by Empire, it is reasonable and appropriate to treat revenue growth from LLCS customers differently.

Q. What would happen if there were not an FAC adjustment related to LLCS revenue growth?

A. Essentially, when an LLCS customer comes on-line, Empire will over-recover revenue. Staff's recommended FAC modification will mitigate that over-recovery and mitigate the FAC impact by ensuring that Empire is not double-compensated by the value of the NBEC multiplied by the millions of kWh to be sold to a new LLCS customer.

Q. Is Staff also recommending a related mechanism to mitigate Empire's financial losses if an LLCS customer is terminated?

A. Yes.

[29] Office of the Public Counsel ("OPC").

Risk Mitigation Strategies

Q. What risks do Empire and non-LLCS customers face if an LLCS customer leaves the system or reduces its load prior to its expected term?

A. To the extent that Empire has built or contracted for additional generation capacity, Empire's customers face a long-term risk of paying for excessive generation capacity. In the short-term, assuming that the LLCS customer's load has been recognized in a rate case, Empire will face a revenue shortfall, and Empire's shareholders may face a potential reduction in earnings. Empire has the near-unilateral ability to choose the timing of its rate cases to minimize these potential shortfalls, and to request that the Commission revert the responsibility for that revenue (including any associated capacity-related revenue requirement) to other ratepayers.

Q. Will any costs or expenses be avoided by Empire if an LLCS customer leaves the system or reduces its load?

A. Yes. Empire will no longer incur the wholesale energy and transmission expenses associated with service to that customer. Those expenses are generally distributed to all customers on the basis of energy through the operation of the FAC. To prevent an unreasonable disgorgement of the portion of revenue associated with the NBEC portion of the LLCS customer's energy charges, Staff recommends that Empire's FAC be modified to incorporate a mechanism similar to the "N Factor" that was utilized in the Ameren Missouri FAC associated with its service to Noranda.[30]

[30] In Case No. ER-2016-0130, on January 12, 2016, the Signatories filed a Non-Unanimous Stipulation and Agreement under which they agreed that an amount in dispute arising from the calculation of an adjustment triggered by Noranda Aluminum, Inc.'s ("Noranda") load changes (an adjustment commonly referred to as the "N Factor") would not be included in the Fuel Adjustment Rate ("FAR") called for by the Company's FAC. An adjustment is triggered if the actual metered kWh sales for either Service Classification 13(M) or 12(M) is equal or greater than 40,000,000 kWh (the normalized monthly kWh billing determinant that was established in Case No. ER-2014-0258).

Q. What specific termination fees, termination procedures, and collateral requirements does Staff recommend?

A. Staff's recommended termination fees and triggering events are set out in the draft tariff. At this time, Staff does not have a specific recommendation regarding collateral requirements. Staff anticipates collaboration with Empire and other parties to develop terms which reasonably balance the risks of termination between existing customers and new LLCS customers.

Revenue Treatment

Q. Absent ordered revenue treatment, will positive regulatory lag result in a failure to align LLCS revenues with non-LLCS responsibilities for increases to revenue requirement caused by the addition of LLCS customers?

A. Yes. In a given rate case, the Commission will order rates designed to recover the utility's revenue requirement from a normalized level of customers, taking service at normalized purchases of energy. To the extent that adding a new LLCS customer increases revenues between rate cases more than it increases the utility's cost of service between rate cases, the utility will overearn, all else being equal. SB 4 requires that the Commission "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."[31] Empire will receive the additional revenue from new LLCS load in real time, while much of the energy costs for new load will be recovered through the FAC from all ratepayers, and while the other costs recovered through the LLCS rates are already being recovered from other ratepayers.

[31] Section 393.130.7, RSMo.

Given Empire's unilateral ability to time its rate cases, it is probable that up to 33% (four years of revenue under a 15-year contract term) of the revenues from an LLCS customer will not be reflected in a rate case and will not offset the overall cost of service of the utility.

Q. Does Staff's recommended rate structure address these issues?

A. Yes. Staff's recommended tariff includes terms to defer revenues in excess of newly-caused cost of service to regulatory liability accounts. These account balances will offset the production cost of service increases caused by LLCS customers. Even if an LLCS customer terminates service after a new power plant has been built to serve that customer, this ratebase offset serves as a non-LLCS customer protection and is a risk mitigation tool on which the Commission can rely. To mitigate the unreasonable retention of positive regulatory lag, Staff recommends the following provision be incorporated into the LLCS tariff:

Treatment of LLCS Customer Revenues:

A. Until a rate case recognizing the customer at the full level of projected demand, the difference between the revenue for each charge considered for that customer in the last general rate case, and the current level of revenue for that charge will be recorded to a regulatory liability account. This treatment is applicable to revenue from all charges except the Customer Charge, Facilities Charge, Demand Deviation Charge, Imbalance Charge, Capacity Shortfall Rate, the Capacity Cost Sufficiency Rider, and the RES Compliance Charge. The resulting regulatory liability will be treated as an offset to production ratebase with a 50 year amortization. The annualized and normalized revenue from these charges shall be reflected in each rate case.

B. All revenue billed under charge the RES Compliance charge will be recorded to a regulatory liability, and that regulatory liability will be treated as an offset to production ratebase with a 50 year amortization. Revenue for the RES Compliance charge will only be addressed through this accumulated regulatory liability, and shall not be considered as rate revenue in rate cases.

C. All revenue billed under the Demand Deviation Charge, 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.

Q. Why are these provisions important?

A. These provisions ensure that Empire does not experience excessive positive regulatory lag, and enables the revenues provided by LLCS customers to prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLCS customers. Treating these accumulated revenues to reduce the ratebase associated with production facilities is intended as a risk mitigation strategy. LLCS customers are going to prompt increases to generation revenue requirement. To the extent that LLCS customers' capacity needs may increase the bills paid by other customers, it is reasonable to capture the lagging LLCS revenues to effectively buy down the increased generation rate base caused by those customers.[32]

Q. In future rate cases, could the Commission order consolidation of tranches of these regulatory liabilities to simplify accounting?

A. Yes. In future cases, clean-up of tranches could be reasonable.

Termination Charges

Q. How does Staff recommend an appropriate termination charge be calculated?

A. Staff's recommended tariff includes termination charges which are intended to discourage early termination, and to mitigate the risks faced by Empire's captive ratepayers. Staff also attempts to avoid a situation where a brief downturn for an LLCS customer would trigger termination charges which would force a closure. Staff's recommended provisions to balance these interests are:

[32] If, for whatever reason, capacity is built to serve LLCS customers, and LLCS customers terminate service prior to that capacity being fully depreciated, the regulatory liability will at least offset some portion of that generation asset to the extent the Commission includes the generation asset in rate base in future cases.

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

Staff supports further work with Empire to develop terms where capacity associated with one LLCS customer could explicitly be transferred to a different LLCS customer to avoid some or all termination charges, and for refinement of appropriate collateral requirements and other risk mitigation techniques related to termination revenue recoveries and customer qualifications.

Captive Customer Risk Mitigation

Q. What additional customer protections are reasonable to incent prudent Empire managerial decisions?

A. Staff recommends the Commission include restrictions on the overall quantity of load to be comprised of LLCS customers, and to require utility responsibility for resource adequacy and the consequences of failure to meet resource adequacy requirements:

> **Other Terms (continued):**
>
> E. Service on this schedule is limited to 33% of Empire's annual Missouri jurisdictional load.
>
> F. Prior to execution of a Service Agreement with a prospective LLCS customer, Empire 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 Empire executes a Service Agreement without adequate capacity, Empire'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.

<u>Empire Rate Modernization</u>

Q. Regarding rate modernization, what was accomplished in Empire's last rate case, ER-2021-0312?

A. In ER-2021-0312, Empire and other parties entered a Non-Unanimous Partial Stipulation and Agreement, which was filed on January 28, 2022 (the "ER-2021-0312 Stipulation"). The ER-2021-0312 Stipulation resulted in significant modernization and restructuring of Empire's rates, including elimination of several end-use rate structures and consolidated rates. The modernized rate structure includes an off-peak discount for energy consumed overnight for all customers except those served on the LPS schedule and lighting customers. Optional rate schedules that do not include a time-based energy discount remains available to all customers.[33]

The agreement also included the following:

> 21. Other Provisions and Future Filings:
>
> a. Empire commits to propose time-variant demand charges in the next rate case, with supporting billing determinants. Empire commits to retain data sufficient for other parties to recommend variations to Empire's proposal, such as shifting the hours to which the demand charge is applicable.
>
> b. Empire shall perform robust education of its customers regarding the cost-basis of time-variant rates, which shall include but not be limited to concepts such as the availability of wind energy and relatively low load conditions of off peak hours, and the nature of load requirements and generation capacity and energy costs during other hours. Such education shall not be limited to marketing of bill savings potential. This education shall focus on the generally-applicable time-variant rates, as opposed to marketing of the opt-in ToU proposed by Empire. Empire agrees to meet with Staff, OPC, and Renew Missouri to discuss its education, marketing

[33] SB 4 includes a new provision, Section 386.1100, stating as follows:

> If the Public Service Commission has ordered adoption of time-of-use rates on a mandatory basis for an electrical corporation's residential customers before the effective date of this section, then within one year from the effective date of this section, the commission shall issue an order which allows for mandated time-of-use rate customers to opt out of participating in time-of-use rates and elect to participate in non-time-of-use rates. The transition to opt out of time-of-use rates may occur in a general rate case or in a standalone tariff proceeding to allow for the transition to conclude no later than one year from the effective date of this section.

Empire's residential customers have available the "Non-Standard Residential Rate Plan, Schedule NS-RG," which is not a time-of-use rate.

> and progress to date (including customer participation and feedback) of TOU rates on a quarterly basis until its next rate case.
>
> c. Empire will file testimony and provide data in its next case describing:
>
> i. how investments and charges are tracked for internal accounting purposes, and how facilities and related costs, expenses, and revenues are flowed through Empire's class cost of service study related to "Special or Excess Facilities Rider XC," and "Transformer Ownership" and interaction with facilities extension policies,
>
> ii. identifying the presence/level of customer-specific investment in each transmission and distribution account, and identifying an average amount of customer-specific infrastructure per account associated with each size of meter.
>
> d. Empire will maintain all sales data, to the extent that such data currently exists and in the same degree of specificity, on a class basis, for February 2021.

Time of Use Rate Implementation Update

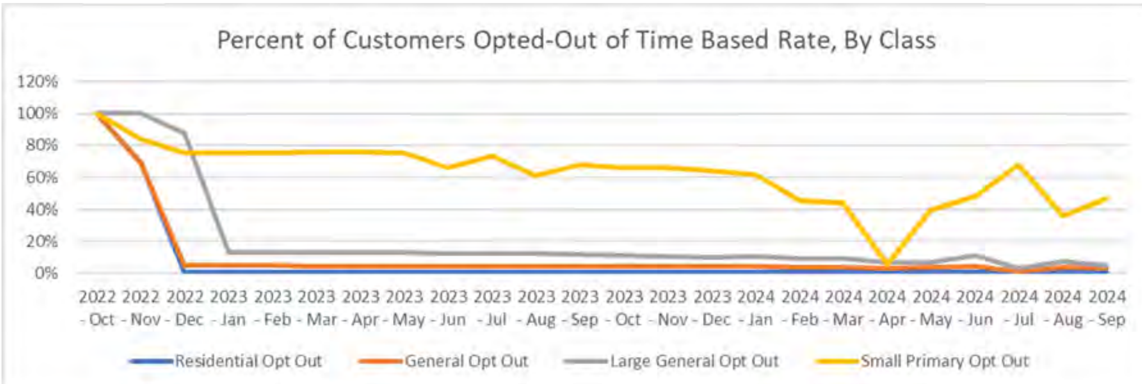
Q. Has Empire educated its customers on Time of Use ("TOU") Rates?

A. Yes. Empire's roll out of the rate restructuring following ER-2021-0312, and beginning in November of 2022, was exemplary. While the billing system change that Empire implemented in 2024, after the rate structure modifications had been fully implemented, did result in significant challenges and customer confusion, the actual TOU roll-out was well-executed on Empire's part. Relatively few questions or concerns were brought to the Commission by Empire customers, and the rate restructure appears to have been relatively well-received by Empire's customers. Few customers have pursued opting-out of the time-based rates, with less than half of a percent of residential customers choosing not to take service on the time-based rate options. Larger customers, especially those in the Small Primary classes, appear to be opting-out at a larger scale.[34] The retention of such a high percentage of

[34] Staff understands that the Small Primary deviations shown in April of 2024 and later months are associated with billing-rendering issues, and are not indicative of actual customer rate election choices.

customers on time-variant rates is a product of calm, measured, and accurate customer education efforts on the part of Empire.

The chart and table below depict the percentage of opt-outs form October 2022 to September 2024:



	2022 - Oct	2023 - Mar	2023 - Oct	2024 - Mar	2024 - Sep
NS RG-Residential	138,879	571	562	520	496
TC RG-Residential	3	139,514	140,333	141,968	129,906
TP RG-Residential	-	53	77	74	183
Total	138,882	140,138	140,972	142,562	130,585
% Opt-Out	100.00%	0.41%	0.40%	0.36%	0.38%
NS GS-General	21,992	1,005	938	880	626
TC GS-General	-	21,066	21,335	21,477	18,103
TP GS-General	-	2	3	4	6
Total	21,992	22,073	22,276	22,361	18,735
% Opt-Out	100%	5%	4%	4%	3%
LG-Large General	2,732	352	309	251	96
TC LG-Large General	-	2,375	2,427	2,499	1,744
Total	2,732	2,727	2,736	2,750	1,840
% Opt-Out	100%	13%	11%	9%	5%
SP-Small Primary	58	44	39	26	21
TC SP-Small Primary	-	14	20	33	24
Total	58	58	59	59	45
% Opt-Out	100%	76%	66%	44%	47%

Stipulation Compliance Issues

Q. Did Empire, as required by the ER-2021-0312 Stipulation, file testimony and provide data in its next case describing:

i. how investments and charges are tracked for internal accounting purposes, and how facilities and related costs, expenses, and revenues are flowed through Empire's class cost of service study related to "Special or Excess Facilities Rider XC," and "Transformer Ownership" and interaction with facilities extension policies,

ii. identifying the presence/level of customer-specific investment in each transmission and distribution account, and identifying an average amount of customer-specific infrastructure per account associated with each size of meter?

A. It is not clear at this time whether Empire has fully complied with these obligations. Empire has provided at least partial information related to each. Staff may provide additional discussion in its rebuttal testimony.

Q. Did Empire maintain all sales data, to the extent that such data currently exists and in the same degree of specificity, on a class basis, for February 2021?

A. It appears that Empire has attempted to comply with this provision, but given the issues associated with its billing system transition, has been unable to provide accurate data for detailed analysis.

Rate Modernization Next Steps

Q. What is left to modernize Empire's rate structure?

A. While Empire is further along than other Missouri utilities, key areas for future work are:

1. Continued monitoring of the off-peak discount rate.
2. Coincident-Peak demand charges: Staff recommends that billing demand charges be based on customers usage during a defined time period, such as 6:00 am – 9:00 pm, as opposed to the customer's non-coincident demand.[35]
3. Explicit rates for each voltage: Consistent with modernization efforts with Ameren Missouri, Evergy Missouri Metro, and Evergy Missouri West, Staff recommends setting out discrete rates within a given

[35] This would not impact hours use calculations or facilities demand calculations.

service classification for service at (1) transmission voltages, (2) subtransmission voltages, (3) primary voltages, and (3) secondary voltages, as applicable.[36]

4. Modernization of the Large Power Rate Schedule.
5. Potential implementation of a reactive demand charge.
6. Consistency across voltages: Consistent with modernization efforts with Ameren and the Evergy utilities, Staff recommends movement toward establishing consistent customer charge rates and facilities demand rates for customers served at a given voltage level, regardless of service classification (except for LLCS, as discussed within).
7. Phase out of hours use billing.
8. Continued monitoring of summer/winter billing seasons, with potential subdivision of the winter billing season to provide different rates for the spring and fall seasons.

However, "the implementation of Customer First has compromised Empire's ability to provide safe and reliable service at just and reasonable rates."[37] As discussed in the direct testimonies of Mr. Thomason and Kim Cox in this case, and as is the subject of the Investigatory Docket, OO-2025-0233, Empire's customers have been faced with significant billing and customer service challenges, and the quality of Empire's billing data is not as high as should be expected. Rather than introduce further confusion with rate structure changes in this case, and rather than rely on data which may not be fully reliable, Staff recommends delaying many of these changes until a future rate case.

In this case, Staff recommends:

1. Elimination of the Optional Time Of Use (OTOU) rate plan, which currently has no customers.
2. Coincident-Peak demand charges: Staff recommends that billing demand charges for all applicable non-residential customer (including LPS) be based on customers usage during a defined time period, such as 6:00 am – 9:00 pm, as opposed to the customer's non-coincident demand.

[36] For example, currently, Empire's Large Power rate schedule states "Where service is metered at transmission voltage, metered kilowatts and kilowatt-hours will be reduced prior to billing by multiplying kilowatts and kilowatt-hours by 0.9756."
[37] Direct Testimony of Charles Tyrone Thomason, page 2.

3. Empire review its billing system capabilities and determine whether it anticipates any challenges in modifying its rates to explicitly bill customers served at a different voltage from what is typical for a rate schedule. Empire should provide this information in its rebuttal filing. Staff anticipates that unless billing systems are unable to accommodate this change, this change will promote clarity and will not negatively (or positively) impact any customer.

4. Staff does not recommend implementation of an optional time-based rate structure for the Large Power Rate Schedule at this time, due to self-selection concerns. Staff supports eventual restructuring the LPS rate schedule to a design that acknowledges the relationship of the time of energy consumption to the price of the energy, which varies with time, on a non-optional basis. However, Staff is not recommending these changes be implemented in its direct because:[38]

1) Concern with Empire's ability to accurately bill its customers at this time;

2) Concern with self-selection reducing the benefits of time-based energy rate variability. Namely, any time a revenue-neutral time-based rate is implemented, some customers will receive a lower bill without changing anything, and some customers will receive a higher bill without changing anything. If all customers are required to remain on that rate structure, the result is revenue neutral to the utility and other classes. However, if customers can opt out of the time-based rates, especially for large, sophisticated customers, there is a tendency for the customers who should pay more for their energy to opt out, and only those customers who benefited by default to remain on the time-based rate option. This scenario appears to have played out for Empire's SPS class.

Because of concern with Empire's ability to accurately bill its customers, and due to the significant customer confusion related to misbillings over the last year, Staff is not recommending further movement on the following issues in this case. These changes should be implemented in Empire's next rate case:

1. Implementation of reactive demand charges, to the extent appropriate.
2. Consistency of related charges across voltages.
3. Phase out of hours use billing.
4. Subdivision of winter billing season.

[38] Note, Staff's recommendation to implement time-based demand charges would apply to the LPS class.

Time-Based Demand Charges for All Non-Residential Rate Schedules

Q. Has Empire filed determinants to calculate reasonable time-variant demand charges as required in the ER-2021-0312 Stipulation?

A. Empire has not reasonably executed this ER-2021-0312 Stipulation commitment. Empire supplied what it characterizes as the time-variant demand determinants in Schedule 5 to the direct testimony of Timothy S. Lyons. However, the determinants provided do not pass an initial screening for reasonableness. A summary of the contents of TLS-5 with regard to the demand determinants is attached to this testimony as Schedule SLKL-d3.

Staff has reviewed Empire's responses to Staff discovery for the demand of each customer during the defined period of 6:00 am – 9:00 pm. As discussed in the testimony of Kim Cox, Empire has revised the billing data several times since this case was filed. While Staff is unable to normalize the individual customer data given the need to reconcile to the class level data used to calculate class-level determinants, Staff has prepared high and low end estimates of the rates customers could expect, (based on Empire's proposed increase request and revenue allocation) attached as Schedule SLKL-d4.

Staff recommends continued work with Empire to develop and normalize appropriate time-variant demand determinants for the compliance tariffs in this case, and to ensure that Empire can accurately render bills if the billing demand charges are modified.

Q. Should the facilities demand rates also be modified to use the time-based determinant?

A. No. Ideally, the facilities demand rate recovers the cost of service associated with a customer's metering equipment, service drop or radial line, and customer-dependent transformers. The sizing of this equipment is dependent on that customer's maximum load, regardless of the coincidence with other customer load.

<u>Class Cost of Service Study</u>

Q. Has Staff been able to perform a CCOS study in this case that is reliable for ratemaking purposes?

A. Largely, yes. However, Staff's study does not fully recognize the demand-carrying capability of the customer-allocated distribution components,[39] nor does Staff's study fully recognize the customer-specific infrastructure required by customers served at voltages above secondary.[40] Further, given the limited data available, Staff's study does not attempt to refine allocations of distribution costs and components to the extent necessary to review the reasonableness of intraclass revenue responsibility as reflected in rate design. Finally, due to concerns with the reliability of hourly data, Staff relies on an Average & Excess (A&E) allocation of dispatchable generation facilities. In general, these shortcomings tend to overallocate revenue responsibility to Residential and General Service customers, and to underallocate revenue responsibility to Large General Service, Small Primary Service, and Large Power Service customers.

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[39] "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost." NARUC Manual, page 95.

[40] With regard to facilities operating at transmission voltage, the NARUC Manual at page 83 states, "The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system." With regard to facilities operating at distribution voltages, the NARUC Manual at pages 87 and 89 states "Assignment or 'exclusive use' costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components."

Revenues

Q. On a normalized and annualized basis, what revenues are currently generated by each class from current tariffed rates?

A. The currently tariffed rates subject to increase in this case are set out below:

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778

The differences between these revenues and calculated class revenues are attributable to reallocation of economic development rider, and the treatment of rate elements such as excess facility charge revenue, solar facilities charge revenue, and related adjustments described in the testimony of Marina Gonzales.

Production, Energy, and Transmission Allocations

Q. How did Staff allocate Empire's costs of owning and operating generation facilities and participating in power purchase and capacity purchase agreements?

A. While Staff has been developing in recent cases an approach to production and related allocation that acknowledges the energy market's influence on the cost of serving each class, due to concerns with the reliability of available hourly class-load data, Staff has not done so in this case. Staff allocated the cost of production facilities with low or no variable operation costs to each class based on each class's energy consumption. Staff allocated the cost of Empire's other production facilities to each class based on an A&E 2 NCP allocation,[41] described by Dr. Poudel. Energy, fuel, and variable Operations & Maintenance ("O&M") expenses are allocated to the classes based on each class's energy consumption.

[41] Non-Coincident Peak, (NPC), refers to the class's maximum usage regardless of when it occurs relative to other classes on the system, while Coincident Peak, (CP) refers to a given class's load in the hour in a given month (or year) when the system has the highest energy usage. For an A&E allocator, it is most reasonable to use the summer and winter peaks to recognize Empire's dual peak.

Transmission net revenue requirement was allocated on each class's share of the coincident peak in each month.

Cost of generation resource ownership and operation

Q. What costs does Empire incur in owning and operating generation resources?

A. Empire incurs capital costs, depreciation expense, operation and maintenance expenses, including property taxes, and fuel expenses associated with ownership and operation of its generation resources. Empire has recorded a portion of the costs directly associated with generation under intangible plant and transmission. For purposes of its CCOS Studies, Staff allocated these assets and expenses as generation.

Q. How did Staff subfunctionalize Empire's generation resource net cost of service?

A. Staff determined that it was most reasonable to subfunctionalize generation assets by operating characteristics.[42] Staff subfunctionalized generation assets as "Type 1," those assets which have significant variable costs of operation which are avoidable if the

[42] Historically, the classification of production cost of service to "energy" and "demand" causation was typically a step in a class cost of service study. However, this simplification is not a good representation of the cost causation of Empire's production cost of service and revenues. Prior to the development of robust integrated energy markets, an electric utility would build its generation fleet to efficiently meet the needs of its customers over time. Meaning, a utility would build baseload, intermediate, and peaking generation in configurations that management determined to be appropriate for its current and anticipated load, with a relatively small amount of excess capacity or energy, or a relatively small shortfall of capacity or energy, which would be balanced among neighboring utilities.

Baseload generation such as nuclear plants or large coal plants are relatively cheap to operate, but very expensive to build. Baseload plants generate energy very efficiently at a given point on the heat rate curve, but are less efficient at the upper and lower bounds of the operating range. While these units could be ramped up and down on a daily basis, they cannot be immediately dispatched and require days or weeks to turn off and on. Intermediate plants could include small coal or oil plants, or combined cycle natural gas plants. These plants could be turned on for a peak season, typically summer, but would have roughly the same range of intra-day variability as larger baseload plants. Peaking plants, such as small natural gas or oil reciprocating or combustion units, and small to large natural gas combustion turbines, can power off and on in minutes. These plants tend to be relatively inexpensive to construct, but very expensive to operate on a per MWh basis, subject to the fluctuations of the natural gas market and pipeline capacity availability. While legacy baseload units remain in operation at Plum Point (coal) and the Iatan units (coal), Empire has retired several of its coal generation assets in recent years. Also, in recent years, Empire has added significant amounts of wind generation, particularly the King's Point, Neosho Ridge, and Northfork Ridge wind projects.

unit is offline and are fully dispatchable with limited exceptions. Staff subfunctionalized generation assets as "Type 2" those assets with no or minimal variable costs of operation, where asset dispatch is often limited by weather conditions or other factors beyond the control of the utility, and many are eligible to comply with Missouri's Renewable Energy Standard.

Q. How did Staff allocate Type 2 assets?

A. Staff allocated Type 2 assets using the partial energy weighting method described at page 49 of the NARUC[43] Manual.[44] This approach allocates the production plant costs to the classes on the basis of the energy loads, but does not classify the costs as "energy-related," in that these costs are not expected to vary with the level of generation produced or consumed.

Q. How did Staff allocate Type 1 assets?

A. Due to concerns with the reliability of available hourly class-load data for the energy market based approach Staff has used in recent cases, Staff allocated Type 1 assets using the A&E 2 NCP allocator.

Classification and Allocation of Distribution System Accounts

Q. Does Empire include assets in its distribution Continuing Property Record ("CPR") accounts that should not be classified and allocated as typical distribution assets?

A. Yes. Empire's CPR includes a relatively small amount of assets that it identifies as associated with production, and includes assets in conductor, poles, and conduit accounts that it identifies as associated with substations:

[43] National Association of Regulated Utility Commission ("NARUC").
[44] This treatment is most reasonable in general, but also particularly in light of the operation of the Fuel and Purchase Power Adjustment Clause.

	Production		Substation	
Poles	$	30,640	$	23,348
Overhead Conductor & Device	$	29,903	$	(11,832)
Conduit	$	78,457	$	(3,226)
Underground Conductor & Device	$	46,739	$	326,304
Transformers	$	8,980	$	99,409

Q. Does Staff have adequate information in this case to assign representative asset costs of radial distribution lines and related infrastructure to the customers who solely utilize those assets?

A. No. Staff is unable to assign representative costs for customer-specific infrastructure to customers served at voltages above secondary in this case. In general, this failure to assign customer specific resources or to allocate reasonable estimates of the cost of customer specific resources will overstate the cost of service for customers served at secondary voltage, and will understate the cost of service for customers served at voltages above secondary. Radial lines for secondary customers are recorded to the "services" account, while the comparable infrastructure for higher voltage customers is recorded to conductor and devices accounts, and poles and conduit accounts.

Q. Does the NARUC manual address this issue?

A. Yes. With regard to facilities operating at distribution voltages, the NARUC Manual at pages 87 and 89 states "Assignment or 'exclusive use' costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components."

Q. Did Staff assign the asset value that Empire identified as "Excess Facilities," to the classes?

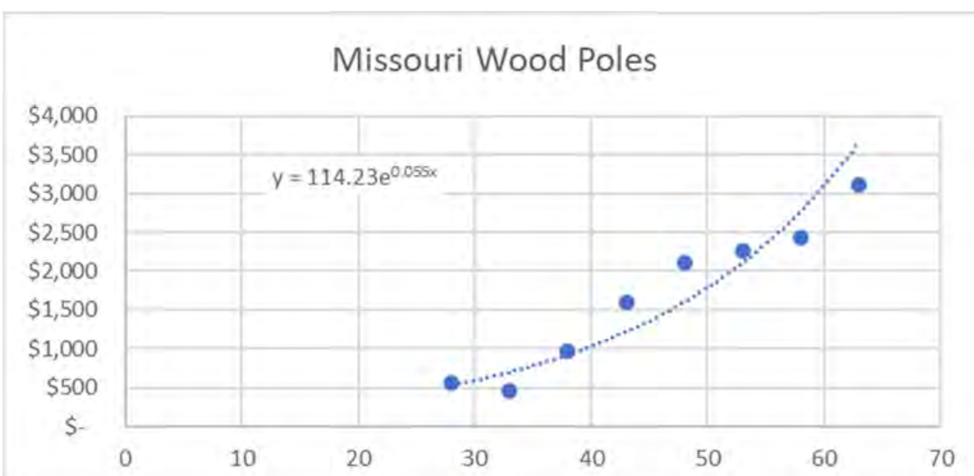
A. Yes. Staff relied on Empire's assignment of excess facilities.

Q. Are excess facilities different from customer-specific facilities?

A. All excess facilities are customer specific, but not all customer-specific facilities are excess. For example, Empire may build a new radial line to a new customer from Feeder Line A. This would be a customer-specific facility. However, the customer may request that Empire *also* build a radial line from Feeder B, to provide a redundant feed in case there is an outage on Feeder A or on the first radial line. This second radial line is also a customer-specific facility, but would also be considered an excess facility.

Q. How did Staff classify the poles account?

A. Staff conducted a zero-intercept study of the poles account to determine the portion of the account to classify as customer-related. Staff reviewed the wood poles recorded to the CPR as Missouri mass property. Staff graphed the poles by height and average cost per pole, excluding poles with low unit quantities, and poles that were over 65'. Staff found the Y intercept of the best-fit line to be $114.23, indicating that were Empire's distribution system to consist of poles that were zero feet tall, the cost of the pole would be $114.23. The cost of these theoretical 0-foot-tall poles are appropriately allocated to the classes on the basis of customer counts, as the cost that is required to have the poles to support an overhead distribution system, regardless of the load requirements of the customer.



Empire's CPR reflects 175,726 total poles and towers recorded to the pole account for the Missouri retail jurisdiction, excluding those recorded within the distribution account but designated as being used for production or substations. Multiplying the pole count by the zero intercept cost results in a customer-allocable amount of $20,073,181. The remainder of the account balance is classified as demand-related.

Q. How did Staff classify the Overhead Conductors & Devices account?

A. For the Overhead Conductors & Devices account, Staff performed four minimum system studies, based on the minimum cost unit for each type of asset. Empire's CPR indicates 69,432,494 feet of cable within the account recorded as Missouri mass property. Staff identified a minimum conductor cost for cable of $0.036/ft, after removing a lower-priced conductor due to low recorded quantities. This results in a customer-allocable amount related to cable of $2,519,173. Empire's CPR indicates 12,888,914 feet of wire within the account recorded as Missouri mass property. Staff identified a minimum conductor cost for wire of $0.093 per foot, after removing wires with low recorded quantities. This results in a customer-allocable amount related to wire of $1,195,193. Staff's review of protection-related devices found 104,303 such devices, at a minimum cost per device of $152.92, for a customer-allocable cost of $15,949,575. Staff's review of switching-related devices found 1,945 such devices, at a minimum cost per device of $841.67, for a customer-allocable cost of $1,637,054.

The conductors and devices in this account are over-sized for secondary customers, and therefore are not a reasonable estimate of the actual minimum system as discussed in the NARUC Manual. "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost**," and "When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs."[45]

The total customer-allocable cost for the Overhead Conductors and Devices account was $21,300,995 under Staff's review, with the remainder to be allocated on the basis of demand. Because Staff does not have information to account for the load-carrying capability of this infrastructure, the Commission should be aware that excess cost of service is allocated to classes such as residential, general service, and lighting, and that the cost of service allocated to classes such as Large Power and Small Primary are unreasonably low.

Q. How did Staff classify the Conduit account?

A. For the Conduit account, Staff's review of the CPR indicated 3,472,604 feet of conduit recorded as Missouri mass property, with a minimum per-unit cost of $4.25, and a customer-allocable cost of $14,754,832. For other items in the account, such as vaults, pads, and pedestals, Staff identified a quantity of 40,727, and a minimum cost of $811.23/unit, resulting in customer-allocable cost of $33,039,010.

[45] NARUC Manual, page 95 [Emphasis added.].

The assets in this account are over-sized for secondary customers, and therefore are not a reasonable estimate of the actual minimum system as discussed in the NARUC Manual.[46]

The total customer-allocable cost for the Conduit account is $47,793,842, with the remainder allocated on the basis of demand. Because Staff does not have information to account for the load-carrying capability of this infrastructure, the Commission should be aware that excess cost of service is allocated to classes such as residential, general service, and lighting, and that the cost of service allocated to classes such as Large Power and Small Primary are unreasonably low.

Q. How did Staff classify the Underground Conductors & Devices account?

A. For the Underground Conductors & Devices account, Staff's review of the CPR indicated 10,002,272 feet of cable recorded as Missouri mass property, with a minimum per-unit cost of $1.28, and a customer-allocable cost of $12,840,292. For protection-related devices in the account, Staff identified a quantity of 19,254, and a minimum cost of $43.46/unit, resulting in customer-allocable cost of $ $836,779. For switching devices in the account, only one retirement unit name was used, so the entire $11,214.75 has been classified as customer-allocable at this time.

The assets in this account are over-sized for secondary customers, and therefore are not a reasonable estimate of the actual minimum system as discussed in the NARUC Manual.[47]

[46] "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost**," and "When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs." NARUC Manual, page 95 [Emphasis added.].

[47] "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method,**

The total customer-allocable cost for the Underground Conductors & Devices account is $15,785,444, with the remainder to be allocated on the basis of demand. Because Staff does not have information to account for the load-carrying capability of this infrastructure, the Commission should be aware that excess cost of service is allocated to classes such as residential, general service, and lighting, and that the cost of service allocated to classes such as Large Power and Small Primary are unreasonably low.

Q. What measure of demand did Staff use to allocate the poles, conduit, and conductors & devices accounts?

A. Staff used the 12 coincident peaks of each customer class, which is reasonable given the seasonal diversity of loads experienced at Empire. While Staff considered use of an NCP factor, because the demand-allocable distribution accounts consist almost exclusively of assets that operate at primary voltage, and because the customer classification of these accounts includes adequate capacity to serve the full demand of secondary customers, Staff selected the CP as most reasonable in this case.

Q. How did Staff functionalize the substation accounts?

A. Empire has recorded substation facilities associated with its wind generation facilities within its substation accounts. Staff functionalized these subaccounts as Production 2, and has allocated them accordingly. Remaining substation assets are allocated using a 12 CP,

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the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost," and "When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs." NARUC Manual, page 95 [Emphasis added.].

consistent with most transmission allocation, and reflecting the diversity of usage associated with substation demand requirements.

Q. How did Staff allocate the transformer account, the services account, and the meter accounts?

A. Staff relied on Empire's allocators, adjusted to reflect Staff's customer counts.

Q. How were distribution and metering expenses allocated to the classes in Staff's CCOS study?

A. Depreciation expense and operating and maintenance expenses associated with distribution and metering were allocated consistent with the allocation of the underlying plant allocation.

Administrative and Overhead Cost of Service

Q. How are items like property taxes, employee benefits, and income taxes treated in Staff's CCOS study?

A. Property taxes are allocated to the classes based on the underlying plant allocation to the classes. Employee benefit expenses are allocated to the classes based on the underlying labor expense allocation to the classes (which was based on the underlying asset allocation). Income taxes, other than tax credits related to renewable energy, are allocated to the classes based on each class's allocated net ratebase.

Where an asset or expense relates to some other allocated cost of service, Staff allocated the asset or expense consistent with that underlying allocation. For example, the Commission assessment is directly related to class level revenue, so it is reasonably allocated to the classes using each class's share of revenue. The net ratebase element of sales and use taxes were also allocated on class revenue.

Q. What is the cost causation of the costs, expenses, and revenues functionalized as Administrative and General in the Staff CCOS study?

A. Other costs in the administrative and general category lack causation that relates to any determinant of any class, or any underlying allocation of assets or expenses.

Q. How does Staff recommend that the non-revenue-related administrative and general cost of service be allocated to the classes?

A. Ultimately, Staff recommends these costs be allocated to the classes on the basis of energy sales, as the basic product of an electric utility. However, for minimization of issues in this already complex case, Staff allocated the administrative and general cost of service to the classes on the basis of the cost of service directly allocated to each class.

Q. What are Staff's full CCOS results?

A. The full study results are provided below:

continued on next page

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
EMS Revenues	$ 248,403,164	$ 61,281,370	$113,773,518	$ 10,520,058	$ 66,407,104	$ 4,674,852	$ 6,537,778
Solar Facilites	$ 28,494	$ 386	$ -	$ 28,668	$ -	$ -	$ -
Net Metering @ QF Rate	$ (349,184)	$ (67,846)	$ (30,250)	$ -	$ -	$ -	$ -
EDR	$ -	$ -	$ -	$ (136,183)	$ (1,607,165)	$ -	$ -
Retail Rates Subject to Adjustment	$ 248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Excess Facilities	$ -	$ 3,399	$ 16,523	$ 299,854	$ 1,268,523	$ 864	$ -
Adjustments to Retail Revenues	$ (320,690)	$ (64,062)	$ (13,727)	$ 192,339	$ (338,642)	$ 864	$ -
Adjusted Retail Revenues before EDR	$ 248,723,854	$ 61,348,830	$113,803,768	$ 10,763,756	$ 69,621,433	$ 4,674,852	$ 6,537,778
Allocated Ratebase	$ 1,171,033,341	$236,365,040	$441,795,684	$ 38,291,368	$254,212,697	$ 16,867,828	$ 34,947,266
Return on Ratebase at System Average	$ 82,253,382	$ 16,602,280	$ 31,031,729	$ 2,689,586	$ 17,855,900	$ 1,184,796	$ 2,454,696
CLASS COST OF SERVICE	$ 304,463,675	$ 63,450,577	$125,114,815	$ 11,391,926	$ 78,914,972	$ 5,857,740	$ 7,316,233
"Other Revenue" Line	$ 7,299,019	$ 1,522,640	$ 3,139,421	$ 329,516	$ 2,125,458	$ 172,544	$ 35,150
"Retail" revenue line	$ 257,939,955	$ 63,559,153	$119,339,820	$ 11,486,575	$ 73,540,590	$ 5,037,422	$ 6,611,022
Retail Rates Subject to Adjustment	$ 248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Disallowance for Customer First	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		**$ -**
Total Cost of Service	**$ 304,463,675**	**$ 63,450,577**	**$125,114,815**	**$ 11,391,926**	**$ 78,914,972**	**$ 5,857,740**	**$ 7,316,233**
Revenues not Subject to Adjustment	**$ 16,515,120**	**$ 3,732,963**	**$ 8,675,473**	**$ 1,188,519**	**$ 7,651,780**	**$ 535,114**	**$ 108,394**
TCS less all revenues not subject to adjustment	**$ 287,948,555**	**$ 59,717,614**	**$116,439,342**	**$ 10,203,407**	**$ 71,263,192**	**$ 5,322,626**	**$ 7,207,839**
Adjusted TCS less Return	$ 205,695,173	$ 43,115,334	$ 85,407,613	$ 7,513,822	$ 53,407,293	$ 4,137,830	$ 4,753,143
Revenue if Equal Percent	$ 316,277,297	$ 78,011,183	$144,712,891	$ 13,514,023	$ 86,486,956	$ 5,944,542	$ 8,313,440
Revenue Available for RoR	$ 110,582,123	$ 34,895,849	$ 59,305,278	$ 6,000,201	$ 33,079,663	$ 1,806,713	$ 3,560,297
RoR before A&G	9.44%	14.76%	13.42%	15.67%	13.01%	10.71%	10.19%
Allocated A&G Expense	$ 34,926,285	$ 7,243,358	$ 14,123,334	$ 1,237,607	$ 8,643,761	$ 645,600	$ 874,264
Allocated A&G Ratebase	$ 201,731,170	$ 41,837,001	$ 81,575,143	$ 7,148,309	$ 49,925,610	$ 3,728,928	$ 5,049,672
Gross Ratebase	$ 1,372,764,511	$278,202,041	$523,370,827	$ 45,439,677	$304,138,307	$ 20,596,756	$ 39,996,938
Gross Adjusted TCS less Return	$ 240,621,458	$ 50,358,691	$ 99,530,947	$ 8,751,429	$ 62,051,054	$ 4,783,429	$ 5,627,407
Revenue Available for RoR	$ 75,655,839	$ 27,652,492	$ 45,181,944	$ 4,762,594	$ 24,435,902	$ 1,161,113	$ 2,686,033
RoR with A&G	5.51%	9.94%	8.63%	10.48%	8.03%	5.64%	6.72%
Return on Ratebase with A&G at System Average	$ 96,422,979	$ 19,540,911	$ 36,761,567	$ 3,191,683	$ 21,362,675	$ 1,446,716	$ 2,809,385
Required Revenue	$ 337,044,437	$ 69,899,603	$136,292,514	$ 11,943,112	$ 83,413,729	$ 6,230,146	$ 8,436,792
Current EDR	$ -	$ -	$ -	$ (136,183)	$ (1,607,165)	$ -	$ -
Reallocated EDR	$ (841,191)	$ (207,483)	$ (384,887)	$ (36,403)	$ (235,462)	$ (15,810)	$ (22,111)
Required Revenue After EDR Reallocation	**$ 337,885,628**	**$ 70,107,086**	**$136,677,401**	**$ 11,979,515**	**$ 83,649,190**	**$ 6,245,956**	**$ 8,458,903**
Study Results Increase to Adjustable Rates	**$ 89,161,774**	**$ 8,758,256**	**$ 22,873,633**	**$ 1,215,759**	**$ 14,027,757**	**$ 1,571,104**	**$ 1,921,125**
% Increase	**36%**	**14%**	**20%**	**11%**	**21%**	**34%**	**29%**
Equal Percent Increase	**$ 67,553,443**	**$ 16,662,353**	**$ 30,909,123**	**$ 2,886,451**	**$ 18,472,687**	**$ 1,269,691**	**$ 1,775,662**
Over/(Under) Contribution $	**$ (20,767,141)**	**$ 8,111,580**	**$ 8,420,377**	**$ 1,570,911**	**$ 3,073,227**	**$ (285,603)**	**$ (123,352)**
Over/(Under) Contribution %	**-21.54%**	**41.51%**	**22.91%**	**49.22%**	**14.39%**	**-19.74%**	**-4.39%**
5% Tolerance	$ 4,821,149	$ 977,046	$ 1,838,078	$ 159,584	$ 1,068,134	$ 72,336	$ 140,469

Note, these results do not include the Customer First disallowance recommended by James A. Busch. Staff has incorporated those results through its Interclass Revenue Responsibility Recommendation

Interclass Revenue Responsibility Recommendation

Q. Should a CCOS study's results be the only factor in applying a rate increase to a utility's charges for service?

A. No. Policy considerations, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, and meeting of incremental costs, are also relevant factors in revenue responsibility allocation, rate structure, and rate design. The precision of a CCOS study is also a factor, in addition to the limitation that a CCOS study filed in direct testimony will reflect the direct case of a given party and will not reflect a Commission-ordered cost of service, revenue quantification, or billing determinants. The availability of data is also a significant limitation to the precision and reliability of a CCOS study, such as Staff has noted on the limitation of distribution data availability resulting in overallocation of cost of service to the residential, general service, and lighting classes, and the underallocation of cost of service to the small primary and large power classes.[48]

Q. What is Staff's general approach to implementing revenue responsibility shifts and the precision of CCOS results?

A. In general, Staff will not recommend any class receive a reduction in a general rate proceeding with a positive net revenue requirement; and Staff will not recommend adjustment to study results unless those results indicate one or more classes' percent change to bring class rate revenue to the studied cost of service exceeds 5% in one direction and another class or classes' indicated change exceeds 5% in the opposite direction.

[48] Because the large general class serves significantly larger customers than other secondary-service classes, it should not receive significant overallocations.

Staff endeavors to provide methods to promote revenue stability and efficiency when implementing any Commission-ordered overall change in customer revenue responsibility in rates. Staff must also balance this, to the extent possible, with retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.

Q. To what revenues should the increase be applied if percentage adjustments are used?

A. The revenues to be adjusted in this case are those derived from retail rate revenue schedules, exclusive of solar facility charges, excess facility charges, economic development discounts, and net metering overage payments. To the extent that any ordered increase is calculated as a percentage of class revenue, only the underlying rate schedule revenues are applicable.

Q. How should the revenue responsibility for the cost of service ordered in this case be recovered from the customer classes?[49]

A. In this case, Staff recommends that the Commission consider Staff's indicated residential class increase as the absolute ceiling in issuing its ordered rate increase implementation, particularly in light of the Customer First implementation failures, and also because:

1. The distribution treatment in Staff's CCOS shifts cost responsibility toward residential and small customer classes and away from larger classes,

[49] The allocation of revenue responsibility among customer classes is also referred to as ***interclass revenue responsibility***, while the pricing of elements of a given class's rate structure can be referred to as ***intraclass revenue responsibility***, or also as ***rate design***.

2. The production allocation is not Staff's recommended approach, and it tends to overallocate cost responsibility toward residential and small customer classes and away from larger classes, but Staff has used it in this case because concerns with the billing issue undermine Staff's preferred approach, and to minimize disputes in this already very complex case.

As discussed by James A. Busch, given the circumstances surrounding this case and the roll out of Empire's "Customer First" billing system and software, Staff recommends that any increase be allocated to the classes on an equal percentage basis prior to consideration of his recommended Customer First disallowance, and that the Customer First disallowance then be applied entirely to the residential class.[50]

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$ 248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Revenue Responsibility Adjusted for Customer First	$ 298,780,247	$ 78,067,727	$144,817,781	$ 13,523,818	$ 86,549,643	$ 5,948,851	$ 8,319,465
Increase	$ 50,056,393	$ 16,718,897	$ 31,014,014	$ 2,896,246	$ 18,535,374	$ 1,273,999	$ 1,781,687
Percent Increase to "Average" Customer Bill	20.13%	27.25%	27.25%	27.25%	27.25%	27.25%	27.25%

This approach can be taken by the Commission regardless of any class cost of service study results presented in this case.

Q. What is Staff's alternative recommended allocation?

A. Staff's alternative recommended allocation is set out below:

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Retail Rates Subject to Adjustment	$248,723,854	$ 61,348,830	$113,803,768	$ 10,627,572	$ 68,014,268	$ 4,674,852	$ 6,537,778
Required Revenue	$337,044,437	$ 69,899,603	$136,292,514	$ 11,943,112	$ 83,413,729	$ 6,230,146	$ 8,436,792
Revenue Responsibility Adjusted for Customer First	$315,570,519	$ 71,075,289	$139,206,022	$ 11,977,731	$ 83,592,758	$ 6,177,749	$ 8,318,331
Increase	$ 66,846,665	$ 9,726,459	$ 25,402,255	$ 1,350,158	$ 15,578,489	$ 1,502,897	$ 1,780,553
Percent Increase to "Average" Customer Bill	26.88%	15.85%	22.32%	12.70%	22.90%	32.15%	27.23%

Q. What are the detailed steps of this calculation?

A. These calculations are set out below.

[50] To the extent the disallowance exceeds the increase applicable to the Residential class, Residential rates should be held constant, with the remaining disallowance being applied against the increase applicable to the General Service class.

	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
	2	3	3	3	3	2	1
Hold	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,775,662
Above Average	$ 84,340,625	$ -	$ -	$ -	$ -	$ 1,498,768	$ -
Below Average	$ -	$ 9,699,739	$ 25,332,472	$ 1,346,449	$ 15,535,693	$ -	$ -
Preliminary Recommended Increase to Adjustable Rates	$ 84,340,625	$ 9,699,739	$ 25,332,472	$ 1,346,449	$ 15,535,693	$ 1,498,768	$ 1,775,662
	33.91%	15.81%	22.26%	12.67%	22.84%	32.06%	27.16%
EDR Factor Up	$ -	$ -	$ -	$ (17,254)	$ (367,106)	$ -	$ -
EDR Factor Up Responsibility	$ 232,332	$ 26,720	$ 69,783	$ 3,709	$ 42,796	$ 4,129	$ 4,891
	Residential	GS	LGS	SPS	LPS	Transmisison	Lighting
Recommended Revenue from Rates Subject to Adjustment	$333,296,811	$ 71,075,289	$139,206,022	$ 11,977,731	$ 83,592,758	$ 6,177,749	$ 8,318,331
Percent Increase to "Average" Customer Bill	34.00%	15.85%	22.32%	12.70%	22.90%	32.15%	27.23%
Revenue Responsibility Adjusted for Customer First	$315,570,519	$ 71,075,289	$139,206,022	$ 11,977,731	$ 83,592,758	$ 6,177,749	$ 8,318,331
Increase	$ 66,846,665	$ 9,726,459	$ 25,402,255	$ 1,350,158	$ 15,578,489	$ 1,502,897	$ 1,780,553
Percent Increase to "Average" Customer Bill	26.88%	15.85%	22.32%	12.70%	22.90%	32.15%	27.23%
Current $/kWh @ Trans Volt	$ 0.134	$ 0.138	$ 0.105	$ 0.098	$ 0.083	$ 0.065	$ 0.361
Studied $/kWh @ Trans Volt	$ 0.183	$ 0.158	$ 0.126	$ 0.109	$ 0.100	$ 0.088	$ 0.467
Recommended $/kWh @ Trans Volt	$ 0.171	$ 0.160	$ 0.129	$ 0.110	$ 0.102	$ 0.087	$ 0.459
Allocated ratebase $/kWh	$ 0.74	$ 0.63	$ 0.48	$ 0.42	$ 0.37	$ 0.29	$ 2.21

<u>Residential EV Charger Pilot</u>

Q. Could you summarize the Residential Smart Charger Pilot program?

A. Yes. The Pilot program became available to customers on October 15, 2022. Under the pilot program ("Pilot"), customers were billed time-based rates based on the usage as metered through the EV charger, and that usage was excluded from the household electric bill at the normal rates. This arrangement was designed to test the feasibility of sub-metering EV charging usage with the EV charger, without installing a second service drop or relying on a second utility-owned meter.

Q. Were there program requirements to attempt to ensure the reliability of the EV charger for use in submetering?

A. There were. Eligible chargers were pre-approved by Empire. The tariff included a provision that "Participants must ensure reliable access to wireless internet service at the location of the charging equipment to ensure remote reading of the EV charger's consumption for use in billing, and commit to provide access to the Company's personnel from time to time to the charger for the purposes of maintenance, and (if required) reading verification."

Q. Has a complication arisen?

A. Yes. In October of 2024, Enel, one of the world's leading EV charger manufacturers, and maker of the popular "JuiceBox" charger line, announced that it was exiting the North American EV charging market. Due to this departure, the JuiceBox chargers installed under the Pilot program became unsupported, prompting significant cybersecurity and operability concerns, and compromising the ability of Empire to access customer charging data necessary for bill calculation under the Pilot.

Q. Are all customers being billed based on their actual usage?

A. No. In response to Staff's discovery in this case, Empire responded, in pertinent part, as follows:

> With respect to the two customer chargers for which the Company is unable to retrieve charging data, program staff suspect that this is a result of suspension of ongoing software maintenance activities such as debugging or patching. While the chargers continue working in an offline mode, Liberty has decided to keep them in place and rely on estimated billing in the interim, using the process laid out in the program tariff. This interim approach has been discussed with both affected customers. While the Company has new Juicebox chargers in its inventory, it is no longer able to connect them to the ENEL online portal that it needs to maintain billing.[51]
>
> The Company notes that residential ChargePoint chargers (or those by other vendors) can be easily purchased through a variety of retail channels in the absence of a commercial vendor contract. However, hardware sold in this manner does not include access to third-party portals that the Company would need to support billing and data analysis. In Liberty's experience, access to such portals can only be gained by entering into data access agreements with technology vendors.

[51] In response to subsequent discovery, Staff Data Request No. 0331, Empire indicated that it has replaced, at ratepayer cost, 13 chargers to date related to this issue.

> Although it has experienced considerable difficulties navigating this issue, Liberty remains optimistic as to its successful resolution, involving restoring reliable service for all program participants and welcoming into the program the customers in the connection queue that have been awaiting the resolution of the current issue. However, in light of this experience, and given that it has access to a sufficient number of customers to complete a variety of planned pilot analysis activities, Liberty's preference is to complete the pilot's originally intended five-year timeline but suspend any further enrollment of new customers. The Company plans to make a filing with the Commission in this regard.[52]

Q. When does the Pilot expire?

A. The Pilot tariff provides for a five-year term, with no new chargers to be installed after the start of year five. Therefore, no new chargers should be installed after October 15, 2026, under the existing tariff terms. However, due to concerns with the availability of suitable billing data for the EV charger usage, Staff recommends that the tariff be revised such that no new chargers be installed after the effective date of rates in this case, and that the Pilot be allowed to expire under its own terms in October of 2027.

Q. Under this approach, what will happen to participants in October of 2027?

A. The Pilot tariff, at P.S.C. Mo. No. 6 Sec. 3 Original Sheet No. 10f, addresses conclusion of the program without a successor program. It states:

> Scenario 1: No RSCPP Successor Program and/or Tariff: If the RSCPP and the associated tariff are discontinued without being replaced by a successor program and tariff, the Participants will have two options:
>
> i. Option A: buy out the remaining Charger capital costs at remaining net book value, thus assuming ownership. Under this option the customer would be responsible for all charger maintenance activities and the associated costs upon the expiration of the Program and would be responsible for procuring replacement equipment; OR
>
> ii. ii. Option B: continue paying charger financing costs under the rates in place prior to the Program's cancellation, by executing an appropriate service extension agreement available exclusively to the legacy RSCPP Participants

[52] Empire Response to Data Request No. 0145.

– the Company would continue maintaining and replacing the assets until equipment is fully depreciated.

Under either option under Scenario 1, the Participants would then be charged for their EV charger's electricity consumption under the regular residential tariff applicable at the time.

Q. Based on the information and communications you are aware of at this time, did Empire act prudently in initially selecting ENEL Juiceboxes as a vendor for the residential charging program?

A. Yes. The ENEL was unquestionably one of the top charger vendors at the time the Pilot began.

Q. What is Staff's recommendation concerning the Pilot?

A. In Empire's tariff, P.S.C. Mo. No. 6 Sec. 3 Original Sheet No. 10b, the sentence "New installations under this program shall not be available during program Year 5," should be replaced with "New installations under this program shall not be available after the effective date of rates in File No. ER-2024-0261."

<u>Conclusion</u>

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area	)))))	Case No. ER-2024-0261

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 *Direct 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 15th day of July 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

Sarah L.K. Lange

I received my J.D. from the University of Missouri, Columbia, in 2007, and am licensed to practice law in the State of Missouri. I received my B.S. in Historic Preservation from Southeast Missouri State University, and took courses in architecture and literature at Drury University. Since beginning my employment with the MoPSC I have taken courses in economics through Columbia College and courses in energy transmission through Bismarck State College, and have attended various trainings and seminars, indicated below.

I began my employment with the Commission in May 2006 as an intern in what was then known as the General Counsel's Office. I was hired as a Legal Counsel in September 2007, and was promoted to Associate Counsel in 2009, and Senior Counsel in 2011. During that time my duties consisted of leading major rate case litigation and settlement, and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints.

In July 2013 I was hired as a Regulatory Economist III in what is now known as the Tariff / Rate Design Department. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and regulatory adjustment mechanisms and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation. I have also participated before the Commission under the name Sarah L. Kliethermes.

Presentations

Midwest Energy Policy Series – Impact of ToU Rates on Energy Efficiency (August 14, 2020)

Billing Determinants Lunch and Learn (March 27, 2019)

Support for Low Income and Income Eligible Customers, Cost-Reflective Tariff Training, in cooperation with U.S.A.I.D. and NARUC, Addis Ababa, Ethiopia (February 23-26, 2016)

Fundamentals of Ratemaking at the MoPSC (October 8, 2014)

Ratemaking Basics (Sept. 14, 2012)

Participant in Missouri's Comprehensive Statewide Energy Plan working group on Energy Pricing and Rate Setting Processes.

Relevant Trainings and Seminars

FRI Advanced Seminar on Transformation Utility Pricing & Rate Design (April 7 - 9, 2025)

Regional Training on Integrated Distribution System Planning for Midwest/MISO Region (October 13-15, 2020)

"Fundamentals of Utility Law" Scott Hempling lecture series (January – April, 2019)

Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30, 2014)

MISO Markets & Settlements training for OMS and ERSC Commissioners & Staff (January 27–28, 2014)

Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)

PSC Transmission Training (May 14 – 16, 2013)

Grid School (March 4–7, 2013)

Specialized Technical Training - Electric Transmission (April 18–19, 2012)

The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)

Mid-American Regulatory Conference Annual Meeting (June 5–8, 2011)

Renewable Energy Finance Forum (Sept. 29–Oct 3, 2010)

Utility Basics (Oct. 14–19, 2007)

Testimony and Staff Memoranda

Company	Case No.
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in Its Missouri Service Area	ER-2024-0261
Evergy Metro, Inc. d/b/a Evergy Missouri Metro In the Matter of the Tariff Filings of Evergy Metro, Inc. d/b/a Evergy Missouri Metro.	ET-2025-0286
Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of the Application of Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Permission and Approval of Certificates of Public Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Manage, Maintain and Control Two Solar Generation Facilities.	EA-2024-0292
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service.	ER-2024-0319
Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2024-0189
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's and Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Solar Subscription Rider Tariff Filings	ET-2024-0182
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West The Staff of the Missouri Public Service Commission, Complainant, v Evergy Metro, Inc. d/b/a Evergy Missouri Metro's and Evergy Missouri West, Inc. d/b/a Evergy Missouri West	EC-2024-0092
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of the Joint 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 Tariff Revisions to TOU Program	ET-2024-0061
Union Electric Company d/b/a Ameren Missouri In the Matter of the Petition of Union Electric Company d/b/a Ameren Missouri for a Financing Order Authorizing the Issue of Securitized Utility Tariff Bonds for Energy Transition Costs related to Rush Island Energy Center	EF-2024-0021
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Requests for Customer Account Data Production from Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West	E0-2024-0002

Company	Case No.
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request to Revise Its Solar Subscription Rider	EO-2023-0423 EO-2023-0424
Evergy Metro, Inc. d/b/a Evergy Missouri Metro Evergy Missouri West, Inc. d/b/a Evergy Missouri West In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism	EO-2023-0369 EO-2023-0370
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	ER-2023-0136
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Certificates of Convenience and Necessity for Solar Facilities	EA-2023-0286
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2022-0337
NextEra Energy Transmission Southwest, LLC In the Matter of the Application of NextEra Energy Transmission Southwest, LLC for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 345 kV Transmission Line and associated facilities in Barton and Jasper Counties, Missouri	EA-2022-0234
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2022-0179
Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West for a Financing Order Authorizing the Financing of Extraordinary Storm Costs Through an Issuance of Securitized Utility Tariff Bonds	EF-2022-0155
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040

Company	**Case No.**
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Convenience and Necessity Under Section 393.170 RSMo Relating to Transmission Investments in Southeast Missouri	EA-2022-0099
The Empire District Electric Company d/b/a Liberty In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	ER-2021-0312
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2021-0240
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 138 kV Transmission Line and associated facilities in Perry and Cape Girardeau Counties, Missouri	EA-2021-0087
Evergy Affiliates 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 a Transportation Electrification Portfolio	ET-2021-0151
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2021-0108
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren for Approval of its Surge Protection Program	ET-2021-0082
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren Missouri to Implement the Delivery Charge Adjustment for the 1st Accumulation Period beginning September 1, 2019 and ending August 31, 2020	GT-2021-0055
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs Approval of a Transportation Electrification Portfolio for Electric Customers in its Missouri Service Area	ET-2020-0390
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs to Increase Its Revenues for Electric Service	ER-2019-0374
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service	ER-2019-0335

Company	Case No.
KCP&L Greater Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company Request for Authority to Implement Rate Adjustments Required by 4 CSR 240-20.090(8) And the Company's Approved Fuel and Purchased Power Cost Recovery Mechanism	ER-2019-0413
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Natural Gas Service	GR-2019-0077
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri Revised Tariff Sheets	ET-2019-0149
The Empire District Electric Company In the Matter of The Empire District Electric Company's Revised Economic Development Rider Tariff Sheets	ET-2019-0029
The Empire District Electric Company In the Matter of a Proceeding Under Section 393.137 (SB 564) to Adjust the Electric Rates of The Empire District Electric Company	ER-2018-0366
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Construct a Wind Generation Facility	EA-2018-0202
Kansas City Power & Light Company KCP&L Greater Missouri Operations Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2018-0145 ER-2018-0146
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program	ET-2018-0132
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff	ET-2018-0063
Laclede Gas Company Laclede Gas Company d/b/a Missouri Gas Energy In the Matter of Laclede Gas Company's Request to Increase Its Revenue for Gas Service, In the Matter of Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenue for Gas Service.	GR-2017-0215 GR-2017-0216
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0316
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0167
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Annual RESRAM Tariff Filing	ET-2017-0097

Company	**Case No.**
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2016-0358
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2016-0325
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	ER-2016-0285
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Subscriber Solar Program and File Associated Tariff	EA-2016-0207
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2016-0179
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0156
Empire District Electric Company In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0023
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri to the Iowa Border and an Associated Substation Near Kirksville, Missouri	EA-2015-0146
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line in Marion County, Missouri and an Associated Switching Station Near Palmyra, Missouri	EA-2015-0145
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	EO-2015-0055
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2014-0370

Company	Case No.
Empire District Electric Company In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	ER-2014-0351
Union Electric Company d/b/a Ameren Missouri City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0316
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2014-0258
Union Electric Company d/b/a Ameren Missouri Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0224
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2014-0207
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Application for Authority to Establish a Renewable Energy Standard Rate Adjustment Mechanism	EO-2014-0151
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Filing for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism	EO-2014-0095
Veolia Energy Kansas City, Inc. In the Matter of Veolia Energy Kansas City, Inc. for Authority to File Tariffs to Increase Rates	HR-2014-0066

Applicability:

Any customer taking service at 34 kV or greater except those served under the Small Primary rate schedule, Large Power rate schedule, or the Transmission Service rate schedule 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 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, Empire 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) Empire's determination that transmission facilities are required.

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

Other Tariff Applicability:

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

1. Interruptible Service, Rider IR
2. Optional Time of Use Adjustment, Rider OTOU
3. Economic Development, Rider EDR
4. Limited Large Customer Economic Development, Rider SBEDR

Customers taking service under Schedule LLCS are required to take service under:

1. Fuel Adjustment Clause, Rider FAC
2. Securitized Utility Tariff Charge, Rider SUTC
3. Charges pursuant to any authorized program under the authority of the Missouri Energy Efficiency Investment Act.

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 Empire, 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 Empire, 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 Empire, but for which Empire 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, Empire 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.

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. 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,
    e. A commitment to notify Empire of any anticipated deviations of +/-10% or more of previously-anticipated load as soon as such potential deviations become anticipated;
    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.
C. A pledge of collateral or other security as ordered by the Commission in this proceeding, which shall equal or exceed the indicated termination fees.

D. 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.
E. 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.
F. Details pertinent to calculation and verification of rates for the Capacity Cost Sufficiency Rider, if applicable.

Capacity Cost Sufficiency Rider:

In the event that Empire 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, Empire may obtain contractual capacity to reliably serve the requesting customer. Empire 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. Empire 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.

Monthly Charges for Service:

Brief Description	Empire	Determinant for Charge
Customer Charge	$ 10,000	$/Customer
Facilities Charge	$ 0.03148	$/$ of Assets
Demand Charge 1 - Charge for Generation Capacity Cost of Service	$ 22.04	$/kW during demand window
Demand Charge 2 - Charge for Transmission Capacity Cost of Service	$ 5.52	$/kW during demand window
Energy Charges		
Summer Off Peak	$ 0.0210	$/kWh
Summer Intermediate	$ 0.0313	$/kWh
Summer On Peak	$ 0.0460	$/kWh
Fall Off Peak	$ 0.0204	$/kWh
Fall Intermediate	$ 0.0342	$/kWh
Fall On Peak	$ 0.0540	$/kWh
Winter Off Peak	$ 0.0286	$/kWh
Winter Intermediate	$ 0.0339	$/kWh
Winter On Peak	$ 0.0372	$/kWh
Spring Off Peak	$ 0.0165	$/kWh
Spring Intermediate	$ 0.0300	$/kWh
Spring On Peak	$ 0.0492	$/kWh
Load-servicing charge (Summer)	$ 0.0020	$/kWh
Load-servicing charge (Non-Summer)	$ 0.0010	$/kWh
RES compliance charge	$ 0.0004	$/kWh
Variable Fixed Revenue Contribution	24.36%	Percent of other charges
Stable Fixed Revenue Contribution	24.36%	Percent of other charges
Demand Deviation Charge		$/kW of deviation
Imbalance Charge		$/kW of deviation
EDD Responsibility Charge		$/kWh
Capacity Shortfall Rate, if applicable		$/kW
Capacity Cost Sufficiency Rider, if applicable		$/Month
Reactive Demand Charge		$/kVar

Treatment of LLCS Customer Revenues:

A. Until a rate case recognizing the customer at the full level of projected demand, the difference between the revenue for each charge considered for that customer in the last general rate case, and the current level of revenue for that charge will be recorded to a regulatory liability account. This treatment is applicable to revenue from all charges except the Customer Charge, Facilities Charge, Demand Deviation Charge, Imbalance Charge, Capacity Shortfall Rate, the Capacity Cost Sufficiency Rider, and the RES Compliance Charge. The resulting regulatory liability will be treated as an offset to production ratebase with a 50 year amortization. The annualized and normalized revenue from these charges shall be reflected in each rate case.
B. All revenue billed under charge the RES Compliance charge will be recorded to a regulatory liability, and that regulatory liability will be treated as an offset to production ratebase with a 50 year amortization. Revenue for the RES Compliance charge will only be addressed through this accumulated regulatory liability, and shall not be considered as rate revenue in rate cases.
C. All revenue billed under the Demand Deviation Charge, 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.

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. 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.
C. LLCS bills shall be paid by the fifteenth business day of the month issued.
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.
E. Service on this schedule is limited to 33% of Empire's annual Missouri jurisdictional load.
F. Prior to execution of a Service Agreement with a prospective LLCS customer, Empire 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 Empire executes a Service Agreement without adequate capacity, Empire'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.

Non-Standard Large General Service	Winter	Summer
Billed Demand kW Determinant	2,281,870	1,166,626
Empire-Proposed Rate	$ 9.10	$ 11.67
Empire-Proposed Revenue (Calculated)	$ 20,765,017	$ 13,614,525
Empire-Proposed Revenue (In Schedule)	$ 20,756,161	$ 13,615,391
Empire-Calculated Time-Variant Determinants	111,394	47,657
Determinant Difference (%)	5%	4%
Empire-Proposed Time-Variant Rate	$ 186.33	$ 285.70
Empire-Proposed Time-Variant Revenue	$ 20,756,044	$ 13,615,605
Time Choice Large General Service	**Winter**	**Summer**
Billed Demand kW Determinant	2,281,870	1,166,626
Empire-Proposed Rate	$ 9.06	$ 11.63
Empire-Proposed Revenue (Calculated)	$ 20,673,742	$ 13,567,860
Empire-Proposed Revenue (In Schedule)	$ 20,675,596	$ 13,562,543
Empire-Calculated Time-Variant Determinants	111,394	47,657
Determinant Difference (%)	5%	4%
Empire-Proposed Time-Variant Rate	$ 185.61	$ 284.59
Empire-Proposed Time-Variant Revenue	$ 20,675,840	$ 13,562,706
Non-Standard Small Primary Service	**Winter**	**Summer**
Billed Demand kW Determinant	221,351	115,030
Empire-Proposed Rate	$ 8.71	$ 11.18
Empire-Proposed Revenue (Calculated)	$ 1,927,967	$ 1,286,035
Empire-Proposed Revenue (In Schedule)	$ 1,928,849	$ 1,286,026
Empire-Calculated Time-Variant Determinants	143,125	20,644
Determinant Difference (%)	65%	18%
Empire-Proposed Time-Variant Rate	$ 13.48	$ 62.30
Empire-Proposed Time-Variant Revenue	$ 1,929,325	$ 1,286,121
Time Choice Small Primary Service	**Winter**	**Summer**
Billed Demand kW Determinant	221,351	115,030
Empire-Proposed Rate	$ 8.71	$ 11.17
Empire-Proposed Revenue (Calculated)	$ 1,927,967	$ 1,284,885
Empire-Proposed Revenue (In Schedule)	$ 1,926,871	$ 1,284,707
Empire-Calculated Time-Variant Determinants	143,125	20,644
Determinant Difference (%)	65%	18%
Empire-Proposed Time-Variant Rate	$ 13.46	$ 62.23
Empire-Proposed Time-Variant Revenue	$ 1,926,463	$ 1,284,676
Large Power	**Winter**	**Summer**
Billed Demand kW Determinant	1,056,146	574,545
Empire-Proposed Rate	$ 17.43	$ 31.58
Empire-Proposed Revenue (Calculated)	$ 18,408,625	$ 18,144,131
Empire-Proposed Revenue (In Schedule)	$ 18,407,023	$ 18,145,106
Empire-Calculated Time-Variant Determinants	1,032,638	251,029
Determinant Difference (%)	98%	44%
Empire-Proposed Time-Variant Rate	$ 17.83	$ 72.28
Empire-Proposed Time-Variant Revenue	$ 18,411,936	$ 18,144,376

Non-Standard Large General Service	Winter	Summer	Winter	Summer	Winter	Summer
Billed Demand kW Determinant	2,281,870	1,166,626				
Empire-Proposed Rate	$ 9.10	$ 11.67				
Empire-Proposed Revenue (Calculated)	$ 20,765,017	$ 13,614,525				
Empire-Proposed Revenue (In Schedule)	$ 20,756,161	$ 13,615,391	**Estimated Determinants at 55%**		**Estimated Determinants at 95%**	
Empire-Calculated Time-Variant Determinants	111,394	47,657	1,255,029	641,644	2,167,777	1,108,295
Determinant Difference (%)	5%	4%	**Estimated Rates at 55%**		**Estimated Rates at 95%**	
Empire-Proposed Time-Variant Rate	$ 186.33	$ 285.70	$ 16.55	$ 21.22	$ 9.58	$ 12.28
Empire-Proposed Time-Variant Revenue	$ 20,756,044	$ 13,615,605				
Time Choice Large General Service	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
Billed Demand kW Determinant	2,281,870	1,166,626				
Empire-Proposed Rate	$ 9.06	$ 11.63				
Empire-Proposed Revenue (Calculated)	$ 20,673,742	$ 13,567,860				
Empire-Proposed Revenue (In Schedule)	$ 20,675,596	$ 13,562,543	**Estimated Determinants at 55%**		**Estimated Determinants at 95%**	
Empire-Calculated Time-Variant Determinants	111,394	47,657	1,255,029	641,644	2,167,777	1,108,295
Determinant Difference (%)	5%	4%	**Estimated Rates at 55%**		**Estimated Rates at 95%**	
Empire-Proposed Time-Variant Rate	$ 185.61	$ 284.59	$ 16.47	$ 21.15	$ 9.54	$ 12.24
Empire-Proposed Time-Variant Revenue	$ 20,675,840	$ 13,562,706				
Non-Standard Small Primary Service	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
Billed Demand kW Determinant	221,351	115,030				
Empire-Proposed Rate	$ 8.71	$ 11.18				
Empire-Proposed Revenue (Calculated)	$ 1,927,967	$ 1,286,035				
Empire-Proposed Revenue (In Schedule)	$ 1,928,849	$ 1,286,026	**Estimated Determinants at 55%**		**Estimated Determinants at 95%**	
Empire-Calculated Time-Variant Determinants	143,125	20,644	121,743	63,267	210,283	109,279
Determinant Difference (%)	65%	18%	**Estimated Rates at 55%**		**Estimated Rates at 95%**	
Empire-Proposed Time-Variant Rate	$ 13.48	$ 62.30	$ 15.84	$ 20.33	$ 9.17	$ 11.77
Empire-Proposed Time-Variant Revenue	$ 1,929,325	$ 1,286,121				
Time Choice Small Primary Service	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
Billed Demand kW Determinant	221,351	115,030				
Empire-Proposed Rate	$ 8.71	$ 11.17				
Empire-Proposed Revenue (Calculated)	$ 1,927,967	$ 1,284,885				
Empire-Proposed Revenue (In Schedule)	$ 1,926,871	$ 1,284,707	**Estimated Determinants at 55%**		**Estimated Determinants at 95%**	
Empire-Calculated Time-Variant Determinants	143,125	20,644	121,743	63,267	210,283	109,279
Determinant Difference (%)	65%	18%	**Estimated Rates at 55%**		**Estimated Rates at 95%**	
Empire-Proposed Time-Variant Rate	$ 13.46	$ 62.23	$ 15.84	$ 20.31	$ 9.17	$ 11.76
Empire-Proposed Time-Variant Revenue	$ 1,926,463	$ 1,284,676				
Large Power	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
Billed Demand kW Determinant	1,056,146	574,545				
Empire-Proposed Rate	$ 17.43	$ 31.58				
Empire-Proposed Revenue (Calculated)	$ 18,408,625	$ 18,144,131				
Empire-Proposed Revenue (In Schedule)	$ 18,407,023	$ 18,145,106	**Estimated Determinants at 55%**		**Estimated Determinants at 95%**	
Empire-Calculated Time-Variant Determinants	1,032,638	251,029	580,880	316,000	1,003,339	545,818
Determinant Difference (%)	98%	44%	**Estimated Rates at 55%**		**Estimated Rates at 95%**	
Empire-Proposed Time-Variant Rate	$ 17.83	$ 72.28	$ 31.69	$ 57.42	$ 18.35	$ 33.24
Empire-Proposed Time-Variant Revenue	$ 18,411,936	$ 18,144,376				