MISSOURI PUBLIC SERVICE COMMISSION

STAFF

RECOMMENDATION

EVERGY MISSOURI METRO
EVERGY MISSOURI WEST

CASE NO. EO-2025-0154

Jefferson City, Missouri
July 25, 2025

** Denotes Confidential Information **

TABLE OF CONTENTS OF

STAFF RECOMMENDATION

EVERGY MISSOURI METRO

EVERGY MISSOURI WEST

CASE NO. EO-2025-0154

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I. Introduction

Staff recommends rejection of the tariffs described in the direct testimony of Brad Lutz.[1] Evergy names this addition to the Large Power Service (LPS) tariff, the Limited Large Power Service (LLPS). Staff recommends finalization and promulgation of its recommended tariff for service to large load customers, and recommended changes to related tariff provisions. Staff's recommended tariff is attached as Appendix 2 - Schedule 1.[2]

In general, Evergy Missouri Metro (EMM) and Evergy Missouri West (EMW) have the obligation to supply electric service to requesting qualified customers in their respective service territories.[3] This obligation is not without exception. For example, EMW's current tariffs allow the company to refuse to provide service when the electrical use may disturb the electrical use of others, and requires the customer to pay for infrastructure necessary to reduce the interference caused in the service to other customers.[4] Similarly, current tariffs reserve the right of EMW to require execution of a contract and requirement of special minimums or other payments

[1] Neither EMM nor EMW have actually filed tariffs related to LLPS service.

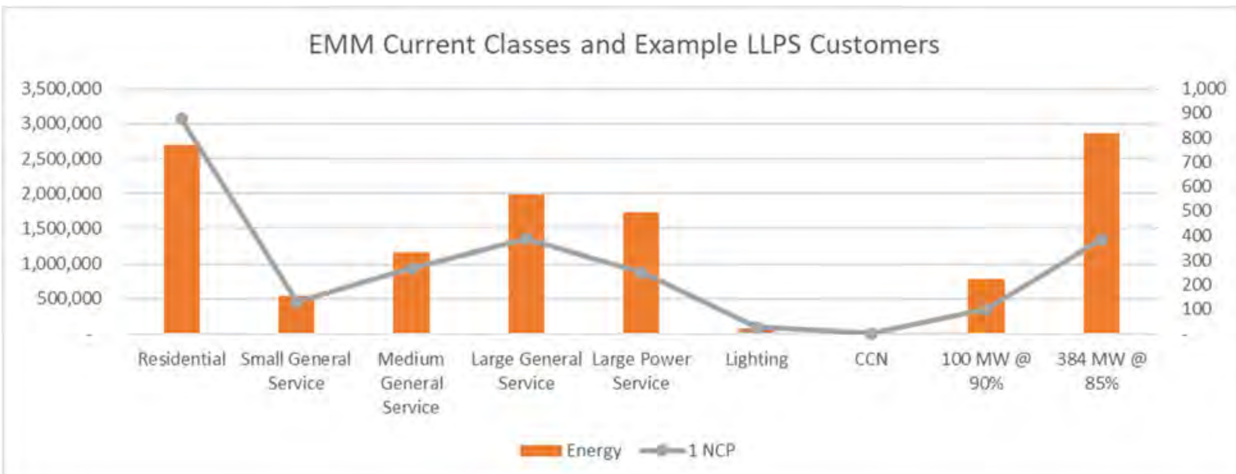
[2] This Report is provided by the indicated Staff witnesses. The credentials of those witnesses are provided as Appendix 1 to this Report.

[3] "The certificate of convenience and necessity issued to the utility is a mandate to serve the area covered and it is the utility's duty, within reasonable limitations, to serve all persons in an area it has undertaken to serve. *State v. Public Service Commission*, 343 S.W.2d 177, 181 (Mo.App.1960)." State ex rel. Missouri Power and Light Co. v. Pub. Serv. Commn. of State of Mo., 669 S.W.2d 941, 946 (Mo. App. W. Dist. 1984).

[4] For example, EMW tariff R-29 states "4.06 Unsafe Condition or Disturbing Uses of Service: Company may refuse to render electric service to or may withdraw it whenever the wiring or equipment of a customer is in an unsafe condition or is designed or operated so as to disturb the electric service to other customers. Customer's equipment may include welding machines, X-ray machines, motors with excessive starting currents, and experimental electric devices to be served by Company if adequate protective devices approved in advance by Company are installed and maintained by the customer in accordance with Company's Rules. If the customer's installations of such equipment require Company to install separate transformers or other special equipment, the customer shall pay, in addition to the bill for electric energy at the appropriate rate tariff, an amount determined by Company and set out in the Special Service Contract." EMM's tariff includes similar provisions at P.S.C. Mo. No. 2, Sheet 1.15 et seq.

in addition to the charges provided by regular rate tariffs.[5] For large customers, EMW's current tariffs explicitly set out the ability of the utility to refuse service except on terms satisfactory to the company.[6]

A customer of the size contemplated by the proposed LLPS tariffs is unique. Staff is not aware of an investor owned utility retail customer in Missouri's history taking service in excess of 95 MW. A single 100 MW customer with a 90% load factor would comprise approximately 9% of EMM's annual energy sales. A single 384 MW customer operating at an 85% load factor, as studied by EMM, would comprise over 25% of EMM's annual energy sales.



[5] For example, EMW R-6 states "2.01 Applications for Service A. Before Company begins rendering any electric service, the person(s), firm, or corporation shall supply the information necessary to complete Company's Standard Application for Service. A separate application shall be made for each customer for each class of service at each metering point, and at each separate location. Areas separated by public streets or alleys shall be considered separate locations. In cases where the installation of new facilities is required before service can be rendered, Company reserves the right to require such customer to execute a special contract consistent with these Rules prior to commencing service. In cases where there may be a succession of service to specific premises which prior to such succession had been covered by a contract requiring the payment of special minimums, or other payments in addition to the charges provided by regular rate tariffs, Company reserves the right to require such successor to execute a contract providing for the same special payments as was provided in the previous contract covering service to such premises. In any case where service is rendered under Company's nonresidential rate tariffs, the customer shall be required to execute an Electric Service Contract prior to receiving service when such contract is requested by Company."

[6] For example, EMW sheet R-6, provision 2.01.C. "All applications for Large Power Service will contain complete information regarding the magnitude of the customer's load, the length of time such load will be operated each day, and the approximate life of the installation for which the customer intends to use the service. Such information will be used by Company to compute the revenue to be received from such customer. Company will then estimate the costs required to provide the facilities necessary to render such service to such customer. After considering the revenue and investment required, Company reserves the right to require the customer to execute a special contract for service prior to commencing the construction of any necessary facilities."

While the EMM load information above is public, the EMW information is confidential due to EMW's Special Incremental Load (SIL) customer. ** [redacted]

[redacted]

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There is also a tension between the obligation to serve customers already physically located within the utility's monopoly service territory, the utility's interest in drawing in additional customers to its service territory, and restrictions on undue discrimination in customer treatments.[7] However, statutory guidance has been provided. Senate Bill 4, which has passed the legislature and has been executed by Governor Kehoe amends Section 393.130 at 393.130.7, RSMo., to require each Missouri Evergy utility to have tariff provisions applicable to customers who are reasonably projected to have above an annual peak demand of one hundred megawatts or more, that "**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**,"[8] and allows the Commission to order tariff schedules applicable to customers with lower annual peak demand.[9]

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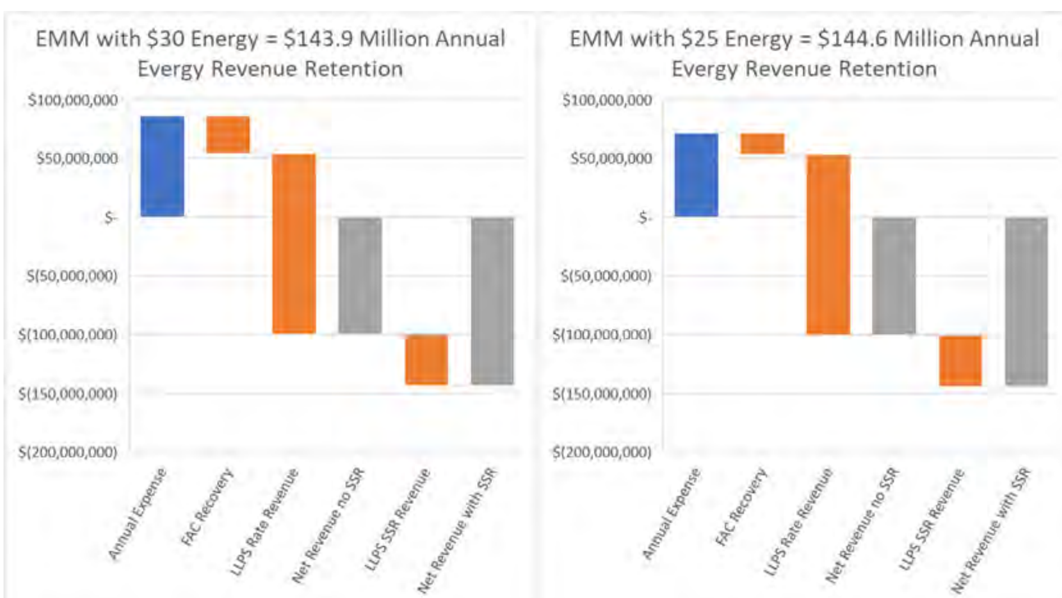
[7] "Discrimination" here, refers to different treatment, whether preferential or anti-preferential. Section 393.140(5), RSMo.

[8] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4 [Emphasis added.].

[9] SB 4 also set out an 80MW threshold applicable to both EMM and EMW with regard to compliance with the Missouri Renewable Energy Standard for qualifying customers.

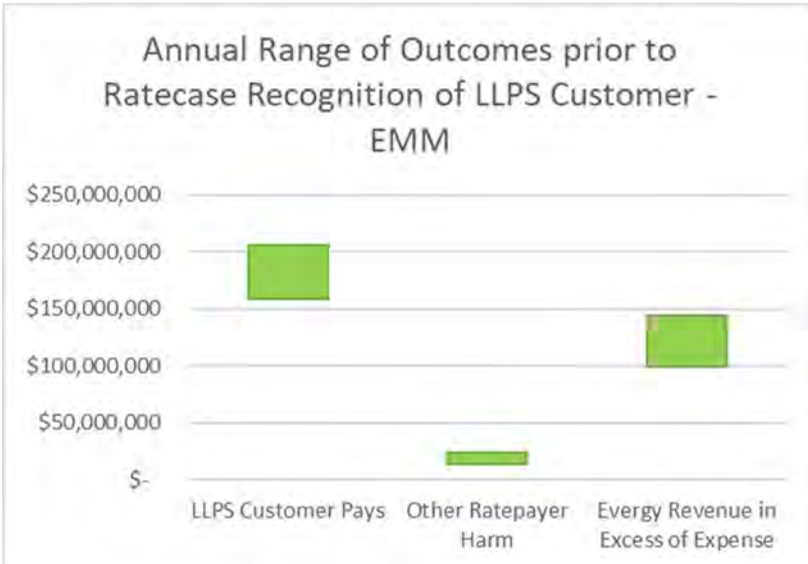
While this docket was opened prior to enactment of Senate Bill 4, and the legislation does not take effect until August 28, 2025, it would be a waste of administrative resources and a source of undue confusion to customers and potential customers to fail to consider provisions relevant to the LLPS tariff and related tariff provisions in this docket. Evergy's proposed LLPS tariffs, associated riders, and other tariff changes will not prevent other customer classes' rates from reflecting unjust and unreasonable costs to other customers. This is due to a combination of the Evergy-requested rate structure, and due to a failure to specify how the revenue from LLPS customers will be treated. Specifically, prior to a rate case recognizing the addition of an LLPS customer, essentially all incremental expenses associated with that LLPS customer will flow through the EMM or EMW FAC[10], however, all revenues will flow to EMM and EMW shareholders. The treatment of revenues and changes in costs of service is discussed in more detail in the section, "Regulatory Lag Considerations."

Using the hypothetical 384 MW customer referenced by Evergy in its workpapers, the addition of an LLPS customer will raise the bills of existing EMM customers approximately $13.5 million to $23.5 million, and will raise the bills of existing EMW customers approximately ** [redacted] ** each year from the time the customer comes on to the system until the customer's load is recognized in a rate case, assuming sufficient capacity to serve the customer. Meanwhile, annually, Evergy will retain revenues in excess of new cost of service in the range of $99.75 million to $144.66 million at EMM.



[10] Fuel Adjustment Clause (FAC).

Similarly, using the modeled customer, each year between when the customer begins taking service and when the customer is recognized in a rate case, EMW will receive revenues net of expense in the range of ** [redacted]. ** The ranges of overall impacts are illustrated below:



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[redacted]

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Depending on the duration and rate of any "ramp" period, for an LLPS customer taking service at full load for 10 years, approximately 40% of that customer's revenue cannot be spread to the recovery of existing "fixed costs," as that revenue will not be recognized in a rate case, and will accrue to the benefit of shareholders through positive regulatory lag. Meanwhile, ratepayers will be paying for a significant amount of the energy to serve that customer through the FAC, therefore resulting in net harm.

After rate case recognition of an LLPS customer, Evergy's proposed rate structure does not reasonably align revenue recovery from the LLPS customers with the cost to serve an LLPS customer, even without consideration of the higher cost of new capacity relative to existing capacity. This results in a failure of the proposed LLPS schedule to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[11]

Staff Witness: Sarah L.K. Lange

Overall Public Policy

Staff does not take a position on the propriety of serving any given potential customer of a regulated utility. However, Staff must note that resources such as land are finite, and that resources such as electric capacity are temporally finite. Staff also must note that generation capacity is expensive, cannot be instantaneously built, is subject to extensive federal and environmental regulation, increases cost of service for decades, and causes its own risks to captive ratepayers. Given the scale of the capacity that will be consumed by a given LLPS customer, some entity other than EMM or EMW (and other respective utilities, in respective cases) must have reasonable input in the allocation of massive amounts of capacity among potential LLPS customers and between LLPS customers and captive ratepayers. State-level entities such as the Department of Natural Resources, the Department of Natural Resources Division of Energy, the Department of Economic Development, and the Governor's office operate in this space, but Evergy has the ultimate decision of which customers it will allow onto its system and what capacity it constructs for current and potential customers.

This Report represents Staff's best efforts to implement the mandate that the LLPS customers' rates reflect their representative share of the costs incurred to serve them and prevent other customers from reflecting any unjust or unreasonable costs arising from service to

[11] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

LLPS customers.[12] However, there will be at least some times when other customers' rates will be higher than they otherwise would be due to buildout of new, costly, capacity to eventually serve LLPS customers.[13] Investor Owned Utilities such as EMM and EMW are in the business of investing shareholder dollars for a return that is paid through regulated rates for the provision of electric service to retail customers. From time to time, EMM and EMW build power plants to facilitate that business. There is no requirement or check in current Missouri regulation that requires EMM or EMW to vet potential customers for the best economic, environmental, public benefit, or any other interest of the State of Missouri, its service territory, or a given community – other than this Commission.[14]

Staff Witness: Sarah L.K. Lange

Contradictory Policy

From a policy standpoint, Evergy's proposal to attract massive amounts of new load from a few customers through Evergy's proposed LLPS tariff is in direct conflict with several of Evergy's recent case filings.

Prior to this case, when the expected cost of capacity and expected SPP[15] resource adequacy shortfalls were lower, Evergy proposed utilizing incremental costs for serving new customers to design rates.[16] Evergy's estimates for the cost to build new generation facilities in recent years has ballooned compared to just five years ago. While Staff's position in this case is not to utilize incremental costs for designing rates for the LLPS customers, it is important to note that doing so would likely lead to higher rates due to the costs of generation facilities associated with serving these customers.[17] Evergy paired the shift of designing large customer rates to an embedded capacity cost approach along with an option, through Rider CER[18], for customers to

[12] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

[13] Under the EMM and EMW structures, there will be additional or pervasive times when other customers' rates will reflect the risk and costs of variable energy market expenses that are not appropriately recovered from the LLPS class.

[14] As described in the testimony of James Busch, those jurisdictions with more mature large load customers are continuing to address the unique challenges and issues presented by large load customers.

[15] Southwest Power Pool (SPP).

[16] See Schedule SIL, associated with Case No. EO-2019-0244 and the respective Schedule MKT associated with Case Nos. EO-2022-0061 and EO-2023-0022.

[17] Staff has concerns over the ever-growing complexity of specialized ratemaking especially for specific customers.

[18] Clean Energy Choice Rider (CER).

designate specific changes to the Preferred Resource Acquisition Strategy. Designing rates based upon embedded capacity costs while allowing specific resources to be built and included in rates of all ratepayers based upon the desires of individual LLPS customers are in direct contradiction and should be rejected.

Furthermore, since 2015 EMW has collected more than $232 million and EMM has collected more than $235 million from its respective ratepayers through Commission approved Demand-Side Investment Mechanisms (DSIM).[19] The programs that are implemented through the DSIM are premised on the concept of avoiding capacity costs, or the costs to build generation facilities. Now, Evergy is actively seeking large customers that will require massive amounts of new generation facilities which will be recovered through the rates of all captive ratepayers, effectively erasing the proposed benefit of avoiding generation facility costs.

The load associated with customers that will be served by an LLPS tariff is still uncertain based upon several factors that have the potential for massive implications on the rates of Evergy's captive ratepayers. The actual load profiles, ramping of load, length of service, and certainty of immediate, mid-range, and long term forecasted demands of LLPS customers will all play a role in the generation resource acquisitions of Evergy. Electric generating plants are generally depreciated for 30+ years. If the load from LLPS customers dwindles over-time, Evergy's captive ratepayers run the risk of paying for a massive generation build-out that is unnecessary to serve the remaining customer base.

Staff Witness: J Luebbert

Estimated Cost of Service for an LLPS Customer

Using the hypothetical 384 MW customer reflected in Evergy's workpapers, under the recommendations set out in this Report – ***including Staff's recommended tariff provisions and recommended revenue treatment*** – a reasonable estimate of an annual average bill for an LLPS customer, on a $/kWh basis, is $0.0751 (plus FAC and other riders) for an EMM LLPS customer, and $0.0573 (plus FAC and other riders) for an EMW LLPS customer. Because Staff's revenue treatments reduce the increases to rate base that will be caused to enable service to LLPS customer, if Staff's recommendations are not adopted in full, these rates would necessarily increase to meet

[19] It should be noted that this dollar value does not account for ratepayer impacts that result from rebasing the DSIM through the general rate case process.

the statutory requirement that the LLPS rates "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."[20]

Staff Witness: Sarah L.K. Lange

Staff's Primary Concerns

Staff's primary concerns with Evergy's proposed tariffs and related requests are summarized below:

1. Revenue treatment between rate cases harms existing customers and unreasonably benefits shareholders. This concern is raised throughout this Report, but is the main subject of the sections, "Regulatory Lag Considerations," "Treatment of Revenue under Evergy Request," and "Risk Allocation."
2. Important terms of service and rates are subject to Evergy's discretion and are not contained in the tariff. This is addressed throughout this Report, but is a main subject of the sections "Overall Public Policy," and "Excessive Utility Discretion and Reliance on Customer Agreement."
3. Risks of overbuilding to serve LLPS customers are not allocated to shareholders or adequately allocated to LLPS customers, and are unreasonably borne by captive customers. These concerns are addressed in the sections "Contradictory Policy," "Captive Customer Risk Mitigation," "Risk Allocation," and in Staff's responses to the requested Riders.
4. Inadequate rate structure and rate design do not comply with the statutory requirement that the LLPS schedule "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."[21] These concerns are addressed throughout the Report, and are the primary subject of the section, "Evergy's CCOS Modeling Does Not Reasonably Demonstrate that the LLPS Customers Will Bear A Representative Share of the Costs Incurred to Serve Them".
5. Requested riders are not adequately developed and some are inconsistent with reasonable regulatory policies and statutory direction. These concerns are addressed in the sections pertaining to each Rider, as well as in the section "Integrated Energy Market Issues," "Resource Adequacy-Related Requirements and Cost of Service," and "Excessive Utility Discretion and Reliance on Customer Agreement."

[20] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.
[21] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

6. In addition to recommending the Commission order Staff's recommended LLPS tariff and other tariff changes, Staff recommends the Commission:
   a. Order a separate commercial load node be established for each LLPS customer, as discussed in "Integrated Energy Market Issues."
   b. Order that any Deficiency Payment incurred after the addition of LLPS customers be borne solely by the LLPS customer class in proportion to the overall peak demand of each customer, as discussed in "Resource Adequacy-Related Requirements and Cost of Service," and
   c. Order Evergy to create subaccounts for each set of interconnection infrastructure associated with each customer interconnecting at transmission voltage, as discussed in "Facility Extension Tariff & 'Increasing Connected Load' Provisions".

Staff Witness: Sarah L.K. Lange

II. Capacity, Energy, and Market Issues

Current and Projected Capacity to Reliably Serve Load

EMW Resource Adequacy

The figure below shows Staff's review of EMW's estimated Summer Capacity Position for 2025-2035, considering the potential change in SPP capacity accreditation methodology, accounting for Dogwood and any known capacity contracts, and the SPP summer reserve margin change.[22] Staff will discuss each of these topics later in this report. The figure below also depicts EMW's load as filed in its most recent IRP[23] and its Supplemental Direct in Case No. EA-2025-0075:

continued on next page

[22] Please note, Staff did not develop its own load or DSM potentials amounts.

[23] Integrated Resource Plan ("IRP").

**
[redacted]
**

The space between the load line(s) and the stacked graph of generation, capacity contracts, and estimated DSM represents an estimate of EMW's need for summer capacity.

The figure below shows Staff's review of Evergy's estimate of EMW's Winter Capacity Position for 2025-2035.

**
[redacted]
**

It should be noted that EMW has two CCN[24] cases currently before the Commission (Case No. EA-2024-0292 and EA-2025-0075) requesting to add two solar facilities and three natural gas facilities which, if approved, would decrease the need shown in the charts above.

Staff Witness: Shawn E. Lange, P.E.

Evergy Metro Resource Adequacy

The figure below shows Staff's review of Evergy's estimate of Evergy Metro's[25] Summer Capacity Position for 2025-2035, considering the potential change in SPP capacity accreditation methodology, accounting for any known capacity contracts, and the SPP summer reserve margin change.[26] Staff will discuss each of these topics later in this report. The figure below also depicts Evergy Metro's load as filed in its most recent IRP and its Supplemental Direct in Case No. EA-2025-0075:

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[redacted]

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[24] Certificate of Convenience and Necessity ("CCN").

[25] Evergy Metro includes both EMM and Evergy Kansas Metro, as Evergy provides this information on a total Evergy Metro basis.

[26] Please note, Staff did not develop its own load or DSM potentials amounts.

** [redacted] **

It should be noted that on May 13, 2025, Evergy Metro contacted Staff regarding an outage. ** [redacted] ** This outage will impact Evergy Metro in the short term but will also impact the longer run accreditation of the facility.

Staff Witness: Shawn E. Lange, P.E.

Green House Gas (GHG) rule

The U.S. Environmental Protection Agency's (EPA) New Source Performance Standards (NSPS) aim to reduce greenhouse gas emissions from new and modified gas turbine power plants (GHG Rule).[27]

[27] EPA proposed a rulemaking on June 17, 2025, to repeal all GHG rules for fossil fuel-fired power plants under 40 CFR 60. A virtual public hearing was held on July 8, and comments on the repeal must be received on or before

For new and reconstructed fossil fuel-fired combustion turbines, EPA is proposing to create three subcategories based on the function the combustion turbine serves:[28]

- A low load ("peaking units") subcategory that consists of combustion turbines with a capacity factor of less than 20 percent with standards of performance ranging from 120 lb CO2/MMBtu to 160 lb CO2/MMBtu, depending on the type of fuel combusted;
- An intermediate load subcategory for combustion turbines with a capacity factor that ranges between 20 percent and a source-specific upper bound that is based on the design efficiency of the combustion turbine with two different performance standards phases.:
  - 1st phase standards: 1,150 lb CO2 /MWh-gross – based on performance of a highly efficient natural gas fired simple cycle turbine
  - 2nd phase standards: 1,000 lb CO2 /MWh-gross – based on performance of a highly efficient natural gas fired simple cycle turbine co-firing 30% (by volume) by 2032;[29] and
- A base load subcategory for combustion turbines that operate above the upper-bound threshold for intermediate load turbines with three phases of performance standards:
  - 1st phase standards: 770 – 900 lb CO2 /MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine. Standard is higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO2 /MMBtu basis.
  - 2nd phase standards for base load units on the CCS pathway: 90 – 100 lb CO2 /MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine implementing 90% CCS by 2035.
  - 2nd phase standards for base load units on the low-GHG hydrogen pathway: 680 lb CO2 /MWh-gross – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine co-firing 30% (by volume) low-GHG hydrogen by 2032.
  - Phase 3 standards are based on 96% (by volume) low-GHG hydrogen by 2038.

The GHG rules would also affect Evergy's coal fleet. The GHG rules require coal units to (1) retire before January 1, 2032, (2) retire before January 1, 2039, and co-fire with at least 40 percent gas starting on January 1, 2030, or (3) install carbon capture and storage with at least a 90 percent capture rate by January 1, 2032.[30]

Staff Witness: Shawn E. Lange, P.E.

August 7. https://www.federalregister.gov/documents/2025/06/17/2025-10991/repeal-of-greenhouse-gas-emissions-standards-for-fossil-fuel-fired-electric-generating-units.

[28] https://www.epa.gov/system/files/documents/2023-05/FS-OVERVIEW-GHG-for%20Power%20Plants%20FINAL%20CLEAN.pdf Page 4.

[29] https://www.epa.gov/system/files/documents/2023-05/111%20Power%20Plants%20Stakeholder%20Presentation2_4.pdf Slide 10.

[30] 89 Fed. Reg. 38,798 (May 9, 2024).

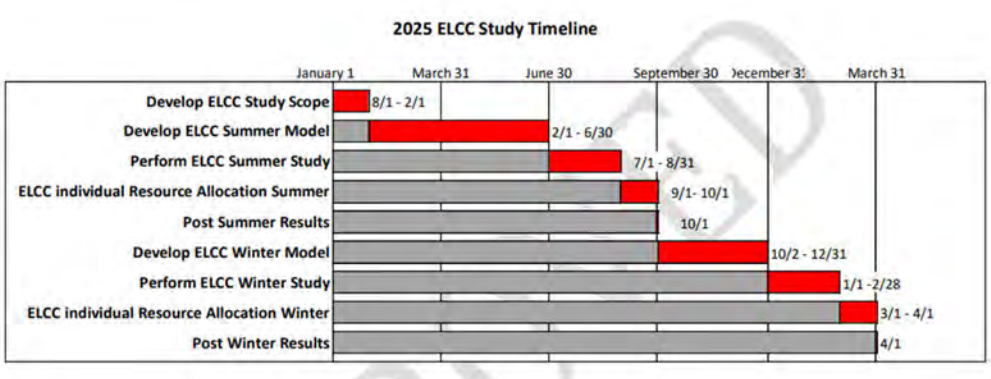
SPP Accreditation Methodology

SPP oversees the bulk electric system and administers the wholesale power market on behalf of a group of electric utilities, including EMW. EMW, as a load-responsible entity (LRE), must ensure it has enough capacity to serve its load at peak times. SPP, through its tariffs, requires EMW and Evergy Metro to demonstrate its compliance with resource adequacy[31] requirements by identifying its owned resources or by procuring capacity through bilateral contracts.

Capacity is the maximum output from a generating resource and no generation resource will always produce its maximum output (i.e. planned and unplanned outages are expected to occur and renewable resources are intermittent). Resource adequacy requirements are designed to consider the accredited capacity of a resource. Accredited capacity is used to compare the dependability of generation resources.

Currently, SPP accredits its wind and solar fleet using historical performance (which includes outages) and accredits conventional generation resources based on their installed capacity ("ICAP") rating.

SPP has filed with the Federal Energy Regulatory Commission (FERC) proposing to implement the following accreditation methodology: (1) an Effective Load Carrying Capability (ELCC)[32] accreditation methodology for wind resources, solar resources, and Electric Storage Resources (ESRs); and (2) a Performance Based Accreditation (PBA) methodology for thermal and other conventional resources, which would utilize a variant of the equivalent forced outage rate (EFORd) method. SPP proposed implementing this change on October 1, 2025, shown in the timeline below:[33]



[31] Resource adequacy is the ability of the electricity system to supply aggregate electric power and energy to meet the requirements of consumers at all times, taking into account scheduled and unscheduled outages of system components.
[32] ELCC is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load.
[33] ER24-1317 SPP FERC Application filing dated 2/23/24.

In the EMW 2024 IRP, EMW assumed a level of renewable generation accreditation summer capacity reduction due to the ELCC implementation. This resulted in a total reduction to the wind generation assets of approximately 147 MW in summer of 2026, as shown in the table below:[34]

Wind PPA	Nameplate MW	2024 Capacity	ELCC
Gray County	110	23	16
Ensign	99	40	27
Cimarron Bend III	130	100	20
Osborn	80	14	15
Rock Creek	120	21	27
Prairie Queen	110	32	23
Pratt	134	85	40
Total	**783**	**314**	**167**

Starting in winter of 2027, EMW shows ** [redacted] ** for those same units' winter capacity.[35]

EMW anticipates a ** [redacted] ** to existing fossil and solar resources' summer capacity of approximately ** [redacted] **, beginning in summer of 2026 and a ** [redacted] ** to existing fossil and solar resources' winter capacity of ** [redacted] ** beginning in winter of 2027.[36]

Evergy Metro anticipates a ** [redacted] ** to existing fossil, wind and solar resources summer capacity of approximately ** [redacted] **, beginning in summer of 2026 and a ** [redacted] ** to existing fossil, wind and solar resources winter capacity of ** [redacted] ** beginning in winter of 2027.[37]

Staff Witness: Shawn E. Lange, P.E.

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[34] EO-2024-0154 Evergy Missouri West Integrated Resource Plan Chapter 4 Page 46.

[35] EA-2025-0075 Confidential supplemental workpaper of Van de Velde " MOW CCN Supp Dir - No McNew and No 2031 Thermal Plan.xlsx".

[36] EA-2025-0075 Confidential supplemental workpaper of Van de Velde " MOW CCN Supp Dir - No McNew and No 2031 Thermal Plan.xlsx".

[37] EO-2025-0250 Evergy Metro Workpaper entitled "Evergy Metro Capacity Walk IRP 2024 to 2025.xlsx"

Planning Reserve Margin Increases

During its August 5-6, 2024, meetings, SPP's Regional State Committee and Board of Directors approved increases to the planning reserve margins[38] (PRM) member utilities are required to maintain in support of regional grid reliability.

SPP's Regional State Committee and Board of Directors approved minimum requirements of a 36% winter-season PRM and a 16% summer-season PRM, effective beginning summer 2026 and winter 2026/27.[39] This means that load responsible entities in SPP's region must have access to enough generating capacity to serve their peak consumption with at least 36% margin during the winter season and at least 16% margin during the summer. The current 15% summer PRM requirement was previously applied to the winter season also.[40]

To determine these recommendations, SPP conducted the 2023 Loss of Load Expectation (LOLE) study for the 2026 and 2029 study years, in accordance with the LOLE Study Scope approved by the Supply Adequacy Working Group (SAWG). A LOLE study is used to determine the probability that generation is sufficient to meet load. SPP's LOLE study considers its entire region. The assumptions and forecasts were developed with the members for the SPP Balancing Authority Area, to incorporate historical operational experiences of resource performance, energy consumption and system conditions as well as projected generating capacity and new generator development timelines. This was the first LOLE study in which SPP directly analyzed seasonal risk beyond the summer season. SPP, with support from the SAWG, performed additional sensitivities beyond those outlined in the 2023 LOLE study scope, which included consideration of reduced amounts of Incremental Cold Weather Outages (ICWO), incremental flexibility for planned and maintenance outages, and varying risks across winter and summer seasons. SPP also evaluated implications of a reduced solar penetration materializing by 2026, based on the solar resource mix that was modeled in the LOLE study.

[38] PRM represents the amount of back-up capacity utilities must have to guard against unplanned conditions or events on the regional power grid.

[39] On April, 4, 2025, SPP provided a recommendation to the Markets and Operations Policy Committee for discussion and vote a proposal to increase the Planning Reserve Margin for Summer from 16% to 17% and for winter from 36% to 38% starting in planning year 2029/2030.

[40] https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/ accessed 2/7/2025.

The LOLE study and associated analysis demonstrated the following key observations:

1. The 2023 LOLE study results show that the current 15% requirement will not satisfy the required 1-in-10 LOLE threshold for the 2026 Summer Season or for any subsequent Winter Season.
2. Cold weather impacts, the resource mix, planned and maintenance outages, as well as the balance of risk in LOLE days and Expected Unserved Energy (EUE), amongst other factors, have significant impacts to the PRM.[41]

Staff Witness: Shawn E. Lange, P.E.

Reliability Standards

The North American Electric Reliability Corporation (NERC), the Electric Reliability Organization (ERO) for North America, is subject to oversight by FERC, and is developing new standards that will require grid planners and operators to assess their ability to consistently meet electricity energy demand at all times.

First, Project 2022-03 Energy Assurance with Energy-Constrained Resources creates a new standard, BAL-007-1, requiring Balancing Authorities to assess the resources necessary to reliably supply energy to serve expected demand with operating reserves for a defined assessment period that is at minimum five days in duration, and at maximum six weeks in duration.

Project 2024-02 Planning Energy Assurance is intended to require the industry to perform energy reliability assessments greater than one year out and determine actions to mitigate any energy deficiencies that are identified.

Planning Scenarios being evaluated by NERC:[42]

• The rapid decline of traditional power plants and their replacement with variable generation resources without an assured fuel supply continues, creating a supply-demand imbalance. This imbalance, coupled with sharp increases in electricity use, leads to significant energy shortfalls. If the shortages cannot be resolved with flexible demand reduction requests and/or through energy stored on the system, the grid operator will be forced to resort to load shedding, or intentionally cutting off power to certain customers to maintain the balance of supply and demand. Load shedding is a last resort to prevent a possible system collapse. The use of load shedding to address energy shortfalls, like those seen during winter storms Elliott and Uri, is increasing and could occur under less severe weather conditions.

[41] https://www.spp.org/documents/71928/prm%20recommendation%207-2-24.pdf Page 1.

[42] See pages 22 of MRO Regional Risk Assessment, January 2025 https://www.mro.net/document/mro-2025-regional-risk-assessment/?download.

• Two-day drought of wind and solar resource output, combined with planned maintenance outages of dispatchable generation, exceed energy storage capabilities and require load shedding to balance supply and demand for a multi-day period.

• A large number of utilities rely on energy imports to meet expected increases in electricity demand in their resource planning efforts. This leads to a broad under development of new generation across the region. A system event occurs with limited energy availability across the entire SPP footprint, reducing the availability of import capacity and requiring operator-initiated load shedding to maintain supply and demand balance.

Actions to Address Risk evaluated by NERC:[43]

• The retirement of traditional, dispatchable power plants must be carefully managed to ensure a reliable and sufficient supply of electricity.

• Flexible, on-demand resources, currently provided by natural gas-fired generation, are crucial for addressing the intermittent nature of variable, weather dependent generation like wind and solar. On-demand resources are capable of filling multi-day supply gaps when variable output is low and will be needed to meet anticipated increases in demand.

• Resource adequacy assessments should consider new metrics that go beyond the frequency-based criterion of the "Loss of Load Expectation" (LOLE), which determines resources needed to allow one-day of customer load loss in a ten-year period, and include supplemental criteria considering the size, timing, and duration of energy shortfalls. A co-sponsored NERC and National Academy of Engineers Section 6 report on Evolving Planning Criteria for a Sustainable Power Grid identifies the need for more robust metrics and criteria for resource adequacy as well as identifies next steps to form an improved approach to resource adequacy.

• Improve load forecasting to comprehensively determine future load growth based on the likelihood and timing of deploying new end-uses of electricity, such as electric vehicles, electric space heating, and large, single-point loads like data centers and industrial facilities.

Staff Witness: Shawn E. Lange, P.E.

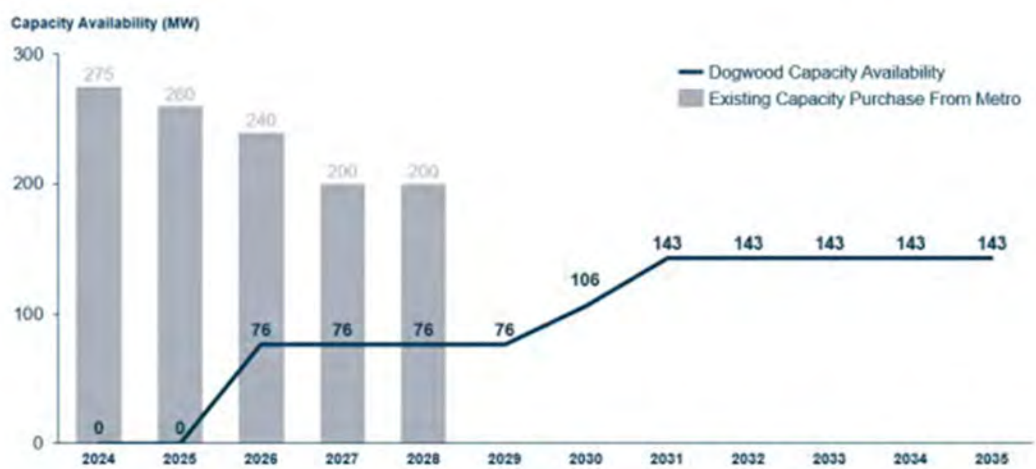
Dogwood

Staff is highlighting the recent Dogwood addition in particular because EMW recently acquired this resource in 2024. While the Dogwood resource in theory would help EMW with its 2025 capacity needs, due to contractual arrangements, EMW will not receive its total share of accredited capacity of Dogwood until 2031.

[43] See pages 22-23 of MRO Regional Risk Assessment, January 2025 https://www.mro.net/document/mro-2025-regional-risk-assessment/?download.

EMW's interest in the Dogwood facility equates to approximately 143 MW capacity.[44] However, the capacity from Dogwood phases in for EMW from 2026 to 2031, as existing capacity contracts roll off.[45]

The Chart below shows EMW's existing capacity purchase from Evergy Metro and the Dogwood Capacity availability:[46]



In other words, while EMW may own the facility, Dogwood capacity is sold to other parties and will not be used to serve EMW customers until 2026. EMW is receiving revenues for the capacity that has already been sold to others for 2025. In 2026, the Dogwood capacity that is available to EMW will increase to approximately 76 MW.[47]

Staff Witness: Shawn E. Lange, P.E.

SPP Update

On July 1, 2025, SPP held a stakeholder engagement concerning integrating large loads. In its PowerPoint, SPP identified three existing solutions to interconnecting large loads with limitations of each solution:

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[44] EA-2023-0291 John Carlson Direct, Page 6, lines 4-5.

[45] EA-2023-0291 John Carlson Direct, Page 4, lines 21-22.

[46] EA-2023-0291 Kayla Messamore Direct, Page 27, Figure 10.

[47] The proposed accreditation methodology of SPP most likely will have Dogwood's accredited capacity less than the 143 MW illustrated.

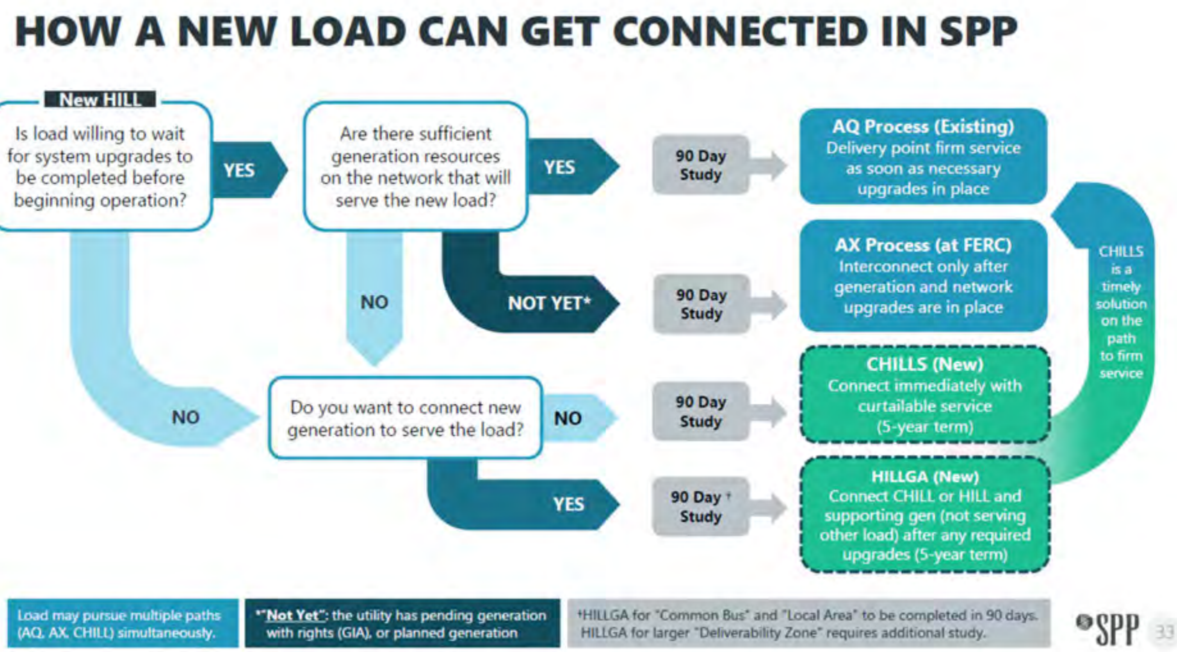
(1) SPP Attachment AQ provides Delivery Point Assessment "[f]or those with sufficient generation and willing to wait for transmission upgrades", but this would not be available to customers without sufficient network capacity.[48]

(2) SPP Attachment Y provides for Aggregate Transmission Service Studies "[f]or those with sufficient generation, willing to wait for transmission upgrades, but needing to secure designated capacity."[49] The limitation of this process is the studies were biannual and resulted in additional wait times.

(3) SPP Attachment AX, the Provisional Load Process currently pending review at the Federal Energy Regulatory Commission with a requested effective date of August 4, 2025. This can provide customers with provisional approval if the customer has plans to acquire generation, "but would be subject to unreserved use charges if firm transmission is not acquired."[50]

Figure 1 below is Slide 33 from the PowerPoint provided at that stakeholder engagement and depicts "How a New Load Can Get Connected in SPP":

Figure 1: Flowchart of SPP Proposal to Quickly Integrate New Large Loads.



Even though SPP's Markets and Operations Policy Committee (MOPC) rejected these proposed tariff changes in its July 15-16 meeting, this process will still be presented to the SPP Board of Directors on August 5 MOPC did approve to hold a special workshop on the large load

[48] Southwest Power Pool. "Large Load Stakeholder Engagement." July 1, 2025, 1:00 PM – 4:00 PM. Slide 21.

[49] Southwest Power Pool. "Large Load Stakeholder Engagement." July 1, 2025, 1:00 PM – 4:00 PM. Slide 21.

[50] Southwest Power Pool. "Large Load Stakeholder Engagement." July 1, 2025, 1:00 PM – 4:00 PM. Slide 21.

integration tariffs before the end of September. Thus, there is room and opportunity for further stakeholder input, so the final product may look different from the current proposal. Evergy's proposed tariffs may need to be revisited and revised to account for these changes and Staff may provide surrebuttal testimony on the topic if needed.

Staff Witness: Michael L. Stahlman

Integrated Energy Market Issues

As Load-Responsible Entities, (LRE), EMM and EMW participate in the integrated market (IM) for transmission, energy, and supportive services such as voltage support, ramping, and regulation. EMM and EMW also participate in these markets as transmission owners and as power producers. EMM and EMW are also responsible for meeting the resource adequacy requirements of SPP and applicable Federal authorities.

Given the size of potential LLPS customers, Staff recommends that the Commission require that each LLPS customer be registered with SPP as a separate commercial pricing node. Absent this treatment, it is difficult to isolate the expenses caused by LLPS customers that would otherwise be flowed through the FAC and which may cause unreasonable impacts on captive ratepayers. Specific expenses and complications are discussed below. In general, Staff's recommended LLPS tariff sets out each area as a discrete charge in its recommended rate structure. Generally, the EMM and EMW proposed tariffs fail to recognize the determinants associated with each of these discrete integrated market expenses for LREs. The requested EMM and EMW riders also induce problematic interactions with the integrated energy market.

Staff recommends that the Commission order in this case includes a condition that LLPS customers will be served via a separate commercial pricing node and that Evergy develop subaccounts that would allow for simple and concise tracking of many of the SPP costs directly associated with each customer.

In the absence of separate commercial pricing nodes for each LLPS customer, Staff recommends that the Commission order each of the conditions included in Appendix 2 – Schedule 2. The conditions included in Appendix 2 – Schedule 2 are not a perfect solution for identifying the costs associated with the LLPS customers, will not allow for full cost causation transparency, and will create additional work processes for Staff and other parties.

However, absent separate commercial pricing nodes, the information provided would provide an improvement over Evergy's current documentation processes.

Staff Witness: J Luebbert

Load and Resource Diversity Complications

The price for energy varies at each interconnection with the transmission system due to congestion. Some variations are slight, some are significant. Generally, energy is worth less closer to generation, and worth more closer to load. Therefore, expense and revenue imbalances exist throughout the service areas of EMM and EMW, and between the service areas and generation such as windfarms and the new gas units to be located in Kansas.

Evergy has proposed riders that would treat distant generation as an offset to the metered energy and demand of LLPS customers. However, this is not reasonable. The energy utilized by the LLPS customer may cost more than the revenue received from energy generated during the same time period at a different location. Furthermore, if the generation added does not coincide perfectly with the load additional cost and revenue imbalances may exist between the timing of energy usage and energy production. To the extent that these imbalances exist in the future, and add to the cost to serve load or reduce off-system sales revenues, non-LLPS customers would realize additional costs through the respective FACs. Each generation station currently owned by Evergy has its own commercial pricing node. As noted in the section below, Staff recommends separate commercial pricing nodes for each of the LLPS customers served by Evergy.

Staff Witness: J Luebbert

Day Ahead and Real Time Imbalances

Every day, as LREs, EMM and EMW must provide forecasts to the SPP of expected energy usage for each hour of the next day. These projected loads are transacted by SPP at the Day Ahead Locational Marginal Price (LMP) for each node. Every day, the SPP reviews the amount of energy actually used in each interval on a given day, and subtracts the forecast from that interval for the actual energy used in that interval. The difference is transacted at the Real Time LMP for each node. While as regulators we see these LMPs as a single Day Ahead (DA) LMP for each interval and a single Real Time (RT) LMP for each interval, the actual bills are written based on the value of the variation at every single point of interconnection for that utility.[51] The single interval values

[51] In various materials, the Day Ahead is also referred to as the Next Day or Day 2 Market, and the Real Time is also referred to as the Balancing Market.

that are provided as load LMPs are actually the weighted-average value of dozens of separate points of interconnection between the utility's distribution system and the transmission system.

Changes to actual operational loads of LLPS customers compared to expected loads that are not reflected in EMW's and EMM's respective bids for load purchases from SPP can cause imbalances in the overall purchased power costs that will flow through the respective Fuel Adjustment Clause (FAC) if these costs are not identified and isolated. The expected LLPS customers' relative loads is important to consider because the load of these customers is expected to be some of the largest on each respective system, and will dramatically impact the overall purchased power costs of EMW and EMM through SPP. The exact dollar impact cannot be determined at this time because the imbalance will be determined on an hour by hour basis, comparing the cleared DA and RT costs, as well as projected load, compared to actual RT load.

Absent active identification, mitigation, isolation, and removal of these costs from the FAC, non-LLPS ratepayers may end up subsidizing these costs.[52] Given the impact that the LLPS load will have on EMW's and EMM's SPP purchased power expense and capacity requirements, EMW and EMM should obtain and understand the LLPS customers' operational requirements on a daily basis to be incorporated into the DA bids.

This potential cost was explicitly recognized in the Stipulation and Agreement in Case Number EO-2019-0244,[53] relating to EMW's cost of serving a customer on the Special Incremental Load tariff, Schedule SIL.[54] The Stipulation and Agreement in the EO-2019-0244 case required Evergy to monitor and isolate costs related to changes in operation

[52] While changes to the FAC cannot be made in this case, isolating these transactions now enables future FAC changes, or other treatment to ensure that captive ratepayers do not pay unreasonable costs associated with LLPS customers.

[53] The non-unanimous stipulation and agreement in Case No. EO-2019-0244 paragraph 7.d. states:

> GMO will monitor Nucor operations and will identify additional SPP-related costs resulting from unexpected operational events. If actual Nucor load experiences a 25% deviation from the expected Nucor load for more than 4 hours and that load change is not reflected in the GMO day-ahead commitments, GMO will quantify the balancing relationship between the hourly and day-ahead prices to identify the effect of the unplanned load change to apportion any additional SPP balancing charges and will incorporate the effect attributed to Nucor into the tracking of Nucor costs. If the effect of this relationship increases costs to non-Nucor customers, the amount will be reflected in a subsequent FAC rate change filing and the portion attributed to Nucor will be identified with supporting work papers and removed from the Actual Net Energy Cost prior to the calculation of the FAC rates. For any incremental Nucor costs not specifically listed in Exhibit 1, including GMO internal costs attributal to Nucor, the costs will be uniquely recorded after they are incurred consistent with the cause of the cost and identified as contingency cost category within Exhibit 1.

[54] Staff has raised concerns in multiple cases regarding Evergy's adherence to terms of the Stipulations and Agreements as well as inclusion of finite load projections from the Schedule SIL customer in the SPP Day-ahead bids.

from expectation, but this requires additional tracking of information and has been raised as an issue in several cases since the original stipulation and agreement.[55] While the tracking and isolation method does not entirely shield EMW customers from all costs associated with serving Schedule SIL customers, it does serve as a non-SIL ratepayer protection.

Evergy could request separate SPP settlement locations for customers as large as the expected LLPS customers, allowing for much cleaner tracking and assignment of actual costs incurred to serve each LLPS customer. However, Evergy has not considered such an approach[56] and states that:

> …the administrative burden for Evergy of managing demand bids daily for every load above 100 MW could become significant. Evergy's market interfacing strategy has never included the concept that different customer types would be handled with separate settlement locations.

Evergy's proposal to add customers of this size is not typical business practice for the company. The customers that are expected to be served are much larger than the largest current customers and the total demand from the LLPS class could exceed the current total peak demand if Evergy's forecasted pipeline comes to fruition. It is imperative that Evergy conducts due diligence when forecasting the loads of customers this large and avoids cross-subsidization from non-LLPS customers by combining the overall load forecast. Doing so is opaque and leads to added complication for identifying costs directly associated with what will be Evergy's largest retail customers. Pairing Evergy's stated intent to ensure that the LLPS customers are not subsidized by other ratepayers with a request to serve the LLPS customers via a separate SPP commercial pricing node is a logical conclusion. Therefore, Staff recommends that the Commission order Evergy to request separate SPP commercial pricing nodes for each LLPS customer which is contemplated, if not supported, by the SPP market protocols and designation of customers of this type as non-conforming load.

Staff Witness: J Luebbert

[55] ER-2022-0130, EF-2022-0155, and EC-2022-0315.
[56] Evergy response to Data Request 23 in this case.

Ancillary Services

Adding large amounts of load to the Evergy system over a relatively short time frame also has the potential of adding additional costs for ancillary services.[57] Section 4.1.3. of the Market Protocols for SPP Integrated Marketplace describes the requirements that are generally related to Operating Reserve Requirements.[58] A brief description of Operating Reserve from the SPP website is listed below:

> Operating Reserve - Resource capacity held in reserve for resource contingencies and NERC control performance compliance which includes the following products: Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.[59]

The changes to these costs would be difficult if not impossible to accurately isolate and quantify, but they should be considered as they could impact the overall costs to all Evergy ratepayers through the FAC.

Staff Witness: J Luebbert

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[57] https://www.spp.org/glossary/?term=ancillary.
Ancillary service - Generally refers to the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. The Integrated Marketplace will set prices for certain ancillary services such as Operating Reserves, as part of both the Day-Ahead Market and the Real-Time Balancing Market.

[58] BA refers to Balancing Authority and BAA refers to Balancing Authority Area https://www.spp.org/documents/71629/excerpt%20of%20appendix%20g%20mitigated%20offer%20methodogoloy%20integrated%20marketplace%20protocols%20106a%20reference%20doc%20for%20mdwg.pdf

"4.1.3 Operating Reserve and, Instantaneous Load Capacity Requirements

> SPP calculates the amount of Operating Reserve required for the Operating Day, on both a system-wide basis and a Reserve Zone basis, to comply with the reliability requirements specified in the SPP Criteria. Additionally, SPP calculates the amount of Instantaneous Load Capacity required for the Operating Day to ensure that unit commitment is sufficient to reliably serve load in real-time while maintaining the Operating Reserve requirements. SPP calculates the hourly Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, Ramp Capability Down, Uncertainty Reserve and Instantaneous Load Capacity requirements on an SPP BAA basis and calculates minimum Operating Reserve requirements and maximum Operating Reserve limitations for each Reserve Zone. (1) SPP BAA Contingency Reserve requirements are set consistent with SPP Criteria and may vary on an hourly basis. (2) SPP BAA Regulation-Up and Regulation-Down requirements are based upon a percentage of forecasted load, adjusted up or down to account for Resource output variability, and may vary on an hourly basis. (3) SPP BAA Instantaneous Load Capacity requirements are set to ensure that expected variations between instantaneous peak load for the interval and the average load forecast for that interval can be reliably served in real-time while simultaneously maintaining the SPP BAA Operating Reserve requirements (4) The SPP BAA requirements, minimum Reserve Zone Operating Reserve requirements and maximum Reserve Zone Operating Reserve limitations are calculated and posted no later than 06:00 Day-Ahead. At this time, SPP will also communicate each Asset Owner's estimated Operating Reserve obligations in each Reserve Zone using the BAA Mid-Term Load Forecast and the Asset Owner load forecasts developed by SPP under Section 4.1.2.1.5. (5) These Operating Reserve requirements and limitations are used by SPP as inputs into the DA Market and RTBM clearing and RUC processes. (a) SPP may increase Operating Reserve requirements for use in RTBM clearing and RUC processes above the requirements used in the DA Market clearing, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions."

[59] https://www.spp.org/glossary/?term=operating+reserve.

Resource Adequacy-Related Requirements and Cost of Service

The SPP Open Access Transmission Tariff (OATT) requires Deficiency Payments from "a Market Participant when one or more of its LREs [Load Responsible Entities] has not met the Resource Adequacy Requirement as calculated in accordance with Section 14.2 of this Attachment AA."[60]

The Deficiency Payment is calculated by multiplying the Deficient Capacity[61] by the product of the SPP defined Cost of New Entry (CONE)[62],[63] and CONE FACTOR.[64] The CONE FACTOR is currently a range of values between 125% and 200% based upon the SPP Balancing Authority Planning Reserve Margin. Essentially, as the Planning Reserve Margins get tighter, the CONE FACTOR increases. Revenues from Deficiency Payments are then allocated to those LREs that have excess capacity.[65]

Based upon the 2025 SPP Summer Resource Adequacy Report, the outlook for Existing SPP Balancing Area Planning Reserve is greater than 8% through 2027 and Anticipated SPP Balancing Authority Area Planning Reserve (including new resources) is greater than 8% through 2030.[66] Therefore, the presumptive cost of any Deficiency Payment is approximately $107.02/kw-year at this time.

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[60] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Section 2 page 3.

[61] "Resource Adequacy Requirement less the sum of Deliverable Capacity and Firm Capacity, or zero if the sum of Deliverable Capacity and Firm Capacity is greater than or equal to the Resource Adequacy Requirement." Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Resource Attachment AA Resource Adequacy - Attachment AA Section 14 page 30.

[62] "The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission."

[63] The SPP defined CONE value has not been updated since July of 2018 and may be subject to future cost increases. For context, in Evergy's recent Certificate of Convenience and Necessity case, EA-2025-0075, the first year cost per kilowatt for the Mullin Creek Simple Cycle Gas turbine exceeds ** [redacted]. ** Workpaper titled Viola_McNew CCGT_Mullin Creek SC_MOW Model_02.06.25_Conf.xlsx provided in support of Evergy West witness John Grace supplemental direct testimony in Case No. EA-2025-0075.

[64] Where the CONE FACTOR shall be:
- (i) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or
- (ii) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or
- (iii) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

[65] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AA Resource Adequacy - Attachment AA Section 14 Attachment AA Section 14 pages 35-37.

[66] https://www.spp.org/documents/74099/2025%20spp%20summer%20resource%20adequacy%20report.pdf.

As discussed below, Staff recommends discrete charges for LLPS customers to recover changes in costs of service caused by those customers. Staff recommends specific charges be implemented to address variation between the capacity requirements that LLPS customers indicated, and actual capacity requirements of LLPS customers. These recommended charges are a "Demand Deviation Charge," to address differences between the capacity requirements stated when a customer initially applies for service, and the capacity requirements stated during an annual update process, and an "Imbalance Charge," for the difference between the current-year updated contract demand and the actual demand charge, to account for imbalances in projected demand and actual demand.

Because deviations in either direction of the year over year projected demand could cause additional costs to be incurred, it is reasonable to apply a charge for both under and over projections to provide a financial incentive for LLPS customers to provide projections that are as accurate as possible for purposes of SPP Resource Adequacy Requirements. Put simply, if the projected demand estimate is too high, Evergy might choose to acquire more capacity than necessary and conversely, if the projected demand estimate is too low, Evergy might incur costs to acquire additional capacity or incur a Deficiency payment. Both of those outcomes have the potential to impact non-LLPS customers and should be mitigated or avoided if possible.

The Imbalance Charge accounts for differences in realized demand during peak periods compared to the contracted demand for that year providing the LLPS customer a financial incentive to operate consistent with the contracted demand.

The Demand Deviation Charge and Imbalance Charge should be revisited in future general rate cases to reflect changes in the SPP Deficiency Payment calculation, including but not limited to, timing of the measured demand (i.e. changes to seasonality), SPP Balancing Authority Area Planning Reserve, SPP calculated value of CONE, and the SPP CONE FACTOR.

It is Staff's understanding that EMW and EMM currently meet the SPP Resource Adequacy requirement on a combined basis and ** [redacted]. ** However, in recent Evergy IRP filings, Evergy has indicated that the excess capacity from its existing resources compared to projected peak demands is dwindling. The 2025 SPP Summer Resource Adequacy Report indicates Evergy Metro (the combination of EMW and Evergy Metro) has approximately 117 MW of excess capacity. Given the size of the customers contemplated by Evergy's LLPS tariff and

Evergy's projected pipeline of potential LLPS customers, Evergy Metro and Evergy Missouri West ratepayers face increased risk of being subject to Deficiency Payments as a direct result of LLPS customers being integrated into the Evergy system prior to additional generation being built. Staff recommends that any Deficiency Payment incurred after the addition of LLPS customers be borne solely by the LLPS customer class in proportion to the overall peak demand of each customer.

Staff's concerns are compounded by the requested Customer Capacity Rider (CCR). Evergy's design for the CCR will introduce additional uncertainty in the projection of demand for SPP Resource Adequacy requirements as well as Evergy controlled capacity. The additional uncertainty and risk could harm non-LLPS customers via Deficiency Payments, additional capacity purchases or reductions in the revenue from LLPS customers beyond the value being provided by the CCR. If Evergy procures capacity, redundant to customer capacity under the CCR, captive ratepayers will pay that excessive cost and bear the risk of stranded assets.

Staff Witness: J Luebbert

SPP Market Protocols for Non-Conforming Load

In a recent presentation by SPP, "Large Load Stakeholder Engagement Forum,"[67] SPP indicated that many of the customers that are sized consistent with those Evergy customers that would be eligible for the LLPS tariff class would be considered non-conforming load customers.[68] SPP requires Market Participants with non-conforming load to provide additional forecasts for those entities. The SPP market protocols specify that the forecasts may be done for individual pricing nodes, as Staff is recommending. Based on the SPP requirements, Evergy is likely already required to do many of the forecasting tasks that it deems to be "administratively burdensome."

SPP requires the following for Non-Conforming Load in accordance with Section 4.1.2.1.2 of the Market Protocols for SPP Integrated Marketplace:

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[67] Southwest Power Pool, Large Load Stakeholder Engagement Forum, July 1, 2025, attached as Appendix 2 – Schedule 3.

[68] Located at: https://www.spp.org/documents/71629/excerpt%20of%20appendix%20g%20mitigated%20offer%20methodogoloy%20integrated%20marketplace%20protocols%20106a%20reference%20doc%20for%20mdwg.pdf.

> Non-Conforming Load, as described in Section 6.2.2, is more process driven and needs to be separated from the load forecast application because it does not follow a predictable pattern. Load that is modeled to represent the charging capabilities of ESRs not registered as an MSR must be considered a Non-Conforming Load. **Market Participants with registered Non-Conforming Load shall submit hourly load forecasts of Non-Conforming Load consumption to SPP before SPP begins the Day-Ahead RUC process for the Operating Day and for six (6) days following the Operating Day. Once the initial submission is received before SPP begins the Day-Ahead RUC process, Market Participants are allowed to submit hourly load forecasts of Non-Conforming Load after SPP begins the Day-Ahead RUC process up to thirty minutes before the Operating Hour. Market Participants are encouraged to submit a forecast of each registered Non-Conforming Load for two (2) hours following the current interval for each 15-minute interval that the forecast deviates from the hourly profile. If the 15-minute forecast is unavailable, SPP shall interpolate using the submitted hourly Non-Conforming Load forecast. Market Participants shall also submit a forecast on a 5-minute rolling 15-minute ahead basis.** The submitted Non-Conforming Load will be added to the conforming load forecasts to create the total SPP Forecast Area forecast. **Market Participants are required to submit actual Non-Conforming Load data for each Non-Conforming Load for which metering is available or estimates of Non-Conforming Load for which metering is not available** (submitted forecast value can be used as actual). [Emphasis added.]

Section 6.2.2 of the Market Protocols for SPP Integrated Marketplace goes on to state:

> Each Asset Owner must identify any Non-Conforming Load asset that the Asset Owner specifically forecasts and the PNode or Aggregate PNode (APNode) at which it resides. A Non-Conforming Load may only be represented by an APNode if the load is in the same location (e.g. a single industrial process served by more than one bus). For the purposes of this registration requirement, any Non-Conforming Load of 50 MW or greater must be identified.

Staff's recommendation for separate SPP commercial pricing nodes would allow for a much cleaner isolation of costs that are attributable to what will be Evergy's largest customers and facilitate the Commission's ability to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers."[69]

Staff Witness: J Luebbert

[69] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

III. Staff-Recommended LLPS Tariff

Staff's recommended tariff for EMM and EMW is attached as Appendix 2 - Schedule 1. This language is consistent with Staff's recommended tariff for The Empire District Electric Company, as filed July 21, 2025, in File No. ER-2024-0261 is attached as Appendix 2 – Schedule 4.

Staff Witness: Sarah L.K. Lange

Applicability

Staff recommends the availability and applicability of the LLPS tariff be as follows:

> Any customer taking service at 34 kV or greater except those served under the Large Power, Special Rate for Incremental Load Service, or Special High-Load Factor Market Rate rate schedules prior to January 1, 2026, or any customer with an expected 15-minute customer Non-Coincident Peak (NCP) of 25 kW or greater at a contiguous site (whether served through one or multiple meters) shall be subject to this Schedule LLPS. *[Note, for the EMM tariff, only the Large Power rate schedule reference is applicable.]*
>
> In the event that a customer with a demand that did not exceed 25 MW prior to January 1, 2026, (1) increases its demand to 29 MW or greater, unless such customer is served on the Special Rate for Incremental Load Service or Special High-Load Factor Market Rate rate schedules, or (2) requires installation of facilities operating at transmission voltage to accommodate increases in its demand, EMM/EMW shall expeditiously work with such customer to execute a service agreement and fully comply with the provisions of this Schedule LLPS within 6 months of (1) the customer's notice that such customer's demand is expected to equal or exceed 29 MW or (2) EMM/EMW's determination that transmission facilities are required.
>
> Customers eligible for service on the LLPS rate schedule are required to take service on this rate schedule.
>
> LLPS customers are required to participate in the following riders:
> - Fuel Adjustment Clause
> - Tax and License Rider
> - Renewable Energy Standard Rate Adjustment Mechanism Rider. *[EMW only]*
> - Securitized Utility Tariff Rider *[EMW only]*
>
> LLPS customers are not eligible to participate in the following riders:
> - Underutilized Infrastructure Rider
> - Economic Development Rider
> - Large Power Off-Peak Rider
> - Limited Large Customer Economic Development Discount Rider
> - Standby Service Rider
> - Voluntary Load Reduction Rider
> - Curtailable Demand Rider
> - Demand Side Investment Mechanism Rider
> - Market Based Demand Response
>
> *[This list prepared based on EMW tariff names]*

25 MW Threshold for LLPS Service

EMM currently provides service to ** [redacted], ** with a demand in excess of 25 kW, ** [redacted]. ** EMW currently provides service to ** [redacted], ** with a demand in excess of 25 kW, ** [redacted] ** served on a specially-designed tariff, which was approved by the Commission following extensive customer-specific testimony, discovery, and negotiations, the "Special Rate for Incremental Load Service." ** [redacted] **

Staff's recommended applicability provisions are more reasonable than Evergy's requested 100 MW for the following reasons:

1. With regard to its selection of 25 MW as the threshold for the "Path to Power," Evergy's response to Google LLC's Data Request G-E-57 stated:

   > The threshold was first identified as part of our industry outreach, specifically discussions with Arizona Public Service (APS). APS believed this to be a breakpoint between distribution and transmission service. Review of this threshold by Evergy personnel confirmed it to be a reasonable threshold.

   The distinction between utilizing existing transmission and distribution networks and requiring the construction of new transmission facilities is a reasonable distinction for separate treatment from existing EMM and EMW customers.
2. Adoption of Staff's recommended provision would not negatively impact any existing EMM or EMW customer, or cause any existing customer to be treated differently than was contemplated prior to the filing of Evergy's application in this docket. These provisions also safeguard for the growth of an existing customer becoming an LLPS customer, with a window to avoid undue customer impacts for normal growth.
3. Adoption of Staff's recommended provision would be consistent with the practice of EMM and EMW for seeking special rate schedules for customers in excess of 25 MW,

a. The Commission should avoid the unreasonable result of streamlining the process for customers greater than 100MW, but still requiring development and promulgation of special tariffs for smaller customers,

b. Evergy has requested the inclusion of important terms in an agreement with LLPS customers that is outside of the Commission's review. It would be an unreasonable result to require more Commission oversight for the development of rates for smaller customers than for larger customers.

4. While 100 MW is the floor set by SB 4, it is reasonable to set a lower floor, which is permissible under SB 4.

5. SPP defines "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:

    69kV or below and the HILL peak demand is 10MWs or greater
    Greater than 69kV and the HILL peak demand is 50MWs or greater".[70]

Economic Development Rider Exemption

Evergy has proposed that most of the LLPS customer's bill would be subject to discounting pursuant to economic development riders. This is distinct from EMW's current Special Rate for Incremental Load Service, Schedule SIL, P.S.C. Mo. No. 1 Original Sheet No. 157, and Special High-Load Factor Market Rate, Schedule MKT, P.S.C. Mo. No. 1 Original Sheet No. 158, which include provisions that service on those schedules cannot be under an Economic Development Rider, an Economic Redevelopment Rider, the Renewable Energy Rider, the Solar Subscription Rider/the Community Solar program, service as a Special Contract, or with participation in programs offered pursuant to the Missouri Energy Efficiency Investment Act, or for participation in programs related to demand response or off-peak discounts.

Missouri statute Section 393.1640 sets out certain statutory economic development discounts to be implemented by electrical corporations. The Commission retains reasonable discretion in the design and application of these discounts.[71] If LLPS rates are set to meet the

[70] https://spp.org/Documents/74189/Large%20Load%20Stakeholder%20Engagement%20Forum%20Meeting%20Materials%2020250701.zip Slide 22. This is also discussed the section, "Emergency Energy Conservation Plan."

[71] For example, Section 393.1640 states, "[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."

statutory requirement that LLPS rates be set to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers,"[72] 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 LLPS 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 LLPS customers is that Section 393.1640.1(2), RSMo., 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 LLPS 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 LLPS rates would be raised to make up for the discount. This result is impractical, unreasonable, illegal, and unnecessary.[73]

As will be discussed in the section "Charges for Contributions to Fixed Cost Recovery," under Staff's recommended structure and design, the LLPS rate will be set to essentially the floor established by Section 393.1640, RSMo., in that LLPS rates will be set to collect 120% of the cost of service that varies with the addition of a new LLPS customer.

Staff Witness: Sarah L.K. Lange

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[72] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

[73] Under Evergy's requested LLPS structure, an additional absurd result occurs in that in a rate case the value of the economic development discount would be allocated to all customer classes on the basis of revenue, while the value of the SSR revenue which Evergy proposes to levy to make up the economic development discount would apparently be retained by the LLPS customers in a CCOS. This would result in the appearance of the LLPS customer overcontributing to the total revenue requirement by the value of the charge that is facially applied to ensure that the LLPS customers contribute to the total revenue requirement.

Service Agreement and Description of Expected Demands and Loads

Staff's recommended LLPS tariff provisions related to the Service Agreement are set out below:

The Service Agreement provisions encompass several different concerns, each set out below:

> The form of the application for LLPS service shall be the Company's standard written application form *[which shall be approved by the Commission in this or another proceeding prior to utilization]*. This form shall include
>
> A. The customer's full corporate name and registration information, and that of any and all parent companies.
> B. 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 EMM/EMW 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 LLPS customer's load forecasting,
>   2. Contact information for the person or persons responsible for executing curtailment of the LLPS load,
>   3. A commitment to maintain updated contact information.
> 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 LLPS tariff. In the event that any additional termination provisions may be necessary or appropriate to address additional risk with a particular LLPS customer, those provisions shall be defined in the service agreement.
> E. The minimum term of service for a customer qualifying for service under LLPS shall be 10 years, following a ramp-up period of up to 5 years.
> F. Details pertinent to calculation and verification of rates for the Capacity Cost Sufficiency Rider, if applicable.

Day to Day Load Forecasts

Accurate daily load forecasts are necessary to mitigate real time market exposure in the SPP Day 1 marketplace.[74] While there may be an implicit assumption that LLPS load will be steady and come with a high load factor, this is not a justified assumption and is contrary to Staff's expectations.[75] 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. Other factors can drive inconsistencies in the day-to-day energy consumption of data centers. Staff reviewed the hourly loads of three data center customers identified by Evergy, each with multiple meters. The first customer, with an aggregate demand of approximately ** [redacted], ** demonstrated an overall load factor of ** [redacted], ** with load factors of ** [redacted]. ** The second customer, with an aggregate demand of ** [redacted], ** demonstrated an overall load factor of ** [redacted]. ** The customer's usage consisted of ** [redacted]. ** The third customer has an aggregate demand of ** [redacted] **

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

[74] As discussed in the section, "Day Ahead and Real Time Imbalances."

[75] Mr. Lutz represents that "Data centers often have load factors of 80 – 95%, which is well above the typical customer load factor."

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 EMM and EMW 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 LLPS 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.[76]

As an illustration, when Mr. Lutz refers at page 23 of his direct testimony to a representative customer as 728 MW with an 85% load factor, 15% variability remains. That 15% variability allows for over 109 MW of variation in a fully average day. That variation from a single customer would account for over a 4.25% variation of EMM's peak load, with far greater variation on a given day, and ** [redacted] ** of EMW's peak load.

Long and Mid-term Forecasts

Given the size of potential LLPS customers relative to current customers and the headroom in EMM and EMW's capacity positions, it is important to have reasonable expectations of the energy and capacity requirements of an LLPS customer over the expected duration of that customer's service requirements.[77] Given the need for EMM and EMW to comply with current and potential future resource adequacy requirements, it is important for Evergy to have reasonably accurate demand forecasts for purposes of satisfying resource adequacy requirements.[78]

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[76] Additional related concerns and recommended mitigations strategies and rate treatments are discussed in the section "Integrated Energy Market Issues."

[77] As discussed Staff Witness Brad J. Fortson in the section "Clean Energy Choice Rider."

[78] As discussed by Staff Witness J Luebbert in the section "Resource Adequacy-Related Requirements and Cost of Service."

Overestimated demand will result in harm to customers due to over-procurement of capacity,[79] and SPP will assess penalties for inadequate capacity relative to load.[80]

Regarding the requirements in the Staff-recommended service agreement, it is anticipated that EMM and EMW will have to build or otherwise acquire capacity to serve LLPS 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 LLPS customer falls on captive ratepayers.[81]

Staff recommends that in the event that EMM or EMW require capacity arrangements to serve LLPS load, that Evergy should seek to expeditiously promulgate a tariff so that those additional expenses can be appropriately recovered from the LLPS customer causing the need for additional capacity. Staff's recommended tariff language is provided below:

Capacity Cost Sufficiency Rider
In the event that EMM/EMW does not have sufficient capacity to reliably serve a requesting LLPS customer and its other load in a given season of a given year of the anticipated Service term, EMM/EMW may obtain contractual capacity to reliable serve the requesting customer. EMM/EMW shall file an ET case and tariff with no less than 45 days effective date, and shall file testimony explaining the potential LLPS customer, that customer's energy and capacity needs, and the capacity arrangements applicable to reliably serving that customer. EMM/EMW may seek a protective order for portions of the testimony as appropriate, but any Capacity Cost Sufficiency Rider Rate to be charged to any LLPS customer must be contained in a published tariff. The Capacity Cost Sufficiency Rider tariff shall contain terms related to treatment of revenues generated by the rider to prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers.

Staff Witness: Sarah L.K. Lange

[79] As discussed Staff Witness J Luebbert in the section, "Contradictory Policy."

[80] As discussed by Staff Witness J Luebbert in the section "Resource Adequacy-Related Requirements and Cost of Service."

[81] 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.

Recommended Rate Structure, Valuation, and Quantification of Cost of Service which Will Vary with the Addition of LLPS Customers

Quantification of rate components is a challenge because there are no current LLPS customers, EMM and EMW do not have pending general rate cases, and Evergy has not been wholly transparent with information it does or should possess, such as the characteristics and requirements of potential or likely LLPS customers with which it has had discussions.[82] Due to these circumstances, except where noted, Staff has relied heavily upon the cost of service estimates contained in Evergy's workpapers in this case, which Evergy has represented are derived from its direct workpapers in each utility's most recent rate case.

Staff has developed this recommended rate structure by identifying the cost of service which will vary with the addition of an LLPS 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, LLPS customers are sophisticated customers who can tolerate and understand the more complex billing structure which enables greater transparency. 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,"[83] and also provides for cleaner calculations of rates in future rate cases.

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[82] Appendix 2 – Schedule 5.

[83] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4. 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.

While the rates discussed in this section are intended to correspond to Staff's recommended LLPS rate structure, the values calculated and presented are also, necessarily, rebuttal to similar values asserted by Evergy. In other words, while Staff does address certain elements of Evergy's requested rate structure in sections that follow, generally, Staff addresses the reasonable structure and pricing here, and Staff will not add to the complexity of this Report by separately addressing each element of Evergy's requested rate structure below.

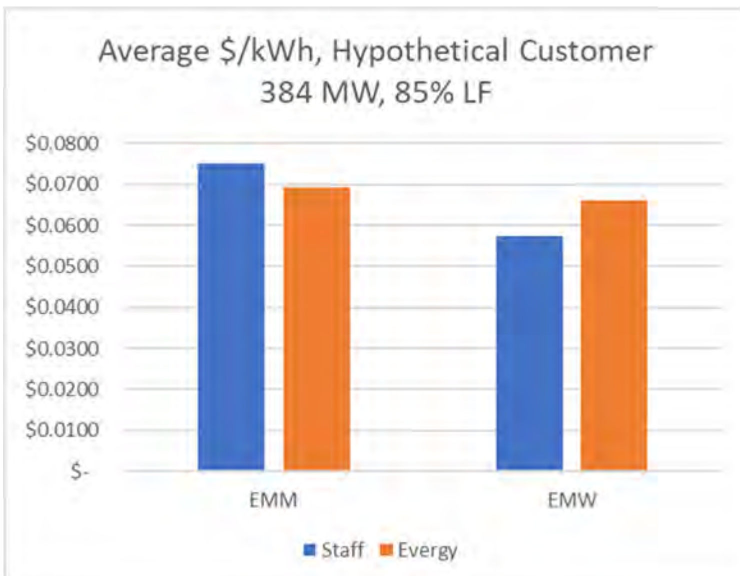
As will be discussed in "Charges for Contributions to Fixed Cost Recovery,", under Staff's recommended structure and design, the LLPS rate will be set to essentially the floor for economic development recipients established by Section 393.1640, RSMo., in that LLPS rates will be set to collect 120% of the cost of service that varies with the addition of a new LLPS customer. The intent of this provision is so that LLPS customers contribute toward the "fixed costs," within the EMM and EMW revenue requirements. "Fixed cost" is an often used, but not particularly useful, term.[84] 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.[85] 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 LLPS rate schedule and design attempts to quantify – based on the limited information available outside of a general rate case – the revenue requirement

[84] The revenue requirement associated with owning a generation facility changes over time, through the effects of depreciation, repairs, upgrades, and additions. The same is true of transmission lines, and all other sorts of utility-related infrastructure.

[85] For a fully-Missouri jurisdictional utility, these components will not vary with changes in energy use, customer counts, or peak demand. However, for multi-jurisdictional utilities such as EMM and EMW, in practice, Evergy level costs and expenses are allocated among jurisdictions based on factors like energy use, customer counts, and peak demand. So, it is likely that the revenue requirement of EMM and EMW associated with these items will increase with the addition of LLPS load, as each growing utility jurisdiction will receive a larger allocation of Evergy-level "fixed costs."

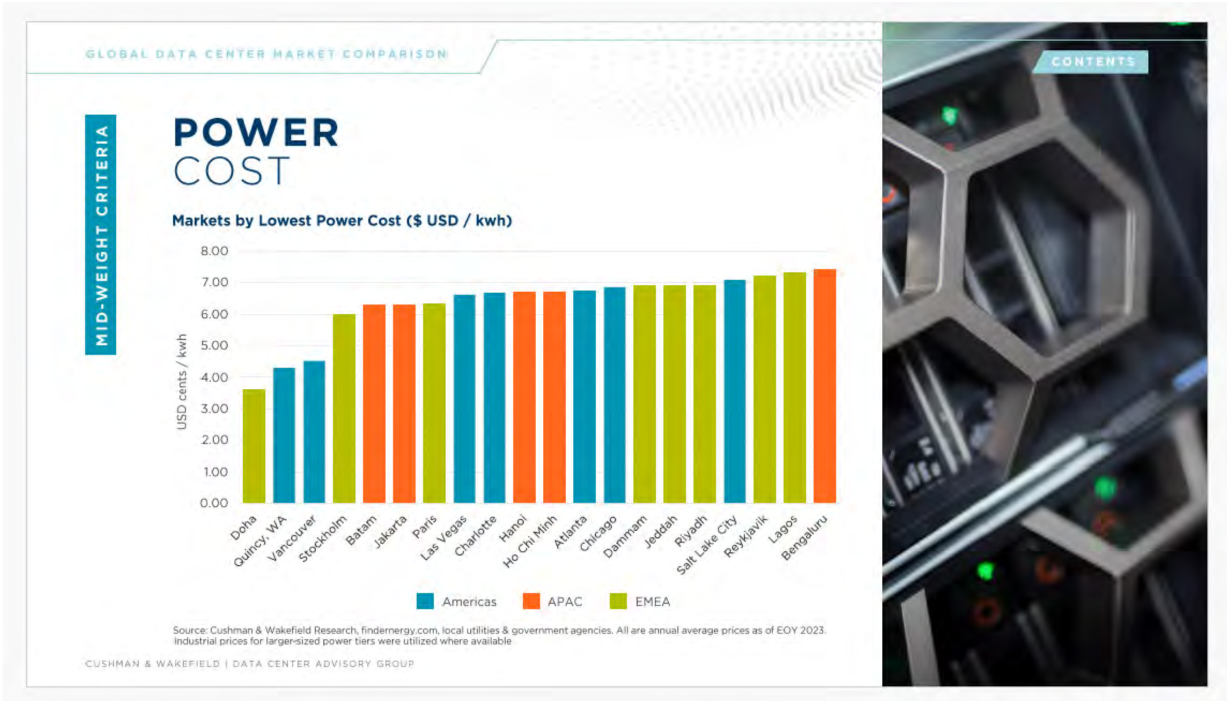
components that will vary due to LLPS customers, and to separately bill for each component. The recommended rate structure then incorporates a charge element to recover 20% of those variable bill charges, so that LLPS customers contribute to the "fixed cost" recovery of the utility.

All in, Staff estimates that this recommended rate design would produce an average cost per /kWh of 5.73 cents per kWh for the Evergy hypothetical LLPS customer on the recommended EMW rate design, and 7.51 cents per kWh for the EMM rate design. Evergy's requested rate design results in an average cost per kWh a rate of 6.597 cents per kWh for the EMW hypothetical LLPS customer, including the SSR[86] revenue, and 6.92 cents per kWh for the EMM hypothetical LLPS customer, including the SSR revenue. Actual experienced average bills under either structure and design will vary based on customer demand and energy characteristics.



In his Direct Testimony at page 10, Mr. Gunn testifies that "[a]ccording to the global real estate firm Cushman & Wakefield, Kansas City is the leading global emerging data center market among cities including Milan, Italy, and Minneapolis, Minnesota," citing to a "Global Data Center Market Comparison" publication. This publication is attached as Appendix 2 – Schedule 6. Reproduced below is the slide indicating the markets, and average costs for data center power in that market, of the 20 lowest-priced international geographic areas:

86 System Support Rider (SSR).



Customer Charge

The intent of this charge is to recover the cost of service associated with interfacing with the customer for load forecasting to the SPP, the salaries and benefits of employees serving LLPS customers, and metering and billing expenses. Staff recommends this charge be initially set at $10,000, for both EMM and EMW as informed by Evergy's responses to Data Requests 19, 19.1, 20, and 20.1, attached as Appendix 2 – Schedule 7. In future cases, this customer charge and all charges will be subject to review and adjustment. This rate in particular will be subject to case-to-case volatility based on the number of LLPS customers, the number and expenses of LLPS-facing employees, and the number and expenses of employees required for LLPS load forecasting and interfacing with the SPP.

The annual revenue produced by this charge is $120,000 per LLPS customer.

Facilities Charge

While the details vary, both Evergy and Staff recommend that LLPS customers pay for the transmission assets that customer will require to interconnect. However, excluding the transmission asset from rate base does not exclude the expenses of owning and operating that asset from a utility's revenue requirement.

The intent of Staff's recommended facilities charge is to recover the cost of service associated with the customer-specific transmission and substation infrastructure serving the customer. At this time, Staff expects this cost of service to consist of labor and nonlabor operations and maintenance (O&M) expense, property tax expense, and insurance expense.

Different LLPS 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 each utility to that utility's 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.[87]

Under this design, if a new LLPS 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.

Relying on the information provided in Evergy's filing and workpapers in this case, Staff estimates reasonable rates for the Facilities Charge at this time to be $0.01075 $/$ of Assets, and $0.00484 $/$ of Assets, for EMM and EMW, respectively. For an LLPS customer requiring

[87] $10,000,000 in expense divided by $100,000,000 in rate base = $0.10. $0.10 / 12 months = $0.083.

$30,000,000 of infrastructure, this charge would produce about $3.8 and $1.7 million in annual revenue, at EMM and EMW, respectively.

Billing Demand Charges

Staff recommends that the LLPS rate structure include two separate Demand Charges, although each will be billed using the same determinant. The first charge is intended to recover the gross cost of service of generation capacity. The second charge is intended to recover the cost of service of transmission capacity, as offset by related transmission revenues.

In calculating its recommended rates, Staff has not included the cost of service associated with things like owning office buildings, offering executive compensation, or other items which may be thought of as "fixed costs." These cost of service elements are generally included in the functionalized production and transmission revenue requirements presented in utility rate cases, with a portion of these elements allocated to the functions "production," "transmission," "distribution," and "customer." Staff's recommended rates do not include offsets for accumulated deferred income taxes and related offsets, which would also be typically allocated to these functions in a class cost of service study.

Each recommended demand charge will be billed based on the actual peak demand of an LLPS customer each winter month between 7:00 AM and 12:00 PM and between 5:00 PM and 9:00 PM, and each spring, summer, and fall month between 2:00 PM and 9:00 PM.[88] While these charges could be combined if necessary for billing purposes, Staff prefers they remain separate to promote transparency and to simplify future rate setting.

Charge for Generation Capacity Cost of Service

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

Reasonable bases include:

1. The entire revenue requirement of the most recent generation asset addition, divided by the estimated LLPS 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 LLPS load, then the rate per kW of LLPS demand each month would be $47.22.

[88] These time periods coincide with the on-peak seasonal time periods Staff recommends, the derivation of which is discussed below.

2. The portion of the revenue requirement of the most recent generation asset addition, prorated by total estimate LLPS 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 LLPS load, then accounting for a 10% reserve margin, the LLPS 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 LLPS demand each month would be $31.17.
3. A Cost of New Entry (CONE) calculation, on a kW-Month basis - the SPP CONE value, which has not been updated since 2018, is 85.61 $/kw-yr.[89]
4. The cost of owning and operating the actual generation fleets of each utility, excluding the cost of fuel and fuel-related operating expenses, divided by the capacity requirements of existing ratepayers.

Staff determined that, among other non-reasonable bases, that any valuation which offsets the cost of owning and operating current generation fleets with revenues currently produced through the operation of those fleets is unreasonable and fails to comply with SB 4.[90] Evergy represents that its requested demand charges were developed in consideration of 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.[91]

The difference between the gross and net costs of production 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 of adding significant load is

[89] For further context, the MISO CONE calculation for Missouri is $ 136,170 per MW Year. This is equivalent to $11.35 per kW-month, which would yield a rate of $12.48/kW, accounting for a reasonable reserve requirement estimate.

[90] While it could be reasonable and compliant with SB 4 to develop an LLPS 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.

[91] While in rate cases Staff and Evergy 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.

increasing the net expense or reducing the net revenue, it is not reasonable to allocate the revenue to the customer causing the revenue reduction.[92]

While it could be reasonable and compliant with SB 4 to develop an LLPS 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 LLPS 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 LLPS customers. However, as plants are built and retired over time, and as other customer classes grow and contract over time, it would be difficult-to-impossible to track where revenue responsibility for a given plant should appropriately lie. Further, at this time, generally, a simple cycle natural gas combustion turbine would be the least costly means of meeting additional capacity requirements caused by an LLPS customer; however, overall system needs should dictate the appropriate plant addition which may be a combined cycle or other more expensive capacity.

Staff's recommended generation capacity demand rate for EMM is calculated through reliance on the workpaper provided by Evergy, which is held out to be their direct CCOS workpaper from the 2022 rate case. Based on this workpaper, the production cost of service for EMM, excluding fuel and variable labor, and without allocated overheads, is $363,144,848 per year.[93] It is not reasonable to offset this revenue requirement with the capacity sales that EMM makes, because those capacity sales will be eliminated, substantially reduced, or offset through the addition of new generation assets due to the addition of an LLPS customer. From related Evergy workpapers, EMM summer coincident peak load is 1,938 MW. This MW value, adjusted to kW, and multiplied by 12, produces a determinant of 23,259,637 kW of annual monthly demand. This results in an LLPS generation-related demand charge of $15.51 $/on-peak kW for EMM.[94]

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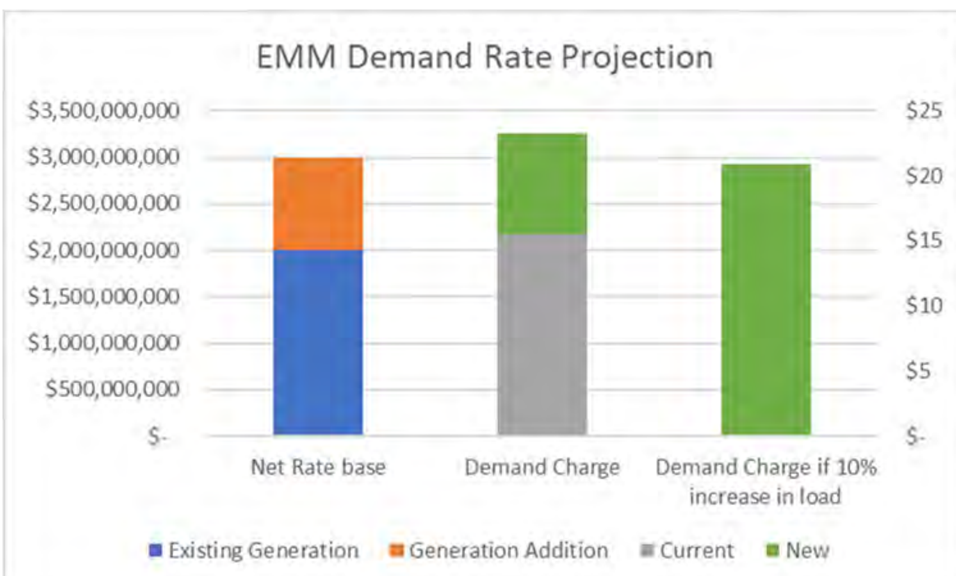
[92] Staff does not allocate fuel or net market expense to the LLPS class in its demand charge quantification. Staff does recommend that LLPS customers be billed an energy charge based on the wholesale cost of energy to serve LLPS customers.

[93] Reflecting plant in service of $3.5 billion, and net rate base of $2 billion.

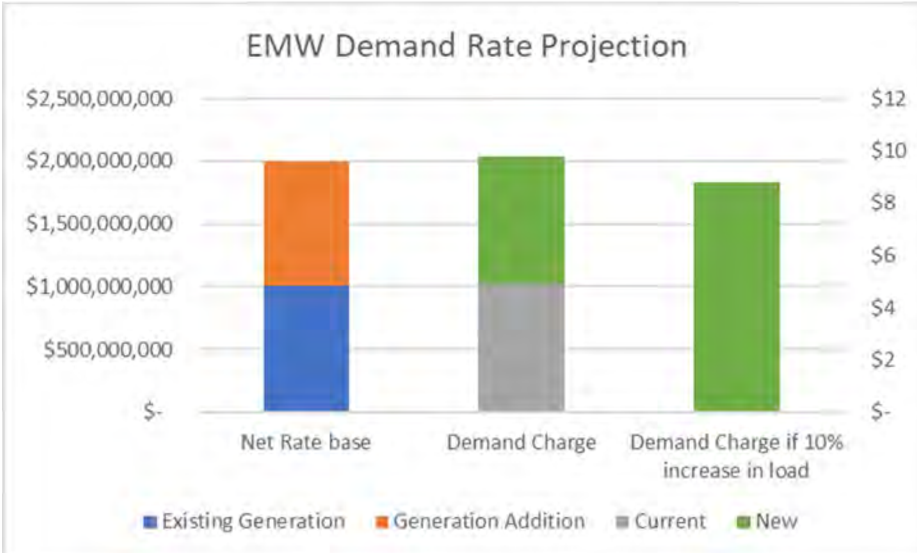
[94] As discussed in the section "Current and Projected Capacity to Serve Load," for the year 2025 and 2026, EMM claims a slight summer capacity surplus. However, EMM's planning documents indicate a summer capacity deficit will begin in 2027.

Staff's recommended generation capacity demand rate for EMW is calculated through reliance on the workpaper provided by Evergy, which is held out to be their direct CCOS workpaper from the 2024 rate case. Based on this workpaper, the production cost of service for EMW, excluding fuel and variable labor, and without allocated overheads, is ** [redacted] ** per year.[95] From related Evergy workpapers, EMM summer coincident peak load is ** [redacted]. ** This MW value, adjusted to kW, and multiplied by 12, produces a determinant of ** [redacted] ** of annual monthly demand. This results in an LLPS generation-related demand charge of $4.89 $/on-peak kW for EMM.

These charges should be expected to increase significantly in any rate case in which EMM or EMW incorporate new generation. With EMM's current net rate base of $2 billion, and EMW's net rate base of $1 billion, the addition of a billion-dollar generation asset coupled with an additional 10% of load will increase the demand charge to around $21 per kW at EMM, and around $8.80 per kW at EMW. If those load increases do not materialize, or if there is a gap between when the generation assets are recognized in a rate case and when the load is fully recognized in a rate case, generation demand charges of about $23.30 and $10.00 should be expected at EMM and EMW, respectively.



[95] Reflecting plant in service of $1.45 billion, and net rate base of just under $1 billion.



Based on filings in recent CCN cases, the cost for new CCGT[96] capacity is over ** [redacted] **/kW-month.[97]

** [redacted] **

[96] Combined Cycle Gas Turbines (CCGT).

[97]This valuation is established in reliance on the revenue requirement projections provided by Evergy in EA-2025-0075, divided by the kW-month determinants described in this Report.

If EMW essentially doubles its current generation rate base through the addition of new generation, and if EMM increases its current generation rate base by approximately 50%, at an average ** [redacted] **/kW cost of generation for a CCGT or with more expensive capacity, the associated rate increases will affect both LLPS and non-LLPS customers.

Charge for Transmission Capacity Cost of Service

The intent of this charge is to recover the net cost of service for transmission for all customers, including the LLPS customer. While the LLPS customers will each have some level of customer-specific transmission facilities, and will also 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-related costs of participating in the shared transmission system. Because EMM and EMW build transmission not only to serve its own loads, but also through participation in the RTOs, it is reasonable to offset the Transmission Capacity cost of service by those revenues. In future general rate cases, the LLPS allocation of these costs will ideally be 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. This results in demand charges of $3.00 $/on-peak KW, and $5.32 $/on-peak kW for EMM and EMW, respectively.

Energy Charges

Staff recommends time-based energy charges 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.
3. It encourages, but does not require, shifting energy consumption to periods when energy costs are low, and away from periods 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 LLPS customer has a perfect load factor, they will not be harmed. If an LLPS 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 LLPS 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.

Staff also recommends additional energy charges that do not vary with the time of day. Staff prefers these energy charges be billed separately to facilitate transparency. The time-based energy charges will be designed to recover the average wholesale cost of energy for each time period in the SPP day-ahead market. Additional energy charges are designed to recover expenses associated with real-time deviations, RES compliance, and EDI responsibility. Each are discussed separately, below.

SPP Nodal Pricing

Every kWh of energy that EMM or EMW sells to any retail customer must be purchased through the SPP integrated marketplace (IM).[98] Every additional kWh of load results in an overall increase in purchased power expense net of revenues.[99] Every kWh of energy required by an LLPS customer will cause the respective utility, EMM or EMW, to purchase an additional kWh of energy through the IM in the interval in which it is needed, at the price of the LMP at the interconnection node.[100] If a transmission constraint exists between the 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.

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[98] 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.

[99] 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 EMM's and EMW'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 EMM and EMW, 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.

[100] 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 EMW 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.

No Missouri utility has experience with a single interconnecting load the size of contemplated LLPS customers. The larger the load at a given interconnecting node, the more likely a transmission constraint will occur, and that the magnitude of the potential transmission constraints will be greater. The 384 MW LLPS customer modeled in Evergy's workpapers has a greater demand and load than the entirety of EMM's Medium General Service Class, and, than the entirety of EMW's Small General Service Class. In other words, each utility is contemplating the addition of demand greater than each and every small business they currently serve, located at a single transmission load node. Depending on the location of the specific constraint in a given interval, these constraints could raise the LMPs of other regional load nodes too.[101]

While there is no realistic way to cap the impact of transmission constraints caused by LLPS customers throughout the service territory, Staff recommends requiring EMM and EMW to register each LLPS customer through the SPP as a separate load to facilitate isolation of the cost of the constraint to the LLPS class. This recommendation is further discussed in the section "Integrated Energy Market Issues."

Charges for Day Ahead Energy Expense

In the future, the LLPS energy charges should be calculated using the nodal prices at LLPS interconnections. For this case, Staff relies on the weighted load LMP for EMM and for EMW. The historic annual average around-the-clock Day Ahead LMPs for each rate jurisdiction are summarized in the table below:

	EMM	EMW
2016	$ 22.31	$ 21.91
2017	$ 21.59	$ 21.33
2018	$ 27.44	$ 26.52
2019	$ 23.08	$ 23.15
2020	$ 20.70	$ 20.64
2021	$ 66.78	$ 70.10
2022	$ 46.62	$ 49.11
2023	$ 25.45	$ 26.13
2024	$ 25.80	$ 24.40

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

The around-the-clock seasonal averages for each year are provided below:

	Raw Averages							
	Metro				Missouri West			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2024	$ 26.73	$ 20.71	$ 35.16	$ 20.19	$ 26.35	$ 20.59	$ 33.10	$ 17.17
2023	$ 34.29	$ 24.16	$ 21.75	$ 21.59	$ 35.15	$ 24.89	$ 22.75	$ 21.69
2022	$ 72.05	$ 45.55	$ 34.61	$ 33.59	$ 70.43	$ 47.47	$ 40.34	$ 37.65
2021	$ 33.56	$ 32.60	$ 194.60	$ 20.14	$ 35.23	$ 38.50	$ 197.63	$ 22.91
2020	$ 25.07	$ 20.89	$ 19.23	$ 17.46	$ 23.24	$ 22.36	$ 20.13	$ 16.72
2019	$ 22.55	$ 21.44	$ 23.35	$ 24.92	$ 22.51	$ 21.35	$ 23.20	$ 25.54
2018	$ 27.74	$ 30.31	$ 25.90	$ 25.70	$ 27.20	$ 29.70	$ 24.98	$ 24.08
2017	$ 26.46	$ 18.81	$ 20.57	$ 20.41	$ 25.66	$ 18.88	$ 20.53	$ 20.16
2016	$ 25.36	$ 26.92	$ 21.05	$ 15.83	$ 25.31	$ 25.56	$ 20.75	$ 15.95

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

	Inflation Adjusted								
	Metro				Missouri West				
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	
2024	$ 26.73	$ 20.71	$ 35.16	$ 20.19	$ 26.35	$ 20.59	$ 33.10	$ 17.17	2.00%
2023	$ 35.66	$ 25.12	$ 22.62	$ 22.46	$ 36.55	$ 25.89	$ 23.66	$ 22.56	4.00%
2022	$ 76.38	$ 48.29	$ 36.69	$ 35.61	$ 74.65	$ 50.32	$ 42.76	$ 39.91	6.00%
2021	$ 36.25	$ 35.21	$ 210.17	$ 21.75	$ 38.05	$ 41.58	$ 213.44	$ 24.74	8.00%
2020	$ 27.58	$ 22.98	$ 21.15	$ 19.20	$ 25.56	$ 24.59	$ 22.15	$ 18.39	10.00%
2019	$ 25.25	$ 24.01	$ 26.15	$ 27.91	$ 25.22	$ 23.91	$ 25.99	$ 28.60	12.00%
2018	$ 31.63	$ 34.56	$ 29.53	$ 29.30	$ 31.00	$ 33.86	$ 28.48	$ 27.45	14.00%
2017	$ 30.70	$ 21.82	$ 23.86	$ 23.67	$ 29.77	$ 21.90	$ 23.81	$ 23.39	16.00%
2016	$ 29.93	$ 31.77	$ 24.84	$ 18.68	$ 29.87	$ 30.16	$ 24.48	$ 18.82	18.00%

Staff next found “Average 1,” based on excluding the minimum and maximum value for each season from the simple average.

	Calculations							
	Metro				Missouri West			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
Simple Average	$ 35.57	$ 29.38	$ 47.80	$ 24.31	$ 35.22	$ 30.31	$ 48.65	$ 24.56
Maximum	$ 76.38	$ 48.29	$ 210.17	$ 35.61	$ 74.65	$ 50.32	$ 213.44	$ 39.91
Minimum	$ 25.25	$ 20.71	$ 21.15	$ 18.68	$ 25.22	$ 20.59	$ 22.15	$ 17.17
Revised Average 1	$ 31.21	$ 27.92	$ 28.41	$ 23.50	$ 31.02	$ 28.84	$ 28.90	$ 23.42

Staff then found 75% of the simple average, and 125% of the simple average to filter outlier prices:

	Calculations							
	Metro				Missouri West			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
Simple Average	$ 35.57	$ 29.38	$ 47.80	$ 24.31	$ 35.22	$ 30.31	$ 48.65	$ 24.56
75% of Average	$ 23.41	$ 20.94	$ 21.30	$ 17.62	$ 23.27	$ 21.63	$ 21.67	$ 17.57
125% of Average	$ 39.01	$ 34.91	$ 35.51	$ 29.37	$ 38.78	$ 36.05	$ 36.12	$ 29.28

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

	Filtered Results							
	Metro				Missouri West			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
2024	$ 26.73	$ 27.92	$ 35.16	$ 20.19	$ 26.35	$ 28.84	$ 33.10	$ 23.42
2023	$ 35.66	$ 25.12	$ 22.62	$ 22.46	$ 36.55	$ 25.89	$ 23.66	$ 22.56
2022	$ 31.21	$ 27.92	$ 28.41	$ 23.50	$ 31.02	$ 28.84	$ 28.90	$ 23.42
2021	$ 36.25	$ 27.92	$ 28.41	$ 21.75	$ 38.05	$ 28.84	$ 28.90	$ 24.74
2020	$ 27.58	$ 22.98	$ 28.41	$ 19.20	$ 25.56	$ 24.59	$ 22.15	$ 18.39
2019	$ 25.25	$ 24.01	$ 26.15	$ 27.91	$ 25.22	$ 23.91	$ 25.99	$ 28.60
2018	$ 31.63	$ 34.56	$ 29.53	$ 29.30	$ 31.00	$ 33.86	$ 28.48	$ 27.45
2017	$ 30.70	$ 21.82	$ 23.86	$ 23.67	$ 29.77	$ 21.90	$ 23.81	$ 23.39
2016	$ 29.93	$ 31.77	$ 24.84	$ 18.68	$ 29.87	$ 30.16	$ 24.48	$ 18.82

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							
	Metro				Missouri West			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring
Simple Average	$ 35.57	$ 29.38	$ 47.80	$ 24.31	$ 35.22	$ 30.31	$ 48.65	$ 24.56
Revised Average 1	$ 31.21	$ 27.92	$ 28.41	$ 23.50	$ 31.02	$ 28.84	$ 28.90	$ 23.42
Revised Average 2	**$ 30.55**	**$ 27.12**	**$ 27.49**	**$ 22.96**	**$ 30.38**	**$ 27.43**	**$ 26.61**	**$ 23.42**

Staff's recommended rates in this case are based on the Revised Average 2 values.

To establish time periods for each season, Staff reviewed the seasonal price variations, by hour, for each season, using 2023 and 2024 prices. Those results are provided in the heat maps on the following page.

EMW Review	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	50%	54%	51%	51%	53%	58%	73%	92%	95%	96%	100%	92%	82%	73%	68%	64%	65%	78%	97%	88%	79%	76%	69%	59%
2023	Winter	42%	45%	42%	42%	45%	53%	67%	86%	94%	90%	100%	94%	80%	74%	69%	66%	66%	74%	96%	87%	75%	68%	61%	53%
2024	Spring	31%	28%	19%	17%	19%	27%	42%	56%	65%	91%	100%	86%	83%	82%	85%	86%	87%	90%	96%	95%	98%	89%	65%	51%
2023	Spring	31%	30%	27%	26%	29%	39%	53%	69%	80%	94%	100%	90%	87%	87%	87%	87%	89%	94%	97%	97%	95%	84%	61%	48%
2024	Summer	31%	30%	26%	23%	22%	24%	28%	30%	37%	47%	51%	54%	62%	70%	81%	87%	93%	100%	97%	88%	73%	60%	49%	40%
2023	Summer	30%	28%	25%	24%	23%	24%	27%	29%	33%	42%	46%	51%	59%	67%	77%	84%	95%	100%	93%	82%	68%	55%	46%	38%
2024	Fall	20%	20%	17%	17%	19%	23%	34%	47%	49%	56%	73%	64%	63%	66%	71%	75%	83%	94%	100%	85%	63%	50%	40%	30%
2023	Fall	33%	33%	29%	27%	32%	34%	45%	63%	71%	79%	86%	81%	74%	74%	80%	83%	88%	97%	100%	91%	76%	62%	53%	43%

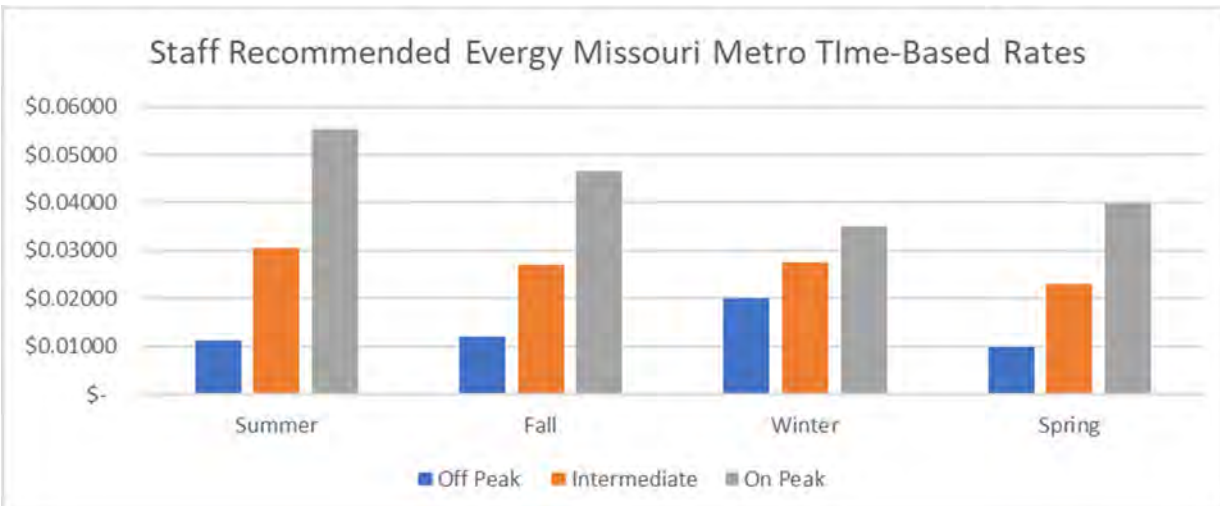
EMM Review	Hour:	Midnight	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
2024	Winter	50%	54%	51%	50%	51%	56%	71%	94%	96%	96%	100%	92%	81%	73%	67%	64%	65%	77%	97%	87%	79%	77%	70%	59%
2023	Winter	38%	40%	38%	38%	41%	49%	64%	85%	93%	89%	100%	94%	80%	74%	69%	66%	66%	74%	97%	87%	74%	67%	60%	50%
2024	Spring	32%	29%	21%	19%	21%	28%	40%	55%	63%	86%	94%	84%	83%	84%	88%	91%	93%	96%	100%	97%	97%	87%	66%	51%
2023	Spring	30%	28%	25%	24%	28%	37%	52%	67%	79%	93%	100%	90%	87%	88%	88%	89%	92%	96%	98%	97%	94%	82%	60%	46%
2024	Summer	28%	27%	23%	20%	20%	22%	26%	28%	35%	44%	47%	50%	57%	66%	78%	85%	93%	100%	96%	86%	69%	56%	46%	36%
2023	Summer	29%	27%	24%	23%	22%	23%	26%	28%	33%	41%	45%	50%	58%	66%	77%	84%	94%	100%	92%	83%	66%	55%	45%	36%
2024	Fall	19%	18%	15%	14%	16%	20%	31%	44%	48%	56%	72%	62%	61%	65%	71%	75%	84%	96%	100%	84%	61%	50%	40%	30%
2023	Fall	31%	30%	27%	25%	30%	32%	43%	60%	68%	77%	85%	78%	73%	72%	80%	82%	88%	97%	100%	90%	74%	59%	51%	41%

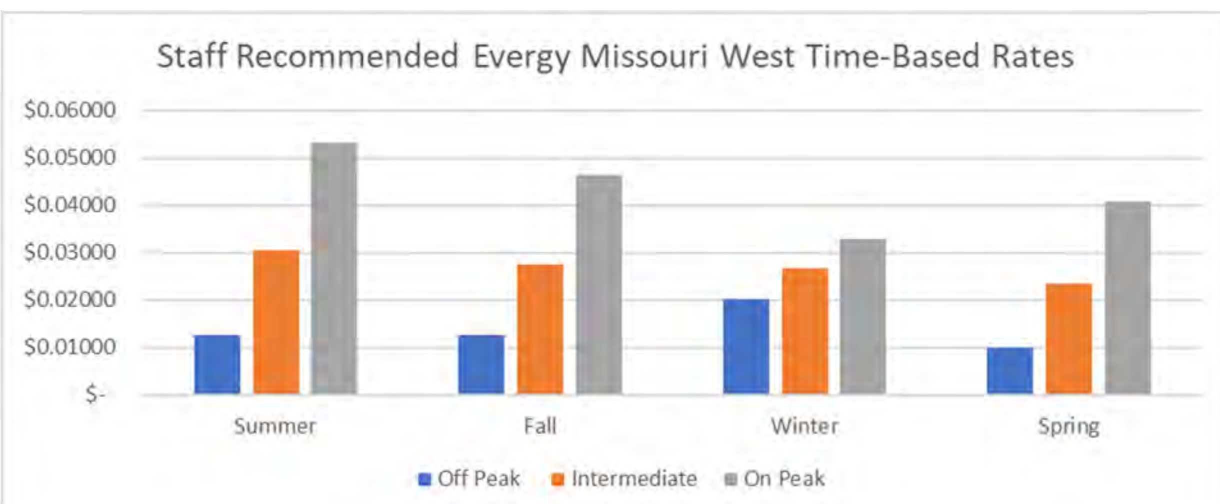
Staff determined the following time periods were a reasonable and appropriate balance of complexity and precision:

	Winter				Spring, Summer, & Fall			
	$Start_1$	End_1	$Start_2$	End_2	$Start_1$	End_1	$Start_2$	End_2
Off Peak	10:00 PM	7:00 AM			10:00 PM	7:00 AM		
Intermediate	12:00 PM	5:00 PM	9:00 PM	10:00 PM	7:00 AM	2:00 PM	9:00 PM	10:00 PM
On Peak	7:00 AM	12:00 PM	5:00 PM	9:00 PM	2:00 PM	9:00 PM		

Staff used the relationship of prices within seasons within 2023 and 2024 to develop the relationship of rates for each time-based period, stated and illustrated below:

	Metro				Missouri West			
Period	**Summer**	**Fall**	**Winter**	**Spring**	**Summer**	**Fall**	**Winter**	**Spring**
Off Peak	$ 0.01122	$ 0.01194	$ 0.02003	$ 0.00978	$ 0.01265	$ 0.01266	$ 0.02017	$ 0.01000
Intermediate	$ 0.03055	$ 0.02712	$ 0.02749	$ 0.02296	$ 0.03038	$ 0.02743	$ 0.02661	$ 0.02342
On Peak	$ 0.05539	$ 0.04662	$ 0.03494	$ 0.03990	$ 0.05316	$ 0.04642	$ 0.03304	$ 0.04068





Load-Servicing Energy Charge

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 LLPS-specific deviations to reflect increased load-forecasting risk. Staff is willing to work with Evergy and other parties to establish realistic rates for the variation between the loads EMM and EMW provide to the SPP for day-ahead dispatch and the actual loads experienced by each in real time. However, as discussed by J Luebbert in the “Integrated Energy Market Issues” section of this report, the addition of an LLPS 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. These rates should be based on the collective net deviation expense of the LLPS class across all LLPS load nodes.

Missouri Renewable Energy Standard Compliance Charge

This charge will recover the approximate value of Renewable Energy Certificates associated with requirements under the Missouri Renewable Standard (RES). Among other things, the RES requires that EMM and EMW generate or purchase renewable energy, or purchase Renewable Energy Certificates (RECs), equal to at least 15% of each utility’s load for years after 2021.[102] Staff recommends that each kWh of LLPS load be billed at a rate equal to 15% of the value of a REC as established in each rate case.

In the event that a customer qualifies for exemption with RES compliance under SB 4, this charge would not be applied to that LLPS customer. At this time, Staff’s recommended rates are $0.00033 $/kWh for EMM, and $0.00040 $/kWh for EMW, based on recent REC valuations.[103]

[102] Section 393.1030, RSMo.

[103] SB 4 included provisions related to Accelerated Renewable Buyers, as defined there-in. Rulemakings will establish the extent to which certain customers may be excepted from the Renewable Energy Standard Compliance Charge.

Economic Development Discount Responsibility Charge

The Economic Development Discount Responsibility Charge will be designed to recover the value of the discounts allocated to the LLPS class in future rate cases. Missouri statute Section 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.

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

Reactive Demand Charge

This charge will recover the cost of service associated with voltages support and regulation to the extent that an LLPS customer requires reactive demand that is out of balance with that customer's consumption of real power. Staff’s recommended rates for this charge are the current tariffed rates of $0.99294 $/kVar for EMM and $0.46 $/kVar for EMW.

Charges for Contributions to Fixed Cost Recovery

The charges discussed above do not reflect any of EMM’s or EMW’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. For a fully-Missouri jurisdictional utility, these components will not vary with changes in energy use, customer counts, or peak demand. However, for multi-jurisdictional utilities such as EMM and EMW, in practice, Evergy level costs and expenses are allocated among jurisdictions based on factors like energy use, customer counts, and peak demand. So, it is likely that the revenue requirement of EMM and

EMW associated with these items will increase with the addition of LLPS load, as each growing utility jurisdiction will receive a larger allocation of Evergy-level "fixed costs."

Staff's recommended structure includes two charges so that the LLPS rate will be set to essentially the floor for economic development discount recipients established by Section 393.1640 RSMo., and so that, with appropriate accounting treatments, these rate schedules will reasonably ensure LLPS 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 LLPS customers. To account for income tax, based on Evergy's workpapers submitted in this case, the bill components will actually need to be multiplied by 24.77% to accomplish a 20% contribution to "fixed costs."

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 Economic Development Discount Responsibility Charge), and the Reactive Demand Charge.

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.

Other Demand-Related Charges

As explained in the recommended tariff language in the section "Long and Mid-term Forecasts," Staff recommends that in the event that EMM or EMW requires capacity arrangements to serve LLPS load, it should seek to expeditiously promulgate a tariff so that those additional expenses can be appropriately recovered from the LLPS customer causing the need for additional capacity. This charge would be reflected on that customer's bill as the "Capacity Cost Sufficiency

Rider." 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. 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 EMM or EMW ratepayers become responsible for payments associated with capacity shortfalls.

Staff Witness: Sarah L.K. Lange

Demand Deviation and Imbalance Charges

Staff recommends specific charges be implemented to address variation between the capacity requirements that LLPS customers indicated, and actual capacity requirements of LLPS customers. These recommended charges are:

1. The Demand Deviation Charge, which addresses differences, if any, between the capacity requirements stated when a customer initially applies for service, and the capacity requirements stated during an annual update process:
    a. The approximated Deficiency Payment be used as the basis of a Demand Deviation Charge equal to $107.02/kW to account for year over year changes to projected demand;
    b. To be applied as 12 equal monthly amounts for any deviations between initial contract demand and the current-year updated contract demand;
    c. Deviations from the original contract of less than +/-5% will not incur a penalty, however: deviations of more than +/-5% will be billed at $8.9177/kW-month.
2. An Imbalance Charge, if applicable, for the difference between the current-year updated contract demand and the actual demand charge, to account for imbalances in projected demand and actual demand.
    a. This charge will be applied to the difference between the projected demand for each month and the actual demand realized during the demand window for that month at a rate of $8.9177/kW.

Because deviations in either direction of the year over year projected demand could cause additional costs to be incurred, it is reasonable to apply a charge for both under and over projections to provide a financial incentive for LLPS customers to provide projections that are as accurate as possible for purposes of SPP Resource Adequacy Requirements.

The Imbalance Charge accounts for differences in realized demand during peak periods compared to the contracted demand for that year providing the LLPS customer a financial incentive to operate consistent with the contracted demand.

The Demand Deviation Charge and Imbalance Charge should be revisited in future general rate cases to reflect changes in the SPP Deficiency Payment calculation, including but not limited to, timing of the measured demand (i.e. changes to seasonality), SPP Balancing Authority Area Planning Reserve, SPP calculated value of CONE, and the SPP CONE FACTOR.

Staff Witness: J Luebbert

Additional Staff-Recommended Tariff Provisions and Regulatory Treatments

Staff's recommended LLPS tariff also includes basic terms of service, as set out below:

Other Terms:

A. LLPS customers shall be billed on a calendar month basis.
B. LLPS bills shall be rendered by the fifth business day of the following calendar month.
C. LLPS 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.

Staff also recommends that the 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 LLPS 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 LLPS customers.[104] It is essential that the Commission use reasonable requirements and regulatory treatments as outlined below to mitigate the risks of unreasonable rate increases to non-LLPS customers caused by EMM's and EMW's managerial decisions related to LLPS customers.

The recommended revenue treatments, termination charges, and risk mitigation strategies interplay. These recommendations are also complicated because the FAC tariffs of EMM and

[104] SB 4 also set out an 80MW threshold applicable to both EMM and EMW with regard to compliance with the Missouri Renewable Energy Standard for qualifying customers.

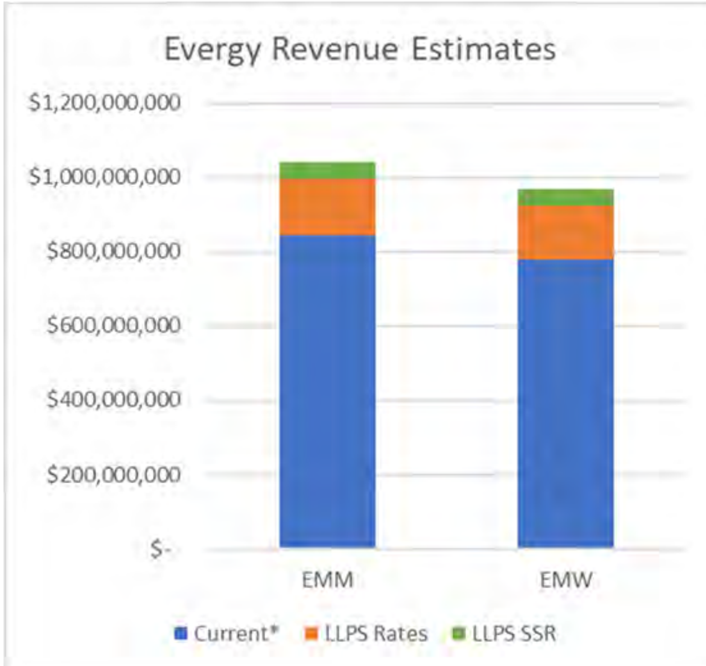
EMW cannot be modified outside of a general rate case. In a future general rate case, Staff intends to make recommendations similar to those recently made in the pending Empire rate case, Case No. ER-2024-0261. In the meantime, Staff provides recommendations here that will be subject to future modification pending the changes to the FAC.

Regulatory Lag Considerations

Due to the inherent lag between when an LLPS customer begins paying its bills, and when that revenue is recognized in a rate case, EMM and EMW 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,
3. The statutory requirement that LLPS 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 LLPS customers cannot be effectuated until those revenues are realized in a rate case to the benefit of other customers, and
4. While Staff does not recommend approval of Evergy's requested riders, revenues under those riders compound these problems. These concerns will be detailed in Staff's discussion of those requested riders.

The scale of an LLPS customer and the associated LLPS revenue are such that EMM or EMW may base rate case timing exclusively on the consideration of accumulating as much un-recognized LLPS revenue as possible. In its filed EMM workpapers, Evergy studied then-current rate revenue of $843,129,436. EMM's proposed rates for studied LLPS customer provide new rate revenue of $162,873,27, which is an increase of 18% over EMM revenues approved in its most recent rate case. EMM assumed an additional $44 million in SSR revenue from the LLPS customer, producing an additional 5% over current revenue. For EMW, the modeled customer at the requested rates produces an increase of over 18.5% of revenues approved in the most recent EMW rate case, and the additional SSR revenues provide an additional 5.71%.



It is the prerogative of Evergy 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, LLPS customer growth will be offset by increases in revenue requirement to a much smaller extent than normal customer growth.

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 LLPS customer, but also there are more offsetting increases to revenue requirement. For an LLPS customer, EMM and EMW will not be paying for some or all of the costs to install a meter, a service line, or a line transformer. Nor will EMM or EMW be paying for the accumulated need to expand distribution systems or substations to serve customers collectively with the addition of an LLPS customer. Rather, the LLPS 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 LLPS growth from ordinary customer growth.[105]

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

It is Staff's understanding that, presently, EMM and EMW lack sufficient capacity to serve new LLPS customers within the parameters of SPP resource adequacy requirements. This means additional capacity must be obtained. This additional capacity may be built, acquired through a contract for a specific asset, or acquired through other contractual arrangements.[106] 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 LLPS 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 Evergy, that can control the pace of construction activities and have discretion in the timing of customer additions; and second, for the practical reason that if EMM or EMW need to build additional capacity to serve the full load of an LLPS customer, then EMM and EMW will not be serving that LLPS 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 EMM or EMW were to make a contractual arrangement of more than 1 year for capacity to enable service of an LLPS customer while constructing a new generation asset, then the utility may be shielded from negative regulatory lag associated with that asset. EMM and EMW are 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, RSMo., 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 EMM and EMW are each recovering the full cost of owning and operating their generation fleets from existing customers, as of the conclusion of each of their last rate cases. If a new LLPS customer begins paying for the generation fleet – as they should – then EMM and EMW 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? Evergy is in the position of the restaurant manager,

[106] If the terms of those contracts or capacity arrangements are less than 1 year, those expenses are included in the FAC, and the FAC will limit the increase in expenses that offset the positive regulatory lag.

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 Evergy shareholders.

Under the treatment requested by Evergy and also under Staff's recommended approach, the only cost of service components that will offset the revenues of new LLPS load between rate cases will be wholesale energy expenses and load and demand-allocated RTO expenses. Notably, EMM and EMW have substantial protection from these expense increases through the operation of the FAC, as discussed below.

FAC Operation

When a new LLPS customer comes onto the system it will begin paying for every kWh of energy it consumes. The energy rates under current consideration range from $0.02988 per kWh under Evergy's requested EMM rate, and $0.0288 per kWh under Evergy's requested EMW rate, to Staff's around-the-clock average EMM rate of $0.0270 and $0.0269 for EMW, with specific rates depending on the time period in which energy is consumed.

Simultaneously, EMM and EMW will reflect additional energy cost in the respective utility's FAC. While required FERC netting may result in this additional load appearing as an increase to expense or as a decrease to revenue in any given accumulation period filing, the reality is that the simple act of selling more energy to retail customers results in EMM or EMW transacting more energy purchases through the FAC. This is applicable to the Day Ahead market, the Real Time market, the ancillary services market, and for various SPP schedules which are assessed to EMM and EMW based on metrics like the load-ratio share, or various measures of demand.

Staff has reviewed the effect of the Evergy hypothetical LLPS customer on the FAC, and prepared two examples for each utility, one reflecting that additional wholesale energy expense to total $25 per MWh, and one reflecting total additional energy expenses of $30 per MWh.[107]

[107] Staff has not separately accounted for transmission expenses that are not fully included in the FAC.

	EMM $25	EMM $30
LLPS Cost of Load	$ 71,481,600	$ 85,777,920
Actual Energy Cost per kWh	0.02003	0.02132
Difference	$ 0.00174	$ 0.00303
95% of Difference	$ 0.00165	$ 0.00288
EMM will Recover	$ 18,226,378	$ 31,807,882
% EMM will Recover	25.50%	37.08%
Other Customers will Pay	$ 13,511,170	$ 23,579,106
% Other Customers will Pay	18.90%	27.49%

** [redacted] **

Using the EMM $25 per MWh scenario, the cost of new load will be $71,481,600. This increases the jurisdictional net cost of load to $221,332,741 from $149,851,141. When the new total is divided by the new kWh of sales, the actual energy cost per kWh would be $0.02003, compared to the base factor of $0.0183. Ninety-five percent of the difference between these two values is $0.0165, which is the amount to be recovered through the FAC. Applying this amount to total kWh, including the LLPS customer, results in Evergy recovering $18 million of the $71 million from all customers, with $13 million collected from customers other than the LLPS customer. Depending on the actual size of the LLPS customer and the wholesale cost of energy in the future, EMM and EMW will recover substantial portions of the LLPS customer's cost of energy through the FAC, and fully recover that cost of energy through LLPS rates. The Net Revenue that EMW and EMM would retain under the proposed rates for the hypothetical LLPS customer are calculated below, with revenues indicated as negative values in the tables:

	EMM $25	EMM $30
Annual Expense	$ 71,481,600	$ 85,777,920
FAC Recovery	$ (18,226,378)	$ (31,807,882)
LLPS Rate Revenue	$ (153,720,516)	$ (153,720,516)
Net Revenue no SSR	$ (100,465,294)	$ (99,750,478)
LLPS SSR Revenue	$ (44,190,720)	$ (44,190,720)
Net Revenue with SSR	$ (144,656,014)	$ (143,941,198)

	EMW $25	EMW $30
Annual Expense	$ 71,481,600	$ 85,777,920
Total FAC Recovery	$ (5,188,135)	$ (18,769,639)
LLPS Rate Revenue	$ (144,207,496)	$ (144,207,496)
Net Revenue no SSR	$ (77,914,030)	$ (77,199,214)
LLPS SSR Revenue	$ (44,421,120)	$ (44,421,120)
Net Revenue with SSR	$ (122,335,150)	$ (121,620,334)

Staff Witness: Sarah L.K. Lange

Staff acknowledges a reverse effect as well if an LLPS customer leaves the system and reduces Evergy's load after that customer has been recognized in base rates and the FAC base factor. Evergy would then no longer incur the wholesale energy and transmission expense associated with service to that customer. In this case, it would be reasonable to make an adjustment so that other customers do not unreasonably benefit from the significant reduction in wholesale energy expense that results. This is a mechanism similar to the "N Factor" that was utilized in the Ameren Missouri FAC associated with its service to Noranda.[108]

It is Staff's understanding that FAC tariff sheets cannot be changed outside of a general rate case. Therefore, Staff recommends that the FAC LLPS adjustments be incorporated in the FAC tariff sheet and agreed to by the parties to take place in the next general rate case(s). Until then, however, the LLPS adjustments should be tracked and recorded as a regulatory asset or liability until the next rate case(s). This is specified in the tariff provision Revenue Treatment, part d.

To calculate this adjustment, the following information should be retained:

1. Actual hourly kWh for each LLPS customer,
2. Actual hourly locational marginal prices for load. If individual load nodes are developed for each customer, those values should be utilized. Otherwise, the applicable EMM or EMW weighted load node values should be used,
3. Actual monthly values of other expenses included in the FAC, such as transmission expenses, which vary with EMM's or EMW's total Missouri jurisdictional load or peak demand.

Staff Witness: Brooke Mastrogiannis

Revenue Treatment

To mitigate the unreasonable retention of positive regulatory lag, Staff recommends the following provision be incorporated into the LLPS tariff:

[108] 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 to or greater than 40,000,000 kWh (the normalized monthly kWh billing determinant that was established in Case No. ER-2014-0258).

Treatment of LLPS 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.

D. Unless the FAC is modified to address positive regulatory lag associated with LLPS customer growth, the difference caused by positive customer growth between normalized and actual LLPS Day Ahead Energy Charge revenues shall be recorded to a regulatory liability. 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.

These provisions ensure that EMW and EMM do not experience excessive positive regulatory lag, and enables the revenues provided by LLPS customers to prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLPS customers. Treatment of these accumulated revenues to reduce the ratebase associated with production facilities is intended as a risk mitigation strategy. LLPS customers are going to prompt increases to generation revenue requirement. To the extent that LLPS customers’ capacity needs may increase the bills paid by other customers, it is reasonable to capture the lagging LLPS revenues to effectively buy down the increased generation rate base caused by those customers.[109]

If, in a future general rate case, the FAC is revised to incorporate a mechanism related to the historic Ameren “N Factor,” then the full inclusion of the energy charge revenues in this

[109] If, for whatever reason, capacity is built to serve LLPS customers, and LLPS 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.

regulatory liability should be adjusted. Also, in future cases, it could be reasonable to consolidate regulatory liability tranches to simplify accounting.

Termination Charges

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

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

A. If a customer anticipates a temporary closure or load reduction related to retooling, construction, or other temporary causation, this anticipated reduction shall not trigger the termination charges described above until the anticipated load reduction has exceeded the anticipated duration by three months;
B. The amount due under the Variable Fixed Revenue Contribution Charge in the event of early termination shall be due at the level associated with normal usage in the most recent applicable rate proceeding. If a rate proceeding has not occurred establishing normal usage, or if the customer was not recognized at the anticipated contract maximum load in the prior rate proceeding, the amount due under the Variable Fixed Revenue Contribution Charge shall be at the level associated with the contract projected usage;
C. In the event an LLPS customer either declares bankruptcy, the facility is closed, or is more than 5 business days late in payment of a properly-rendered bill for service, termination charges are immediately due;
D. Except in the case of bankruptcy, closure, or lack of timely payment, termination charges are due on the due date of the bill for the third month of 50% or lower usage;
E. The portion of termination charge revenue associated with the Facilities Charge shall be recorded as a regulatory liability, and treated as an offset to transmission plant. The amortization period for this regulatory liability shall be set to coincide as closely as is practicable with the depreciable life of the transmission-related infrastructure associated with the LLPS customer;
F. The remaining termination charge revenue shall be recorded as a regulatory liability and treated as an offset to production ratebase in perpetuity, without amortization;
G. Provisions contained herein supersede the Termination of Service provisions of the Rules and Regulations of the generally-applicable tariff.

Captive Customer Risk Mitigation

Staff recommends the Commission include restrictions on the overall quantity of load to be comprised of LLPS 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 EMM/EMW's annual Missouri jurisdictional load.

F. Prior to execution of a Service Agreement with a prospective LLPS customer, EMM/EMW shall ensure that it has adequate capacity available for resource adequacy calculations to serve all existing customers and the prospective LLPS customer. In the event EMM/EMW executes a Service Agreement without adequate capacity, EMM/EMW's existing customers shall be held harmless from any SPP or other RTO capacity charges, and held harmless from any penalties assessed by any entity related to those capacity shortfalls.

Staff Witness: Sarah L.K. Lange

IV. Concerns with Evergy's Requested LLPS Tariff

Staff opposes EMM's and EMW's proposed tariffs, provided through Mr. Lutz's direct testimony schedules, as the proposed tariffs are non-complaint with the requirement that the rate schedules "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."[110] The proposed tariffs also set up an unnecessarily opaque rate structure, and raise additional concerns. These concerns can generally be characterized as related to Evergy's requested revenue treatment, excessive utility discretion, risk allocation, and rate structure and design. Generally, Staff will avoid repeating concerns that have been highlighted already in this Report. For example, Staff's recommended tariff includes different applicability requirements, different rate designs, and different rider eligibilities than those requested by Evergy.

[110] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

The Interim Capacity Charge and the System Support Rider (SSR) are clear examples of unreasonable utility discretion, failure to include key components of the terms of service in the promulgated tariff, and unreasonable reliance on the Service Agreement. Evergy testimony concerning Interim Capacity states,

> Interim Capacity Charge: This is an optional element in the tariff that provides a method to recover specific capacity procurements needed to serve a Schedule LLPS customer prior to fully incorporating its load into an Integrated Resource Plan ("IRP"). This will be billed as a per kW charge. If the existing system cannot meet a customer's load requirements or load timing needs, the Company, after reaching an agreement with the customer, may enter into specific market contracts to provide interim capacity to the customer. In such case, the Company will charge the customer an additional demand charge reflecting the cost of this temporary capacity as a direct pass-through charge to the Schedule LLPS customer. Interim capacity and the related charge will not be utilized for all Schedule LLPS customers. Billing-related details concerning the Interim Capacity will be documented in the Service Agreement.[111]

The requested tariff includes less detail, including only the following two terms:

> INTERIM CAPACITY
>
> If the Customer's load cannot be served by the Company's existing system capabilities the Company may enter into specific market contract agreements to provide the necessary capacity requirements of the Customer until sufficient system capacity may be supplied by the Company. The Customer and the Company must mutually agree on the terms for the interim capacity. The Customer shall be subject to an additional demand charge calculated according to these terms.[112]
>
> [Under Termination provisions:]
>
> If the Customer is receiving any Interim Capacity at the time of written notice, the Company and Customer shall take steps to repurpose the related capacity contract(s) prior to termination of service under this schedule. If the Interim Capacity cannot be repurposed, the Customer will be responsible for all costs associated with termination of the capacity contract(s).[113]

[111] Brad Lutz Direct, pages 17-18.

[112] Brad Lutz Direct, Schedule BDL-1, page 88.

[113] Brad Lutz Direct, Schedule BDL-1, page 89.

This Interim Capacity component is therefore fully in the discretion of EMM and EMW, to the extent that a customer signs on, with no opportunity for Staff or Commission review. The terms exist outside of the tariff, and there is no language proposed to cause the revenue received from the Interim Capacity Charge to offset the costs and expenses that EMM and EMW incur for the interim capacity. If arrangements related to the provision of interim capacity are less than a year in duration, those expenses would automatically flow through the FAC of the respective utility.

Staff Witness: Sarah L.K. Lange

Treatment of Revenue under Evergy Request

Staff asked a series of data requests attempting to ascertain how Evergy would record the various payments received from LLPS customers. Evergy's responses indicated that with limited exceptions, all payments from LLPS customers, would be "For accounting purposes, the proposed treatment would be to treat it as normal tariff-based revenue. However, the final determination of accounting treatment will be based on the language in the final approved tariff."[114] These responses are attached as Appendix 2 – Schedule 8.

In response to Data Request 11, Evergy stated:

> Barring some unexpected change in the nature of these costs, the proposed treatment would be to treat all revenues from customer, grid, demand, reactive demand, and energy charges consistent with treatments used for like charges in other rates today, generally as ordinary tariff-based revenue. However, the final determination of accounting treatment will be based on the language in the final approved tariffs.

For the other rate elements,

- Schedule LLPS (Large Load Power Service)
    - Interim Capacity: ordinary revenue
    - Fees: ordinary revenue
    - Collateral: Dependent on the form of the collateral. Non-cash collateral is not recognized as revenue.
- Schedule SR (System Support Rider)
    - SR Charge: ordinary revenue
- Schedule CCR (Customer Capacity Rider)
    - CCR Credit: no revenue expected/reduction of revenue
- Schedule DRLR (Demand Response & Local Generation Rider)
    - Reduction Credit: ordinary revenue

[114] Response to Data Request 11.

- Schedule CER (Clean Energy Choice Rider)
  - CER Charge: contribution to work in progress
- Schedule RENEW (Renewable Energy Program Rider)
  - Renewable Energy Charge: ordinary revenue, will be included in FAC as an offset to costs
- Schedule AEC (Alternative Energy Credit Rider)
  - AEC Charge: ordinary revenue, will be included in FAC as an offset to costs
- Schedule GSR (Green Solution Connections Rider)
  - GSR Rate: ordinary revenue, will be included in FAC as an offset to costs

As discussed elsewhere, failure to capture significant revenues from the LLPS rates will result in excessive positive regulatory lag for Evergy, and will fail to and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to LLPS customers. This issue is particularly blatant with regard to the System Support Rider. In its response to Data Request 10,[115] concerning System Support Rider revenues, Evergy stated that the revenues from the System Support Rider would be reflected in an Evergy CCOS only for the amount that occurred during the test period and that the System Support Rider revenues between rate cases would not be considered to benefit other customers during a rate case.

Evergy's testimony concerning the rationale behind the Acceleration Component of the SSR is reproduced below:[116]

> Q: Is the System Support Rider intended to address any other effect of Schedule LLPS tariff?
>
> A: Yes. The SR is also designed to address the acceleration of resource investment required to serve large loads.
>
> Q: Why is it important to address this resource acceleration?
>
> A: Generally speaking, the Company strives for customer equity across all rate classes. However, today's large load customers have needs and characteristics that will create impacts to other customers if not appropriately considered. One of the more significant impacts is an acceleration of load growth, causing Evergy to build or procure additional generation resources to meet the new system load and to maintain its SPP-mandated planning reserve margins. Left to existing processes, we expect that this accelerated investment would increase costs for all customers. To

[115] See Appendix 2 – Schedule 8.

[116] Brad Lutz Direct, pages 31 – 32.

> address these cross-subsidization concerns, we have designed the System Support Rider. Specifically, Schedule SR will help mitigate potential cross-subsidization by contributing amounts to existing non-Schedule LLPS customers. The amounts charged under the schedule will address the acceleration of costs caused by new large loads, such as the accelerated development of new generation projects and increased transmission congestion that may be attributable to these new large loads.
>
> Q: How does the Company propose to determine this cost acceleration?
>
> A: The Company has established a scenario-based approach where it will determine net present value revenue requirements tied to a representative 700 MW CCGT that is constructed 10 years sooner than otherwise would have occurred under normal planned growth and its costs recovered over a 30-year period. In a sense, we are seeking to isolate a time value of money element of the cost.

Staff does not recommend approval of the System Support Rider, as discussed below. However, Evergy's planned approach to benefit from the initial positive regulatory lag of System Support Rider revenues unreasonably bills LLPS customers for the benefit of Evergy shareholders, and without benefit to non-LLPS ratepayers. Based on the examples Evergy has provided, Evergy calculates that adding an LLPS customer will cause excessive increases to the revenue requirement of other ratepayers for \$44 million per year, for 15 years, approximately \$660 million dollars. Yet Evergy will retain roughly \$177 million (26%) of that revenue when received from the hypothetical LLPS customer through positive regulatory lag under the revenue treatment it describes in its data request responses.

EMM and EMW request a "Capacity Reduction Fee." Under requested treatment, if an LLPS customer substantially reduces its monthly demand, the LLPS customer must prepay the difference between its actual bill and the minimum bill that would have been due for the remainder of its contract – essentially a partial termination fee. In response to Staff's data requests, Evergy indicated its intent would be to treat those revenues as ordinary revenue, unless the Commission orders a contrary provision be included in the tariffs in this case.[117] This means that unless the receipt of those revenues happened to fall in the test period of a rate case, they would be retained by Evergy and not offset the revenue shortfall that will be caused in future years due to the change in the LLPS customer's demand.

[117] See Appendix 2 – Schedule 8, Response to Data Request 6.

As discussed in the section, "Regulatory Lag Considerations," EMM and EMW will be fully recovering their current costs of service based on rates and determinants set in prior rate cases, and will incur few, if any, new cost of service for new LLPS customers aside from market energy cost, which will be flowed through the FAC. If EMM and EMW do not have sufficient capacity to serve the new LLPS customer, Evergy requests the ability to assess an Interim Capacity Charge at a rate of its choosing and not subject to Commission review. If that capacity has been acquired under a contract with a term of less than a year, it will be flowed through the FAC. Essentially, EMM and EMW have requested to double-recover virtually all revenue received from a new LLPS customer until a rate case is completed recognizing the addition of that customer, unless the Commission orders otherwise.

Staff Witness: Sarah L.K. Lange

Excessive Utility Discretion and Reliance on Customer Agreement

EMM and EMW reserve the discretion to decide whether or not a customer is billed an Interim Capacity Charge, and if so, for what demand, and at what rate.[118] Evergy requests the ability to vary key terms of the LLPS tariff applicability and determinants, at its discretion, through the execution of Customer Agreements, including the demand applicable for charges under the System Support Rider Acceleration Component and the Interim Capacity Charge. EMM and EMW request the ability to modify the demand determinants applicable to these charges through the interaction of the various riders.

Evergy states in its proposed tariff language that it has discretion to request curtailment under the DRLR for "system reliability, address resource adequacy, offset forecasted system peaks that could result in future generation capacity additions, and/or provide a more economical option to available generation or market energy purchases in the wholesale market."[119]

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[118] "If the Customer's load cannot be served by the Company's existing system capabilities the Company may enter into specific market contract agreements to provide the necessary capacity requirements of the Customer until sufficient system capacity may be supplied by the Company. The Customer and the Company must mutually agree on the terms for the interim capacity. The Customer shall be subject to an additional demand charge calculated according to these terms." Brad Lutz Direct Testimony, Schedule BDL-1, page 88.

[119] Brad Lutz Direct Testimony, Schedule BDL-1, page 82.

Evergy requests in the Customer Capacity Rider that all contracting with customers is subject to the full discretion of EMM and EMW.[120] Evergy also requests sole discretion to determine if capacity to be considered under that rider is operationally or economically detrimental.[121] Evergy requests complete discretion in preparation of its "Clean Energy Preferred Resource Plan," and its execution.[122] Evergy requests sole discretion over the availability of its proposed Alternative Energy Credit Rider, and its proposed Renewable Energy Program Rider.[123]

Evergy requests discretion in which customers would be subject to the LLPS tariff, under its requested term that:

> A facility served under this schedule shall generally mean a single point of interconnection. Aggregation of loads under this schedule shall be limited. The Company shall exercise reasonable discretion when choosing to aggregate loads, with such discretion based on factors including, but not limited to, premises sharing one or more of the following: common owner(s), a common parent company, common local electrical infrastructure, physical layout, character of service, end use, and common control.

Evergy also requests sole discretion as to whether or not a study deposit of $200,000 will be required of applying customers.[124]

While neither Staff nor the Commission should be managing the day-to-day business of the utility, the discretion EMM and EMW reserve to themselves steps over into areas that must be subject to regulation through published tariffs. If there is concern that a tariff does not offer the flexibility to address situations as they arise, then it would be reasonable to set out procedures for expedited Commission resolution, rather than to include so many reservations of such broad discretion.

While Evergy has not submitted a draft customer agreement with its direct filing, it has previously shared drafts with Staff, and several riders refer to the inclusion of key terms in the customer agreement. In general, Staff recommends that terms of service and rates for service be

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[120] "This rider is available to Customers receiving permanent electric service under the Company's retail rate Schedule LLPS, subject to Company's capacity need and the Company's full discretion." Brad Lutz Direct Testimony, Schedule BDL-1, page 77.

[121] "Customer capacity shall not be detrimental, either operationally, or economically, to the Company's existing electrical system, as determined in the Company's sole discretion." Brad Lutz Direct Testimony, Schedule BDL-1, page 78.

[122] Brad Lutz Direct Testimony, Schedule BDL-1, page 80.

[123] Brad Lutz Direct Testimony, Schedule BDL-1, page 94, and Schedule BDL-1, page 76.

[124] "The Company shall have sole discretion on the deposit applicability and managing projects in the queue." Brad Lutz Direct Testimony, Schedule BDL-1, page 97.

reflected in the promulgated tariff, and not reserved to confidential agreements that are not subject to Commission review and might be subject to change at Evergy's discretion.

Staff Witness: Sarah L.K. Lange

Risk Allocation

Evergy has near unilateral control over the timing of EMM and EMW rate cases to recognize revenues from LLPS customers, and Evergy has near unilateral control over timing of EMM and EMW rate cases to recognize increased cost of service associated with power plant additions. Absent Commission orders to the contrary, captive non-LLPS customers will bear the risk of Evergy's decisions of which power plants to build, when to build them, and what LLPS load to serve. Unless recovery of a power plant's cost of service is disallowed as imprudent, or unless LLPS revenues are imputed in a rate case, Staff is unaware of any real risk borne by EMM or EMW when it comes to LLPS customers.

Evergy is in the business of earning returns on investments through the regulated rates that it collects for provision of electric service. Power plants are one key form those investments can take. Evergy bears little risk of disallowance of investment in power plant. Evergy may bear little negative regulatory lag for investments in power plants due to statutory provisions for Plant in Service Accounting related to generation assets.[125] The Commission should take care to minimize the opportunities of EMM and EMW to experience significant positive regulatory lag, such as through Staff's recommended revenue treatments. Without Staff's recommended revenue treatments, EMM and EMW have prioritized immediate revenues over long-term risks in their exercise of managerial discretion in acquiring LLPS customers.

As discussed above, the Commission should expect EMM and EMW to leverage the positive regulatory lag of LLPS customers -- with little to no offset to increased cost of service due to tools enacted to mitigate negative regulatory lag – to cause EMM and EMW to delay rate cases recognizing new LLPS customers. Given the risks of LLPS customers ceasing service, it is possible that an LLPS customer could come and go with essentially all revenues from that customer accruing only to the benefit of utility shareholders and the remaining responsibility

[125] EMM and EMW are 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, RSMo., 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.

for the excess capacity costs falling entirely on captive ratepayers, absent meaningful Commission-ordered revenue treatments.

The termination provisions and collateral requirements should be safeguards to mitigate the risks of overbuilt capacity in the event LLPS customers quit taking service. It is important that these provisions work to offset future cost of service that would have otherwise been borne by LLPS customers.

In general, Staff recommends the termination provisions it has recommended in the Staff-proposed tariff. However, Staff suggests that if the Evergy language is relied upon, it be modified:

1. To apply triggering of the charges to a flat floor of 10 MW as well as to the included term of 10%,
2. To allow for explicit transfer of capacity among LLPS customers that would allow for waiver of termination provisions for charge elements other than those related to local facilities.

Staff's rate of return experts have reviewed Evergy's requested Collateral Requirements language. Because this is a unique and developing area, Staff has no specific recommendations concerning Evergy's requested language at this time. Staff continues to monitor customer responses and gather information regarding the Collateral Requirements proposed by Evergy, and will report its findings and recommend revised language, if needed, in subsequent testimony in this proceeding or in Evergy's next major rate proceeding.

Staff Witness: Sarah L.K. Lange

Rate Structure and Design

The Interim Capacity Charge is an integral feature to support Evergy's assertions that additions of LLPS customers will spread the fixed costs of utility service in that, as it was described in the testimony of Mr. Lutz at pages 17-18, it is the stopgap to cover utility expenses that would not be incurred but-for the LLPS customer's demand requirements and timing requirements. While Evergy requests that the extent of any such shortfall, the cost of capacity to address the shortfall, and the rate recovery related to the shortfall be contained in a customer agreement, Staff's recommended tariff includes provisions for an expedited tariff promulgation to give the Commission an opportunity to review the rate and applicable terms.

As discussed below, the System Support Rider is also integral to Evergy's approach to LLPS rates in that if offsets the revenue lost to LLPS customer participation in the other LLPS riders, and that it compensates for the underpriced demand charges included in the LLPS tariff. Staff prefers and recommends that appropriate rates be structured and designed from the outset, as opposed to publishing an underpriced rate in the tariff, which is then buttressed with a complex interplay of riders, discounts, credits, bill offsets, bill offset offsets, and bill elements based on hypothetical plants built on hypothetical timelines.

Staff is unaware of any advantage to including the LLPS customer class as a subclass of the Large Power Service rate schedule. Staff recommends the rates for LLPS customers be set out as a separate rate schedule, and studied and set separately in future rate cases. Staff recommends reliance on discrete charge elements built around the cost of service of EMM and EMW, respectively. These elements should include time-based pricing to reflect the variability of this expense, and to not incent excessive energy consumption during times of high prices. Staff recommends the overall revenue recovery for LLPS customers and revenue treatment be as set out in its recommended tariff.

Staff Witness: Sarah L.K. Lange

V. Recommendations Concerning Requested Riders and Other Tariff Provisions

Evergy's requested tariffs include opening the availability of several riders to customers on other rate schedules. Staff opposes this requested expansion in addition to its stated opposition to the riders for the reasons discussed below. The requested tariffs also include proposals to freeze the availability of the EMW Special Rate for Incremental Load Service. Staff does not oppose this request. Staff suggests it is also reasonable to freeze the availability of the MKT rate schedule, although a grandfathering provision may be reasonable for customers who will commence service under that schedule soon.

Staff Witness: Sarah L.K. Lange

Clean Energy Choice Rider

Staff has reviewed the Company's proposed Clean Energy Choice Rider ("Schedule CER"). Company witness Brad Lutz's direct testimony, pages 53 – 54, states:

> Some large load customers have corporate sustainability or decarbonization goals that seek not only to ensure that the energy they consume meets their energy goals, but also to influence the overall

> renewable or carbon-free energy generation supply portfolio that serves the jurisdiction(s) where they choose to locate. The Company's Schedule CER is a new rider designed to facilitate this interest by providing a means for LLPS customers to sponsor and accelerate new clean energy acquisitions through the Company's IRP[126] process.

Schedule CER would allow new LLPS customers to influence the Company's IRP analysis, the Company's Preferred Resource Plan (PRP),[127] and the Company's resource acquisition strategy.[128]

20 CSR 4240-22.080(1)(A) requires Evergy to submit its triennial compliance filing (IRP) every three years, starting on April 1, 2012. EMM and EMW's most recent IRPs were filed on April 1, 2024, in Case Nos. EO-2024-0153 and EO-2024-0154, respectively. 20 CSR 4240-22.080(3)(B) requires the Company to prepare an annual update report in the years a triennial compliance filing is not required. This rule further states that, "The depth and detail of the annual update report shall generally be commensurate with the magnitude and significance of the changing conditions since the last filed triennial compliance filing or annual update." While PRPs and resource acquisition strategies are not required to change or be updated in annual update reports, and historically for certain utilities often are not updated, EMM's and EMW's change every year. Staff sent Data Request 58, which asked:

> Since the Company has historically updated its Preferred Resource Plan annually, could the Company take into consideration any LLPS customers want or need for new clean energy in its capacity expansion modeling for IRP annual updates or triennial compliance filings in lieu of the proposed Schedule CER? Could the Company still allocate any incremental costs to requesting LLPS customers?

The Company's response to Data Request 58 stated:

> Yes, the Company could include customer requests in its IRP modeling, however the Rider is useful to set clear terms and conditions for the consideration and to clearly provide for the recovery of the incremental cost

[126] Integrated Resource Plan.

[127] 20 CSR 4240-22.020(46) defines preferred resource plan as "the resource plan that is contained in the resource acquisition strategy that has most recently been adopted by the utility decision-maker(s) for implementation by the electric utility."

[128] 20 CSR 4240-22.020(51) defines resource acquisition strategy as "a preferred resource plan, an implementation plan, a set of contingency resource plans, and the events or circumstances that would result in the utility moving to each contingency resource plan. It includes the type, estimated size, and timing of resources that the utility plans to achieve in its preferred resource plan."

> between the Company Preferred Plan and the Clean Energy Preferred Resource Plan. Concerning allocation, the similar is true. Incremental cost could be allocated, but the Rider would clarify and formalize the treatment.

Staff is concerned with adding Schedule CER, a new tariffed rider, when by its own admission Evergy could consider customer requests and cost allocation in its current IRP modeling.[129]

Further, the IRP process is likely to drastically change with the recent passage and signing of Senate Bill 4 ("SB 4"). SB 4 adds Section 393.1900, RSMo, and Section 393.1900.1, RSMo states in part that, "[t]he commission shall, by August 28, 2027, and every four years or as needed thereafter, commence an integrated resource planning proceeding for electrical corporations." In Data Request 60, Staff asked, "[w]hat is the soonest the Company anticipates any customer could receive service under the LLPS rate class?" The Company responded that, "[t]he soonest a customer might receive service under the Schedule LLPS rate is the first quarter of 2026." A new rider allowing a large customer or customers to influence the IRP process, an IRP process likely drastically changing with over eleven pages of new legislation and likely several more pages of yet-to-be approved Commission Rule language expanding on the new legislation, is of great concern to Staff.

In EMM's most recent *2025 IRP Annual Update* (public version), filed on March 13, 2025, in Case No. EO-2025-0250, EMM stated:[130]

> …Evergy Metro has included an updated load ramp for a new large load customer profile in its base load forecast for its IRP.
>
> In recent months, the customer completed Evergy's internal review process that allows the Company to complete due diligence on large load customer requests, sets forth numerous data points to vet the feasibility of the customer locating in Evergy's service territory, and requires a sizeable deposit to support analysis to study the viability of the customer's project. In January 2025, Evergy submitted an Attachment AQ study to the SPP to study the transmission upgrade requirements of the incremental new large load. Additionally, Evergy Metro and the new large load customer continue to progress with negotiations and expect to have Construction and Service Agreements fully executed in the second quarter of 2025 with an expected project announcement in the second half of 2025.

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[129] Staff is not advocating deviations from prudent resource planning to accommodate customer preferences with or without the CER.

[130] Evergy Missouri West has the same, or very similar, language in its 2025 Annual Update.

> Evergy has a large pipeline of prospective new large load customers, but not all are included in base load planning until certain progress on Evergy's internal review process has been met to avoid exposing our Preferred Plan to unnecessary risks.[131]

Evergy further states that:

> Overall, striking the correct balance for forecasting these loads will be challenging, and no industry best practice has yet emerged. Revisiting how load forecasting should be completed in light of new large loads, like data centers, will likely be necessary… Policy and regulation can help lower risk associated with these new large loads, as can investment in other infrastructure such as expanding or enhancing transmission and distribution networks. More best practices will likely emerge in the coming months and years as data center demand comes online.[132]

Lastly in regard to the Evergy's 2025 Annual Updates, Staff filed comments in those cases.[133] In response to one of Staff's comments, Evergy responded that:

> Evergy agrees that passage of Senate Bill 4 in parallel with the dynamic large load growth that the electric utility industry is facing creates an opportunity to evaluate the existing electric utility resource planning guidelines. The appropriate planning and reporting of large load is likely a state-wide issue and may or may not be best-suited to be handled in the existing IRP process. Evergy prefers these matters be considered by the Commission within the revisions contemplated in Senate Bill 4 and not specific to the Company's IRP process.[134]

Staff notes these citations to highlight that Evergy has included only one large load customer in each EMM's and EMW's 2025 IRP Annual Updates. There may be a "pipeline" and more to come, but as of the date of this filing, only one is accounted for in EMM's and EMW's IRPs. Evergy admits that "Policy and regulation can help lower risk associated with these new large loads…"[135] and "Evergy prefers these matters be considered by the Commission within the

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[131] File No. EO-2025-0250, EFIS Item No. 1, 2025 Evergy Metro Annual Update_Public 3-13-2025, page 13.

[132] File No. EO-2025-0250, EFIS Item No. 1, 2025 Evergy Metro Annual Update_Public 3-13-2025, page 113.

[133] Evergy Missouri West's Annual Update was filed as EO-2025-0251 and Staff's Comments related to EO-2025-0250 and EO-2025-0251.

[134] File Nos. EO-2025-0250 and EO-2025-0251, EFIS Item No. 27, *Response to Alleged Deficiencies and Concerns*, Evergy Response to IRP Comments_Public 6-20-2025, page 3.

[135] File No. EO-2025-0250, EFIS Item No. 1, 2025 Evergy Metro Annual Update_Public 3-13-2025, page 113.

revisions contemplated in Senate Bill 4 and not specific to the Company's IRP process."[136] With only one large load customer currently included in EMM's and EMW's 2025 Annual Updates, that would receive service under the Schedule LLPS rate no sooner than the first quarter of 2026, and the new legislation requiring an integrated resource planning proceeding commencing by August 28, 2027, Staff is of the position that a new rider such as Schedule CER not be approved at this time. The Commission should allow for the new IRP process to be developed and understood prior to considering a rider that allows for customers to influence prudent resource planning.

In this case, Staff sent Data Request 62 in regard to Schedule CER asking:

> Is the Company aware of any other programs/tariffs submitted or approved in other states that are the same or similar to the proposed Schedule CER? If so, please provide those programs/tariffs and a detailed description of the similarities and differences between those programs/tariffs and the proposed Schedule CER.

Evergy's response to Data Request 62 stated:

> No, the Company is not aware of another program that shares this design. The closest known program is the Clean Transition Tariff proposed by NV Energy. The Clean Energy Choice Rider mostly aligns with the purpose of the Clean Transition Tariff, to allow customers to influence resources deployed by the utility, but otherwise differs in nearly all respects.

According to a Utility Dive article, Google and NV Energy requested "permission to enter into a power supply agreement based on the 'Clean Transition Tariff' that would allow large energy users to pay a premium for 24/7 clean energy from new resources."[137] "Under the power supply agreement, NV Energy would buy electricity from Fervo Energy's 115 MW Corsac Station Enhanced Geothermal Project, and sell it to Google for a set rate. Google would receive credit for the project's energy and generation capacity on electric bills for its data centers in Storey County, Nevada, offsetting demand charges associated with those facilities."[138] "The tariff is intended to

[136] File Nos. EO-2025-0250 and EO-2025-0251, EFIS Item No. 27, *Response to Alleged Deficiencies and Concerns*, Evergy Response to IRP Comments_Public 6-20-2025, page 3.

[137] Emma Penrod, NV Energy seeks new tariff to supply Google with 24/7 power from Fervo geothermal plant, Utility Dive, https://www.utilitydive.com/news/google-fervo-nv-energy-nevada-puc-clean-energy-tariff/719472/ (accessed July 8, 2025).

[138] *Id.*

spur the deployment of more carbon-free dispatchable energy resources, like geothermal or nuclear generation, by allowing energy users to make up the difference between the cost of these capital intensive resources and low-cost options like solar or natural gas".[139] A Google spokesperson stated that "[i]nstead of having to overbuild solar and add new natural gas to keep up with customers' desire for renewable energy while ensuring firm supply, the utility will gain access to firm, dispatchable renewable energy without running afoul of least-cost regulatory requirements."[140]

While NV Energy's Clean Transition Tariff appears to allow customers to influence resources deployed by the utility, as Evergy states in its response to Data Request 62, by entering into a power supply agreement for specific generation – potentially offsetting, or potentially partially offsetting the need for other generation – it does appear to differ in nearly all other respects, as Evergy also stated in its response. With the changes to the IRP process due to the passage of SB 4, and the relatively near-term timeline for those changes to take place, a seemingly first-of-its-kind rider which allows customers to influence a utility's prudent resource planning further contributes to Staff's concern.

On page 57 of Mr. Lutz's direct testimony in this case he states, "[s]hould a requesting customer terminate its service at any point after the company has implemented a Clean Energy Preferred Resource Plan for a specific customer and before the cost differential of the Clean Energy Preferred Resource Plan, or allocated portion, has been fully paid, the customer shall be required to pay the outstanding cost differential as a single payment." Staff sent Data Request 63 referencing that statement and requesting additional information. The questions Staff asked and Evergy's responses to each are as follows:

1) What happens if a customer terminates service before the cost differential is fully paid, then challenges the outstanding cost differential?

   Response: The sponsoring Customer enters into an agreement with the Company that will detail the terms of participation. There will be a clear expectation of full payment, even if the Customer terminates service.

2) What are the Company's plan(s) to pursue collection of an outstanding cost differential from a customer?

[139] *Id.*
[140] *Id.*

Response: The Company has not established plans for collection. However, should default occur, the Company would fully exhaust all collection and legal remedies available to uphold the terms of the Customer agreement.

3) What will the Company do if a customer ultimately does not pay the outstanding cost differential?

Response: Similar to the response to parts 1 and 2 in this response. The Company will use all remedies to ensure the Customer abides by the terms of the Customer agreement.

4) If the customer does not pay the outstanding cost differential, will other customers have to bear the cost?

Response: It is difficult to say for certain given the range of possible remedies, but under extreme conditions, it is plausible that the cost differential could ultimately be recovered from other non-sponsoring customers.

5) What will happen to the generating unit(s) included in the Clean Energy Preferred Resource Plan that were requested by a customer that has terminated service, both before and after the cost differential has been payed?

Response: Resources added as a result of a Clean Energy Choice Preferred Plan will have been vetted through subsequent filings such as a request for Certificate of Convenience and Necessity and rate case and will be considered a Company resource for the service of all customers. Termination of sponsoring customers will not impact these resources.

6) Is there a scenario where the generating unit(s) become a stranded asset?

Response: No.

7) How will the Company ensure that the generating unit(s) do not become a stranded asset?

Response: Please refer to the other parts of this response. If the Clean Energy Preferred Resource Plan meets the Company's obligation to provide safe, reliable, and efficient service for all customers and meets the Commission's IRP Rule, the resource will be vetted through subsequent filings such as a request for Certificate of Convenience and Necessity and rate case and will be considered a Company resource for the service of all customers. Persistence of the original sponsoring customer is not required.

Staff is greatly concerned with Evergy's response to subpart 4) above. Extreme conditions or not, Staff is of the position that the cost differential agreed to be paid by the sponsoring customer(s) should not be paid by "non-sponsoring customers" in any scenario. Even though Evergy's response in subpart 5) frames resources added as a result of a Clean Energy Choice Preferred Plan to be considered a Company resource for the service of all customers, those resources would be added as a direct request by a sponsoring customer to meet its renewable energy goals. On page 56 of Mr. Lutz's direct testimony he provides the following Q&A:

> Q: What will occur with respect to the renewable attributes associated with any renewable resources procured as part of a Clean Energy Preferred Resource Plan approved under the Clean Energy Choice Rider?
>
> A: The Company will retire the renewable attributes on behalf of the customer, up to an amount equal to the requesting customer's annual energy usage.

Further, the Evergy's responses to Data Request 63 subparts 5) and 7) reference a Certificate of Convenience and Necessity ("CCN"). Along with the IRP process change due to SB 4, the CCN process for certain resources will be changing as well. For example, 393.1900.5.(1), RSMo states in part, that:

> If the commission determines that the preferred resource plan is a reasonable and prudent means of meeting the electrical corporation's load serving obligations, such determination shall constitute the commission's permission for the electrical corporation to construct or acquire the specified supply-side resources, or a specified quantity of supply-side resources by supply-side resource type, or both, identified by the commission… With respect to such resources, when the electrical corporation files an application for a certificate of convenience and necessity to authorize construction or acquisition of such resource or resources… the commission shall be deemed to have determined that the supply-side resources for which such a determination was made are necessary or convenient for the public interest. In such a certificate of convenience and necessity proceeding, the commission's inquiry shall be limited… The commission shall take all reasonable steps to expedite such a certificate of convenience and necessity…

The new IRP process is very likely to be contentious with the Commission now having the authority to determine that an electric utility's preferred resource plan is reasonable and prudent and grant permission to the utility to construct or acquire specified resources. That contentiousness would likely be exacerbated with a rider such as the proposed Schedule CER that would allow customers to influence the IRP. For all of the reasons and concerns stated above, Staff recommends the Commission reject the Evergy's proposed Schedule CER.

Staff Witness: Brad J. Fortson

Rate and Revenue Concerns with CER

The cost estimates of generating resource additions included within Evergy's IRPs are based upon generic assumptions that have been subject to the discretion of Evergy's management. The IRP cost estimates often differ, at times substantially, from the overall costs that are included within CCN applications and the finalized costs of assets requested to be included in rates through the general rate case process. For example, Evergy's 2024 IRP assumed that the High Total Build Cost Estimate for Natural Gas Combined Cycle (NGCC) was approximately ** [redacted] ** but Evergy's supplemental direct testimony in the CCN case estimated the cost of Evergy's proposed NGCCs to be ** [redacted] **, an increase of approximately ** [redacted] ** within a short time frame. The assumed cost of Simple Cycle Combustion Turbines was subject to similar adjustments between Evergy's IRP filing and the application for a CCN. As the period of time studied increases, the cost certainly decreases.

Staff Witness: J Luebbert

It is not reasonable to rely on the difference between two subjective regulatory fictions, as adjusted improperly for the time-value of money, to compensate captive ratepayers for some portion of the real costs and the real risks to which they will be exposed by failing to adhere to prudent utility planning.

NPVRR, as used in this context, is a utility's estimate, in today's dollars, of the revenue requirement over a future period of decades. Even if every other assumption in the calculation was perfectly predicted, the choice of the number of years, and of the interest rate used, will cause very different results to an NPVRR calculation. Evergy calculates NPVRR from the perspective of a shareholder who is deciding whether to invest in the studied investment opportunity, or to invest in some other enterprise. This is done by discounting the annual revenue requirement additions by the carrying cost percent the shareholder would like to receive on the investment opportunity. While NPVRR comparisons of various scenarios could be a useful tool to a private investor, it is not relevant to compensating ratepayers 30 years from now for deviations from prudent resource planning made today.

While Staff strongly opposes the CER, revenues from any approach conceptually similar to the CER should be used to offset the production rate base caused by a utility decision to deviate from prudent resource planning in response to a customer's wishes.

Staff Witness: Sarah L.K. Lange

System Support Rider

The System Support Rider ("SSR")[141] is a proposed mandatory rider for any LLPS customer. The SSR consists of two portions, the first being the Cost Recovery Component, which Evergy asserts "is designed to ensure the appropriate recovery of costs incurred to serve Schedule LLPS customers."[142] The second portion is the Acceleration Component, which Evergy asserts is "designed to reflect the acceleration of resource investment required to serve large loads that take service under Schedule LLPS, as well as other acceleration-related impacts associated with operating new resources."[143] Staff recommends rejection of Evergy's proposed SSR.

Staff Witness: Brodrick Niemeier

Cost Recovery Component of SSR

Evergy represents that it has designed the Cost Recovery Component to offset the bill reductions some customers will experience through the design of the other requested riders, such as the Customer Capacity Rider and Demand Response & Local Generation Rider. Additionally, Evergy witness Jeff Martin asserts that Evergy is concerned with current Economic Development discounts shifting the cost to serve LLPS customers to other customers and resulting in an "unreasonable subsidy", and that the Cost Recovery Component of the System Support Rider, along with a minimum bill requirement contained within the LLPS Tariff, will minimize the risk of this "unreasonable subsidy."[144]

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[141] Staff notes there is already a Schedule SSR (Standby Service Rider) for EMM and EMW, Staff recommends renaming the System Support Rider.

[142] Brad Lutz direct testimony, page 30.

[143] Brad Lutz direct testimony, page 30.

[144] Pages 18 and 19 of Evergy witness Jeff Martin's direct testimony.

Staff recommends rejection of the Cost Recovery Component of the SSR. Further, Staff recommends that any provisions designed to ensure LLPS customers bear the costs and risks of serving LLPS customers electricity should be included within the tariff itself, not an external rider. *Staff Witness: Brodrick Niemeier*

Instead of adding the System Support Rider as a charge to prevent an "unreasonable subsidy" of LLPS customers due to economic development discounts, Staff recommends that LLPS customers be ineligible for participation in economic development discounts. Staff's recommendation is consistent with the current EMW SIL tariff, which includes "Service under this tariff may not be combined with service under an Economic Development Rider, an Economic Redevelopment Rider, the Renewable Energy Rider, Community Solar program, service as a Special Contract, or be eligible for participation in programs offered pursuant to the Missouri Energy Efficiency Investment Act, or for participation in programs related to demand response or off-peak discounts, unless otherwise ordered by the Commission when approving a contract for service under this tariff."[145] Staff's recommendation is also consistent with the current EMW MKT tariff, which includes, "Service under this tariff may not be combined with service under an Economic Development Rider, an Economic Redevelopment Rider, the Renewable Energy Rider, the Solar Subscription Rider, service as a Special Contract, or be eligible for participation in programs offered pursuant to the Missouri Energy Efficiency Investment Act, or for participation in programs related to demand response or off-peak discounts, unless otherwise ordered by the Commission when approving a contract for service under this tariff."[146]

Staff recommends that the Commission exercise the discretion it is afforded under Section 393.1640 to exempt LLPS customers from the availability of economic development discounts.[147] If LLPS rates are set to meet the statutory requirement that LLPS are meant to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers," then it is not reasonable to immediately reduce those

[145] P.S.C. Mo. No. 1 Original Sheet No. 157.

[146] P.S.C. Mo. No. 1 Original Sheet No. 158.

[147] 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."

rates by 40%, or other customer classes' rates will necessarily reflect unjust and unreasonable costs caused by LLPS 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 the economic development discount is added to the revenue requirement of all other customers.

Complicating any potential application of the statutory economic development discount to LLPS 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 as follows:

> [T]he 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 LLPS 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 LLPS rates would be raised to make up for the discount. Meanwhile, the System Support Rider revenues would be billed and attributed to the LLPS customers in a class cost of service study. This result is impractical, unreasonable, illegal, and unnecessary.

Staff Witness: Sarah L.K. Lange

Acceleration Component of SSR

Conceptually, the Acceleration Component addresses the increases to revenue requirement caused by LLPS customer demands. However, the details of Evergy's implementation of this component and its interaction with other proposed riders is problematic, and Staff recommends it be rejected. Instead, the issues the Acceleration Component seeks to address are best handled through the rate structure and rate design of the LLPS tariff.

Evergy calculated the Acceleration Component rate by finding the difference in the net present value of revenue requirement if a combined cycle natural gas turbine was constructed ten years ahead of when it would otherwise be required to meet Evergy's normal planned load growth for non-LLPS customers, ** [redacted]. **[148] Staff's first concern with this approach is that it is unclear as of what point in time, and for which customer, this calculation should apply. It appears that the applicability of the Acceleration Component would be contingent on whether or not EMM or EMW reflected anticipated LLPS load growth in a given Integrated Resource Plan. Further, generation additions are "lumpy". After a new power plant is built, EMM or EMW will have sufficient capacity to serve an LLPS customer. However, prior to that plant being built, the addition of a new LLPS customer necessitates acceleration of construction of the power plant.

Evergy proposes that the Acceleration Component of the rider last for a term at least 15 years for a given customer, after which a customer can request this component of the rider's charge to be terminated, under specific circumstances:

- If the customer is able to supply over 80% of its requested capacity through the Customer Capacity Rider. As long as Evergy "does not identify other rate design concerns with doing so."[149] The SSR is unclear as to whether or not the LLPS customer must wait until the end of the initial 15 year term to request termination of this charge using this method.[150]
- If their annual peak demand has not increased by more than 5% annually over the previous five years, except that if the customer increases their demand by more than 20% or 20 megawatts after the Acceleration Component has been terminated, a new term of 15 years shall begin when this component is applied.

If EMM or EMW build a power plant to serve an LLPS customer, and that customer participates in the Customer Capacity Rider to eliminate 80% or more of its capacity requirements through EMM or EMW, then the problem that Evergy asserts the Acceleration Component is designed to address has been made worse, not better. Namely, the problem is not only that the power plant was built sooner than it would have been, it is now that the power plant provides

[148] See Appendix 2 – Schedule 9, Evergy response to DR G-E-81.

[149] Schedule BDL-1, page 44.

[150] If the Commission approves an acceleration component as a part of the SSR (rather than Staff's recommendation to address the acceleration issue as part of rate structure and design), Staff recommends the SSR tariff be clear that termination of the acceleration component may be requested after the initial 15-year term.

excess capacity that may not be needed otherwise. This problem is exacerbated if a customer subject to the Acceleration Component begins to offset some of its capacity through the Customer Capacity Rider or by any other means.[151]

Staff is also concerned with the practicalities of the termination calculation as applied to LLPS customers. For example, a 500 MW LLPS customer who provides an 80% offset to their capacity requirements would still have a net capacity requirement of 100 MW. It is not reasonable to exempt this customer from the Acceleration Component if the Acceleration Component is truly necessary. Setting aside Staff's concerns with the Customer Capacity Rider, this remaining demand would still be a massive portion of the total demand of EMM or EMW. Evergy seems to acknowledge this concern by noting its ability to identify "rate design concerns" that would allow Evergy to deny a customer's request to terminate the Acceleration Component. Staff does not find this clause sufficient to address its concern.

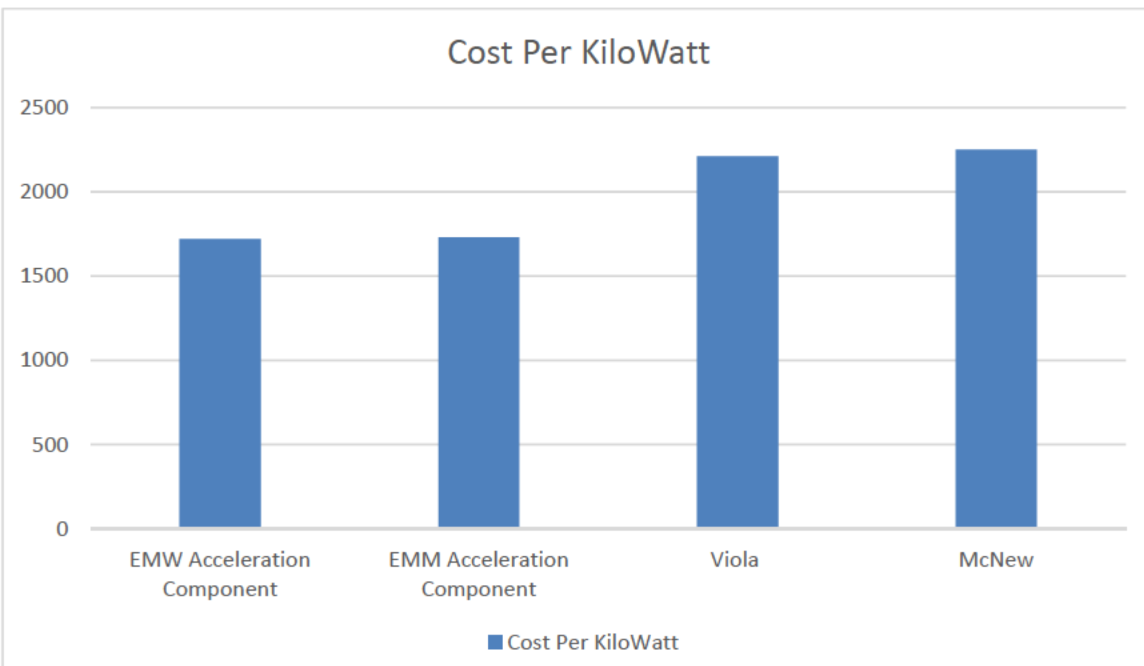
Regarding the ability of a customer to request termination at the conclusion of the 15-year term, Staff appreciates that the likely intent of this provision is acknowledgement that the term of service under the LLPS tariff is 15 years. However, if the intent of the Acceleration Component is to reflect the changes in revenue requirement associated with building a theoretical power plant 10 years sooner than would otherwise be applicable, then the charge should effectuate the full difference in revenue requirement recovery over the life of that theoretical power plant.

The proposed tariff also does not explain how capacity is measured for purposes of the SSR. LLPS customers may peak in different seasons. For instance, a data center might see peak demand in summer where extra energy is required to cool the computers, while a foundry might see peak demand in winter. Additionally, a customer's actual demand may vary significantly from its initial planned demand. It is unclear to which demand the Acceleration Component will be applicable, or which demands will be considered for a customer's termination request. The rider fails to clearly state which demand determinant will be the basis of the Acceleration Component and Cost Recovery Component, between seasonal and annual demand, and planned and actual demand.

Staff is also concerned with the calculation of the Acceleration Component rate. Within the SSR, Evergy states that the acceleration component value was calculated based off recovering the

[151] Staff's concerns with the Customer Capacity Rider are addressed separately.

costs of a CCGT over 30 years. However, within Evergy witness Brad Lutz's workpaper,[152] the Acceleration Component was calculated by ** [redacted]. ** This inconsistency effects the rate calculation. EMW requests a rate of $9.64/kW-month, and EMM a rate of $9.59/kW-month. Applying these rates for a 15-year term, each Megawatt of capacity will cost LLPS customers in EMW $1.72 million and in EMM $1.73 million, or in terms of kilowatts: $1,720/kW in EMW and $1,730/kW in EMM. In the recently-considered CCN for EMW (File No. EA-2025-0075), EMW has estimated half of the capital costs for Viola to be $788 million (or $2,210/kW), and half of McNew to be $800 million (or $2,250/kW).[153] The graph below compares the price per kW between Viola's and McNew's estimated capital costs and the Acceleration Component's revenue requirement. Over a 15-year term, Evergy would receive revenues for 77.6 percent[154] of the capital cost to currently construct a power plant, which would not decrease or offset the rate of return and depreciation expense that Evergy would receive from all ratepayers for that power plant.



[152] CONF System Support Rider Model_CCGT_01.27.25.

[153] The CCN was for 50% of the capacity of Viola and 50% of the capacity of McNew, each being 355MW. These plants are combined cycle gas turbines ("CCGT"), which is the same resource type Evergy used to calculate the Acceleration Component.

[154] This was found by dividing Evergy West's $616 million acceleration charge by the average cost to construct Viola and McNew. This calculation was done with Evergy West as it has the most recent CCGT acquisition cost.

Evergy asserts that the Acceleration Component is not designed to reimburse Evergy for the cost to construct a generating facility. According to Evergy, ** [redacted] **[155] However, all customers will still have to contribute towards the cost to construct and operate the generation unit over the life of that unit, just not Evergy's calculated cost of constructing the unit earlier than planned.

Staff Witness: Brodrick Niemeier

The Acceleration Component will result in payment of excess revenue to Evergy, and will fail to comply with the statutory requirement that LLPS rates be set to "reasonably ensure such customers' rates will reflect the customers' representative share of the costs incurred to serve the customers and prevent other customer classes' rates from reflecting any unjust or unreasonable costs arising from service to such customers." Evergy's shareholders can avoid rate case recognition of the Acceleration Component for up to four years.

As discussed in the section, "Regulatory Lag Considerations," as of the conclusion of each rate case, the customer usage reflected in that rate case fully recovers EMM's or EMW's annualized cost of service. When a new LLPS customer begins to take service, EMM or EMW will begin to over-recover for the existing generation fleet, all else being equal. With the Acceleration Component, revenues will flow from the LLPS customer to EMM and EMW – not to EMM and EMW ratepayers – causing EMM or EMW to over-recover even more.

Hypothetically, assume EMM or EMW builds a new power plant in 2030 to accommodate a new LLPS customer. Evergy's theory of the Acceleration Component is that an LLPS customer should pay tens of millions of dollars a year to EMM or EMW from 2026 – 2030, because non LLPS ratepayers will have a higher revenue requirement from 2030 – 2060. This result is completely unreasonable.[156]

The additional cost of service caused by building a power plant sooner than it would otherwise be build will not be experienced by EMM or EMW ratepayers until that power plant is

[155] Evergy Response to DCC Data Request 14.

[156] While the portion of the Acceleration Component that would be reflected in the net revenue requirement from 2030-2041 in this scenario could be reasonable, the portion that would be retained by EMM or EMW prior to rate case recognition is completely unreasonable.

recognized in a rate case. Charging LLPS customers for the revenue requirement impacts of the accelerated construction of a power plant that has not yet been built is not reasonable. Allowing EMM and EMW to retain those revenues is wholly unreasonable.

Staff Witness: Sarah L.K. Lange

Demand Response and Local Generation Rider

As described below, Staff recommends rejection of the Demand Response & Local Generation Rider ("DRLR").

Demand Response Issues

Staff reviewed the demand response portion and certain participation costs of the DRLR of the LLPS tariff. Staff recommends rejection of the DRLR program, but encourages Evergy to continue discussions with potential LLPS customers to develop a future tariff filing for a reasonable demand response program.

Staff's opposition to Evergy's requested DRLR program is based on the lack of a non-performance penalty and the inclusion of an "Earnings Opportunity Fee," which Staff cannot support outside of an authorized and statutorily-compliant program authorized under the Missouri Energy Efficiency Investment Act (MEEIA). Additional concerns with the program design are described below.

In summary, some sort of demand curtailment program may be a reasonable means to mitigate the incremental capacity that will be caused by LLPS customers, or may be beneficial for mitigation of the wholesale energy costs driven by LLPS customer load, but the proposed program will not result in adequately reliable demand reductions to support a reduction in required capacity, and relies on an unlawful compensation mechanism to Evergy.

<u>Earnings Opportunity Fee</u>

Evergy is proposing a demand response earning opportunity fee. This is described on page 39 of Mr. Lutz's direct testimony as a "fee to recover any foregone earnings from demand response realized capacity reduction and an administrative charge to support the delivery and implementation of the Schedule DRLR program."[157] Staff's position is that an earnings opportunity should not be considered because the only reason earnings opportunities are permitted

[157] Lutz Direct Testimony, page 39, lines 7-10.

in MEEIA demand response is there is a statute allowing it. Staff is not aware of a statute authorizing an earnings opportunity for demand response programs outside of MEEIA.

<u>No Penalty for Non-Performance</u>

According to Evergy's response to Data Request 97, there is no penalty for non-performance by a customer when an event[158] is called; more particularly, Evergy responded that "Participants do not receive incentive compensation or penalties if they fail to participate."

Staff is apprehensive about having no penalty for non-participation when Evergy is viewing this curtailment as a resource. These are potentially larger curtailments than what is in the current demand response programs for Evergy Metro[159] and Evergy West.[160] For this reason, Staff recommends that there be some sort of penalty for non-participation if this type of program is approved. More specifically, if the Commission approves the DRLR program, then Staff recommends that some type of penalty structure should be required to make sure the participant is participating for the full event call time. An example of a penalty structure could be 100% incentive for participating 100% of the event, 75% incentive for 75% event participation and so on. This penalty structure, combined with a removal after a certain number time of non-participation (opt outs), seems reasonable if Evergy plans to rely on the curtailment as a resource during peak hours.

<u>Potential Participant Interest</u>

Staff has doubts if what Evergy has proposed is palatable to large load/data center customers. Evergy's DRLR includes a "DR Earnings Opportunity Fee" that participants must pay to Evergy to be participants in this rider. This fee is included so Evergy can receive an earnings opportunity as mentioned above. Evergy admits in its response to Data Request 48.1 that all customers will be paying for the participant to receive an incentive. Therefore, ratepayers could be paying incentives for two programs, considering there is already a ratepayer-funded demand response program in MEEIA. There is no earnings opportunity fee exclusively paid by curtailment participants in the current MEEIA programs.

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[158] A demand response event occurs when a utility requests that users shift or reduce their electricity use to help manage the grid during periods of extra-high demand. This voluntary reduction or shift of electricity use by customers helps to stabilize the power grid by balancing supply and demand.

[159] Tariff Tracking No. JE-2020-0056, Currently Effective Tariff, P.S.C. MO. No. 2, 1st Revised Sheet No. R-2.05 to 2.08.

[160] Tariff Tracking No. JE-2020-0046, Currently Effective Tariff, P.S.C. MO. No. 1, 1st Revised Sheet No. R-80 to R-82.

Additionally, this program will have an administration fee, which will be in addition to the earning opportunity fee. According to Evergy's response to Data Request 96:

> Anticipated administrative costs would include incremental expenses associated with delivering the DRLR program to enrolled participants. An administration fee has been included within the DRLR tariff and is stated as:
>
> *A fixed charge shall be recovered for all costs [from the participating customer] associated with Program delivery, implementation/management, and evaluation, which shall be recovered based on a forecasted estimate and trued up annually based on actual Program expenditures for the recovery period.*

If ARCs (Aggregator of Retail Customers)[161] can provide curtailment to these large load customers with incentives to curtail, and can ask for shorter curtailment events, with no extra earnings opportunity fees or administration fees, then Staff is not sure why a large load customer would choose to go with Evergy's proposed DRLR program.

Examples of Similar Programs

Staff continues to struggle to find another utility that has a large load only tariff with a demand response program like the one Evergy is proposing, where the utility earns an earnings opportunity that is exclusive to large load customers. Evergy provided examples of utility programs where the utility is rewarded with an earnings opportunity, but from Staff's review and research, it appears that the examples provided by Evergy were more in line with energy efficiency programs much like the MEEIA demand response programs already in place and not an exclusive large load tariff rider. Recently, Ameren Missouri has also applied for a similar large load tariff (Case No. ET-2025-0184), but has not proposed any sort of demand response program outside of their current MEEIA program.

Affordability

The lack of a similar type of program proposed by Evergy leads into Staff's next concern of affordability. Evergy already has a Business MEEIA demand response program. Stakeholders and the Commission have recently raised concerns, in recent hearings and agenda meetings, with

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[161] An aggregator of retail customers is a person or business "that aggregates demand response from retail customers for the purpose of marketing, selling, or marketing and selling the aggregated distributed energy resources to an electric public utility or into a wholesale electricity market". https://www.lawinsider.com/dictionary/aggregator-of-retail-customers.

affordability of service. Incentive[162] and Administrative costs[163] from this new DRLR Tariff will be one more item requested to be put into base rates in Evergy's next general rate case. For example, Evergy provided the following in response to Data Request 48.1:

> Q: Please provide where and how the additional revenue requirement will be generated in order to provide the incentives for the proposed DRLR; if it is not through additional revenue requirement, please explain. Which rate class(es) will costs be allocated to for the Company to recover these incentive costs?
>
> A: Recovery of costs associated with the Schedule DRLR rider would occur as part of a future rate case where these costs would be included in the determination of a jurisdictional revenue requirement. These costs would be recovered from all rate classes.

Staff Witness: Jordon T. Hull

Local Generation Issues

Staff recommends rejection of the DRLR. Evergy proposes that an LLPS customer may participate in the DRLR through on-site generation. The tariff does not define the type of on-site generation, so Staff assumes it could be renewables such as wind or solar, a diesel generator, or battery storage. The DRLR fails to include requirements similar to the Parallel Generation Service Tariff[164] and safety language, equipment and interconnection cost language, and system emergency language similar to that which exists in the cogeneration rule. Evergy has not provided evidence that the DRLR provides a reasonable trade off of revenue and capacity requirements as it effects the overall revenue requirement of EMM or EMW. Thus, this proposal is not consistent with Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

Staff questions the possible interest customers will have in this rider. According to the Department of Natural Resources Rule 10 CSR 10-6.061(3)(A)2.BB., fossil fuel generators are only exempt from requiring air permits if their sole use is as an emergency generator. Generators used in curtailment would have to go through emissions permitting which could limit the number

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[162] Demand Response incentives encourage consumers and businesses to reduce or shift their electricity usage during peak periods in exchange for financial incentives or rewards.

[163] Administrative costs are expenses incurred by a business that are not directly tied to the production of goods or services, including salaries, and supplies.

[164] 20 CSR 4240-20.060.

of customers who may be interested in using this rider. While not specifically identified, it appears solar and wind power qualify for participation under the Evergy-proposed DRLR, but are not always able to operate and thus may not generate power when Evergy requests a customer to curtail. Additionally, most renewable generation will operate as long as the sun is shining or the wind is blowing, making them good options to lower or offset energy usage as opposed to achieving targeted reductions to demand. It is unclear how Evergy would address consistent reductions to demand against the specific curtailment events required under the DRLR.

EMM and EMW do offer the Parallel Generation Contract Service Rider. Under this Rider if a customer has a generator, they can opt to supply Evergy with electricity at a current rate of $0.0190/kWh for EMM and $0.0198/kWh for EMW, although this option is limited to generators of 100kW or less. It may be reasonable to increase this limit in a future case, or to otherwise create reasonable tariff provisions to accommodate customers who may collocate their own generation, while not unreasonably shifting cost recovery to captive ratepayers. The current Standby Rider rates are inadequate for addressing the potential demand requirements for a customer of this magnitude in a manner that adequately complies with the requirements of SB 4.

Staff Witness: Brodrick Niemeier

Revenue Treatment Issues

Evergy proposes to credit participating customers a maximum of $54 per year for every kilowatt that can be curtailed upon request.[165] EMM's proposed demand charge is $14 per kW per summer month, and $12 per kW per non-summer month. EMW's proposed demand charge is $10 per kW per summer month, and $8 per kW per non-summer month. On an annual basis, an EMM customer could avoid approximately 36% of the otherwise-applicable demand charge revenue, and an EMW customer could avoid approximately 52% of the otherwise-applicable demand charge revenue for each kW of participation in the Local Generation option of the DRLR.[166]

Staff Witness: Sarah L.K. Lange

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[165] For a customer to receive the $54 per year bill credit or each kilowatt that can be curtailed, they must agree to unconstrained curtailment and participate whenever Evergy requests them to. If the customer agrees to constrained curtailment, they are only given a $43.20 per year bill credit.

[166] These percentages could be higher depending on a given customer's actual month-to-month load factor.

Customer Capacity Rider

The Customer Capacity Rider (CCR) provides an LLPS customer with a bill credit for contracting customer-controlled generation capacity to either EMM or EMW, were that generation not located behind the customer's meter. The generation source can either be owned by the customer or contracted by the customer. Some customers may desire to own or contract for their own generation to address that customer's corporate green policies or emissions reduction goals. However, as a Load Responsible Entity under SPP Resource Adequacy requirements, EMM or EMW is still responsible for adequate capacity and reserve for all customers, including LLPS customers who may own or contract for other generation.[167] Evergy asserts that "The primary tangible benefit of the Customer Capacity Rider is to allow customers to provide solutions, in addition to the solutions Evergy develops or acquires, to meet Evergy's overall future load requirements in situations where the Company needs to build or acquire capacity."[168] This means that purchasing the capacity from these customers allows Evergy to avoid constructing additional generation purely to meet part of its capacity requirements. Evergy also claims that this option could be more economic for both itself and the customer.

However, Staff has major concerns with Evergy's requested tariff language, and recommends the Customer Capacity Rider be rejected. Staff notes that nothing prohibits EMM or EMW from entering into agreements with an LLPS customer to purchase energy or capacity from that customer, including customers who may be considered qualifying facilities as contemplated in the Commission's rule regarding cogeneration and small power production, 20 CSR 4240-20.060. However, these contracts should remain subject to the same prudency standards as any other power supply contract.

Staff's concerns include:

1. The excessive discretion provided to Evergy in the terms applicable to transactions under the CCR, and the lack of key terms within the CCR tariff,
2. The interaction of the CCR with the Resource Adequacy requirements of EMM and EMW,
3. The interference of the CCR with prudent resource planning,
4. The inclusion of Schedule MKT customers within the rider eligibility,
5. The interaction of the CCR with the LLPS tariff and the SSR, and
6. The revenue losses through the CCR will be harmful to other customers.

[167] The SPP Open Access Transmission Tariff requires Load Responsible Entities, which includes Evergy Metro and Evergy West, to maintain capacity equal to the entity's summer season net peak demand plus a reserve margin of 15%.

[168] Evergy's response to Data Request 83.

Essentially, the proposed tariff provides EMM and EMW authority to enter into agreements of their choice, with customers of their choice, on terms of their choice, and for the results of those agreements to modify the otherwise applicable bills of their largest customers. It is unclear what oversight the Commission may possibly exercise over these transactions and over the revenue requirement impact of these transactions.

Staff also has concerns about the CCR's language relating to revenue decreases and make whole payment provisions. Evergy's proposed SSR Cost Recovery Component is needed by Evergy to address the revenue losses caused by the CCR, which is more complicated than simply reasonably administering capacity contracts to begin with. Additionally, the explanation concerning the make whole payment fails to specify items such as when the company will annually review the customer's accredited capacity as well as how and when the customer will be billed concerning this payment.

Staff Witness: Brodrick Niemeier

Resource Adequacy Concerns

The proposed CCR does include reference to "make whole payments," in the event that the actual capacity is less than contracted, and for additional compensation in the event that the actual capacity is more than contracted. However, excess capacity calculated after the fact has essentially no value to the ratepayers who will be compensating the LLPS customer for this capacity, and, as discussed in the section, "Resource Adequacy-Related Requirements and Cost of Service," the monetary consequences for failing to meet resource adequacy requirements may dwarf any contracted make-whole payment value.

Staff Witness: Brodrick Niemeier

Resource Planning Concerns

EMM and EMW should acquire generation assets and enter into capacity contracts based on prudent resource planning. Staff is concerned that contracts from the CCR may not take resource planning into account. Consistent with the concerns stated in regard to the CER, Staff's concern is particularly relevant in light of recent legislative changes to resource planning requirements and new legislative generation acquisition requirements. To the extent that the CCR could be viewed as a means for EMM or EMW to modify its prudent resource plans, or to acquire rights to capacity or generation outside of a prudent planning process it is unreasonable.

Staff Witness: Brad J. Fortson

Interaction of the CCR with LLPS Ratemaking

The proposed tariff states that "the Customer shall receive a credit equal to the price difference between the Schedule LLPS Demand Charge price and the negotiated pricing in the capacity contract for each accredited kW of contracted customer capacity, reduced by the applicable Southwest Power Pool ("SPP") planning reserve margin."[169] If the Commission determines in this proceeding that the appropriate demand charge for all EMM LLPS customers is $10 per kW per month, under the CCR, EMM could enter into a contract so that one customer has an effective rate of $7 per kW per month, and another has an effective rate of $2 per kW per month. In a rate case, the revenue from those LLPS customers would not offset the EMM revenue requirement to the same extent that LLPS revenue would be offset without those contracts. It is unclear, when, how, or on what timeline Staff or the Commission has an opportunity to review the reasonableness of those contracts. Staff, the Commission, and other stakeholders will have no knowledge of, or access to, the negotiation of these contracts between Evergy and a LLPS customer.

Further, it appears that Evergy intends that a resource under the CCR would offset – in whole or in part – the Acceleration Component charges that it asserts is appropriate under the SSR. If a power plant is built to enable service of an LLPS customer, and the customer subsequently enters into a CCR agreement with EMM or EMW, then the problem that Evergy asserts the Acceleration Component is designed to address has been made worse, not better. Namely, the problem is not only that the power plant was built sooner than it would have been, it is now that the power plant provides excess capacity that may not be needed otherwise.

Staff Witness: Brodrick Niemeier

Evergy proposes that the determinant for the LLPS demand charge is the customer's NCP. Under the CCR, the LLPS demand determinant would "be determined by seasonal capacity accreditation (annually for both summer and winter), as determined by the pertinent SPP methodology." There is no reason to conclude that the accredited value of a generation resource, wherever it may be located, is coincident with an LLPS customer's peak demand at its point of interconnection. However, the CCR effectively treats this remote resource's output at a given point in time as a one-for-one reduction to the LLPS customer's demand. This result is not

[169] From the proposed Customer Capacity Rider tariff language, Schedule BDL-1 page 77.

reasonable, and transfers responsibility for the LLPS customer's cost of service to other ratepayers. This result is not consistent with Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

Staff Witness: Sarah L.K. Lange

Renewable Energy Program Rider

Program Description

Evergy has proposed its Renewable Energy Program Rider ("Schedule RENEW"), which would give customers the option to purchase unbundled RECs[170] at a fixed price that is adjusted annually. This program would be eligible to customers participating in a voluntary renewable energy program.[171] Evergy witness Bradley D. Lutz discussed Schedule RENEW on page 44 of his direct testimony. Customers may subscribe for up to 100% of their annual energy usage in increments of 10%. The subscription is voluntary, month-to-month, with no upfront costs or contract. Participants can change their subscription or cancel at any time with no penalties or fees.

RECs will be retired annually by Evergy on behalf of the customer and revenues collected will be recognized in the associated resource's jurisdictional FAC for the benefit of all respective jurisdictional customers. This program has already been in place in Evergy's Kansas territory and has 21,000 Evergy Kansas customers participating.

Evergy intends to determine the amount of kWh available to participants based on the amount of RECs anticipated to be available to the Company for any program year. If demand in a given year exceeds the amount available, the Company will purchase RECs from external sources if they can be procured at prices equal to or less than the tariffed renewable energy charge.[172] If this is not possible, Evergy will issue a refund to each participating Customer at the end of each

[170] Renewable Energy Credits or Certificates ("RECs") are a means of tracking and certifying energy generated from renewable energy resources. One REC represents that 1 MWh of electricity has been generated from a certified renewable energy resource. RECs can be generated, traded, bought, or sold. Once a REC has been utilized to comply with the RES requirements, it must be retired and cannot be used for any other purpose. The purchase or sale of an unbundled REC represents that only the REC was purchased or sold and it did not accompany the energy that it represents.

[171] Lutz Direct Testimony, Schedule BDL-1, page 40.

[172] Response to Data Request 73.2.

program year for the difference between the customers pro rata share of the RECs and the RECs for which they were contracted.[173]

Evergy does not intend to acquire new owned or outside renewable generation resources for the sole purpose of providing service under this Program. The renewable energy resources utilized in this program consist of the same renewable resources the costs of which are currently being recovered in rates.[174] The charge for the program is as follows:

Renewable Energy Charge = REC Charge + Administrative Charge[175]

- REC Charge: $0.00255/kWh ($2.55/MWh)
- Administrative Charge: $0.00010/kWh ($0.10/MWh)

Discussion

An issue that must be kept in mind when discussing renewable programs is the interaction with the Missouri Renewable Energy Standard ("RES") compliance. Section 393.1030.2., RSMo. prevents an electric utility from using a credit derived from a green pricing program for RES compliance. Given many of the programs Evergy proposes are green pricing programs,[176] it is necessary to distinguish these programs from Evergy's RES compliance activities. Evergy has not had any issues meeting RES requirements and in fact has had excess RECs, which Staff has consistently recommended that Evergy sell rather than let the RECs expire.

At the end of 2024, EMW had a total of 4,592,235 non-solar RECs and 232,462 SRECs ("solar RECs") and EMM had a total of 4,606,092 non-solar RECs and 190,716 SRECs banked in the North American Renewables ("NAR") registry.

Additionally, Evergy provided its projected renewable energy generation and RES requirements in its 2025 RES Compliance Plans for EMW and EMM. Evergy stated in response to Data Request 3 in Case Number EO-2025-0258 that a large load data center customer is included in the load projections, however the load forecast does not include any customers that have not yet committed to service or are under contract. Even with this included in its projections, Evergy's excess RECs are expected to increase over the next few years as shown in the graphs below.

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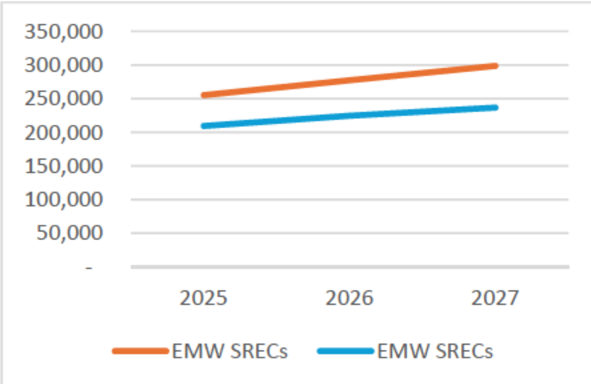
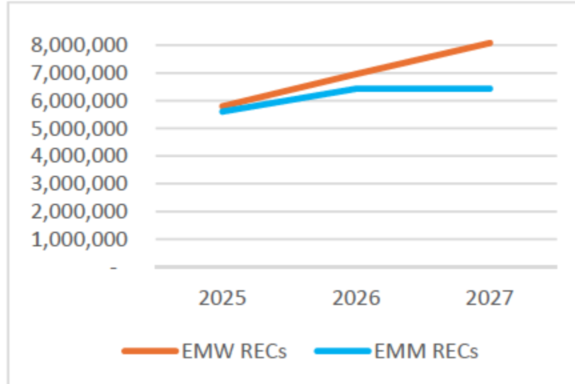
[173] Lutz Direct Testimony, Schedule BDL-1, page 42, paragraph 5.

[174] Lutz Direct Testimony, Schedule BDL-1, page 42, paragraph 4.

[175] Lutz Direct Testimony, Schedule BDL-1.

[176] 20 CSR 4240-20.100(1)(H) defines green pricing programs, "Green pricing program means a voluntary program that provides an electric utility's retail customers an opportunity to purchase renewable energy or renewable energy credits (RECs)".





However, the full impact of large load customers is still unknown. By RES statute, the RES requirement is calculated as 15% of total retail electric sales.[177] As sales increase, so will the RES requirement which means the addition of large load data center customers could increase the RES requirement significantly.

Additionally, SB4 modifies the RES. On April 9, 2025, SB4 was signed into law and will go into effect August 28, 2025. SB4 included some changes to the existing RES as it applies to electric utilities with between 250,000 and 1 million electric retail customers, which would apply to EMM and to EMW. Specifically, SB4 included provisions regarding "accelerated renewable buyers", which the bill defines as "a customer of an electric utility with an aggregate load over eighty average megawatts, that enters into a contract" to obtain RECs or energy bundled with RECs.[178] As the Commission is aware, Staff is currently working on a rule amendment proposal to incorporate these changes. However, stakeholders may raise considerations informally or during a rulemaking hearing. Thus, the details will not be known until a rule is effective.

Another issue that must be kept in mind when discussing renewable programs is the opportunity to sell excess RECs. The graphs above indicate that Evergy clearly has and will continue to have excess RECs, contingent on the level of load growth from LLPS customers. From this, and given that RECs expire after 3 years, there is a need to sell excess RECs in order to receive any kind of benefit from them.

However, these proposed programs are not the only means that Evergy has of selling RECs. Along with its three existing renewable programs designed to serve distinct customer segments,

[177] 20 CSR 4240-20.100(2).

[178] SB4 at p. 62 makes changes to Section 393.1030.2(4), RSMo to include this definition.

Renewable Energy Rider program, Solar Subscription – Market Rate program, and the Solar Subscription – Income Eligible program, Evergy also sells excess RECs to third-party brokers or other entities. Evergy previously provided its REC sales data in EO-2025-0283, in response to Data Request 3. The weighted average REC sales price for all REC sales since 2022 is $2.67/REC for EMW and $2.20/REC for EMM.

Additionally, NAR has limits on the amount of RECs that can be retired on behalf of others. NAR Operating Procedures sets the limit at an aggregate of 499,999 RECs in a calendar year.[179] In 2024, EMW retired an aggregate of ** [redacted] ** RECs for its Renewable Energy Rider ("RER") and Solar Subscription Pilot ("SSP") Tariffs, and EMM retired an aggregate of ** [redacted] ** RECs for its RER and SSP Tariffs, and on behalf of others outside of its tariffs. Thus, Staff questions the practicality of adding additional renewable programs that will cause Evergy to retire RECs on behalf of others.

In its review Staff asked Evergy if it had performed any market research or polling among its customers to gauge interest, need, and preference regarding the four renewable/carbon-free programs discussed in the Direct Testimony of Bradley D. Lutz[180]. Evergy stated, ** [redacted] **

<u>Recommendations</u>

RENEW is a program that would sell Evergy's excess RECs from resources that it already owns or for which it is contracted. Staff's position is that Evergy should sell excess RECs rather than letting them expire. Although Evergy has not done a full cost analysis of this program,[181] the proposed price of $2.65 is in line with its average sale prices since 2022. However, due to NAR REC retirement limitations and other concerns including the need for improvement of the

[179] NAR Operating Procedures, page 6, (c). NAR-Operating-Procedures-_October-2016.pdf.

[180] Staff Data Request 70.

[181] Response to Data Request 126.

associated tariff language, it is not reasonable to offer this program at this time. Further no customer would be harmed by taking the time to improve the tariff language, Staff recommends the Commission reject the proposed RENEW program.

Among the concerns to be addressed in a future tariff filing, are the need to clarify the definition on page 3 of the Renewable Energy Program Rider for both the EMW and EMM Riders to clarify the definition of the term "discounted Renewable Energy Charge" and to clarify that RECs represent the energy generated by Company-owned resources and outside renewable sources:

> 4. Renewable Energy shall be limited to the sum of (a) Renewable Energy Credits representing generation produced by Company-owned renewable sources, (b) Renewable Energy Credits representing outside renewable sources available to the Company and (c) Renewable Energy Credits purchased by the Company at a cost below the level of the Renewable Energy Charge (~~or~~ "discounted Renewable Energy Charge"~~, if applicable~~). Service under this Renewable Energy Program Rider may be limited ~~at the sole discretion of the Company~~ to such available resources. Evergy Missouri West has not and will not acquire new owned or outside renewable generation resources for the sole purpose of providing service under this Renewable Energy Program Rider. The renewable energy resources utilized in this program consist of the same renewable resources the costs of which are currently being recovered in rates. Participants in this program elect to provide this additional financial support of renewable resources to motivate renewable resource development.

Additional terms should be added to the tariff to clarify that the location-based credit of 1.25 is not applicable to RECs sold to customers under this program, and that RECs qualifying for the 1.25 credit under the Missouri RES should not be the first sold under the program.

Also, Staff recommends that in any future program, that Evergy denote all RECs retired under the program in the Commission-approved tracking system as being retired on behalf of beneficial owner. This designation is necessary for Staff to review RES compliance as no REC retired under this program may count toward Missouri RES compliance.

Staff Witness: Amanda Arandia

Green Solution Connections

<u>Program Description</u>

The Green Solution Connection Rider ("GSR") is a voluntary, subscription-based program that gives Commercial and Industrial ("C&I") customers the ability to subscribe to the renewable attributes of ** [redacted]. **[182] This Rider is specific to EMM customers[183] receiving permanent electric service from EMM through Schedules SGS, MGS, LGS, LPS, SGA, MGA, LGA, PGA, MKT, or LLPS.[184] Evergy has proposed that customers may subscribe to the percentage of the renewable asset output (kW) needed to match up to 100% (in single percentages) of the customer's eligible annual usage[185] to align with the renewable asset's estimated annual generation.

Under the proposed program, customers will subscribe to ** [redacted]. **[186]

Discussion

In Case No. EA-2024-0292, Evergy applied for a CCN for the two program resources and proposed the GSR program for EMW. A Stipulation and Agreement was filed on May 29, 2025, in which Staff agreed that the Commission should authorize a subscription-based Green Solution Connections Program for these resources. However, Staff and the Company committed to continuing to work on the details of the program and file specimen tariffs in the docket for Commission approval at least six months prior to the expected completion of the two facilities. At this time, Staff recommends that work to continue in EA-2024-0292 in order to ensure consistency between the programs for EMW and EMM.

Recommendations

In order to ensure consistency for the Green Solution Connections Program between EMW and EMM, Staff recommends the Commission reject the Green Solution Connections Program as filed in this case until such time that the program has been approved in EA-2024-0292.

Staff Witness: Amanda Arandia

[182] Response to Data Request 73.

[183] The GSR discussed in this case is specific only to EMM. Evergy first introduced this program in Case No. EA-2024-0292 for EMW in the direct testimony of Kimberly Winslow, which stated that the program would first be offered to EMW customers and, if the program were not fully subscribed after 30 days, then the program would open to EMM customers. Direct testimony of Kimberly Winslow, page 24, lines 5-8.

[184] Lutz Direct Testimony, Schedule BDL-1, page 31

[185] Lutz Direct Testimony, Schedule BDL-1, page 32.

[186] Confidential response to Data Request 71, Q0071_CONF_Schedule GSR_Price Curve Workpaper.

Alternative Energy Credit Rider

<u>Program Description</u>

The Alternative Energy Credit ("AEC") Rider is a newly proposed program which would allow all C&I customers, including Large Light and Power Service ("LLPS") customers, to purchase AECs produced from Evergy's Wolf Creek Nuclear Generating Station located in Kansas.[187] Specifically, this program would be available to customers currently receiving permanent electric service from Evergy through Schedules SGS, MGS, LGS, LPS and LLPS who have an annual average monthly peak demand greater than 200kW.[188]

An AEC is a certificate similar to a REC, however it represents that 1 MWh of electricity has been generated from an alternative energy source such as a nuclear energy facility. This concept is still relatively new and as such there are currently no registries that track AECs. Evergy has proposed that it will hire a third party to certify the AECs on an annual basis.[189] Similar to the LLPS Rate Plan, customers will enter into a participation agreement for a span of one, three, or five years in which they will designate a subscription level in single percentage increments up to 100% of their annual usage.[190]

Customers are required to be in good standing in order to participate - customers will be ineligible if they have received a disconnect notice within the previous 12 months.[191] If the AECs from Wolf Creek are insufficient to meet subscription demands, Evergy will refund each subscriber an amount equal to the AEC Rate multiplied by the difference between the subscriber's annual subscription and the subscriber's pro rata annual share of the subscribed generation.[192]

Revenues collected will be treated for the benefit of all jurisdictional customers by crediting the revenues through the FAC.[193] The proposed program pricing is provided below:[194]

1 year $0.00866/kWh = $8.66/MWh
3 year $0.00827/kWh = $8.27/MWh
5 year $0.00788/kWh = $7.88/MWh

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[187] Direct Testimony of Bradley Lutz, page 52, lines 1-6.
[188] Direct Testimony of Bradley Lutz, Schedule BDL-1, page 18.
[189] Direct Testimony of Bradley Lutz, page 52, lines 9-12.
[190] Direct Testimony of Bradley Lutz, page 52, lines 14-16.
[191] Direct Testimony of Bradley Lutz, page 52, lines 17-19.
[192] Direct Testimony of Bradley Lutz, page 53, lines 6-10.
[193] Direct Testimony of Bradley Lutz, page 53, lines 13-14.
[194] Lutz Testimony, Schedule BDL-1, page 20.

Discussion

AECs, as defined in Evergy's proposal, are different than RECs, are not included in RES, there is currently no existing market for AECs[195] and there is also no standard set by statute or rule. Evergy would be unable to sell these AECs outside of this program. Additionally, Evergy performed a survey in 2024 of its key account customers which showed divided customer interest in AECs, of a total of 63 participants, ** [redacted].[196] [redacted].[197] **

Evergy stated that it ** [redacted] **[198] which sells AECs at $0.000035/kWh,[199] but then utilized REC pricing data to determine the proposed pricing of $0.00866/kWh - $0.00788/kWh, depending on contract length. Additionally, registries do not track AECs like they do RECs, so Evergy would need to find and hire a third party in order to track and retire AECs.[200]

Recommendations

Staff recommends the Commission reject the AEC Rider at this time. Staff questions whether the price has been set appropriately and how attribute retirements will be tracked. Additionally, there are details that still need to be worked out regarding standards and reporting. If the Commission chooses to approve the AEC Rider, Staff recommends the Commission require that Evergy first obtain the third party tracking system in order to track and retire the AECs and file on an annual basis an update of the program showing how the AECs are being tracked and proving that the AECs are not being utilized more than once.

Staff Witness: Amanda Arandia

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[195] Response to Data Request 127.

[196] Survey results provided in response to Data Request 70.

[197] Response to Data Request 70.1.

[198] Response to Data Request 127.

[199] https://renew-arkansas.entergy.com/go-zero/go-zero-plans.

[200] Response to Data Request 86.

Requested Rider Interaction with FAC

It is Staff's understanding that FAC tariff sheets cannot be changed outside of a general rate case. Therefore, Staff recommends that the Renewable Energy Credit ("REC") revenues or related revenues from the RENEW, GSR, and AEC riders be tracked and recorded as a regulatory liability, with the value of such regulatory liability, if any of those riders are approved.

Staff Witness: Brooke Mastrogiannis

Facility Extension Tariff & "Increasing Connected Load" Provisions

Evergy's facility extension provisions are tariffed at EMW Sheets R-46 – R-54 and EMM 2 Sheets 1.30-1.31. While the current language of this tariff refers to "service connection" and "distribution system extension," where a customer's interconnection to the utility system occurs at a transmission voltage, those facilities are functionally distribution and properly recorded to distribution accounts.[201]

However, the tariff language in the facilities extension provisions should be clarified to include transmission-voltage equipment, and modified to require full prepayment of extensions related to transmission-level interconnections. Staff has prepared a comprehensive revision of the EMW facility extension tariff to incorporate necessary changes, and recommends the same changes be made to the EMM tariffs. The EMW version of the tariff is attached as Appendix 2 – Schedule 10.

Evergy's proposed tariff revisions appended to Mr. Lutz's direct testimony fail to adequately modify terms referring to distribution infrastructure to clearly include equipment that operates at transmission voltages, and apply only to customers interconnecting on the proposed LLPS tariff. Also, Evergy's proposed revisions exclude the costs associated with "network upgrades" from the responsibility of the interconnecting customer. Staff's recommended tariff revisions address these concerns with the Facility Extension Tariffs.

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[201] The Uniform System of Accounts regarding "Transmission and Distribution Plant," states that "Transmission system means… …All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply," and "Distribution system means… …facilities employed between the primary source of supply (i.e., generating station, or point of receipt in the case of purchased power) and of delivery to customers, which are not includible in transmission system, as defined in paragraph A, whether or not such land, structures, and facilities are operated as part of a transmission system or as part of a distribution system."
https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

In addition to these recommended tariff changes, Staff recommends the Commission order Evergy to create subaccounts for each set of interconnection infrastructure associated with each customer interconnecting at transmission voltage.

Finally, EMW's provision 4.04 "Increasing Connected Load" on sheet R-28 states "If the customer's connected load is increased without prior approval by Company, then the customer shall assume full responsibility for the quality of their service and for any damage to Company's distribution facilities and metering installations. The customer shall pay for such increased service at the appropriate rate tariff. Upon request by Company, the customer shall execute a new agreement at Company's regular published rate covering the total connected load or demand as so increased." This provision should be modified to refer to "transmission, substation, or distribution facilities and metering installations," and similar changes should be made to similar EMM tariff provisions.

Staff Witness: Sarah L.K. Lange

Emergency Energy Conservation Plan

The North American Electric Reliability Corporation (NERC) established a Large Load Task Force (LLTF). The purpose of the LLTF is to "better understand the reliability impact(s) of emerging large loads… and their impact on the bulk power system".[202] As the Commission is aware, there are many challenges that the electric industry is facing. As NERC[203] notes:

> Integrating emerging large loads onto the grid poses several challenges including accurately forecasting future demand, ensuring that transmission and generation capacity keeps pace with this demand, and managing rapid fluctuations in consumption during all conditions – both fault and normal – which can destabilize the grid.

NERC's work plan includes several forthcoming whitepapers. One will address the unique risks of large loads, and the second will assess whether existing "Reliability Standards can adequately capture and mitigate reliability impact(s) of large loads interconnected to the BPS [Bulk Power System]."[204] Additionally, the task force plans to develop a reliability guideline identifying potential risk mitigations, which is expected to be completed in the second quarter of 2026.

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[202] https://www.nerc.com/comm/RSTC/Pages/LLTF.aspx.

[203] https://www.nerc.com/comm/RSTC/LLTF/Large Loads FAQs.pdf.

[204] https://www.nerc.com/comm/RSTC/LLTF/LLTF Work Plan.pdf.

Regionally, SPP is seeking approval of Revision Request 696 – Integrate and Operate High Impact Large Loads from its board and FERC. Similarly, to NERC, SPP notes:[205]

> Without proper evaluation, planning and safeguards, haphazard interconnection of large loads could lead to reliability challenges, generation shortfalls and potentially more adverse impacts to the regional electric grid.

Revision Request 696 includes several elements related to the process of interconnection and study (see Staff Report section regarding "Path to Power"). Additionally, it creates a path for conditional service through a proposed solution referred to as Conditional High Impact Large Load ("CHILL"), "with the trade-off of potential temporary curtailments, in exchange for quick and thorough study results that allow them to integrate and operate as quickly as possible."[206]

Evergy's Emergency Energy Conservation Plan is tariffed for EMW at P.S.C. MO. No. 1, 2nd Revised Sheet R-55 – R-56 and for EMM at P.S.C. MO. No. 2, 1st Revised Sheet No 1.59 – 1.60. These tariffs outline Evergy's Load Management and Manual Load Shed Plan and are to be updated as needed. After Reliability Coordinator review is complete, EMM and EMW are required by its tariffs to make a revised Plan available to Commission Staff as Evergy's plans are considered Critical Energy/Electric Infrastructure Information (CEII).

Staff recommends the Commission order Evergy to include in its Emergency Energy Conservation Plan tariffs the following language:

> Customers taking service under Schedule LLPS may be interrupted during grid emergencies under the same circumstances as any other customer.

Staff Witness: Claire M. Eubanks, P.E.

"Path to Power"

Background

On pages 7 through 16 of the direct testimony of Jeff Martin, Evergy describes its process for studying new large loads, coined "Path to Power." Additionally, Brad Lutz presents Evergy's

[205] faq - spp large load interconnection solutions 2025 07 07.pdf, page 1.

[206] SPP Frequently Asked Questions Large Load Integration, Revised July 15, 2025, page 1. faq - spp large load interconnection solutions 2025 07 14.pdf.

proposed tariff changes applicable to loads greater than 25 MW requesting service from the Company. The exemplar tariff sheets related to "Path to Power" are listed below:

EMM

P.S.C. MO. No. 2, Original Sheet No. 1.09C, page 45 of Schedule BDL-1[207]

P.S.C. MO. No. 2, 1st Revised Sheet No. 1.30H, page 46 of Schedule BDL-1

EMW

P.S.C. MO. No. 1, 2nd Revised Sheet No. R-21, page 97 of Schedule BDL-1

P.S.C. MO. No. 1, 3rd Revised Sheet No. R-54, page 98 of Schedule BDL-1

Mr. Martin outlines[208] the following steps in establishing service to loads greater than 25 MW:

1. Initial Evaluation (2 to 4 weeks) – Evergy provides an assessment of the customer's project in relation to the system based on anticipated load ramp. Evergy provides explanation of process. No formal cost estimates are provided during this evaluation.
2. Project Details Phase (2-3 months) – Customer submits information and requirements including proof of land rights, customer signs letter of agreement and provides a $200,000 deposit. Indicative pricing provided after Evergy executive approval.
3. AQ Study Phase (90 days) – An Initial Project Activities agreement is signed by customer, Evergy submits the project to the Southwest Power Pool ("SPP") for further study.
4. Completion of Project Phase (2-6 months) – May run in parallel to the AQ Study Phase. Evergy and customer negotiate and execute agreements including Interconnection Agreement, Right-of-Way Agreements, and Facilities Extension Agreements.
5. SPP Submittal and Evaluation Phase – Formal load request to SPP reflecting load and its ramp schedule.

Evergy intends to group large load projects in batches of four projects at a time across jurisdictions. Additionally, Evergy intends to prioritize community interest projects in its queue and waive the initial deposit requirement in certain circumstances. Community interest projects are part of a competitive search in which Evergy is competing against at least one other location, the customer reasonably demonstrates that the project will employ 250 permanent, full-time

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[207] Schedule BDL-1 is contained in the Direct Testimony of Brad Lutz.

[208] Direct testimony of Jeff Martin, graphic on page 9, line 1.

employees, and an accredited state or regional economic development organization certifies that the absence of a deposit and expedited timing are critical to the state winning the project.[209]

Discussion

Certain necessary information regarding the process is not contained in the exemplar tariffs. Importantly, Evergy fails to provide within its proposed tariff the expected duration of any of the steps or the entire process. Several agreements are noted as typically needed in Mr. Martin's direct testimony (Interconnection Agreement, Right-of-Way Agreement, and Facilities Extension Agreement), but are not referenced in the exemplar tariff attached to Mr. Lutz's direct testimony.

In addition, Evergy included in the tariff that, in regards to the community interest projects, deposit applicability and managing projects in the queue are subject to Evergy's "sole discretion."[210] As tariffs are binding on the Commission as well as the utility and its customers, the proposed language is unnecessarily vague. Staff expects Evergy to manage its queue and determine deposit applicability in line with the guardrails established by the Commission in this case; however, if an issue arises, the tariff should not, directly or indirectly, prohibit applicants, customers, or other parties from bringing formal complaints or making prudence recommendations to the Commission. In other words, the tariffs of EMM and EMW should obligate each to manage the queue reasonably, appropriately, and in a non-discriminatory manner; and nothing in the tariff should directly or indirectly prohibit the Commission from the appropriate review of EMM and EMW's queue management and processing.

One of the guardrails Evergy is requesting to put in place regarding selection of community interest projects is project certification from an accredited state or regional economic development organization. Evergy itself is an accredited economic development organization[211] and the only one listed in the Kansas City, Missouri, area. Evergy contemplates requiring membership in the International Economic Development Council rather than being accredited by the International Economic Development Council.[212]

[209] P.S.C. MO. No. 2, Original Sheet No. 1.09C, page 45 of Schedule BDL-1 and P.S.C. MO. No. 1, 2nd Revised Sheet No. R-21, page 97 of Schedule BDL-1.

[210] Proposed P.S.C. MO. No. 2 Original Sheet No. 1.09C, page 45 of Schedule BDL-1 and Proposed P.S.C. MO. No. 1, 2nd Revised Sheet No. R-21, Canceling P.S.C. MO. No. 1, 1st Revised Sheet No. R-21, page 97 of Schedule BDL-1.

[211] International Economic Development Council, List of AEDOs - International Economic Development Council.

[212] Response to Data Request 128.

Evergy intends to include additional details regarding "queue process and submission" on its website that will be updated from time to time. The language is unclear and any changes to major process and submission requirements should be made through tariff filings with the Commission.

Staff also notes that SPP is seeking approval of Revision Request 696 – Integrate and Operate High Impact Large Loads from its board and the Federal Energy Regulatory Commission ("FERC"). Revision Request 696 includes several elements related to the process of interconnection and study. Staff recommends the Commission require Evergy to revisit its proposed tariffs to align timing of any applicable SPP studies if SPP's Revision Request 696 receives its board and FERC approval.

<u>Recommendations</u>

Staff recommends the Commission order EMM and EMW to make the following changes in compliance tariffs to its rules and regulations regarding service to loads greater than 25 MW:

- Include expected duration for each phase.
- Include deliverables from Evergy to customer for each applicable phase, such as indicative cost estimates.
- Include the title of all required agreements.
- Remove reference to Company's "sole discretion" regarding deposit applicability and managing projects in the queue.
- Prohibit Evergy from being the entity providing certification to its large load customers that the absence of a deposit and expedited timing are critical to the state winning the project.
- Modify language regarding the website and require Evergy to maintain on its website a list of accredited state or regional economic development organizations who may certify the criticality of timing and deposit waiver for a specific customer project.

The above recommendations are reflected in redline to the language presented by Evergy in Appendix 2 – Schedule 11.

Additionally, Staff recommends the Commission require Evergy to revisit its proposed tariffs to align timing of any applicable SPP studies if SPP's Revision Request 696 receives its board and FERC approval.

Staff Witness: Claire M. Eubanks, P.E.

VI. Response to Evergy's Valuation of LLPS Customer Cost of Service and Revenue Requirement Impacts

The Class Cost of Service (CCOS) modeling, as presented by Evergy, is unhelpful to the Commission's decision-making process. It would be difficult, if not impossible, to use an embedded cost study, particularly outside of a rate case, to determine whether or not a proposed LLPS rate complies with the statutory requirement that LLPS 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."[213] Staff will first explain specific shortcomings in the modeling provided by Evergy, and then explain issues with use of an embedded cost study for compliance with the statutory protections enacted through SB 4. For the reasons explained below, Staff recommends that the Commission place no reliance on Evergy's modeled CCOS results or any conclusions drawn by any other Evergy witness from those studies or results.

Evergy designed its requested LLPS rates and conducted its CCOS modeling around a new 384 MW LLPS customer, using 2,859,264 annual MWh of energy (85% load factor) with a 90% coincidence factor,[214] requiring 346 additional MW of system capacity (not grossed up for reserve margin). Using the rates provided in the draft tariffs attached to Mr. Lutz's testimony, this customer would pay an average LLPS bill of $144,207,496 (5.043 cents/kWh) for EMW LLPS service, or $153,720,516 (5.373 cents/kWh) for EMM LLPS service. One difficulty in explaining Staff's concerns with Evergy's actual design of the LLPS rate schedules and Evergy's CCOS modeling is that the rates designed do not relate to the CCOS results.

For EMM, if no new generation is needed, Evergy's modeling results in the new LLPS customer being allocated a cost of service of 5.469 cents/kWh, also assuming the new customer makes an additional annual payment of $44.2 million. If new generation is needed, the EMM model results in the LLPS customer being allocated a cost of 6.026 cents/kWh also assuming the new customer does not make the additional $44.2 million annual payment.

[213] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

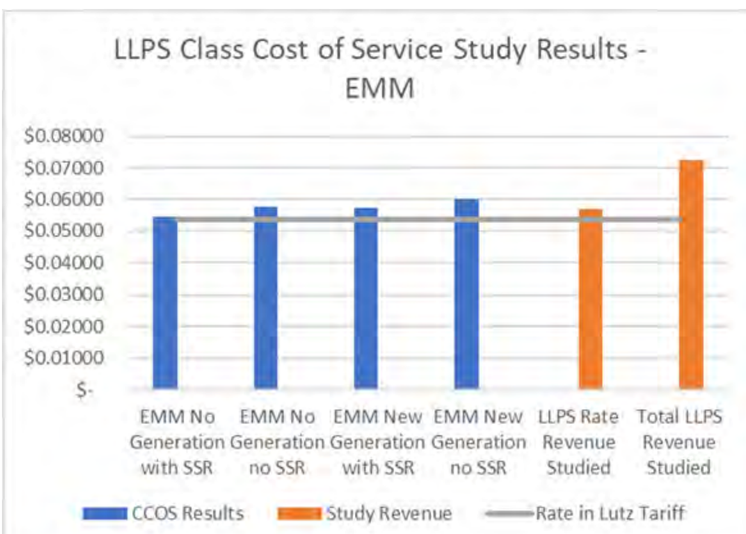
[214] Evergy provided no support for this coincidence factor, and it is not facially reasonable. It would be most reasonable to assume a 100% coincidence factor for any use case where a stable load exists, or where a stable load and a weather-sensitive load contribute to total demand.

For EMW, if no new generation is needed, Evergy's modeling results in the new LLPS customer being allocated a cost of service of 4.225 cents/kWh also assuming the new customer makes an additional annual payment of $44.4 million. If new generation is needed, the EMW model results in the LLPS customer being allocated a cost of 4.780 cents/kWh also assuming the new customer does not make the additional $44.4 million annual payment.[215]

Evergy does not provide any of the above information in its filing or directly in its workpapers, further complicating the Commission's consideration and Staff's review. Instead,

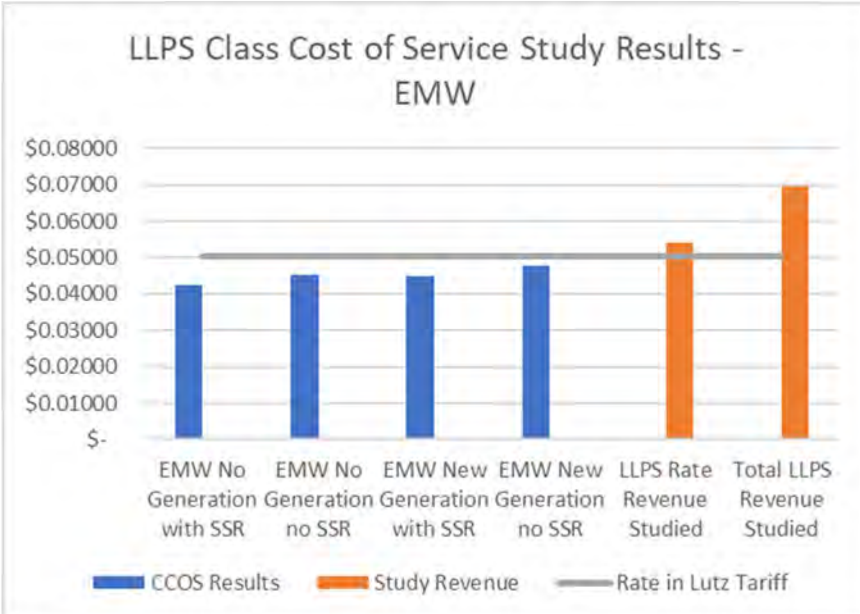
1. Evergy subsumes the new LLPS customer into the LPS class, without breaking out the LLPS customer's studied costs;
2. Evergy models the new LLPS customer paying higher rates than the rates contained in the specimen tariffs appended to the direct testimony of Brad Lutz. The CCOS model uses an average bill value of 5.396 cents/kWh for EMW, which is 7% higher than the requested rate design, and 5.696 cents/kWh for EMM, which is 6% higher than the requested rate design;[216]
3. Evergy models an additional $44.2 million for the EMM customer, and $44.4 million for the EMW customer, of annual payments by the LLPS customer of "System Support Rider" charges;
4. Evergy does not present its results as average cost of service or average bill results for the LLPS customer or for existing classes, which is a much clearer metric;
5. Evergy allocated the System Support Rider revenue differently in its CCOS studies than it stated those revenues would be allocated in future rate cases.

A summary of Staff's review of the EMM CCOS Studies, addressing these considerations, is provided below:



[215] Evergy models the addition of a 400 MW combined cycle gas turbine generator with an initial capital cost of $628.5 million, for each EMM and EMW.
[216] Evergy's response to DR 120 stated that Evergy used LPS rates, not the requested LLPS rates, for estimating new LLPS revenue.

A summary of Staff's review of the EMW studies is provided below:



Additionally, undermining the reliability of the Evergy CCOS modeling for use in determining whether the requested LLPS 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,"[217] is that in the Evergy models:

1. The cost of energy to serve the LLPS customer as an increase to revenue requirement is understated, does not include increased transmission and market expenses, and is unreasonably offset by additional wholesale energy revenues;
2. The cost of capacity to serve the LLPS customer in the "No Generation" scenarios is underestimated;
3. The allocation of distribution costs within the EMM study is not representative of a reasonable rate case outcome, in that the LLPS customer is allocated $25.88 million of distribution revenue requirement in the EMM case based on Evergy's 2022 CCOS approach, but the LLPS customer is allocated only a token allocation for its meter cost in the EMW case, based on Evergy's 2024 CCOS approach. If the distribution revenue requirement is excluded from the EMM modeling and all other EMM assumptions are preserved, then for the "No Generation" scenario the average allocated cost drops to 4.564 cents/kWh. It is reasonable to assume that LLPS customers would aggressively pursue decreasing the LLPS tariffed rate to that level

[217] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

in a rate case, which would further undermine the revenues assumed in Evergy's modeling here; and

4. The embedded cost approach, even if the underlying study were reasonably conducted, is not the appropriate means to study for compliance with the SB 4 language; Staff does not concede that the classifiers and allocators relied upon by Evergy are reasonable, although Staff will attempt to avoid over litigation of specific classifiers and allocators in this case, given the existing complexity, and the inapplicability of an embedded cost CCOS to the question at hand – namely, does the requested rate comply with the requirements that LLPS 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."[218]

Evergy's CCOS Modeling Does Not Reasonably Demonstrate that the LLPS Customers Will Bear A Representative Share of the Costs Incurred to Serve Them

Illustrating the inapplicability of the embedded cost approach to the question of SB 4, Evergy's modeling:

1. Allocates to LLPS customers 15.81% (EMM) and 15.00% (EMW) of the net revenue requirement of each respective jurisdiction's generation fleet; in other words, LLPS customers are allocated the net benefit of the accumulated deferred income tax and other ratebase offsets, and are given the benefit of historic pricing on existing plants, without consideration of the increased capital costs of newer facilities. This occurs on the basis of capacity allocation;
2. Allocates to LLPS customers 24.77% (EMM) and 24.39% (EMW) of the profit for the operation of each respective jurisdiction's generation fleet. This occurs on the basis of what Evergy calls the "Energy Fuel" allocator;
3. Allocates back to the LLPS customer approximately $7 million dollars of the $44.2 million System Support Rider payment made by the EMM LLPS customer, and allocates back to the EMW LLPS customer approximately $7.5 million of the $44.4 million charged to the EMW LLPS customer;
4. Relies heavily on System Support Rider revenues being distributed to the existing customers, however the SSR rate calculation is problematic, and it is likely that most or all of the SSR revenues would accrue to the benefit of EMW and EMM rather than customers, due to regulatory lag.

[218] Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

Energy Expense Is Undervalued

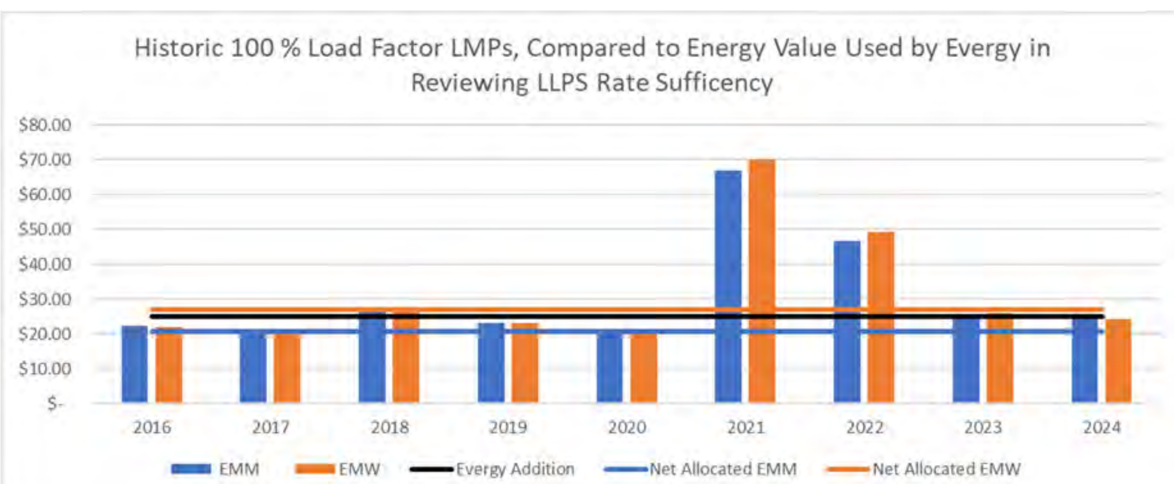
The new LLPS customer's allocated cost of energy is only 2.09 cents per kWh in the EMM version of the modeling, and 2.69 cents per kWh in the EMW version, due to:

1. Evergy's decision to allocate to the new LLPS customer the revenues from profits on existing generation;
2. Evergy's unreasonable approach to interpolating the results of two production cost models that it alleges have been performed, but were not produced with workpapers; and
3. The failure to model any incremental SPP charges assessed on Evergy's load, demand, or load ratio-share.

For reference, the average around-the-clock Day Ahead LMPs for each rate jurisdiction are summarized in the table below:

	EMM	EMW
2016	$ 22.31	$ 21.91
2017	$ 21.59	$ 21.33
2018	$ 27.44	$ 26.52
2019	$ 23.08	$ 23.15
2020	$ 20.70	$ 20.64
2021	$ 66.78	$ 70.10
2022	$ 46.62	$ 49.11
2023	$ 25.45	$ 26.13
2024	$ 25.80	$ 24.40

These values, compared to the incremental and net energy costs modeled by Evergy, are illustrated below:



** [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] **

Notably, production cost modeling and the inputs to the production cost model are hotly contested issues in most rate cases, and are often settled, in no small part, due to the complexity of the issues and the interplay of the production model results with the FAC base.

** [redacted][219]

[redacted]

[219] ** [redacted] **

[redacted]

[redacted][220] [redacted]

[redacted][221] [redacted]

---

[220] ** [redacted] **

[221] ** [redacted] **

[redacted][222]

[redacted]

[redacted]

[redacted]

---

[222] ** [redacted] **

[redacted] **

Additional Capacity Expense Is Undervalued

For the "No Generation" scenarios provided in its workpapers, Evergy assumed that the cost of 384 MW of additional capacity is available to EMM and to EMW at the same cost per kW as existing Evergy generation, which it quantified at $11/kW month. Evergy's valuation assumes that the cost of serving additional load, for which it does not have capacity, can be met by obtaining capacity at the same cost as its existing generation, including Wolf Creek and Jeffrey. This is not a reasonable assumption for purposes of estimating the cost of incremental capacity. Based on filings in recent CCN cases, the cost for new CCGT capacity is over ** [redacted] **/kW-month.[223] Staff does not recommend a specific cost of incremental capacity be substituted in the embedded cost studies because embedded cost studies are not a reasonable means of estimating compliance with the requirements of SB 4.[224]

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[223] EA-2025-0075.

[224] Data Request 115 requested:

> A) Please confirm that in the file "Evergy (Mo West) 2024 CCOS Model - No Generation (2-5-25)" Evergy models annual capacity expenses of $131,316/MW for a 384 MW customer. B) Please explain how the valuation (also expressible as $11/kW-month) was derived. C) Please confirm that the value used for additional capacity expenses in the CCOS files does not include an allowance for Renewable Energy Credits, other means of Missouri RES compliance, or costs/expenses assessed by SPP to load serving entities on the basis of load and/or load ratio share, or any measure of peak. If it does include such amounts, please provide such amounts and please explain how those amounts were estimated. D) Please explain all costs or expenses intended to be reflected in the $11/kW-month valuation.

Evergy's response was:

A. The annual capacity expense is $132,000/MW ($11.00/kW-month x 12).

B. The Company examined current costs to define a per kW value for system capacity. Costs included are,

- Return on production plant, production depreciation reserve, fuel inventory, and deferred income taxes
- Plus production depreciation

SSR Revenues Are Uncertain, at Best

Evergy also modeled over $44 million in System Support Rider revenue in its CCOS workpapers for the hypothetical customer at EMM and at EMW. Mr. Lutz testifies at page 33 that the acceleration component of the SSR "will be calculated and updated as part of each Company rate proceeding," and that "The Schedule SR is not a cost recovery rider. There is no total amount that needs to be recovered. Instead, this rider is established to ensure that Schedule LLPS customers contribute additional revenue, based on the time-value-of-money concept, that reflects revenue that will be attributed to other customers to keep them from bearing the cost of this accelerated generation investment." Mr. Lutz further testifies that "Evergy believes that this approach will also promote transparency and fairness."

Staff has reviewed the Acceleration Component workpaper relied upon to calculate the ** [redacted] **/kW-month used in the EMM CCOS and the ** [redacted] **/kW-month used in the EMW CCOS.[225] While additional concerns with the calculations will be discussed in the Section "System Support Rider," for purposes of reviewing the CCOS the most significant issues are that:

1. The calculation is wholly dependent on the forecasted LLPS Peak Load, which is subject to significant concerns with information asymmetry, as is necessitated by Evergy's requested tariff design;
2. The revenue modeled was not treated in the CCOS the way Mr. Lutz described in his testimony;
3. This revenue is particularly subject to regulatory lag, such that it solely benefits Evergy shareholders through strategic rate case timing; and
4. This rate is particularly subject to well-heeled opposition from the customers subject to the rate, and will drive intense litigation of hypothetical load, hypothetical generation units, and appropriate interest rates.

- Less capacity sales
- Plus non-fuel production O&M

Costs were divided by overall system capacity to ultimately produce the per kW-month value. The Company examined these values for both the Missouri Metro and Missouri West jurisdictions, considering the values with and without Purchased Power costs and selected $11.00 per kW-month as a representative value within the range of these results.

C. The value does not include any allowance for RES compliance.

D. Please see part "B" above.

[225] Response to Data Request 79.

The selection of the horizon over which to reflect LLPS peak load has significant impact on the rate calculated. The peak loads used in Evergy's modeling ** [redacted]. ** While Evergy does not specify the horizon over which peak load is to be considered, based on the design of the rate calculation, it would appear that either the required four year FAC rate case intervals, or a 10 year outlook could effectuate Evergy's apparent intent.[226] These calculations each produce rates different than those used in the Evergy CCOS studies submitted in this case, and result in a 21% difference in annual revenue between EMM calculations, and a 34% difference in annual revenue between EMW calculations.

**

[redacted]

**

However, in that Evergy reserves the apparently unilateral right to discontinue the application of the acceleration component of the SSR charge, and because the capacity to which the acceleration component can be applicable is subject to change through interaction with other

[226] EMM's most recent general rate case rates became effective January 9, 2023. EMW's most recent general rate case rates became effective January 1, 2025.

requested riders, it is not reasonable to rely on SSR revenue for estimating the impact of new LLPS customers on existing customers.[227]

In the CCOS, SSR revenues are recorded to Account 447.01, and functionalized as Production Demand. These revenues are allocated using the A&E 4CP factor. In response to Data Request 8, Evergy states that "Within class cost of service and for ratemaking purposes we expect the revenues will be uniquely identified and allocated to all classes based on class revenues less all LLPS base rate revenues." This difference in treatment shifts over $5 million in revenue away from the existing LPS customers:

	LLPS SSR Revenue	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
As Allocated in CCoS	$ 44,190,720	$ 17,096,987	$ 2,656,328	$ 5,272,359	$ 7,293,452	$ 11,674,026	$ 194,697	$ 2,872
Allocated as Stated in DR 8	$ 44,190,720	$ 17,868,647	$ 3,598,869	$ 6,477,936	$ 9,353,654	$ 6,367,215	$ 520,492	$ 3,908
Difference ($):		$ 771,660	$ 942,541	$ 1,205,576	$ 2,060,202	$ (5,306,811)	$ 325,795	$ 1,036
Difference (%):		4.5%	5.5%	7.1%	12.1%	-31.0%	1.9%	0.0%

This reallocation flips the results of EMM's claims regarding the impact of LLPS customers on existing LPS customers, as illustrated below:

Large Power Service	TY Original Values	Including LPS Test Customer (EMM CCOS)	Change (EMM CCOS)	Reallocated SSR Per DR 8	Change (Reallocated)
Revenue	$ 121,482,208	$ 284,355,479	$ 162,873,271	$ 284,355,479	$ 162,873,271
Net Revenue Requirement	$ 87,551,889	$ 208,797,391	$ 121,245,502	$ 214,104,202	$ 126,552,313
Net Operating Income	$ 33,930,320	$ 75,558,088	$ 41,627,768	$ 70,251,277	$ 36,320,957
Rate Base	$ 352,376,054	$ 738,736,460	$ 386,360,406	$ 738,736,460	$ 386,360,406
Rate of Return at Present Rates	9.63%	10.23%	**0.60%**	9.51%	**-0.12%**
Return Required at Equalized ROR	$ 24,780,846	$ 51,951,642	$ 27,170,796	$ 51,951,642	$ 27,170,796
Gross Revenue Deficiency	$ (12,014,082)	$ (30,997,389)	$ (18,983,307)	$ (18,299,635)	$ (6,285,553)
Indicated % Adjustment	-9.89%	-10.90%	**-1.01%**	-6.44%	**3.45%**

Staff Witness: Sarah L.K. Lange

[227] Mr. Lutz testifies at page 34 in part as follows:

> After the initial 15-year term of service under Schedule LLPS, customers whose annual peak demand has not increased by more than five percent in the prior five years may request to terminate the acceleration component of the Schedule SR. However, if the customer subsequently modifies its Customer Capacity commitment (as defined under Schedule LLPS by 20 percent or 20 MW, whichever is lower) after removal of the acceleration component, the acceleration component will be applied for the remainder of the Schedule LLPS term beginning in the year when this threshold is met. Additionally, should a customer participate in the Customer Capacity Rider (Schedule CCR), and supply in excess of 80 percent of the capacity required to serve its load, the customer may request to terminate the acceleration component of this charge for the term of the Schedule CCR participation. The Company shall reasonably grant this request if it does not identify other rate design concerns with doing so.

VII. Conclusion and Summary of Recommendations

For the reasons stated in this Report and discussed in the Rebuttal Testimony of James A. Busch, Staff recommends that the Commission order Evergy to cooperate with Staff to finalize tariffs for service to a new class of customers taking service at 34 kV or greater, or with a peak demand of 25 kW or greater, that is consistent with the recommended tariff and rates attached as Appendix 2 - Schedule 1. The Commission should also order the creation of the regulatory liability accounts for revenue from these customers as described in that tariff.

Staff also recommends that the Commission order Evergy to effectuate Staff's recommended changes concerning facilities extensions, increasing connected loads, emergency energy conservation planning, and the "Path to Power."

The Commission should also order that a separate commercial load node be established for each LLPS customer, order that any Deficiency Payment incurred after the addition of LLPS customers be borne solely by the LLPS customer class in proportion to the overall peak demand of each customer, order Evergy to create subaccounts for each set of interconnection infrastructure associated with each customer interconnecting at transmission voltage.

Staff does not recommend that the Riders that Evergy has proposed be approved at this time, but Staff will continue to work with Evergy and other Stakeholders for development of reasonable Riders as noted in the Report.

Staff Witness: Sarah L.K. Lange

Appendix 1 - Staff Credentials

Appendix 2 - Referenced Schedules

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF AMANDA ARANDIA

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, AMANDA ARANDIA, and on her oath declares that she is of sound mind and lawful age; that she contributed to the attached *Staff Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Amanda Arandia
AMANDA ARANDIA

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 21st 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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF CLAIRE M. EUBANKS, PE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, CLAIRE M. EUBANKS, PE, and on her oath declares that she is of sound mind and lawful age; that she contributed to the attached *Staff Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks
CLAIRE M. EUBANKS, PE

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 24th 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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF BRAD J. FORTSON

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, BRAD J. FORTSON, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

BRAD J. FORTSON

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 21st 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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF JORDAN T. HULL

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, JORDAN T. HULL, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Jordan Hull
JORDAN T. HULL

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 14th 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

DSuzieMankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, **SARAH L.K. LANGE**, and on her oath declares that she is of sound mind and lawful age; that she contributed to the attached *Staff Report*; 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 23rd 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

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF SHAWN E. LANGE, PE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, SHAWN E. LANGE, PE, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Shawn E Lange
SHAWN E. LANGE, PE

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 21st 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

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

AFFIDAVIT OF J LUEBBERT

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, J LUEBBERT, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

J Luebbert

J LUEBBERT

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 21st day of July 2025.

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

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AFFIDAVIT OF BROOKE MASTROGIANNIS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, BROOKE MASTROGIANNIS, and on her oath declares that she is of sound mind and lawful age; that she contributed to the attached *Staff Report*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Brooke Mastrogiannis
BROOKE MASTROGIANNIS

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 23rd day of July 2025.

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

BEFORE THE PUBLIC SERVICE COMMISSION
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AFFIDAVIT OF BRODRICK NIEMEIER

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, BRODRICK NIEMEIER, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brodrick Niemeier

BRODRICK NIEMEIER

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 21st 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

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AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

COMES NOW, MICHAEL L. STAHLMAN, and on his oath declares that he is of sound mind and lawful age; that he contributed to the attached *Staff Report*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

MICHAEL L. STAHLMAN

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 21st 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

Notary Public