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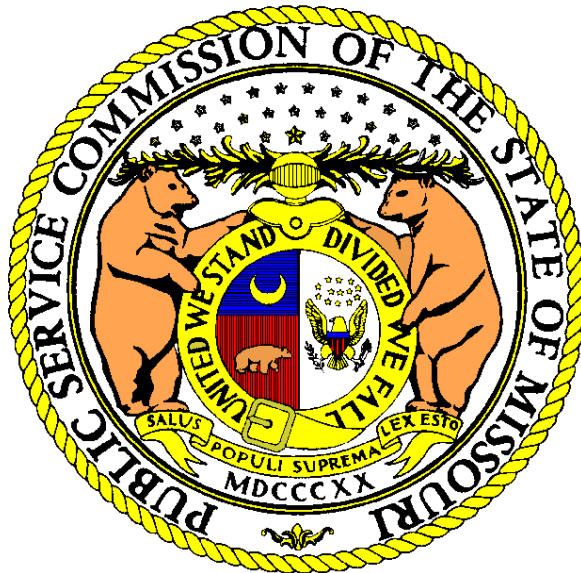
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Staff Report & Recommendation
File No. EO-2025-0154

MISSOURI PUBLIC SERVICE COMMISSION

STAFF

RECOMMENDATION



**EVERGY MISSOURI METRO
EVERGY MISSOURI WEST**

CASE NO. EO-2025-0154

*Jefferson City, Missouri
July 25, 2025*

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EVERGY MISSOURI WEST
CASE NO. EO-2025-0154**

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1 **STAFF RECOMMENDATION**

2 **EVERGY MISSOURI METRO**

3 **EVERGY MISSOURI WEST**

4 **CASE NO. EO-2025-0154**

5 **I. Introduction**

6 Staff recommends rejection of the tariffs described in the direct testimony of Brad Lutz.¹
7 Evergy names this addition to the Large Power Service (LPS) tariff, the Limited Large Power
8 Service (LLPS). Staff recommends finalization and promulgation of its recommended tariff for
9 service to large load customers, and recommended changes to related tariff provisions.
10 Staff's recommended tariff is attached as Appendix 2 - Schedule 1.²

11 In general, Evergy Missouri Metro (EMM) and Evergy Missouri West (EMW) have
12 the obligation to supply electric service to requesting qualified customers in their respective
13 service territories.³ This obligation is not without exception. For example, EMW's current tariffs
14 allow the company to refuse to provide service when the electrical use may disturb the electrical
15 use of others, and requires the customer to pay for infrastructure necessary to reduce the
16 interference caused in the service to other customers.⁴ Similarly, current tariffs reserve the right
17 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.

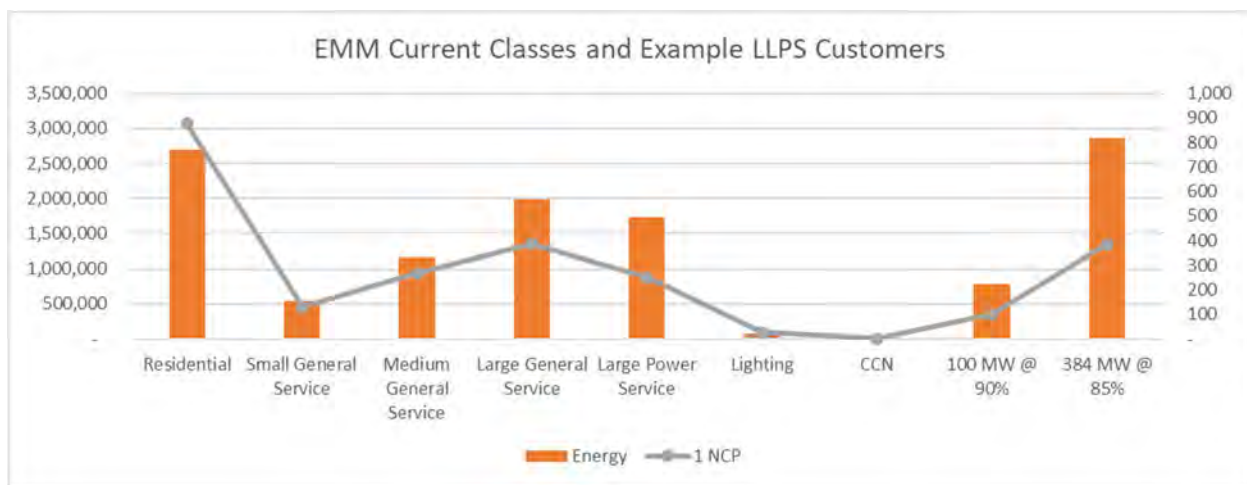
² This Report is provided by the indicated Staff witnesses. The credentials of those witnesses are provided as Appendix 1 to this Report.

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."

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

3 [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7
8 **

9 There is also a tension between the obligation to serve customers already physically located
10 within the utility's monopoly service territory, the utility's interest in drawing in additional
11 customers to its service territory, and restrictions on undue discrimination in customer treatments.⁷
12 However, statutory guidance has been provided. Senate Bill 4, which has passed the legislature
13 and has been executed by Governor Kehoe amends Section 393.130 at 393.130.7, RSMo.,
14 to require each Missouri Evergy utility to have tariff provisions applicable to customers who
15 are reasonably projected to have above an annual peak demand of one hundred megawatts or
16 more, that **"reasonably ensure such customers' rates will reflect the customers' representative**
17 **share of the costs incurred to serve the customers and prevent other customer classes' rates**
18 **from reflecting any unjust or unreasonable costs arising from service to such customers,"**⁸
19 and allows the Commission to order tariff schedules applicable to customers with lower annual
20 peak demand.⁹

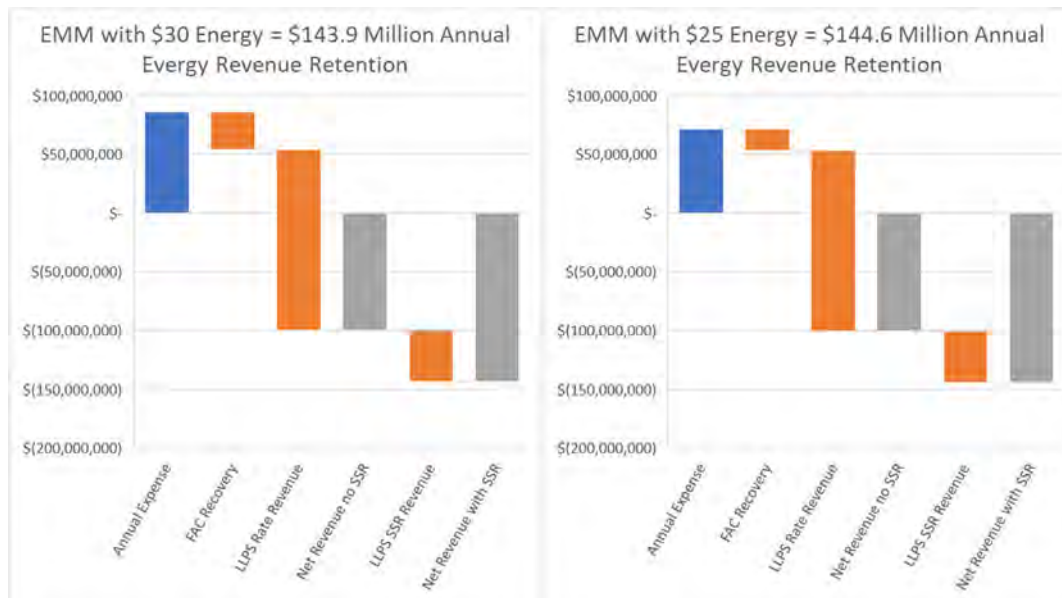
⁷ "Discrimination" here, refers to different treatment, whether preferential or anti-preferential. Section 393.140(5), RSMo.

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.

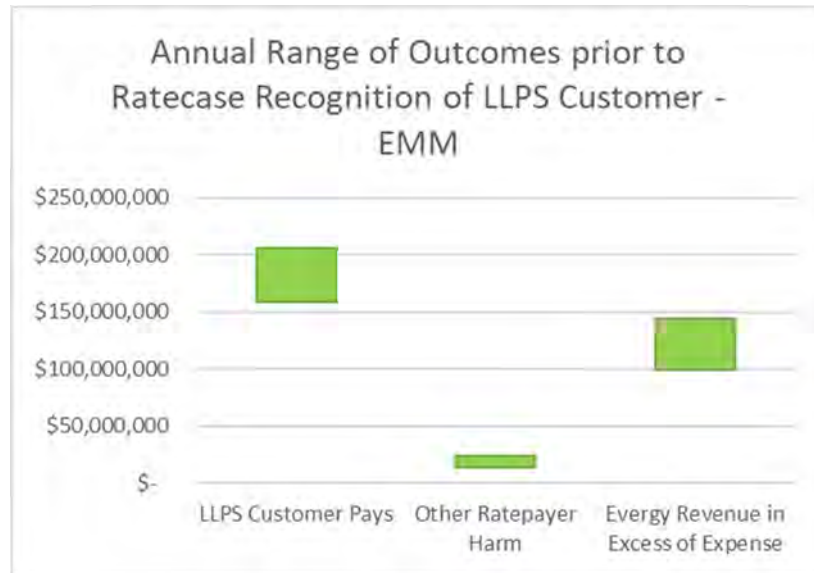
While this docket was opened prior to enactment of Senate Bill 4, and the legislation does not take effect until August 28, 2025, it would be a waste of administrative resources and a source of undue confusion to customers and potential customers to fail to consider provisions relevant to the LLPS tariff 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 FAC¹⁰, 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.

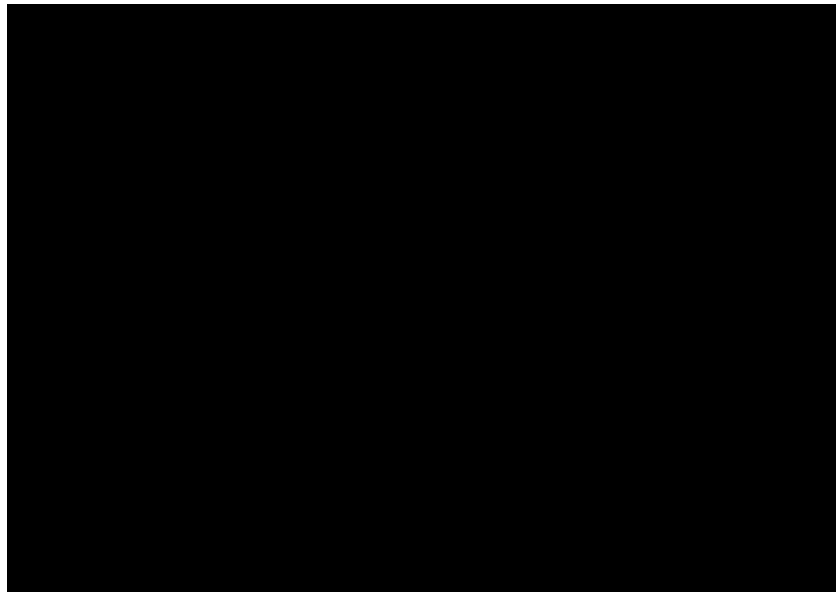


¹⁰ Fuel Adjustment Clause (FAC).

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 **. The ranges of overall impacts are illustrated below:



**



**

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

1 will accrue to the benefit of shareholders through positive regulatory lag. Meanwhile, ratepayers
2 will be paying for a significant amount of the energy to serve that customer through the FAC,
3 therefore resulting in net harm.

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

11 *Staff Witness: Sarah L.K. Lange*

12 **Overall Public Policy**

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

26 This Report represents Staff's best efforts to implement the mandate that the LLPS
27 customers' rates reflect their representative share of the costs incurred to serve them and
28 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.

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

10 *Staff Witness: Sarah L.K. Lange*

11 **Contradictory Policy**

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

15 Prior to this case, when the expected cost of capacity and expected SPP¹⁵ resource
16 adequacy shortfalls were lower, Evergy proposed utilizing incremental costs for serving new
17 customers to design rates.¹⁶ Evergy's estimates for the cost to build new generation facilities in
18 recent years has ballooned compared to just five years ago. While Staff's position in this case is
19 not to utilize incremental costs for designing rates for the LLPS customers, it is important to note
20 that doing so would likely lead to higher rates due to the costs of generation facilities associated
21 with serving these customers.¹⁷ Evergy paired the shift of designing large customer rates to an
22 embedded capacity cost approach along with an option, through Rider CER¹⁸, 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).

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

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

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

20 *Staff Witness: J Luebbert*

21 **Estimated Cost of Service for an LLPS Customer**

22 Using the hypothetical 384 MW customer reflected in Evergy's workpapers, under the
23 recommendations set out in this Report – ***including Staff's recommended tariff provisions and***
24 ***recommended revenue treatment*** – a reasonable estimate of an annual average bill for an LLPS
25 customer, on a \$/kWh basis, is \$0.0751 (plus FAC and other riders) for an EMM LLPS customer,
26 and \$0.0573 (plus FAC and other riders) for an EMW LLPS customer. Because Staff's revenue
27 treatments reduce the increases to rate base that will be caused to enable service to LLPS customer,
28 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 IRP²³ and its Supplemental Direct in Case No. EA-2025-0075:

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

²³ Integrated Resource Plan (“IRP”).

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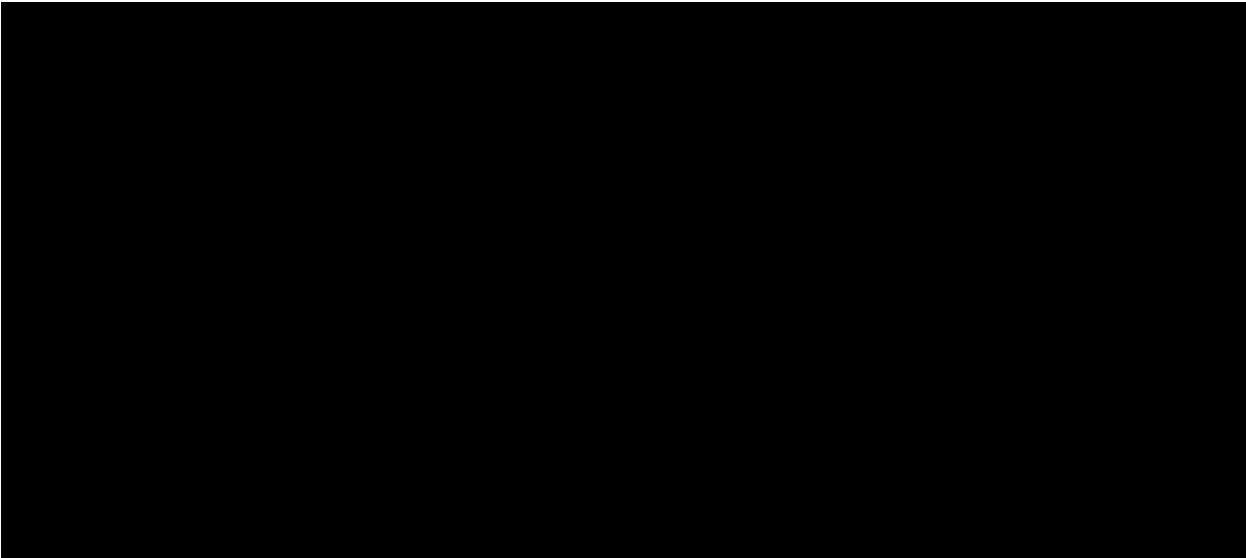


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3
4 The space between the load line(s) and the stacked graph of generation, capacity contracts,
5 and estimated DSM represents an estimate of EMW's need for summer capacity.

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

8 **



9 **

10 **

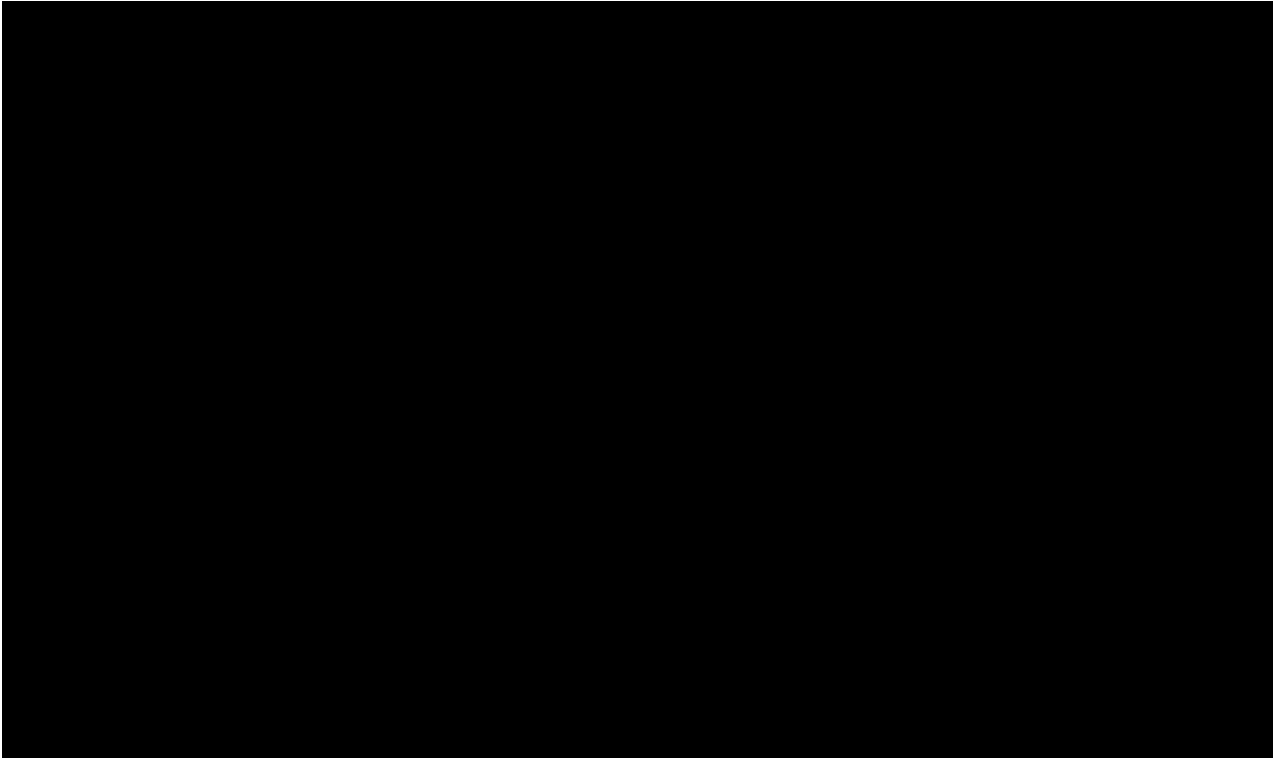
It should be noted that EMW has two CCN²⁴ cases currently before the Commission (Case No. EA-2024-0292 and EA-2025-0075) requesting to add two solar facilities and three natural gas facilities which, if approved, would decrease the need shown in the charts above.

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's²⁵ 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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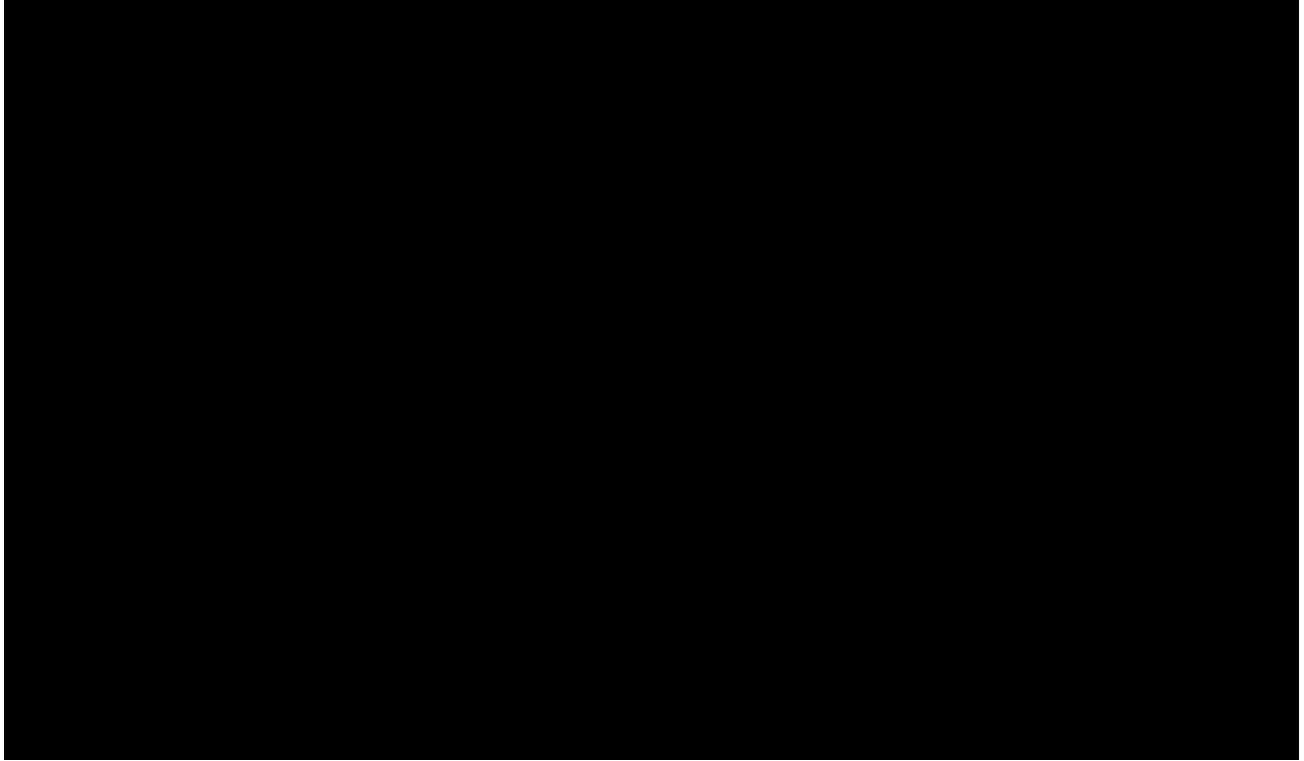
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²⁴ Certificate of Convenience and Necessity ("CCN").

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.

1 **



3 **

4 It should be noted that on May 13, 2025, Evergy Metro contacted Staff regarding an outage.

5 **



7 ** This outage will impact Evergy Metro in the short term but will also
8 impact the longer run accreditation of the facility.

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

10 **Green House Gas (GHG) rule**

11 The U.S. Environmental Protection Agency's (EPA) New Source Performance Standards
12 (NSPS) aim to reduce greenhouse gas emissions from new and modified gas turbine power plants
13 (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:
 - o 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.
 - o 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.
 - o 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.
 - o 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.

²⁹https://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).

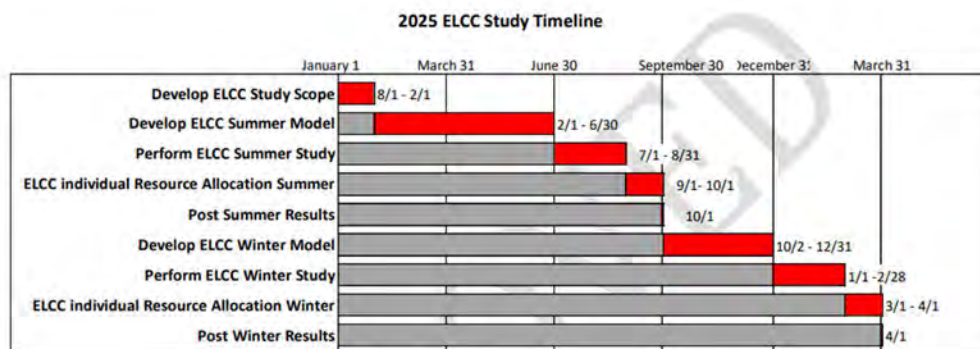
SPP Accreditation Methodology

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 adequacy³¹ 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.

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 margins³⁸ (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:

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

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

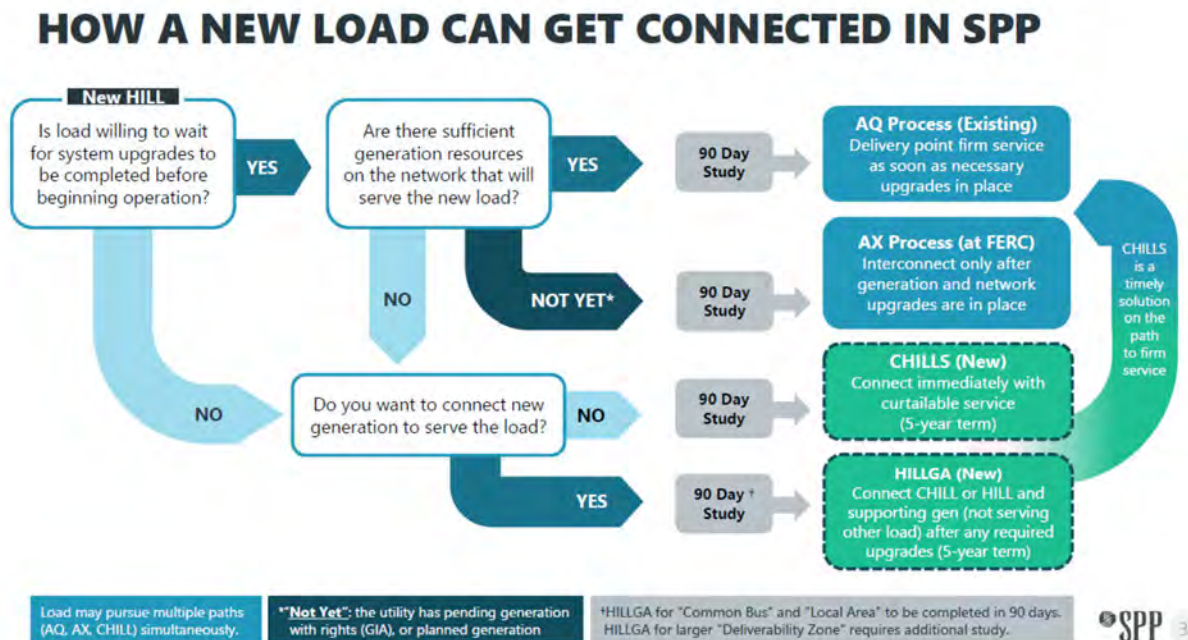
⁴⁶ EA-2023-0291 Kayla Messamore Direct, Page 27, Figure 10.

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.

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

5 *Staff Witness: Michael L. Stahlman*

6 **Integrated Energy Market Issues**

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

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

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

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

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

3 *Staff Witness: J Luebbert*

4 **Load and Resource Diversity Complications**

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

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

20 *Staff Witness: J Luebbert*

21 **Day Ahead and Real Time Imbalances**

22 Every day, as LREs, EMM and EMW must provide forecasts to the SPP of expected energy
23 usage for each hour of the next day. These projected loads are transacted by SPP at the Day Ahead
24 Locational Marginal Price (LMP) for each node. Every day, the SPP reviews the amount of energy
25 actually used in each interval on a given day, and subtracts the forecast from that interval for the
26 actual energy used in that interval. The difference is transacted at the Real Time LMP for each
27 node. While as regulators we see these LMPs as a single Day Ahead (DA) LMP for each interval
28 and a single Real Time (RT) LMP for each interval, the actual bills are written based on the value
29 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.

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

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

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

17 This potential cost was explicitly recognized in the Stipulation and Agreement in
18 Case Number EO-2019-0244,⁵³ relating to EMW's cost of serving a customer on the
19 Special Incremental Load tariff, Schedule SIL.⁵⁴ The Stipulation and Agreement in the
20 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 attributable 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.

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

5 Evergy could request separate SPP settlement locations for customers as large as the
6 expected LLPS customers, allowing for much cleaner tracking and assignment of actual costs
7 incurred to serve each LLPS customer. However, Evergy has not considered such an approach⁵⁶
8 and states that:

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

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

26 *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

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%20methodology%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 Capacity⁶¹ 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.

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 **. **. 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>.

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

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

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

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

25 It is Staff’s understanding that EMW and EMM currently meet the SPP Resource
26 Adequacy requirement on a combined basis and ** [REDACTED]

27 [REDACTED]. ** However, in recent Evergy
28 IRP filings, Evergy has indicated that the excess capacity from its existing resources compared to
29 projected peak demands is dwindling. The 2025 SPP Summer Resource Adequacy Report
30 indicates Evergy Metro (the combination of EMW and Evergy Metro) has approximately 117 MW
31 of excess capacity. Given the size of the customers contemplated by Evergy’s LLPS tariff and

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

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

14 *Staff Witness: J Luebbert*

15 **SPP Market Protocols for Non-Conforming Load**

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

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

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%20methodology%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 **, **, with a demand in excess of 25 kW, **. EMW currently provides service to **, **, with a demand in excess of 25 kW, **. ** 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.” **.

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.”

1 statutory requirement that LLPS rates be set to “reasonably ensure such customers' rates will reflect
2 the customers' representative share of the costs incurred to serve the customers and prevent other
3 customer classes' rates from reflecting any unjust or unreasonable costs arising from service to
4 such customers,”⁷² then it is not reasonable to immediately reduce those rates by 40%, or other
5 customer classes' rates will necessarily reflect unjust and unreasonable costs caused by LLPS
6 customers. This is because the statutory economic development discount – once recognized in a
7 rate case – does not reduce utility revenue. Rather, the revenue not paid by customers receiving a
8 discount is added to the revenue requirement of all customers.

9 Complicating any potential application of the statutory economic development discount to
10 LLPS customers is that Section 393.1640.1(2), RSMo., is also clear that the customer receiving
11 the discount must meet variable costs and provide a contribution to fixed costs, specifying:

12 the cents-per-kilowatt-hour realization resulting from application of any
13 discounted rates as calculated shall be higher than the electrical
14 corporation's variable cost to serve such incremental demand and the
15 applicable discounted rate also shall make a positive contribution to fixed
16 costs associated with service to such incremental demand. If in a
17 subsequent general rate proceeding the commission determines that
18 application of a discounted rate is not adequate to cover the electrical
19 corporation's variable cost to serve the accounts in question and provide a
20 positive contribution to fixed costs then the commission shall increase the
21 rate for those accounts prospectively to the extent necessary to do so.

22 In other words, if the LLPS rate is set appropriately, then a customer's bill is reduced by
23 the economic development discount, the discount would be unreasonably paid for by other
24 customers (in contravention of SB 4), and then in the next case the LLPS rates would be raised to
25 make up for the discount. This result is impractical, unreasonable, illegal, and unnecessary.⁷³

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

30 *Staff Witness: Sarah L.K. Lange*

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]

[REDACTED]

[REDACTED]. ** The second customer, with an aggregate demand of ** [REDACTED] **, demonstrated an overall load factor of ** [REDACTED] **. ** The customer’s usage consisted of ** [REDACTED]

[REDACTED]. **

The third customer has an aggregate demand of ** [REDACTED]

[REDACTED]

[REDACTED]

[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

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 reliably 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.

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.

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

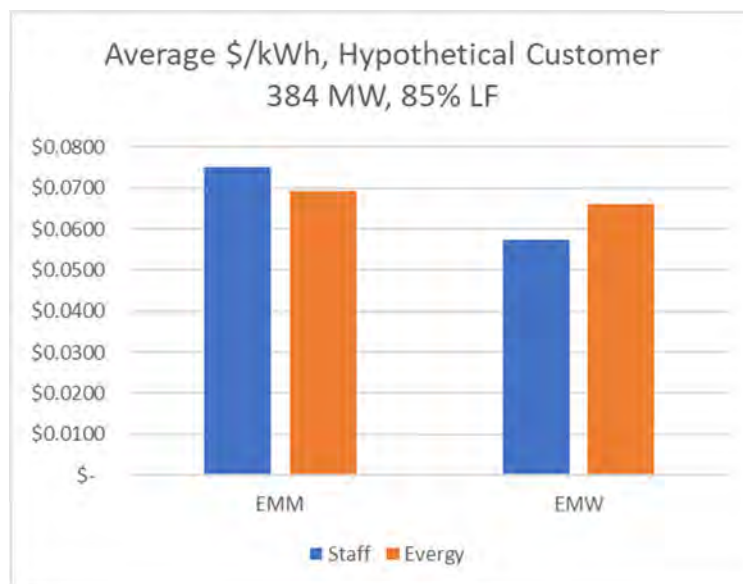
7 As will be discussed in “Charges for Contributions to Fixed Cost Recovery,” under
8 Staff’s recommended structure and design, the LLPS rate will be set to essentially the floor for
9 economic development recipients established by Section 393.1640, RSMo., in that LLPS rates will
10 be set to collect 120% of the cost of service that varies with the addition of a new LLPS customer.
11 The intent of this provision is so that LLPS customers contribute toward the “fixed costs,” within
12 the EMM and EMW revenue requirements. “Fixed cost” is an often used, but not particularly
13 useful, term.⁸⁴ The initial screen for identifying a “fixed cost” would be to consider any revenue
14 requirement component that does not vary directly with changes in the utility’s overall load, overall
15 demand, or overall number of customers to not be “fixed,” with those remaining revenue
16 requirement components – such as computer systems, computer software, office buildings, office
17 furniture, management employees, investor relations costs and expenses, other overheads, and the
18 revenue requirement associated with policy-driven activities, such as solar rebates, electric vehicle
19 charging stations, and supports for low-income rate payers. These revenue requirement
20 components do not relate to the often-referenced utility functions of “production/generation”,
21 “transmission,” or “distribution,” but are to be recovered by the utility from its ratepayers.⁸⁵
22 While analysts will disagree on how to most reasonably recover this revenue requirement in a
23 given case, there is no dispute that all customers will bear some portion of this revenue
24 requirement. Staff’s recommended LLPS rate schedule and design attempts to quantify – based
25 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.”

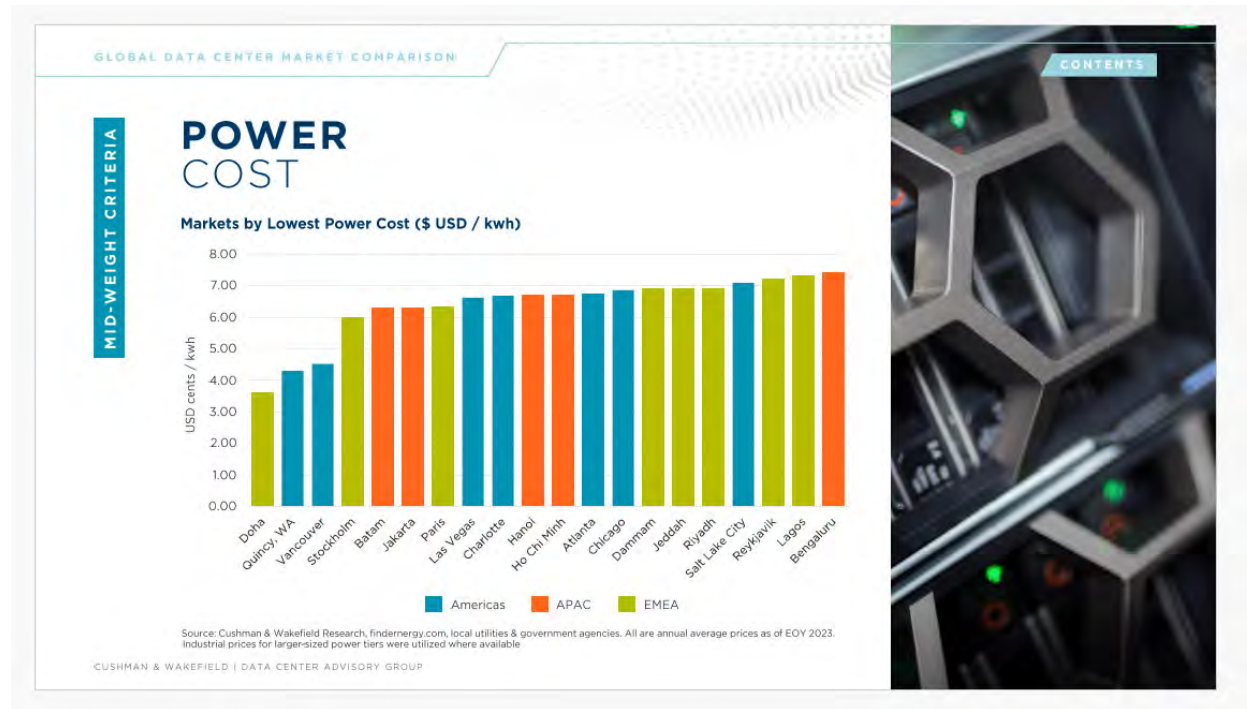
components that will vary due to LLPS customers, and to separately bill for each component. The recommended rate structure then incorporates a charge element to recover 20% of those variable bill charges, so that LLPS customers contribute to the “fixed cost” recovery of the utility.

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 SSR⁸⁶ 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.

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

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

13 Therefore, Staff recommends the Facilities Charge be charged based on the dollar value of
14 customer-specific infrastructure. This value will be specified in the Service Agreement. The rate
15 will be set based on the proportion of those transmission expenses for each utility to that utility's
16 gross transmission plant. Staff does not intend to require individual tracking of these expenses per
17 customer, rather the rates will be set based on the total applicable expenses for all transmission
18 assets, divided by the total transmission plant for each utility, divided by 12.

19 A simple example would be if a utility had \$100,000,000 in transmission assets and the
20 annual property tax, insurance, and O&M expense for those assets was \$10,000,000, then the
21 facilities charge rate would be \$0.0083/\$ of Assets.⁸⁷

22 Under this design, if a new LLPS customer required construction of a \$10,000,000
23 transmission asset, then that customer would be required to pay \$83,333 per month to cover the
24 expenses associated with owning and operating a transmission asset of that value. If a different
25 customer required construction of a \$5,000,000 transmission asset, then that customer would be
26 required to pay \$41,667 per month.

27 Relying on the information provided in Evergy's filing and workpapers in this case, Staff
28 estimates reasonable rates for the Facilities Charge at this time to be \$0.01075 \$/\$ of Assets, and
29 \$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.

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

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

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

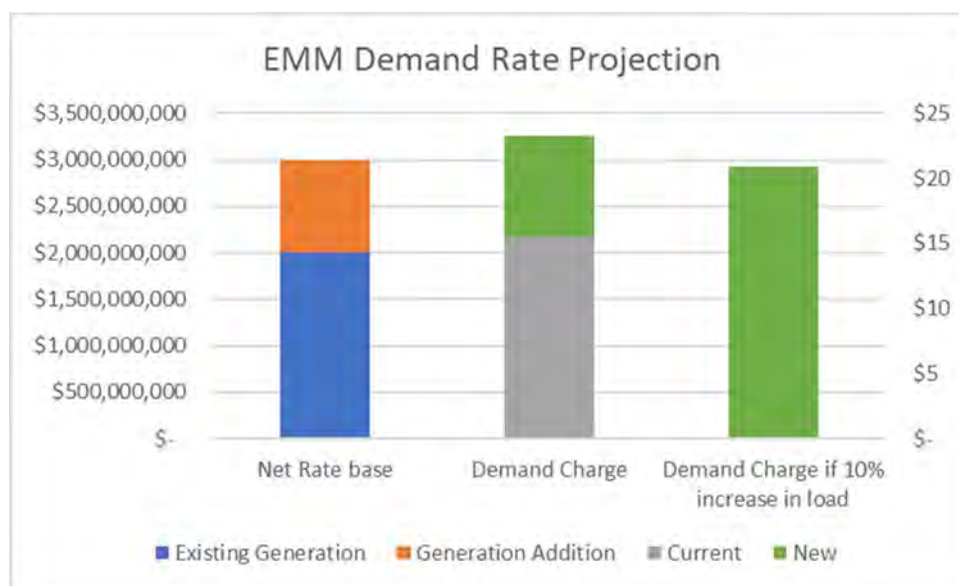
⁹² Staff does not allocate fuel or net market expense to the LLPS class in its demand charge quantification. Staff does recommend that LLPS customers be billed an energy charge based on the wholesale cost of energy to serve LLPS customers.

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.

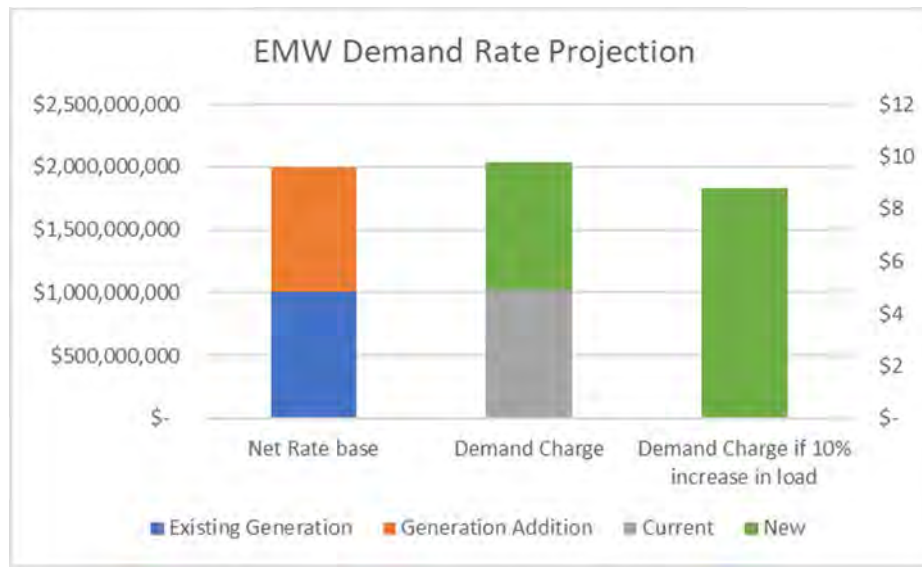
Staff's recommended generation capacity demand rate for EMW is calculated through reliance on the workpaper provided by Evergy, which is held out to be their direct CCOS workpaper from the 2024 rate case. Based on this workpaper, the production cost of service for EMW, excluding fuel and variable labor, 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.

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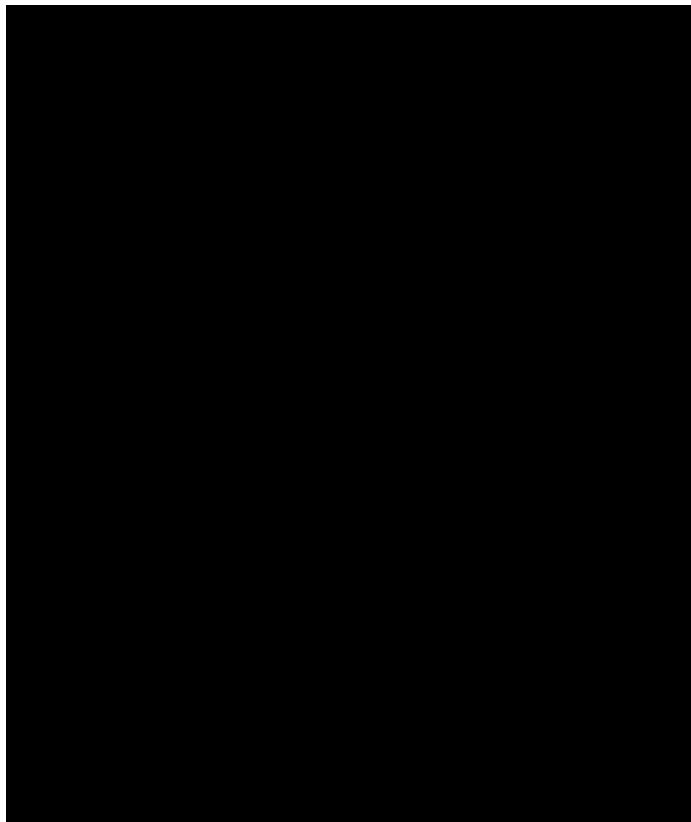
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Based on filings in recent CCN cases, the cost for new CCGT⁹⁶ capacity is over

** [REDACTED] **/kW-month.⁹⁷

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6

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⁹⁶ Combined Cycle Gas Turbines (CCGT).

⁹⁷This 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.

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

5 **Charge for Transmission Capacity Cost of Service**

6 The intent of this charge is to recover the net cost of service for transmission for all
7 customers, including the LLPS customer. While the LLPS customers will each have some level
8 of customer-specific transmission facilities, and will also cause specific transmission expenses,
9 these customers will also rely on the interconnected transmission system and should contribute
10 towards the cost of service associated with building, owning, and operating transmission lines, and
11 with the RTO-related costs of participating in the shared transmission system. Because EMM and
12 EMW build transmission not only to serve its own loads, but also through participation in the
13 RTOs, it is reasonable to offset the Transmission Capacity cost of service by those revenues.
14 In future general rate cases, the LLPS allocation of these costs will ideally be calculated through
15 the CCOS study. Historically, transmission costs, revenues, and expenses have been allocated
16 using the 12 monthly CPs. In this case, Staff bases the initial charge development using the
17 summer utility CP. This results in demand charges of \$3.00 \$/on-peak KW, and \$5.32 \$/on-peak
18 kW for EMM and EMW, respectively.

19 **Energy Charges**

20 Staff recommends time-based energy charges for several reasons:

- 21 1. It most clearly relates revenue responsibility and cost causation.
- 22 2. While Staff's recommended rates are cost-based and are not intended to drive
23 behavioral changes, these rates do not encourage consumption at times when energy
24 costs are high, and do not discourage consumption at times when energy costs are low.
- 25 3. It encourages, but does not require, shifting energy consumption to periods when
26 energy costs are low, and away from periods when energy costs are high. For
27 customers with variable loads related to manufacturing or metallurgy, extensive energy
28 use can be targeted to times with lower rates to the extent the customer chooses. Some
29 customers may find thermal energy storage to be cost-effective.
- 30 4. If an LLPS customer has a perfect load factor, they will not be harmed. If an LLPS
31 customer has usage peaks which coincide with times of low energy prices, they will

1 experience a lower bill than if on a flat rate; and if an LLPS customer has usage peaks
2 which coincide with times of high energy prices, they will experience a higher bill than
3 if on a flat rate.

4 5. Times of high energy prices generally coincide with times of high generation and
5 transmission demand. Times of low energy prices generally coincide with times of
6 system under-utilization.

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

13 **SPP Nodal Pricing**

14 Every kWh of energy that EMM or EMW sells to any retail customer must be purchased
15 through the SPP integrated marketplace (IM).⁹⁸ Every additional kWh of load results in an overall
16 increase in purchased power expense net of revenues.⁹⁹ Every kWh of energy required by an LLPS
17 customer will cause the respective utility, EMM or EMW, to purchase an additional kWh of energy
18 through the IM in the interval in which it is needed, at the price of the LMP at the interconnection
19 node.¹⁰⁰ If a transmission constraint exists between the node at which energy is required and the
20 nodes at which the lowest-priced energy could be generated, then the price of energy at the
21 interconnecting load node will be increased to account for redispatch of energy at a location that
22 can serve the load despite the transmission constraint.

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 $\$7,000 / 150 = \$46.67/\text{MWh}$.

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%	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%	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%	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%	94%	100%	90%	87%	87%	87%	87%	89%	94%	97%	97%	95%	84%	61%	46%
2024 Summer	31%	30%	26%	23%	22%	24%	28%	30%	37%	47%	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%	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%	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%	79%	86%	81%	74%	74%	80%	83%	88%	97%	100%	91%	76%	62%	53%	43%

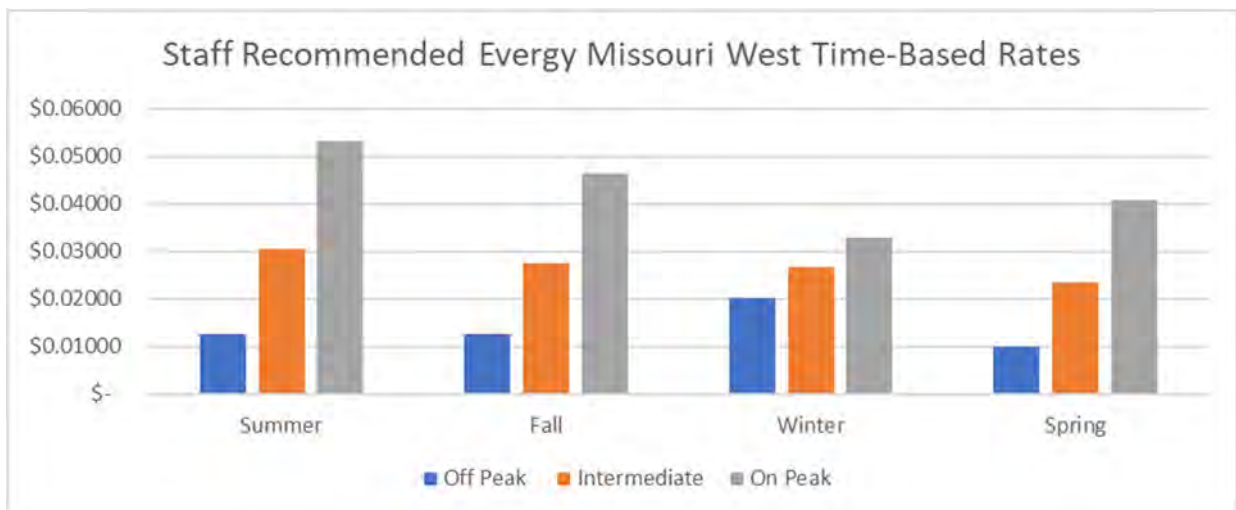
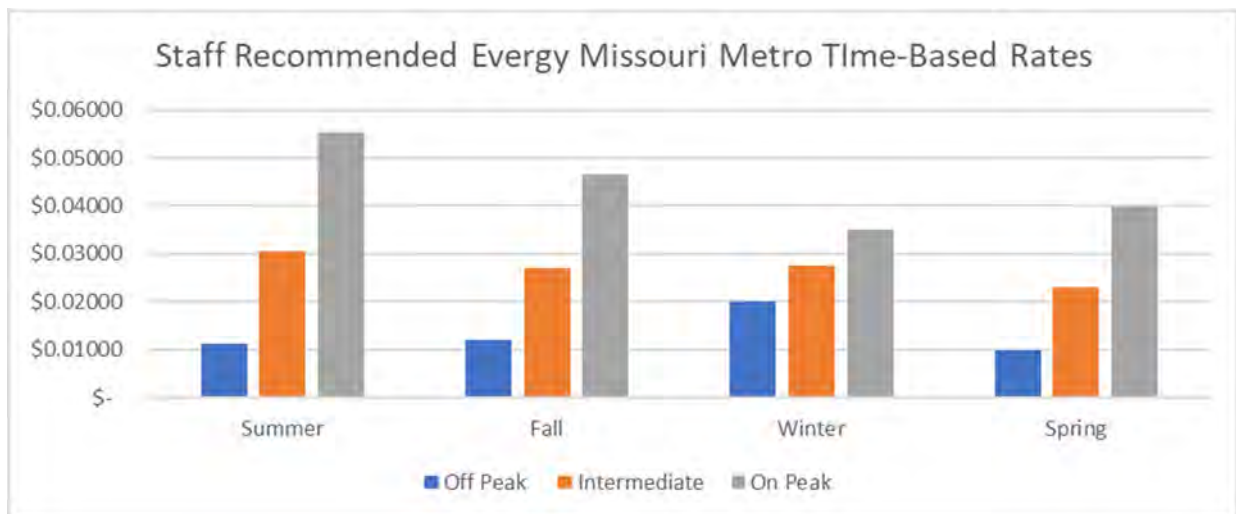
EMW Review	Hour:	Midnight	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM
2024 Winter	50%	54%	51%	50%	51%	56%	71%	94%	96%	96%	96%	100%	92%	81%	73%	67%	64%	65%	77%	97%	87%	79%	77%	70%	59%
2023 Winter	38%	40%	38%	38%	41%	49%	64%	85%	93%	89%	86%	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%	83%	84%	88%	89%	93%	96%	100%	97%	97%	87%	60%	51%
2023 Spring	30%	28%	25%	24%	28%	37%	52%	67%	79%	93%	100%	90%	87%	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%	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%	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%	75%	84%	96%	100%	84%	61%	50%	40%	30%
2023 Fall	31%	30%	27%	25%	30%	32%	43%	60%	68%	77%	85%	78%	73%	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:

Period	Metro				Missouri West			
	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

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

3 Staff’s recommended structure includes two charges so that the LLPS rate will be set to
4 essentially the floor for economic development discount recipients established by Section
5 393.1640 RSMo., and so that, with appropriate accounting treatments, these rate schedules will
6 reasonably ensure LLPS customers rates will reflect the customers' representative share of the
7 costs incurred to serve the customers and prevent other customer classes' rates from reflecting any
8 unjust or unreasonable costs arising from service to LLPS customers. To account for income tax,
9 based on Evergy’s workpapers submitted in this case, the bill components will actually need to be
10 multiplied by 24.77% to accomplish a 20% contribution to “fixed costs.”

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

17 The Stable Fixed Revenue Contribution Charge will be applied to only the Demand Charge
18 amounts. This charge calculation varies in that it recovers for the greater of actual demand in a
19 month or contracted demand for that month. Specifically, the Stable Fixed Revenue Contribution
20 Charge applies to the greater of the rate for the Generation Capacity Charge rate multiplied by the
21 updated contract demand for the month OR the actual charge calculated for the Generation
22 Capacity Charge, and to the greater of the rate for the Transmission Capacity Charge rate
23 multiplied by the updated contract demand for the month OR the actual charge calculated for the
24 Transmission Capacity Charge.

25 **Other Demand-Related Charges**

26 As explained in the recommended tariff language in the section “Long and Mid-term
27 Forecasts,” Staff recommends that in the event that EMM or EMW requires capacity arrangements
28 to serve LLPS load, it should seek to expeditiously promulgate a tariff so that those additional
29 expenses can be appropriately recovered from the LLPS customer causing the need for additional
30 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.

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

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

8 *Staff Witness: J Luebbert*

9 **Additional Staff-Recommended Tariff Provisions and Regulatory Treatments**

10 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.

11
12 Staff also recommends that the tariff address Revenue Treatment, Termination Charges,
13 and specific provisions to provide some rate mitigation to captive ratepayers. The effects of
14 positive and negative regulatory lag must be considered in establishing rates that will reasonably
15 ensure LLPS customers rates will reflect the customers' representative share of the costs incurred
16 to serve the customers and prevent other customer classes' rates from reflecting any unjust or
17 unreasonable costs arising from service to LLPS customers.¹⁰⁴ It is essential that the Commission
18 use reasonable requirements and regulatory treatments as outlined below to mitigate the risks of
19 unreasonable rate increases to non-LLPS customers caused by EMM's and EMW's managerial
20 decisions related to LLPS customers.

21 The recommended revenue treatments, termination charges, and risk mitigation strategies
22 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.

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

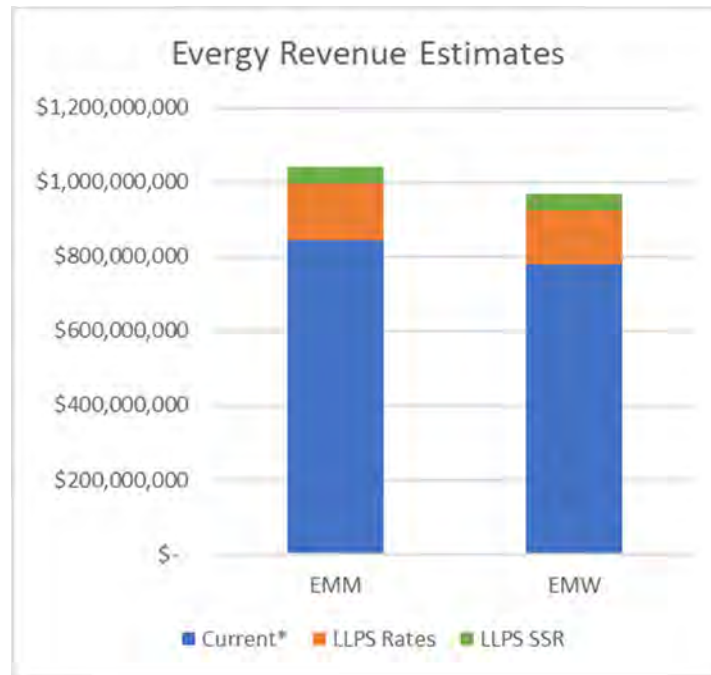
5 **Regulatory Lag Considerations**

6 Due to the inherent lag between when an LLPS customer begins paying its bills, and when
7 that revenue is recognized in a rate case, EMM and EMW will experience positive regulatory lag.
8 This lag is different than ordinary positive lag associated with customer growth for the following
9 reasons:

- 10 1. Scale,
- 11 2. Lack of offsetting revenue requirement increases,
- 12 3. The statutory requirement that LLPS customers rates will reflect the customers'
13 representative share of the costs incurred to serve the customers and prevent other
14 customer classes' rates from reflecting any unjust or unreasonable costs arising from
15 service to LLPS customers cannot be effectuated until those revenues are realized
16 in a rate case to the benefit of other customers, and
- 17 4. While Staff does not recommend approval of Evergy's requested riders, revenues
18 under those riders compound these problems. These concerns will be detailed in
19 Staff's discussion of those requested riders.

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

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3 It is the prerogative of Evergy management to time rate cases to maximize shareholder
4 benefit. With ordinary customer growth, offsetting increases to revenue requirement would negate
5 some of the positive benefits of regulatory lag to shareholders. However, LLPS customer growth
6 will be offset by increases in revenue requirement to a much smaller extent than normal customer
7 growth.

8 When a new home or business begins taking service, not only is the scale of revenue growth
9 much smaller than will be the case for an LLPS customer, but also there are more offsetting
10 increases to revenue requirement. For an LLPS customer, EMM and EMW will not be paying for
11 some or all of the costs to install a meter, a service line, or a line transformer. Nor will EMM or
12 EMW be paying for the accumulated need to expand distribution systems or substations to serve
13 customers collectively with the addition of an LLPS customer. Rather, the LLPS customer will be
14 prepaying for its transmission interconnection, its meter, and any infrastructure in between. This
15 required customer contribution is reasonable and appropriate, but it also distinguishes LLPS
16 growth from ordinary customer growth.¹⁰⁵

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

1 It is Staff's understanding that, presently, EMM and EMW lack sufficient capacity to serve
2 new LLPS customers within the parameters of SPP resource adequacy requirements. This means
3 additional capacity must be obtained. This additional capacity may be built, acquired through a
4 contract for a specific asset, or acquired through other contractual arrangements.¹⁰⁶ If the capacity
5 is built, it is unlikely that there would be a timing scenario where a rate case would capture the
6 increased revenues from a new LLPS customer prior to capturing the increased revenue
7 requirement associated with the new generation asset. This is, first, because that timing would be
8 unlikely to be chosen by Evergy, that can control the pace of construction activities and have
9 discretion in the timing of customer additions; and second, for the practical reason that if EMM or
10 EMW need to build additional capacity to serve the full load of an LLPS customer, then EMM and
11 EMW will not be serving that LLPS customer at full load until that capacity addition is up and
12 running unless some other arrangement is in place or unless SPP penalties are incurred.

13 If EMM or EMW were to make a contractual arrangement of more than 1 year for capacity
14 to enable service of an LLPS customer while constructing a new generation asset, then the utility
15 may be shielded from negative regulatory lag associated with that asset. EMM and EMW are
16 substantially shielded from negative regulatory lag associated with construction of renewable
17 generation (unless that rate-base addition increases revenues by allowing service to new customer
18 premises) under the provisions of Section 393.1400, RSMo., related to Plant in Service Accounting
19 (PISA). Recently enacted SB 4 allows the same protection from negative regulatory lag for new
20 natural gas generation units, effective August 28, 2025.

21 It is important to note that EMM and EMW are each recovering the full cost of owning and
22 operating their generation fleets from existing customers, as of the conclusion of each of their last
23 rate cases. If a new LLPS customer begins paying for the generation fleet – as they should – then
24 EMM and EMW will over-recover that amount. As a very simple example, consider four friends
25 who decide to buy a \$20.00 pizza. Each of the four hands \$5 to the cashier. Just then a fifth friend
26 walks in and joins them. Should this newcomer also give the cashier \$5? Or should the newcomer
27 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.

1 who would be pleased to accept a \$5.00 gratuity on that \$20.00 pizza. As described below,
2 reasonable accounting authority should be ordered to ensure a fair outcome for the existing rate
3 payers, and to avoid unreasonable accumulation of positive regulatory lag to the benefit of Evergy
4 shareholders.

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

10 **FAC Operation**

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

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

24 Staff has reviewed the effect of the Evergy hypothetical LLPS customer on the FAC, and
25 prepared two examples for each utility, one reflecting that additional wholesale energy expense to
26 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%

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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		EMW \$25	EMW \$30
Annual Expense	\$ 71,481,600	\$ 85,777,920	Annual Expense	\$ 71,481,600	\$ 85,777,920
FAC Recovery	\$ (18,226,378)	\$ (31,807,882)	Total FAC Recovery	\$ (5,188,135)	\$ (18,769,639)
LLPS Rate Revenue	\$ (153,720,516)	\$ (153,720,516)	LLPS Rate Revenue	\$ (144,207,496)	\$ (144,207,496)
Net Revenue no SSR	\$ (100,465,294)	\$ (99,750,478)	Net Revenue no SSR	\$ (77,914,030)	\$ (77,199,214)
LLPS SSR Revenue	\$ (44,190,720)	\$ (44,190,720)	LLPS SSR Revenue	\$ (44,421,120)	\$ (44,421,120)
Net Revenue with SSR	\$ (144,656,014)	\$ (143,941,198)	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).

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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.

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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

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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.

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

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

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

19 INTERIM CAPACITY

20 If the Customer’s load cannot be served by the Company’s existing
21 system capabilities the Company may enter into specific market contract
22 agreements to provide the necessary capacity requirements of the Customer
23 until sufficient system capacity may be supplied by the Company. The
24 Customer and the Company must mutually agree on the terms for the
25 interim capacity. The Customer shall be subject to an additional demand
26 charge calculated according to these terms.¹¹²

27 [Under Termination provisions:]

28 If the Customer is receiving any Interim Capacity at the time of
29 written notice, the Company and Customer shall take steps to repurpose the
30 related capacity contract(s) prior to termination of service under this
31 schedule. If the Interim Capacity cannot be repurposed, the Customer will
32 be responsible for all costs associated with termination of the capacity
33 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)
 - o CER Charge: contribution to work in progress
- Schedule RENEW (Renewable Energy Program Rider)
 - o Renewable Energy Charge: ordinary revenue, will be included in FAC as an offset to costs
- Schedule AEC (Alternative Energy Credit Rider)
 - o AEC Charge: ordinary revenue, will be included in FAC as an offset to costs
- Schedule GSR (Green Solution Connections Rider)
 - o 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.

1 address these cross-subsidization concerns, we have designed the System
2 Support Rider. Specifically, Schedule SR will help mitigate potential
3 cross-subsidization by contributing amounts to existing non-Schedule
4 LLPS customers. The amounts charged under the schedule will address the
5 acceleration of costs caused by new large loads, such as the accelerated
6 development of new generation projects and increased transmission
7 congestion that may be attributable to these new large loads.

8 Q: How does the Company propose to determine this cost
9 acceleration?

10 A: The Company has established a scenario-based approach where
11 it will determine net present value revenue requirements tied to a
12 representative 700 MW CCGT that is constructed 10 years sooner than
13 otherwise would have occurred under normal planned growth and its costs
14 recovered over a 30-year period. In a sense, we are seeking to isolate a time
15 value of money element of the cost.

16 Staff does not recommend approval of the System Support Rider, as discussed below.
17 However, Evergy's planned approach to benefit from the initial positive regulatory lag of
18 System Support Rider revenues unreasonably bills LLPS customers for the benefit of Evergy
19 shareholders, and without benefit to non-LLPS ratepayers. Based on the examples Evergy has
20 provided, Evergy calculates that adding an LLPS customer will cause excessive increases to the
21 revenue requirement of other ratepayers for \$44 million per year, for 15 years, approximately
22 \$660 million dollars. Yet Evergy will retain roughly \$177 million (26%) of that revenue when
23 received from the hypothetical LLPS customer through positive regulatory lag under the revenue
24 treatment it describes in its data request responses.

25 EMM and EMW request a "Capacity Reduction Fee." Under requested treatment, if an
26 LLPS customer substantially reduces its monthly demand, the LLPS customer must prepay the
27 difference between its actual bill and the minimum bill that would have been due for the remainder
28 of its contract – essentially a partial termination fee. In response to Staff's data requests, Evergy
29 indicated its intent would be to treat those revenues as ordinary revenue, unless the Commission
30 orders a contrary provision be included in the tariffs in this case.¹¹⁷ This means that unless the
31 receipt of those revenues happened to fall in the test period of a rate case, they would be retained
32 by Evergy and not offset the revenue shortfall that will be caused in future years due to the change
33 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

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.

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

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

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

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

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

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

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.

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

3 *Staff Witness: Sarah L.K. Lange*

4 **Risk Allocation**

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

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

22 As discussed above, the Commission should expect EMM and EMW to leverage the
23 positive regulatory lag of LLPS customers -- with little to no offset to increased cost of service due
24 to tools enacted to mitigate negative regulatory lag -- to cause EMM and EMW to delay rate cases
25 recognizing new LLPS customers. Given the risks of LLPS customers ceasing service, it is
26 possible that an LLPS customer could come and go with essentially all revenues from that
27 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.

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

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

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

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

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

21 *Staff Witness: Sarah L.K. Lange*

22 **Rate Structure and Design**

23 The Interim Capacity Charge is an integral feature to support Evergy's assertions that
24 additions of LLPS customers will spread the fixed costs of utility service in that, as it was described
25 in the testimony of Mr. Lutz at pages 17-18, it is the stopgap to cover utility expenses that would
26 not be incurred but-for the LLPS customer's demand requirements and timing requirements.
27 While Evergy requests that the extent of any such shortfall, the cost of capacity to address the
28 shortfall, and the rate recovery related to the shortfall be contained in a customer agreement, Staff's
29 recommended tariff includes provisions for an expedited tariff promulgation to give the
30 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 it 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 IRP¹²⁶ 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."

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

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

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

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

20 ...Evergy Metro has included an updated load ramp for a new large load
21 customer profile in its base load forecast for its IRP.

22
23 In recent months, the customer completed Evergy’s internal review process
24 that allows the Company to complete due diligence on large load customer
25 requests, sets forth numerous data points to vet the feasibility of the
26 customer locating in Evergy’s service territory, and requires a sizeable
27 deposit to support analysis to study the viability of the customer’s project.
28 In January 2025, Evergy submitted an Attachment AQ study to the SPP to
29 study the transmission upgrade requirements of the incremental new large
30 load. Additionally, Evergy Metro and the new large load customer continue
31 to progress with negotiations and expect to have Construction and Service
32 Agreements fully executed in the second quarter of 2025 with an expected
33 project announcement in the second half of 2025.
34

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.

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

5 Evergy further states that:

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

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

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

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

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.

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

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

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

15 Evergy’s response to Data Request 62 stated:

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

21 According to a Utility Dive article, Google and NV Energy requested “permission to enter
22 into a power supply agreement based on the ‘Clean Transition Tariff’ that would allow large
23 energy users to pay a premium for 24/7 clean energy from new resources.”¹³⁷ “Under the power
24 supply agreement, NV Energy would buy electricity from Fervo Energy’s 115 MW Corsac Station
25 Enhanced Geothermal Project, and sell it to Google for a set rate. Google would receive credit for
26 the project’s energy and generation capacity on electric bills for its data centers in Storey County,
27 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.*

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

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

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

- 23 1) What happens if a customer terminates service before the cost differential
24 is fully paid, then challenges the outstanding cost differential?
25

26 Response: The sponsoring Customer enters into an agreement with the
27 Company that will detail the terms of participation. There will be a clear
28 expectation of full payment, even if the Customer terminates service.
29

- 30 2) What are the Company’s plan(s) to pursue collection of an outstanding cost
31 differential from a customer?
32

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 paid?

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.

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

8 Q: What will occur with respect to the renewable attributes associated with
9 any renewable resources procured as part of a Clean Energy Preferred
10 Resource Plan approved under the Clean Energy Choice Rider?

11 A: The Company will retire the renewable attributes on behalf of the
12 customer, up to an amount equal to the requesting customer's annual energy
13 usage.

14 Further, the Evergy's responses to Data Request 63 subparts 5) and 7) reference a
15 Certificate of Convenience and Necessity ("CCN"). Along with the IRP process change due to
16 SB 4, the CCN process for certain resources will be changing as well. For example,
17 393.1900.5.(1), RSMo states in part, that:

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

32 The new IRP process is very likely to be contentious with the Commission now having the
33 authority to determine that an electric utility's preferred resource plan is reasonable and prudent
34 and grant permission to the utility to construct or acquire specified resources. That contentiousness
35 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

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.”

1 rates by 40%, or other customer classes' rates will necessarily reflect unjust and unreasonable costs
2 caused by LLPS customers. This is because the statutory economic development discount – once
3 recognized in a rate case – does not reduce utility revenue. Rather, the revenue not paid by
4 customers receiving the economic development discount is added to the revenue requirement of
5 all other customers.

6 Complicating any potential application of the statutory economic development discount to
7 LLPS customers is that Section 393.1640 is also clear that the customer receiving the discount
8 must meet variable costs and provide a contribution to fixed costs, specifying as follows:

9 [T]he cents-per-kilowatt-hour realization resulting from application of any
10 discounted rates as calculated shall be higher than the electrical
11 corporation's variable cost to serve such incremental demand and the
12 applicable discounted rate also shall make a positive contribution to fixed
13 costs associated with service to such incremental demand. If in a
14 subsequent general rate proceeding the commission determines that
15 application of a discounted rate is not adequate to cover the electrical
16 corporation's variable cost to serve the accounts in question and provide a
17 positive contribution to fixed costs then the commission shall increase the
18 rate for those accounts prospectively to the extent necessary to do so.

19 In other words, if the LLPS rate is set appropriately, then a customer's bill is reduced by
20 the economic development discount, the discount would be unreasonably paid for by other
21 customers (in contravention of SB 4), and then in the next case the LLPS rates would be raised to
22 make up for the discount. Meanwhile, the System Support Rider revenues would be billed and
23 attributed to the LLPS customers in a class cost of service study. This result is impractical,
24 unreasonable, illegal, and unnecessary.

25 *Staff Witness: Sarah L.K. Lange*

26 **Acceleration Component of SSR**

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

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

12 Evergy proposes that the Acceleration Component of the rider last for a term at least
13 15 years for a given customer, after which a customer can request this component of the rider's
14 charge to be terminated, under specific circumstances:

- 15 • If the customer is able to supply over 80% of its requested capacity through the
16 Customer Capacity Rider. As long as Evergy "does not identify other rate design
17 concerns with doing so."¹⁴⁹ The SSR is unclear as to whether or not the LLPS
18 customer must wait until the end of the initial 15 year term to request termination of
19 this charge using this method.¹⁵⁰
- 20 • If their annual peak demand has not increased by more than 5% annually over the
21 previous five years, except that if the customer increases their demand by more than
22 20% or 20 megawatts after the Acceleration Component has been terminated, a new
23 term of 15 years shall begin when this component is applied.

24 If EMM or EMW build a power plant to serve an LLPS customer, and that customer
25 participates in the Customer Capacity Rider to eliminate 80% or more of its capacity requirements
26 through EMM or EMW, then the problem that Evergy asserts the Acceleration Component is
27 designed to address has been made worse, not better. Namely, the problem is not only that the
28 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.

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

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

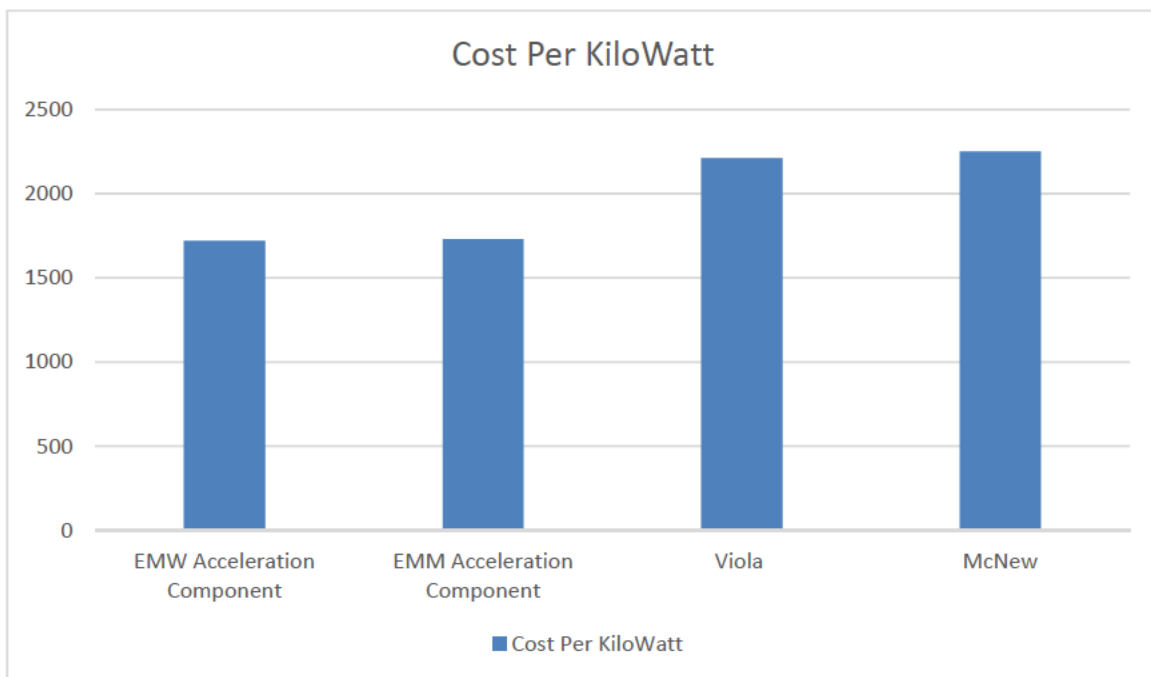
13 Regarding the ability of a customer to request termination at the conclusion of the 15-year
14 term, Staff appreciates that the likely intent of this provision is acknowledgement that the term of
15 service under the LLPS tariff is 15 years. However, if the intent of the Acceleration Component
16 is to reflect the changes in revenue requirement associated with building a theoretical power plant
17 10 years sooner than would otherwise be applicable, then the charge should effectuate the full
18 difference in revenue requirement recovery over the life of that theoretical power plant.

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

28 Staff is also concerned with the calculation of the Acceleration Component rate. Within the
29 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 **.
 **. ** 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 percent¹⁵⁴ 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.

1 Evergy asserts that the Acceleration Component is not designed to reimburse Evergy for
2 the cost to construct a generating facility. According to Evergy, ** [REDACTED]

3 [REDACTED]
4 [REDACTED] **155

5 However, all customers will still have to contribute towards the cost to construct and operate the
6 generation unit over the life of that unit, just not Evergy's calculated cost of constructing the unit
7 earlier than planned.

8 *Staff Witness: Brodrick Niemeier*

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

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

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

26 The additional cost of service caused by building a power plant sooner than it would
27 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.

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

4 *Staff Witness: Sarah L.K. Lange*

5 **Demand Response and Local Generation Rider**

6 As described below, Staff recommends rejection of the Demand Response & Local
7 Generation Rider (“DRLR”).

8 **Demand Response Issues**

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

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

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

23 Earnings Opportunity Fee

24 Evergy is proposing a demand response earning opportunity fee. This is described on page
25 39 of Mr. Lutz’s direct testimony as a “fee to recover any foregone earnings from demand response
26 realized capacity reduction and an administrative charge to support the delivery and
27 implementation of the Schedule DRLR program.”¹⁵⁷ Staff’s position is that an earnings
28 opportunity should not be considered because the only reason earnings opportunities are permitted

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

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

3 No Penalty for Non-Performance

4 According to Evergy's response to Data Request 97, there is no penalty for
5 non-performance by a customer when an event¹⁵⁸ is called; more particularly, Evergy responded
6 that "Participants do not receive incentive compensation or penalties if they fail to participate."

7 Staff is apprehensive about having no penalty for non-participation when Evergy is
8 viewing this curtailment as a resource. These are potentially larger curtailments than what is
9 in the current demand response programs for Evergy Metro¹⁵⁹ and Evergy West.¹⁶⁰ For this
10 reason, Staff recommends that there be some sort of penalty for non-participation if this type of
11 program is approved. More specifically, if the Commission approves the DRLR program, then
12 Staff recommends that some type of penalty structure should be required to make sure the
13 participant is participating for the full event call time. An example of a penalty structure could be
14 100% incentive for participating 100% of the event, 75% incentive for 75% event participation
15 and so on. This penalty structure, combined with a removal after a certain number time of
16 non-participation (opt outs), seems reasonable if Evergy plans to rely on the curtailment as a
17 resource during peak hours.

18 Potential Participant Interest

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

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.

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

3 Anticipated administrative costs would include incremental expenses
4 associated with delivering the DRLR program to enrolled participants.

5 An administration fee has been included within the DRLR tariff and is
6 stated as:

7 *A fixed charge shall be recovered for all costs [from the participating*
8 *customer] associated with Program delivery,*
9 *implementation/management, and evaluation, which shall be recovered*
10 *based on a forecasted estimate and trued up annually based on actual*
11 *Program expenditures for the recovery period.*

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

16 Examples of Similar Programs

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

26 Affordability

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

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>.

1 affordability of service. Incentive¹⁶² and Administrative costs¹⁶³ from this new DRLR Tariff
2 will be one more item requested to be put into base rates in Evergy's next general rate case.
3 For example, Evergy provided the following in response to Data Request 48.1:

4 Q: Please provide where and how the additional revenue requirement will
5 be generated in order to provide the incentives for the proposed DRLR; if it
6 is not through additional revenue requirement, please explain. Which rate
7 class(es) will costs be allocated to for the Company to recover these
8 incentive costs?
9

10 A: Recovery of costs associated with the Schedule DRLR rider would occur
11 as part of a future rate case where these costs would be included in the
12 determination of a jurisdictional revenue requirement. These costs would
13 be recovered from all rate classes.

14 *Staff Witness: Jordon T. Hull*

15 **Local Generation Issues**

16 Staff recommends rejection of the DRLR. Evergy proposes that an LLPS customer may
17 participate in the DRLR through on-site generation. The tariff does not define the type of on-site
18 generation, so Staff assumes it could be renewables such as wind or solar, a diesel generator, or
19 battery storage. The DRLR fails to include requirements similar to the Parallel Generation Service
20 Tariff¹⁶⁴ and safety language, equipment and interconnection cost language, and system
21 emergency language similar to that which exists in the cogeneration rule. Evergy has not provided
22 evidence that the DRLR provides a reasonable trade off of revenue and capacity requirements as
23 it effects the overall revenue requirement of EMM or EMW. Thus, this proposal is not consistent
24 with Section 393.130.7, RSMo., to be effective August 28, 2025, enacted pursuant to SB 4.

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

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.

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

8 EMM and EMW do offer the Parallel Generation Contract Service Rider. Under this Rider
9 if a customer has a generator, they can opt to supply Evergy with electricity at a current rate of
10 \$0.0190/kWh for EMM and \$0.0198/kWh for EMW, although this option is limited to generators
11 of 100kW or less. It may be reasonable to increase this limit in a future case, or to otherwise create
12 reasonable tariff provisions to accommodate customers who may collocate their own generation,
13 while not unreasonably shifting cost recovery to captive ratepayers. The current Standby Rider
14 rates are inadequate for addressing the potential demand requirements for a customer of this
15 magnitude in a manner that adequately complies with the requirements of SB 4.

16 *Staff Witness: Brodrick Niemeier*

17 **Revenue Treatment Issues**

18 Evergy proposes to credit participating customers a maximum of \$54 per year for every
19 kilowatt that can be curtailed upon request.¹⁶⁵ EMM's proposed demand charge is \$14 per kW per
20 summer month, and \$12 per kW per non-summer month. EMW's proposed demand charge is
21 \$10 per kW per summer month, and \$8 per kW per non-summer month. On an annual basis,
22 an EMM customer could avoid approximately 36% of the otherwise-applicable demand charge
23 revenue, and an EMW customer could avoid approximately 52% of the otherwise-applicable
24 demand charge revenue for each kW of participation in the Local Generation option of
25 the DRLR.¹⁶⁶

26 *Staff Witness: Sarah L.K. Lange*

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, where that generation is 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 prudence 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.

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

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

13 *Staff Witness: Brodrick Niemeier*

14 **Resource Adequacy Concerns**

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

22 *Staff Witness: Brodrick Niemeier*

23 **Resource Planning Concerns**

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

31 *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 RECs¹⁷⁰ 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.

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

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

7 Renewable Energy Charge = REC Charge + Administrative Charge¹⁷⁵

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

10 Discussion

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

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

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

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.

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

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

13 In its review Staff asked Evergy if it had performed any market research or
14 polling among its customers to gauge interest, need, and preference regarding the four
15 renewable/carbon-free programs discussed in the Direct Testimony of Bradley D. Lutz¹⁸⁰.
16 Evergy stated, ** [REDACTED]

17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED] **

23 Recommendations

24 RENEW is a program that would sell Evergy’s excess RECs from resources that it already
25 owns or for which it is contracted. Staff’s position is that Evergy should sell excess RECs rather
26 than letting them expire. Although Evergy has not done a full cost analysis of this program,¹⁸¹
27 the proposed price of \$2.65 is in line with its average sale prices since 2022. However, due to
28 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

Program Description

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

1 attributes of **. [REDACTED] **. ¹⁸²

2 This Rider is specific to EMM customers¹⁸³ receiving permanent electric service from EMM
3 through Schedules SGS, MGS, LGS, LPS, SGA, MGA, LGA, PGA, MKT, or LLPS.¹⁸⁴ Evergy
4 has proposed that customers may subscribe to the percentage of the renewable asset output (kW)
5 needed to match up to 100% (in single percentages) of the customer's eligible annual usage¹⁸⁵ to
6 align with the renewable asset's estimated annual generation.

7 Under the proposed program, customers will subscribe to **. [REDACTED]

8 [REDACTED] **. ¹⁸⁶

9 Discussion

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

18 Recommendations

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

22 *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

Program Description

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

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 AECs¹⁹⁵ 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]

[REDACTED]¹⁹⁶ [REDACTED]

[REDACTED]

[REDACTED]

[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

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.

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>.

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

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

13 *Staff Witness: Sarah L.K. Lange*

14 **Emergency Energy Conservation Plan**

15 The North American Electric Reliability Corporation (NERC) established a Large Load
16 Task Force (LLTF). The purpose of the LLTF is to "better understand the reliability impact(s) of
17 emerging large loads... and their impact on the bulk power system".²⁰² As the Commission is
18 aware, there are many challenges that the electric industry is facing. As NERC²⁰³ notes:

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

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

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-1²⁰⁷

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 outlines²⁰⁸ 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

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 organization²¹¹ 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.

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

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

11 Recommendations

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

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

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

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

32 *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.

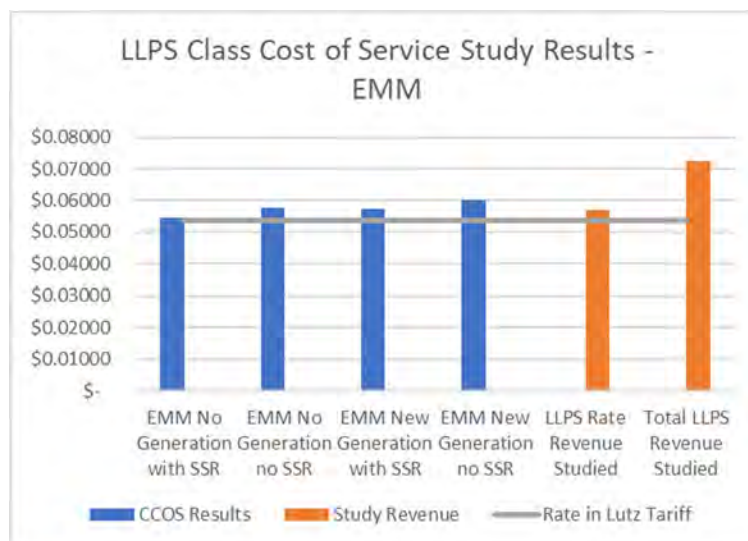
²¹⁴ Evergy provided no support for this coincidence factor, and it is not facially reasonable. It would be most reasonable to assume a 100% coincidence factor for any use case where a stable load exists, or where a stable load and a weather-sensitive load contribute to total demand.

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.

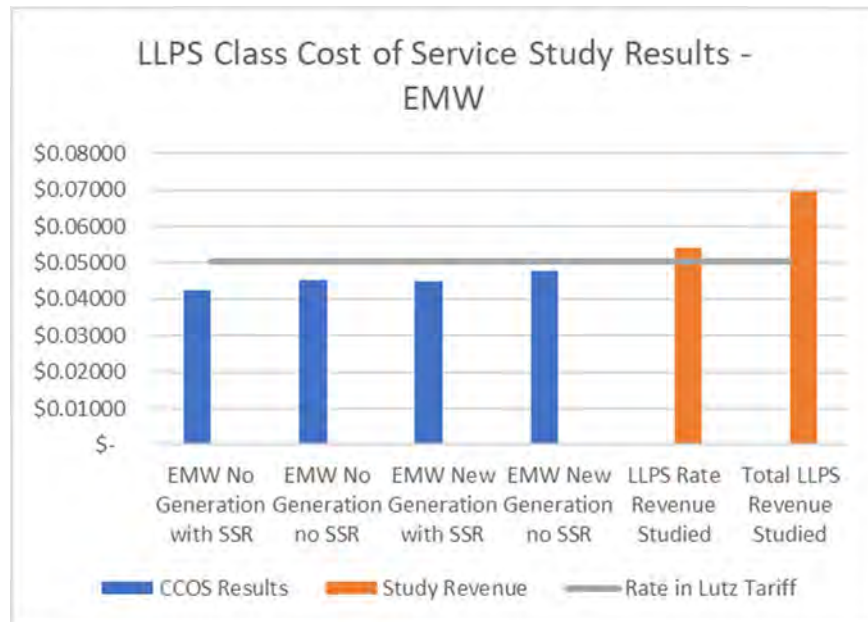
A summary of Staff's review of the EMM CCOS Studies, addressing these considerations, is provided below:



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

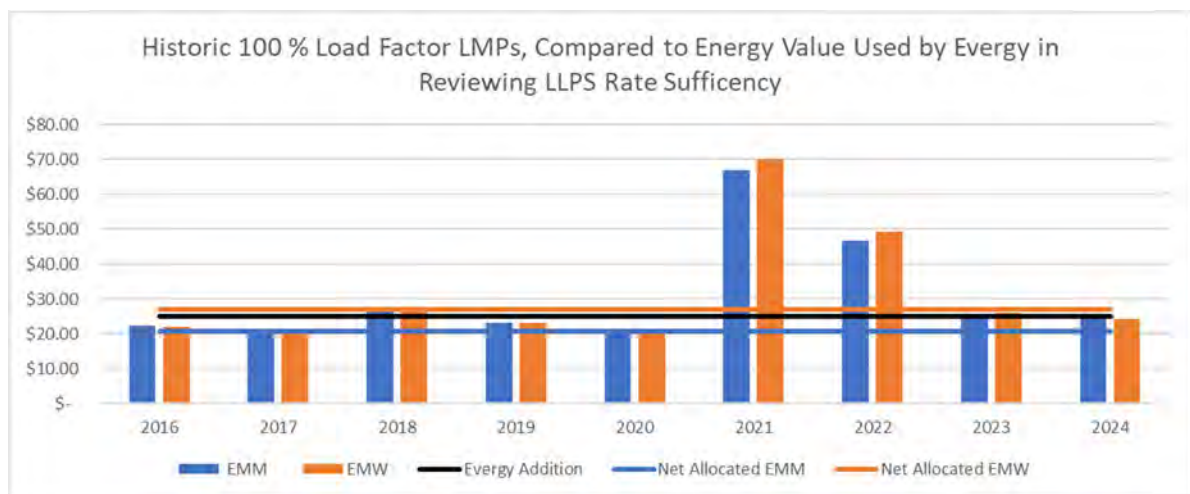
The new LLPS customer's allocated cost of energy is only 2.09 cents per kWh in the EMM version of the modeling, and 2.69 cents per kWh in the EMW version, due to:

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:



1 ** [REDACTED]

2 [REDACTED]

3 [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10

1 [REDACTED]

2 [REDACTED] **

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

6 ** [REDACTED]

7 [REDACTED]

8 [REDACTED]

9 [REDACTED]

10 [REDACTED]

11 [REDACTED]

12 [REDACTED]

13 [REDACTED]

14 [REDACTED]

15 [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 [REDACTED]

20 [REDACTED]

21 [REDACTED]

22 [REDACTED] 219

23 [REDACTED]

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219 ** [REDACTED] **

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222 **

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8 [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

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.

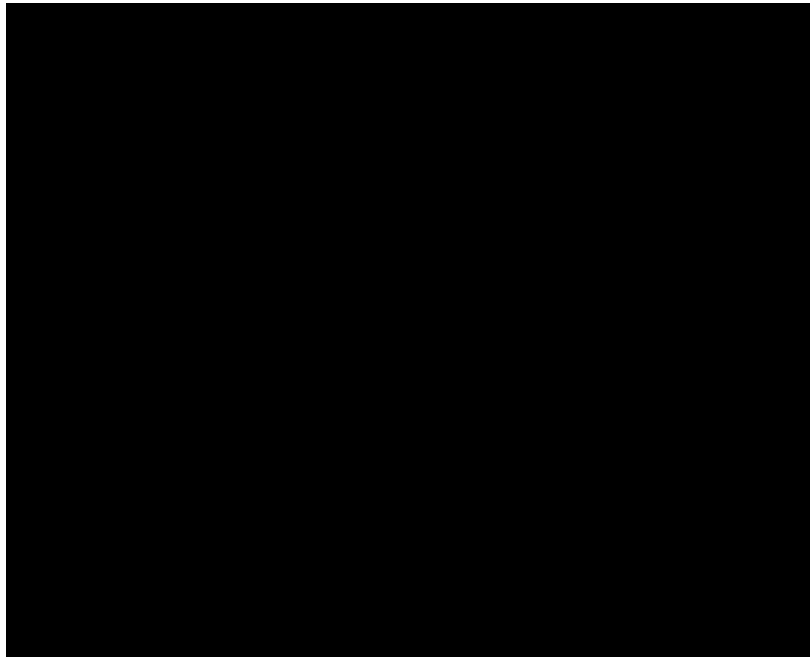
C. The value does not include any allowance for RES compliance.

D. Please see part “B” above.

²²⁵ Response to Data Request 79.

1 The selection of the horizon over which to reflect LLPS peak load has significant impact
2 on the rate calculated. The peak loads used in Evergy's modeling **. 
3 . ** While Evergy
4 does not specify the horizon over which peak load is to be considered, based on the design of the
5 rate calculation, it would appear that either the required four year FAC rate case intervals, or a
6 10 year outlook could effectuate Evergy's apparent intent.²²⁶ These calculations each produce
7 rates different than those used in the Evergy CCOS studies submitted in this case, and result in a
8 21% difference in annual revenue between EMM calculations, and a 34% difference in annual
9 revenue between EMW calculations.

10 **



11
12 **

13 However, in that Evergy reserves the apparently unilateral right to discontinue the
14 application of the acceleration component of the SSR charge, and because the capacity to which
15 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	)	Case No. <u>EO-2025-0154</u>
and Evergy Missouri West, Inc. d/b/a	)	
Evergy Missouri West for Approval of	)	
New and Modified Tariffs for Service to	)	
Large Load Customers	)	

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.

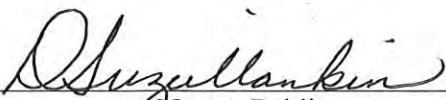
Further the Affiant sayeth not.


AMANDA ARANDIA

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.




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.

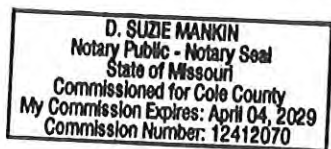
Further the Affiant sayeth not.

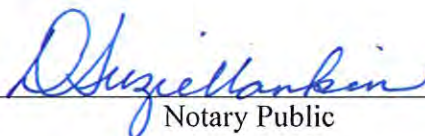


CLAIRE M. EUBANKS, PE

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.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

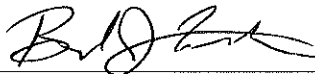
In the Matter of the Application of Evergy)
Metro, Inc. d/b/a Evergy Missouri Metro) Case No. EO-2025-0154
and Evergy Missouri West, Inc. d/b/a)
Evergy Missouri West for Approval of)
New and Modified Tariffs for Service to)
Large Load Customers)

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.

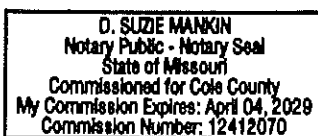
Further the Affiant sayeth not.

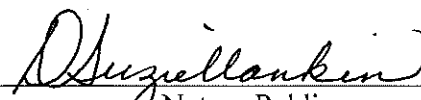


BRAD J. FORTSON

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.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

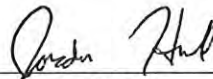
In the Matter of the Application of Evergy	)	
Metro, Inc. d/b/a Evergy Missouri Metro	)	<u>Case No. EO-2025-0154</u>
and Evergy Missouri West, Inc. d/b/a	)	
Evergy Missouri West for Approval of	)	
New and Modified Tariffs for Service to	)	
Large Load Customers	)	

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.

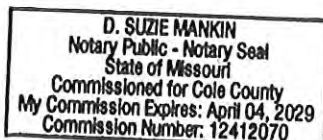
Further the Affiant sayeth not.

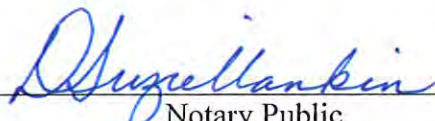


JORDAN T. HULL

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.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

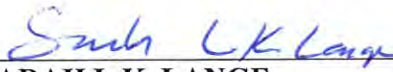
In the Matter of the Application of Evergy)	
Metro, Inc. d/b/a Evergy Missouri Metro)	<u>Case No. EO-2025-0154</u>
and Evergy Missouri West, Inc. d/b/a)	
Evergy Missouri West for Approval of)	
New and Modified Tariffs for Service to)	
Large Load Customers)	

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.

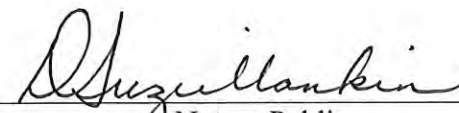


SARAH L.K. LANGE

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.





Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

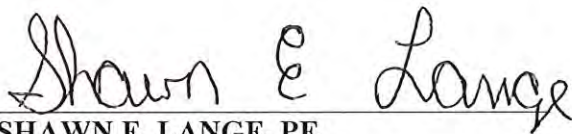
In the Matter of the Application of Evergy)
Metro, Inc. d/b/a Evergy Missouri Metro) Case No. EO-2025-0154
and Evergy Missouri West, Inc. d/b/a)
Evergy Missouri West for Approval of)
New and Modified Tariffs for Service to)
Large Load Customers)

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.

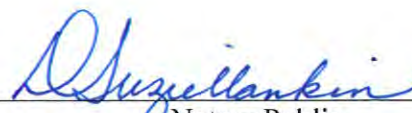
Further the Affiant sayeth not.


SHAWN E. LANGE, 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.




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 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.

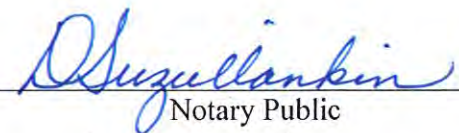
J LUEBBERT



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.





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)
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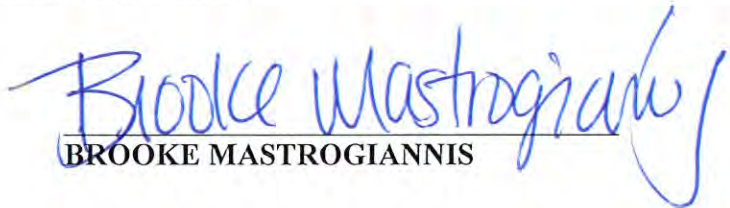
Case No. EO-2025-0154

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.

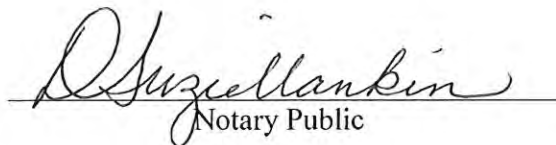
Further the Affiant sayeth not.


BROOKE MASTROGIANNIS

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.




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	)	<u>Case No. EO-2025-0154</u>
and Evergy Missouri West, Inc. d/b/a	)	
Evergy Missouri West for Approval of	)	
New and Modified Tariffs for Service to	)	
Large Load Customers	)	

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.

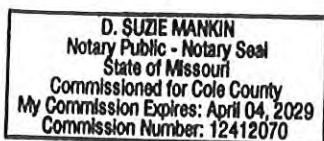
Further the Affiant sayeth not.



BRODRICK NIEMEIER

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.





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 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.

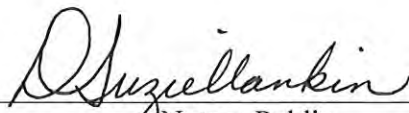


MICHAEL L. STAHLMAN

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.





Notary Public